Entergy

Entergy Nuclear Northeast
Indian Point Energy Center
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Fred Dacimo
Site Vice President
Administration

June 16, 2004

Re: Indian Point Unit No. 2
Docket No. 50-247
NL-04-073

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

SUBJECT: **Reply to Request for Additional Information Regarding Indian Point 2 Stretch Power Uprate (TAC MC1865)**

References:
1. NRC letter to Entergy Nuclear Operations, Inc; "Request for Additional Information Regarding Stretch Power Uprate", dated May 14, 2004.
2. Entergy letter to NRC (NL-04-005); "Proposed Changes to Technical Specifications: Stretch Power Uprate Increase of Licensed Thermal Power (3.26%)", dated January 29, 2004.

Dear Sir:

This letter provides additional information, requested by the NRC in Reference 1, regarding the license amendment request submitted by Entergy Nuclear Operations, Inc (Entergy), in Reference 2.

The responses to questions are provided in Attachment I, with the exception of selected responses that contain proprietary information. The proprietary and non-proprietary versions of the affected responses are provided in Attachments II and III, respectively.

The Westinghouse authorization letter, regarding proprietary information (CAW-04-1850, dated June 11, 2004), with the accompanying affidavit, Proprietary Information Notice, and Copyright Notice, is enclosed. As Attachment II 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 2.790 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 2.790 of the Commission's regulations.

Correspondence with respect to the copyright on proprietary aspects of the items listed

AP01

above or the supporting affidavit should reference CAW-04-1850 and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company, P. O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

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 6/16/2004.

Sincerely,

Fred R. Dacimo
Site Vice President
Indian Point Energy Center

Enclosure: Westinghouse Application for Withholding

Attachments:
I. Replys to Request for Additional Information
II. Replys to RAIs Containing Proprietary Information; Proprietary Version
III. Replys to RAIs Containing Proprietary Information; Non-Proprietary Version

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. Att.)
Regional Administrator
Region I
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475 Allendale Road
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Resident Inspector's Office (w/o prop. Att.)
Indian Point Unit 2
U.S. Nuclear Regulatory Commission
P.O. Box 59
Buchanan, NY 10511

Mr. William M. Flynn (w/o prop. Att)
New York State Energy, Research and Development Authority
Corporate Plaza West
286 Washington Avenue Extension
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Mr. Paul Eddy (w/o prop. Att)
New York State Dept. of Public Service
3 Empire Plaza
Albany, NY 12223

ENCLOSURE TO NL-04-073

Westinghouse authorization letter dated June 11, 2004 (CAW-04-1850), with the accompanying affidavit, Proprietary Information Notice, and Copyright Notice

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 2
DOCKET NO. 50-247

Westinghouse

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Nuclear Services
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USA

U.S. Nuclear Regulatory Commission
Document Control Desk
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Our ref: CAW-04-1850

June 11, 2004

APPLICATION FOR WITHHOLDING PROPRIETARY
INFORMATION FROM PUBLIC DISCLOSURE

Subject: Westinghouse Transmittal PU2-W-04-024 (IPP-04-84), Indian Point Nuclear Generating Unit No. 2 Stretch Power Uprate Project, Westinghouse Responses to 5/14/04 NRC RAIs, June 11, 2004.

The proprietary information for which withholding is being requested in the above-referenced report is further identified in Affidavit CAW-04-1850 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-04-1850, and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P.O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

Very truly yours,

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

Enclosures

cc: W. Macon
E. Peyton

bcc: J. A. Gresham (ECE 4-7A) 1L
R. Bastien, 1L, 1A (Nivelles, Belgium)
C. Brinkman, 1L, 1A (Westinghouse Electric Co., 12300 Twinbrook Parkway, Suite 330, Rockville, MD 20852)
RCPL Administrative Aide (ECE 4-7A) 1L, 1A (letter and affidavit only)
S. Ira (WM F2D7) 1L, 1A
R. Laubham (ECE 419F) 1L, 1A
T. Timmons (ECE 406F) 1L, 1A
T. Gerlowski (ECE 413C) 1L, 1A
J. Stukus (ECE 419G) 1L, 1A
D. Morris (ENN) 1L, 1A
C. Jackson (ENN 1L, 1A
K. Kingsley (ENN) 1L, 1A
W. Wittich (ENN) 1L, 1A
J. Curry (ENN) 1L, 1A
J. Jawor (ENN) 1L, 1A

CAW-04-1850

AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA:

ss

COUNTY OF ALLEGHENY:

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

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

PATRICIA L. CROWN
COMMONWEALTH OF PENNSYLVANIA
NOTARY PUBLIC

Sworn to and subscribed
before me this 11th 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 Attachment A to PU2-W-04-024, "Indian Point Nuclear Generating Unit No. 2 Stretch Power Uprate Westinghouse Responses to 5/14/04 NRC RAIs" (Proprietary) dated June 11, 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.

PROPRIETARY INFORMATION NOTICE

Transmitted herewith are proprietary and/or non-proprietary versions of documents furnished to the NRC in connection with requests for generic and/or plant-specific review and approval.

In order to conform to the requirements of 10 CFR 2.390 of the Commission's regulations concerning the protection of proprietary information so submitted to the NRC, the information which is proprietary in the proprietary versions is contained within brackets, and where the proprietary information has been deleted in the non-proprietary versions, only the brackets remain (the information that was contained within the brackets in the proprietary versions having been deleted). The justification for claiming the information so designated as proprietary is indicated in both versions by means of lower case letters (a) through (f) located as a superscript immediately following the brackets enclosing each item of information being identified as proprietary or in the margin opposite such information. These lower case letters refer to the types of information Westinghouse customarily holds in confidence identified in Sections (4)(ii)(a) through (4)(ii)(f) of the affidavit accompanying this transmittal pursuant to 10 CFR 2.390(b)(1).

ATTACHMENT I TO NL-04-073

REPLY TO NRC REQUEST FOR ADDITIONAL INFORMATION REGARDING PROPOSED LICENSE AMENDMENT REQUEST FOR INDIAN POINT 2 STRETCH POWER UPRATE

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 2
DOCKET NO. 50-247

Fire Protection RAIs

Question 1:

In NRR RS-001, Revision 0, "Review Standard for Extended Power Uprates," Attachment 2 to Matrix 5, "Supplemental Fire Protection Review Criteria," states that "... power uprates typically result in increases in decay heat generation following plant trips. These increases in decay heat usually do not affect the elements of a fire protection program related to (1) administrative controls, (2) fire suppression and detection systems, (3) fire barriers, (4) fire protection responsibilities of plant personnel, and (5) procedures and resources necessary for the repair of systems required to achieve and maintain cold shutdown. In addition, an increase in decay heat will usually not result in an increase in the potential for a radiological release resulting from a fire. However, the licensee's application should confirm that these elements are not impacted by the extended power uprate..."

Section 10.1, "Fire Protection (10CFR50 Appendix R) Program," of application report (Attachment III to the January 29 letter) does not address these items. At a minimum, provide a statement to address each of these items.

Response:

IP-2 SPU results in increase decay heat generation following plant trips. The RHR Cooldown Analysis for SPU, documents cold shutdown is achieved and maintained within 72 hours. It should be noted that the subject analysis includes a specific "Appendix R" cooldown case that uses only the limited equipment set credited in the IP2 Appendix R Safe-Shutdown Model. The updated cooldown analysis addressing SPU confirms that cold shutdown can be achieved and maintained using this same limited equipment set, inclusive of the additional burden associated with SPU. Appendix R program administrative controls are unchanged. The elements of the program such as Fire Suppression; Fire Barriers; Fire protection responsibilities of plant personnel are unchanged. Procedures and resources necessary for the repair of systems required to achieve and maintain cold shutdown are unaffected and the radiological release resulting from a fire is also unchanged.

Question 2:

In NRR RS-001, Attachment 2 to Matrix 5, states that "... where licensees rely on less than full capability systems for fire events..., the licensee should provide specific analyses for fire events that demonstrate that (1) fuel integrity is maintained by demonstrating that the fuel design limits are not exceeded and (2) there are no adverse consequences on the reactor pressure vessel integrity or the attached piping. Plants that rely on alternative/dedicated or backup shutdown capability for post-fire safe shutdown should analyze the impact of the power uprate on the alternative/dedicated or backup shutdown capability ... The licensee should identify the impact of the power uprate on the plant's post-fire safe shutdown procedures."

Section 10.1, of application report does not address the items above. As a minimum, provide a statement to address each of these items.

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Response:

The evaluation of the IP2 Fire Protection Program was conducted to determine the effect of SPU on the program. There are no modifications required by the SPU to the plant equipment used for post-fire safe shutdown. There are minor changes required for the procedures. The procedures are capable of being used to achieve post-fire safe shutdown as shown by the response to item FP-3b and as noted in sections 6.9 and 4.1.3 of the IP2 SPU Licensing Report.

Additional detail is provided in the response to question 3c.

Question 3:

Section 10.1 of Attachment III (WCAP-16157-P) to the License Amendment Request, states that "for the SPU, the steam generator dryout time provides adequate time for the operator to supply feedwater to the secondary side of the steam generator. The Appendix R plant cooldown analysis under SPU conditions shows that IP2 complies with the Appendix R requirement that cold shutdown be achieved within 72 hours after reactor trip following a fire."

a. Provide a discussion, including numerical values, of the change, if any, in steam generator dry-out time as a result of the SPU, and reference to the calculations performed to determine there is adequate time for the required operator action.

b. Provide a discussion, including numerical values, of the change, if any, in time to achieve cold shutdown as a result of the SPU, and reference to the calculations performed to determine that it can be achieved within the required time frame.

c. Provide corresponding references, including appropriate extracts from the Updated Final Safety Analysis Report (UFSAR), plant-specific Appendix R evaluation, etc., that justify these claims.

Response 3a:

The Indian Point Fire Protection Program Plan references a steam generator dryout time of approximately 35 minutes based on generic evaluations performed in NUREG-0611. For the Stretch Power Uprate, the steam generator dry out time was predicted using the RETRAN code and an IP2 plant-specific calculation. The initiating event was a Loss of all AC Power to the Station Auxiliaries. The analysis conservatively assumed an initial power level of 102% of 3216 MWt and a minimum initial SG level of 42%. Decay heat was based on the 1979 version of ANS 5.1 and includes a 2-sigma uncertainty. The results of this analysis showed that the steam generators would boil dry after approximately 43 minutes.

To assure continued natural circulation and removal of decay heat by steaming to the atmosphere, auxiliary feedwater should be injected prior to the steam generator dryout. This ability was demonstrated by timed field walkdowns, which showed that auxiliary feedwater could be injected well within 30 minutes.

Fire Protection RAIs

Response 3b:

For purposes of Appendix R cooldown analysis, the natural circulation cooling analysis discussed in Section 6.9 of WCAP-16157-P documents the analysis of cooldown from normal operating temperature (NOT) to RHR cooldown initiation conditions at 350°F. The RHR cooldown analysis for Appendix R conditions is discussed in Section 4.1.3 of WCAP-16157-P and documents the cooldown from the RHR cooldown initiation to achieving cold shutdown with in the Appendix R requirement of 72 hours.

Natural Circulation Cooling Analysis (NOT to 350°F)

To demonstrate that the stretch power uprate (SPU) does not adversely affect the natural circulation cooling capability of the IP2 plant, an analysis simulation was performed. In addition to supporting the technical basis for the EOPs, this simulation demonstrated 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 power-operated relief valves (steam generator ARVs) does not limit the capability to cooldown to RHR cut-in conditions (350°F), and
- RHR can be placed in service prior to depletion of the Technical Specification volume in the condensate storage tank (CST) (360,000 gallons).

The IP2 plant EOPs, which are based on the ERGs, were followed in performing the natural circulation cooling analysis simulation. This analysis was 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, 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.

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 as follows:

- Hot-leg/core exit temperature = 593°F
- Hot-to-cold leg ΔT = 37°F
- Cold-leg temperature = 556°F
- Core flow rate $\cong 6.1 \times 10^6$ 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 setpoint (1080 psia, T_{sat} = 554°F). Soon after reactor trip, the operator would control this temperature to no-load

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(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 9°F. The above hot-leg/vessel-outlet temperature is approximately 13°F less than the maximum Performance Capability Working Group (PCWG) temperature of 605.8°F (see Table 2.1-2 in Attachment III to the LAR). 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.

It was determined that the capacities of the steam generator ARVs did not restrict the cooldown capability of the RCS. After borating to cold-shutdown boron concentration, the cooldown was simulated by controlling the pressure setpoints for the four steam generator ARVs. At approximately 15.6 hours after reactor trip, the RCS hot-leg and cold-leg temperatures had reached 346°F and 320°F, respectively, conditions that would allow the RHR to be placed in service once the RCS is depressurized. Based on saturated critical flow from the four SG ARVs, the cooldown could be maintained at the assumed 20°F/hr rate with the valves slightly less than full open (~93 percent calculated).

The simulation was then extended to include the 8-hour upper-head soak, followed by depressurization and stabilization at RHR entry conditions. At the end of the 27-hour transient, the RCS pressure was stabilized at 375 psia (360 psig), T_{hot} = 339°F in all hot legs and at the core exit, and T_{cold} = 318°F in the cold legs. At that time, approximately 128 gpm of auxiliary feedwater was being used to remove decay heat (approximately 20.9 MWt, or ~0.64 percent of full power).

RHR Cooling Analysis (350°F to 200°F)

The SPU Program 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 Program. 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 SPU conditions.

The following considerations were applied to the SPU cooldown analysis:

- The CCW and RHR heat exchanger data assumes 5-percent tube plugging, as was used for the previous cooldown analyses of record.
- One train of RHR cooling and two CCW heat exchangers were assumed in the Appendix R analysis.
- Various CCW system auxiliary heat loads and the RCS heat capacity were included in the Appendix R plant cooldown cases. These heat loads, along with an increase in the spent fuel pit (SFP) heat load (assuming a full SFP of fuel that has operated at 3216 MWt) were used in the cooldown analysis. For Appendix R case 2, no SFP heat loads were assumed.
- Decay heat curves based on 24-month fuel cycles were used.
- Service water flow rates for Appendix R cooldown were varied to minimize service water flow demand while meeting the Appendix R criteria as shown in this RAI response as Table FP-1.

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- Service water supply temperature of 95°F and the CCW supply temperature of 125°F were used for the Appendix R cooldown calculation.

The Appendix R cases had a 72-hour time limit for cooldown. For these cases, the minimum CCW heat exchanger service water flow to meet the 72-hour cooldown time limit was determined. In the case considering the SFP heat load (Appendix R, Case 1) the required service water flow rate is 1.510 Mlb/hr or about 3033 gpm per CCW heat exchanger (6066 gpm total). In the case of assuming the SFP heat load is isolated (Appendix R Case 2), the required service water flow is 1.100 Mlb/hr or about 2210 gpm per CCW heat exchanger (4420 gpm total).

Table FP-1
SPU Cooldown Analyses Results

Case	RHR Cut-in Time (hours after shutdown (ASD))	Time to Cooldown (hours ASD)	Time to Cooldown in 1.4% MUR Analysis (hours ASD)
1. Normal Cooldown with CCW Auxiliary Heat Loads	20.0	113.6 (~48 hours to 200°F)	101.1 (33 hours to 200°F)
2. Appendix R Cooldown Case 1 includes the SFP heat exchanger heat load Case 2 assumes that the SFP heat load is isolated	28.0(1) 30.0(1)	71.9 (SW flow = 1.510 Mlb/hr) 71.9 (SW flow = 1.100 Mlb/hr)	70.9

Note: 1. For Appendix R cooldown, this is the required RHR cut-in time.

Appendix R Cooldown analysis demonstrates that IP2 can be cooled from the normal operating temperature to the RHR initiation conditions using a natural circulation cooling process in 27 hours and from the RHR initiation condition to cold shutdown within the requirement of 72 hours.

Response 3c:

The Indian Point Unit 2 Fire Protection Program Plan, referenced in the FSAR, details the functions of the IP2 Alternate Safe Shutdown System (ASSS) as:

- Provide the necessary shutdown functions for a fire that damages the capacity to power and control equipment from IP-2 sources.
- Provide the capability to perform only selected safe shutdown functions where these have been lost due to a fire.
- Satisfy the performance requirements of section III.L of 10CFR50, Appendix R; and

Fire Protection RAIs

- Provide the capability to perform the above shutdown functions independent of fire zones that, if involved in a fire, would require the use of the ASSS.

The ASSS provides the capability to perform the following critical safety functions: reactor subcriticality, core cooling for hot shutdown (through natural circulation, and primary system pressure and inventory control), reactor coolant system integrity, secondary heat removal for hot shutdown, long term decay heat removal, and process monitoring.

Following the unlikely loss of normal and preferred alternate power, additional independent and separate power supplies from the IP-1 440-V switchgear are provided through the ASSS for a number of safe shutdown components. The Unit 1 440-V switchgear is supplied from the Buchanan 13.8-kV system through separate transformers. These can also be powered from an onsite gas turbine generator; an alternate onsite AC power source that is credited in the Appendix R safe-shutdown model and methodology.

Independent power supplies from IP-1 auxiliaries are hardwired to manually operated transfer switches to power one train of the following safe shutdown components to maintain the ASSS safe shutdown functions mentioned above:

1. Component cooling pump 23
2. Auxiliary boiler feed pump 21
3. Service water pump 23
4. Service water pump 24
5. Charging pump 23
6. RHR pump 21 or SI pump 21 (through use of casualty cables)
7. Safe-shutdown process monitoring instrumentation.

The ASSS is designed to function given a loss of off-site power. The system will also properly function if off-site power is available.

Long term decay heat removal capability is provided so that heat due to decay of fission products can be removed for at least the 72 hour time period required by Appendix R, and to provide the capability to cool down below hot shutdown and achieve cold shutdown conditions within that 72 hour time period following reactor trip. Two major functions are required to accomplish this. These include operation of the RHR system to transfer core heat to the RHR heat exchangers, and operation of the CCW and service water systems to transfer heat to the river water.

Following postulated plant fires, the capability to cooldown to cold shutdown via the RHR heat exchangers is needed to meet 10CRF50 Appendix R requirements.

The IP-2 SPU evaluation has resulted in no modifications to any ASSS equipment or procedures.

Electrical RAIs

Question 1:

Address the compensatory measures that the licensee would take to compensate for the depletion of the nuclear unit megavolt-ampere reactive (MVAR) capability on a grid-wide basis.

Response:

Indian Point 2 is connected to the Con Edison electrical transmission system that is operated under the rules of the New York Independent System Operator (NYISO). The NYISO has reviewed and approved the MVAR capability of IP2 at SPU conditions. Any "depletion" of MVAR capability on a grid-wide basis would be addressed by the NYISO requesting units connected to the transmission system to increase VARS (either lagging or leading). Once the maximum VAR capability of the units connected to the system has been reached, the NYISO has the authority to order reduction in power to achieve the needed VARS. Indian Point 2 is obligated to respond to such a request.

The committed reactive MVAR provided to the grid is based on an annual test. The MVAR values attained during the testing have not been limited by the generator nor main transformers MVA ratings, but are impacted by grid conditions. At uprate conditions, at the increased MW load, the reactive MVAR loading is still within the generator and main transformers capability/rating. The isophase bus duct that connects the generator to the main transformers will be modified and upgraded to handle the increased load current at uprate conditions without restriction or limitation.

As the equipment ratings support the operation at the uprate conditions, any change in the committed reactive MVAR provided to the grid would change primarily based on the grid conditions during the annual testing. NYISO approval of the SPU did not require any compensatory measures.

Instrumentation and Controls RAIs

Question 1:

Item 5 (Instrumentation & Controls) of Attachment III to the April 12 letter indicates that Allowable Values (AVs) are determined by a methodology based upon Method 2 of Instrument Society of America (ISA) Standard 67.04.02. Section 5.12.1 (page 60) of Entergy Specification FIX-95-001, Revision 1, clearly shows that an AV is computed from Limiting Setpoint (LSP), not directly from Analytical Limit (AL). Since the computation appears to match Method 3 rather than Method 2, explain this apparent difference. In addition, the NRC staff has not accepted the Entergy Specification FIX-95-001, Revision 1, methodology during its review of Amendment No. 238 dated November 21, 2003 (IP2 Improved Technical Specification conversion), which method has been used to determine the AVs for stretch power uprate application?

Response:

The IP2 Allowable Values have been calculated in accordance with Section 5.12.1 and 5.12.2 of FIX-95-A-001, Rev. 1. The Channel Statistical Allowance (Channel Uncertainty) of each instrument loop with Allowable Value changes in the power uprate submittal was calculated using the Westinghouse Methodology given in Appendix A of FIX-95-A-001. Therefore the Alternate Method described in Section 5.12.2 was used.

These sections describe the use of a method that is similar to ISA-RP67.04 Part II Method 3 with a modification. The check calculation is always required. Per ISA-RP67.04 Part II the Check Calculation is used "if the allowance is not determined in a method that is consistent with the method used for determination of the setpoint." In the case of IP2 the method for the trip setpoint and the AV are consistent (both use SRSS), therefore the use of Check Calculation per Method 3 would be unnecessary.

FIX-95-A-001 Section 5.12.1 and 5.12.2 contain the statement:
"Assure when $\sqrt{PMA^2 + PEA^2 + STE^2 + RTE^2 + SPE^2} + BIAS$ are applied to Analytical Value, the calculated value does not infringe on the Allowable Value. If it does, add more conservatism to Allowable Value." PMA= Process Measurement Accuracy, PEA=Process Element Accuracy, STE= Sensor Temperature Accuracy, RTE=Rack Temperature Accuracy, SPE=Sensor Pressure Effects, BIAS= Biases including environmental effects.

When the Check Calculation is a combination of "non-calibration" errors that is applied in the direction of the setpoint from the Analytical Limit, this is the same as the Allowable Value calculation for Method 2; "calculating the instrument uncertainty without including those items identified previously in 7.3 (drift, calibration uncertainties observed during normal operations)."

The Allowable Value calculations themselves contain an Allowable Value calculation by Method 3 and by Check Calculation. In every case the Check Calculation results have been more conservative. In every case the Check Calculation result has been chosen as the Allowable Value. Therefore, in practice, ISA-RP67.04 Part II Method 2 has been applied to all Allowable Values submitted for the IP2 Power Uprate for those parameters with Analytical Limits.

The Allowable Value calculations submitted for the IP2 SPU have been reviewed. For each AV being changed, the Allowable Value has been computed from the Analytical Limit and the of the

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terms from the Channel Uncertainty equation that are required for the Check Calculation in FIX-95-A-001, Revision 1 have been included.

Question 2:

Explain how the component test procedure acceptance criteria are determined, and how the criteria provide adequate assurance that the channel AVs are suitably protected. In addition, explain how this approach meets the requirements of 10 CFR 50.36, which requires that the limiting safety system settings be specified in the Technical Specifications (TSs). Since channel performance is not assessed against the TS AVs unless some other criterion indicates that closer examination is warranted, those other criteria, which are not controlled by the TSs, can result in the TS criteria not being applied.

Response:

The component test procedure acceptance criterion is the "As Found" tolerance. According to FIX-95-A-001, Rev. 1 Section 5.8.17, the "As Found" Tolerance is composed of component or string uncertainty terms associated with calibration CU_{CAL} and is calculated as follows.

$$A/F = \pm\sqrt{RA^2 + D^2 + A/L^2 + MTE^2}$$

RA=Reference Accuracy (0 if historical drift is used)

D = Drift A/L= As Left tolerance MTE=Measuring and Test Equipment

When a test fails its "As Found" criteria this triggers an evaluation of the entire loop to determine if the Allowable Value has been exceeded. In practice the "As Found" tolerance is usually significantly less than the "As Found" allowance in FIX-95-A-001. This is the case because most test criteria were developed prior to the issuance of Revision 1.

Testing and calibration of transmitter and rack components typically occurs in two different surveillance tests. The transmitter is tested as a lone component and the rack is tested as a string, that is, the bistable actuation data is taken from a DVM placed on a test point prior to the first component in the rack. There are a few exceptions where the instrument loops are broken into as many as 4 surveillance tests. These tests are not done at the same time and are usually done at different intervals; for example, transmitters are calibrated on a refueling basis and the rack components up to and including the bistable are tested quarterly or semiannually. It is this diverse scheduling condition that precludes the possibility of directly exercising any Allowable Value that is a true 'Loop Allowable Value' as licensed for IP2. Therefore, when one test is done, the state of the remainder of the loop is assumed to be within its acceptance band based on previous acceptable As-Left conditions. This condition will be re-evaluated if the part of the loop under test fails its As-found allowance to a degree that depletes the total positive margin included in the implemented trip setpoint. If margin is found to still exist for the particular UNSAT As-Found condition, then the Loop Allowable Value is considered to be still protected based on the previous acceptable condition for the part of the loop not being tested. The component or string that failed the As-Left tolerance will be evaluated under the Performance Monitoring Program relative to its present and previous performance data. The component or

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components involved in the test UNSAT condition will be either replaced or included in the program's degraded components watch list.

Since ISA-RP67.04 Method 2 establishes the Allowable Value without regard to the magnitude of CU_{CAL}, the "As Found" tolerance for a component or string theoretically could exceed the Allowable Value. Were this to be the case, the component or string could be found beyond the Allowable Value and no Condition Report would be initiated for further evaluation. The setpoints, corresponding "As Found" values, and Allowable Values have been reviewed for each parameter in the IP2 SPU submittal. No component or string in the IP2 SPU submittal has an "As Found" tolerance that exceeds the Allowable Value.

Since the "As-Found " tolerance is composed of CU_{CAL} terms (sensible) only, no terms of the Method 2 Allowable Value (unsensible CU_{NONCAL} terms) are imbedded in it. It is this specific difference, i.e. testing to sensible terms and declaring operability based on non-sensible terms that creates a higher (than necessary in our judgment) potential for INOPERABLE declarations.

For any acceptable As-Found surveillance results to protect a Method 2 Allowable Value with 95/95 certainty the distance between the Trip Setpoint and the Method 2 Allowable Value would have to be equal to or greater than CU_{CAL} since this value is the distance to a less restrictive Method 3 Allowable Value which is based on only the sensible conditions that we deal with in the surveillances. Doing this is equivalent to an ISA RP67.04 Method 1 Setpoint and Allowable Value determination, which provides the least operating margin of all ISA methods.

The NRC has endorsed the use of Method 2, which is more conservative than Method 3, which is under review. In the IP2 implementation of Method 2, the LSSS is protected because when a component or string under test is found to perform outside of its uncertainty expectations by more than available setpoint margin, an investigation into the uncertainty condition of the rest of the loop will be performed. When completed, this investigation will provide a reliable assessment of the operability of the loop.

Question 3:

The description of the determination of operability in Item 5 of Attachment III refers to the consideration of "actual" errors. Because measurement and test equipment (M&TE) is not perfect and the performance of test procedures is often influenced by setting or reading tolerances and by noise or other inherent errors, the exact magnitude of "actual" errors cannot be determined. At best, device errors can only be statistically bounded. Uncertainty in the assessment of the measurement error introduced by a device is often not insignificant when compared with the uncertainty in the device itself. Some procedures allow the M&TE uncertainty to be as large as 25% or more of the composite uncertainty of the device(s) being tested. Therefore, explain what is meant by the consideration of "actual" errors, and describe how these errors are determined and how they are used in the referenced analyses.

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Response:

It is recognized that the exact errors cannot be determined and can only be statistically bounded. The "actual" errors referred to in Item 5, Attachment III are measurements performed on components other than the component that failed. If measured data is needed to complete an operability analysis, this data is usually collected utilizing the calibration surveillance procedure.

The collection of measured data is included in the analysis of channel error to determine if the entire loop met the Allowable Value. At this point all terms are combined algebraically to determine operability as opposed to combined statistically to predict total uncertainty. If the Allowable Value has been exceeded, then the instrument loop is determined to have been inoperable.

Question 4:

Provide setpoint calculation documents for the following protection system trip functions listed in Table 6.10-1 of application report:

- Overtemperature delta-T Reactor Trip and Overpower delta-T Reactor Trip functions.
- Reactor Coolant System (RCS) Flow Low Reactor Trip function.
- Steam Generator Water Level-Low-Low Reactor Trip function.
- Steam Generator Water Level-High-High Feedwater Isolation function.
- Steamline Pressure Low (safety injection/steamline [SI/SL] actuation).
- Steam Flow in Two Steamline-High (SI/SL actuation)
- T_{avg}-Low (SI/SL actuation).

Response:

The response this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments II and III, respectively.

Question 5:

In Table 2, "Cross-Map of Technical Specification Changes to WCAP-16157-P Analyses," of Attachment I to April 12 letter, the comments on Function 9, "Reactor Coolant Flow - low," and Function 13, "Steam Generator water level - low-low," stated that "since one of the non-tested uncertainties (process measurement accuracy) changed slightly for the SPU, a revised allowable value was calculated." Provide a further explanation of the uncertainty and the revised value.

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Response:

The response this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments II and III, respectively.

Question 6:

In Attachment III to April 12, Item 6, "RTD [resistance temperature detector] Replacement Project," stated, in part, that each RCS hot leg and cold leg has three narrow-range RTDs, the existing direct-immersion RTDs will be removed, and new well-mounted dual-element RTDs will be inserted into two of the three thermowells. The third thermowell will be capped for future use. Because these RTDs provide inputs to the protection system, provide additional detailed information of the RTD design modification and the supporting safety analyses for the modification.

Response:

The license amendment request for stretch power uprate does not include a request for NRC approval of the RTD replacement project because Entergy has determined that this modification can be implemented under the 10 CFR 50.59 program. The new RTD configuration will provide the same functional inputs and channelization as provided by the existing RTDs. The existing design consists of three direct-immersion RTDs in the four hot legs and the four cold legs, for a total of 24 RTDs. One hot leg and one cold leg RTD in each loop is used for measuring Tavg and delta-T. The other two RTD pairs in each loop are installed spares. The modification being installed during the Fall 2004 refueling outage will replace the 24 existing direct immersion RTDs with 32 RTDs mounted in new thermowells. The configuration for these 32 RTDs is two dual-element RTDs installed in each of the four hot legs and four cold legs. As with the existing design, one hot leg and one cold leg RTD is each loop is used for measuring Tavg and delta-T. The remaining RTDs are spares. The existing RTDs and associated cabling are not environmentally qualified (EQ). The modification will provide for RTDs and cabling that do meet EQ requirements. In addition, since the new RTDs will be thermowell mounted, instead of direct immersion, new time constants will be used in these instrument loops to account for the change in response time.

Since the RTD modification is being implemented in conjunction with the SPU, the safety analyses and uncertainty calculations that were performed for the SPU use the design parameters for the new RTDs. Therefore, the setpoint calculations addressed by RAI #4 reflect the RTD replacement for the Overtemperature ΔT, Overpower ΔT, RCS Low Flow, and Low Tavg parameters.

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Question 7:

Provide a statement to clarify that no modification to exiting instrumentation and controls are required for the SPU, except for certain reactor trip system/engineered safety feature actuation system nominal trip setpoint and TS AV changes, and that the IP2 instrumentation and control systems will continue perform their intended safety functions.

Response:

The IP2 instrumentation and control systems will continue to perform their intended safety functions. Specifically, as identified in the LAR submittal, specific Reactor Trip and ESFAS nominal trip setpoints and TS AV changes will be implemented to support SPU power level conditions. However, in addition to these calibration/administrative changes, we are also implementing a modification to the Main Steamline Flow monitoring instrument channels.

SPU analysis of the limiting HFP MSLB event prompted a recommendation that the calibrated span of the Main Steam flow transmitters be increase from the current 4 million #/hr to 4.3 million #/hr. In conjunction with implementing this change, a qualified scaling module will be added to each of the 8 flow monitoring channels to ensure accurate tracking of steam flow conditions under both normal and accident conditions (resulting from the above steam line break event). The added scaling modules, which will receive their inputs from the recalibrated flow transmitters, will have a scaling factor chosen to replicate the existing 4 million #/hr span (for normal operation) while at the same time, accurately follow and propagate signal levels proportional to the new 4.3 million #/hr span (for accident mitigation purposes). The use of these scaling modules ensures continued support of intended safety functions while at the same time provides the benefit of being able to retain the existing scaling of all associated instrument systems such as SG Level Control and all Main Steam and Main Feedwater Flow indicators, recorders and computer inputs.

Pressure Vessel Materials RAIs

Question 1:

Table 5.1-3 of the application report indicates that all beltline materials will have Charpy upper-shelf energy (USE) greater than 50 ft-lbs. Paragraph IV.A.1.a of Appendix G to 10 CFR Part 50 requires the Charpy USE to be greater than 50 ft-lbs throughout the life of the vessel unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of Charpy USE will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code).

The reduction in Charpy USE from neutron irradiation may be calculated using methods described in Regulatory Guide (RG) 1.99, "Radiation Embrittlement of Reactor Vessel Material," Revision 2. This RG indicates that the reduction in Charpy USE should be determined from surveillance data when two or more credible surveillance data sets become available from the reactor. IP2 has Charpy test data from four surveillance capsules.

a. Provide the results of an evaluation of each IP2 surveillance material (Intermediate Shell Plate B-2002-1, Intermediate Shell Plate B-2002-2, Intermediate Shell Plate B-2002-3, and Intermediate Shell Axial Welds 2-042 A/C) to determine its percent drop in Charpy USE and projected USE value at the end of life (EOL) at the power uprate conditions using the methodology in RG 1.99, Revision 2, Section 2.2. Provide all surveillance data and analysis of the data.

b. If the projected Charpy USE value is less than 50 ft-lbs, provide an analysis in accordance with paragraph IV.A.1.a of Appendix G of 10 CFR Part 50. The analysis should be performed using the criteria and methodology in RG 1.161, "Evaluation of Reactor Pressure Vessels with Charpy Upper Shelf Energy less than 50 ft-lb," and Appendix K of Section XI of the ASME Code. The analysis should be performed at EOL including the effects of the power uprate for all materials with Charpy USE values less than 50 ft-lbs.

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Response 1a:

The measured % decrease in USE from the surveillance material tests were used to determine the Predicted % decrease in USE for the Intermediate Shell Plates B-2002-1, -,2 -3, and the Intermediated & Lower Shell Axial Welds. These measured values are documented in Table C-1 of WCAP-15629, Rev. 1. As a result, all predicted USE values at EOL remain above the 50 ft-lb screening criteria. The following table, Table 5.1-3 from WCAP-16157-P, provides the requested results.

Table PVM-1
Predicted 32 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[1] (ft-lb)	Projected USE Decrease (%)	Projected EOL USE (ft-lb)
Intermediate Shell Plate B-2002-1	0.19	0.772	70	20	56
Intermediate Shell Plate B-2002-2	0.17	0.772	73	21	58
Intermediate Shell Plate B-2002-3	0.25	0.772	74	32	50.3
Lower Shell Plate B-2003-1	0.20	0.772	71	27	52
Lower Shell Plate B-2003-2	0.19	0.772	88	27	61
Intermediate & Lower Shell Longitudinal Welds (Heat # W5214)	0.21	0.521	121	43	69
Intermediate to Lower Shell Girth Weld (Heat # 34B009)	0.19	0.772	82[2]	32	56

Notes:
1. These values were obtained from original test reports. Values reported in the NRC Database RVID2 are identical with exception to Intermediate Shell Plates B-2002-1, 2. RVID2 reported the initial USE as 76 and 75. This evaluation conservatively used the lower values of 70 and 73.
2. Value was obtained from the average of three impacts tests (71, 84, 90) at 10°F performed for the original material certification.

Response 1b:

Projected Charpy USE values for all plates and welds are greater than 50 ft-lbs as shown in Table 5.1-3 (above and in Attachment III to the LAR). Therefore, analysis in accordance with paragraph IV.A.1.a of Appendix G of 10CFR Part 50 is not applicable.

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Question 2:

Section 5.1.2.2 of the application report indicates the slight change in fluence due to the updated power distributions (the stretch power uprate fluence) also had no effect on the applicability date of the existing Pressure-Temperature (P-T) limit curves. The IP2 P-T curves are applicable for 25 effective full power years (EFPY) and are contained in WCAP-15629, Revision 1. The limiting material for establishing the IP2 P-T limit curves is the Intermediate Shell Plate B-2002-3 with an adjusted reference temperature (ART) at the 1/4 thickness (T) location at 25 EFPY of 195 °F, which was calculated using surveillance data in accordance with RG 1.99, Revision 2, Position 2.1.

Provide the ART at the 1/4 T location at 25 EFPY including the effect of the proposed power uprate. If the ART for the power uprate condition exceeds 195 °F, provide updated P-T limit curves. In addition, provide the values for neutron fluence at the 1/4 T location, 3/4 T location, and chemistry factor for plate B-2002-3.

Response:

The P-T Limit curves that IP2 is using are from WCAP-15629, Rev. 1. WCAP-15629, Rev.1 incorporated the SPU fluence prior to the SPU Project. As a result, the specific analysis performed for the SPU LAR only had to incorporate the effect of actual thermal & power history data from the additional operating cycles attained since the WCAP was originally issued. This effect was determined by calculating a new applicability date, *not new ART values*. Therefore, new ART values do not exist. The new applicability date was only 0.3 EFPY different, which Westinghouse determined to be negligible. Therefore, the IP2 EFPY value was left at 25 EFPY.

Question 3:

Note 1 of Table 5.9-3 of the application report references RG 1.99, Revision 2, to indicate the justification for a 1/5 thickness (T) defect for the outlet nozzle to shell weld based on the use of highly reliable non-destructive inspection techniques that assure the capability of detecting such a flaw and that the probability of detecting a flaw 0.50 inch into the base material of the nozzle inner radius is greater than 99.9%. Section 5.9.3.2 of the licensee's submittal indicates Welding Research Bulletin 175, "PVRC [Pressure Vessel Research Committee] Recommendations on Toughness Requirements for Ferritic Materials," provides procedures for considering postulated defect sizes smaller than 1/4 T. RG 1.99, Revision 2 does not discuss flaw size and reliability of non-destructive inspection.

a. Identify the references for the report that justifies the use of a 1/5 T defect for the outlet nozzle to shell weld. Identify whether the analysis satisfies the requirements of Article G-2220 of Section XI of the ASME Code.

b. Describe the non-destructive inspection technique which will be utilized to examine the nozzle inner radius at the outlet nozzle to shell region.

c. Provide the data and describe the analysis that the probability of detecting a flaw with a depth of 0.5-inch is greater than 99.9%.

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Response 3a:

The Reference (RG 1.99) identified in Note 1 of Table 5.9-3 of Attachment III to the LAR is incorrect. The correct Reference (Proceedings of ASME 2001 Pressure Vessels and Piping Conference, Atlanta, GA, "Technical Basis for Elimination of Reactor Vessel Nozzle Inner Radius Inspections", W. H. Bamford, et. al., July 2001.) was inadvertently deleted. This reference illustrates that the probability of detecting a flaw 0.5 inch into the base material of reactor vessel nozzle-to-shell weld or the inner radius is greater than 99.9%. For IP2, postulated flaws were based on past inspection procedures that ensured detection of such indications. Moreover, the original Appendix G calculation for IP2 also utilized a 1/5T defect for the outlet nozzle-to-shell weld. The completed analysis does satisfy the requirements of Article G-2220 of Section XI, Appendix G.

Response 3b:

The reactor vessel nozzle inside radius (RPVN1 – N8), are ASME Category B-D, Item B3.100. These locations require volumetric examination as per ASME Section XI 1989 Edition, no Addenda. Based on the excellent operating history of the Indian Point Unit 2 reactor vessel, as well as the reliability of UT examinations previously conducted, Entergy is adopting Code Case N-648-1 to perform a VT-1 visual examination in lieu of a volumetric exam for the Third 10-Year Interval, which ends in April 2006. Code Case N-648-1 was approved in Regulatory Guide 1.147 with a condition. Implementation of the Code Case, as approved in the Reg. Guide, entails performing a visual examination with enhanced magnification that has a resolution sensitivity to detect a one mil width wire or crack, utilizing the allowable flaw length criteria of Table IWB-3512-1 with limiting assumptions on the flaw aspect ratio.

Response 3c:

The probability of detection (POD) of a flaw in the reactor vessel nozzle inner radius is provided in the following reference: "Proceedings of ASME 2001 Pressure Vessels and Piping Conference, Atlanta, GA, "Technical Basis for Elimination of Reactor Vessel Nozzle Inner Radius Inspections", W. H. Bamford, et. al., July 2001". Based on Figure PVM-5 shown below, the probability of detection for a flaw with depth equal to 0.5 inch into the base metal is approximately 99.9%.

The following text, which describes the analysis, was taken directly from that document.

Nozzle Inner Radius Examination Capability from the Inside Surface

Regulatory Guide 1.150 stimulated improvement in examinations of the clad to base-metal interface. The same techniques have been used for more than 10 years for Nozzle inner radius examinations performed from the bore (PWR case). Capability demonstrations for the clad to base-metal interface have been conducted at the EPRI NDE Center since 1983. These demonstrations were performed primarily for the belt-line region. However, the same techniques are used for both the vessel belt-line and the nozzle from the inside surface.

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PDI Appendix VIII demonstrations were initiated in 1994, for Supplements 4 and 6. Vendors performing these PDI demonstrations found that few if any changes were required to achieve high success rates for the clad to base-metal interface, Supplement 4.

Five inspection vendors and more than 50 personnel have completed Appendix VIII Supplement 4, clad to base metal demonstrations. In this time no individual, even those who failed the test, failed to detect cracks larger than approximately 0.25 inch. Sizing capability was also very good. The mean sizing error was 0.12 inch RMS. Sizing errors for the lead personnel, who normally make acceptability decisions, were even better, at 0.08 inch RMS.

Figure PVM-5 depicts the expected rejection probability as a function of flaw size. Correct rejection probability considers the detection capability and the sizing capability for flaws. For example, as shown in Figure PVM-5, the probability of detecting and rejecting a flaw 0.25 inch into the base material is equal to or greater than 90%.

Examinations using modern technology have been performed industry-wide since 1989, and so these examinations have been compiled in Table PVM-2.

In addition to these examinations, some 2500 examinations have been completed using earlier technologies, with no indications ever being discovered.

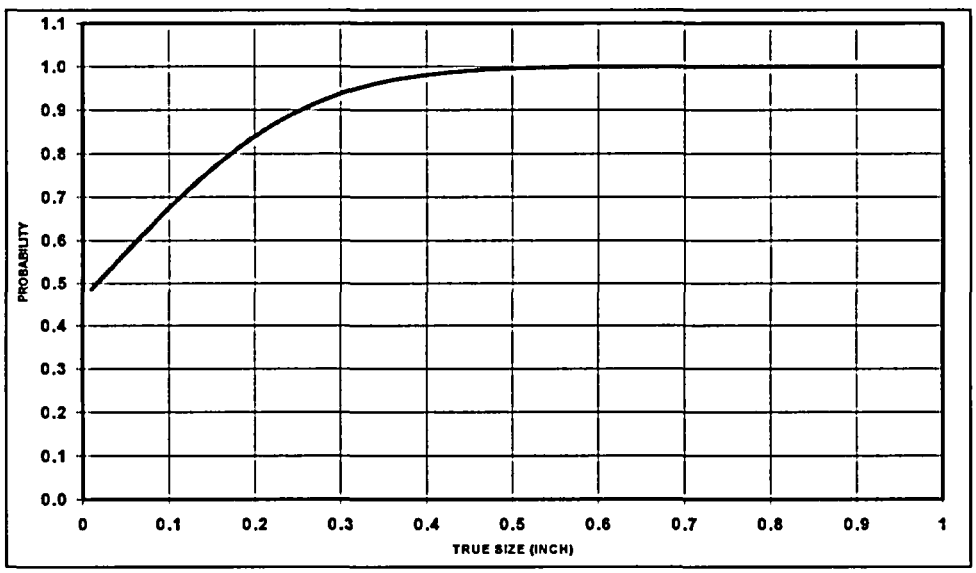

Figure PVM-5
Probability of Correct Rejection
Sizing, Std. Dev. = 0.12, Acceptable Flaw Size 0.15

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Table PVM-2. Inspection Results Using Modern Technology		
Inspection Agency	**Number of Nozzles Inspected**	**Indications**
Westinghouse	210	0
IHI – Southwest	196	0
Framatome Technologies	148	0
Total	554	0

Question 4:

Table 5.9-5 of the application report indicates a flaw depth of 0.50-inch for safety and relief nozzle (corner) and 0.15-inch for upper shell meet the fracture toughness requirements of Appendix G of the ASME Code (NOTE: Table 5.9-5 indicates K_I/K_{IR} is 0.94 for the safety and relief nozzle (corner) and 1.0 for the upper shell).

a. Describe the analysis that determined a 0.50-inch flaw depth for the safety and relief nozzle (corner) and a 0.15-inch flaw depth for the upper shell will meet the fracture toughness requirements of Appendix G of the ASME Code.

b. Identify whether the analysis satisfies the requirements of Article G-2220 of Section XI of the ASME Code. Does the analysis for the safety and relief nozzles and upper shell satisfy these structural factors?

c. Describe the non-destructive examination technique which will be utilized to inspect the safety and relief nozzles and upper shell.

d. Provide the data, a description of the analysis, and the probability of detection of flaws with a depth of 0.50-inch for the safety and relief nozzle and 0.15-inch for the upper shell.

Response 4a:

Safety and Relief Nozzle:

A Thermal Stress Factor (TSF) of 1.10 was derived to account for the change in ΔT_{cold} due to the IP2 SPU. The primary and secondary membrane (σ_m) and bending (σ_b) stresses for the pressurizer safety and relief nozzle are taken from Reference 4 for the governing transient (Normal & Upset) and are listed below. The secondary membrane (σ_m) and bending (σ_b) stresses are adjusted by the Thermal Stress Factor (TSF). The minimum temperature for this transient is 225°F, therefore the reference stress intensity factor K_{IR} is 164 ksi$\sqrt{in}$ (for EOL RT_{NDT} = +60°F per WNET-130).

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Primary: σ_M = 28.71 ksi; σ_B = 0 ksi; Secondary: σ_m = 0 ksi; σ_b = 65.02 ksi

Postulated flaw size of 1/7 section thickness (a=0.503") was used for the Safety and Relief Nozzle which is justified based on the use of highly reliable non-destructive NDE flaw detection capability.

The Membrane correction factor M_m from Figure G-2214-1 of Appendix G is 2.08 (for a postulated flaw size of 1 inch), with bending correction factor M_b being 1.39. For a different flaw size postulated, the ratio of the square roots can be used to account for the change in stress intensity. M_m and M_b values were adjusted to account for the reduced defect size of 1/7 section thickness of 3.52 inches, a ratio of the square roots of 1/7T and 1 inch $\left(\frac{\sqrt{0.503"}}{\sqrt{1"}} = 0.7091\right)$ was applied to the M_m and M_b factors, resulting M_m = 1.47 and M_b = 0.98.

The applied stress intensity factor is:

$$= 2.0\ M_m\ \sigma_M + 2.0\ M_b\ \sigma_B + (1.0\ M_m\ \sigma_m + 1.0\ M_b\ \sigma_b) * TSF$$

$$= 2.0(1.47)(28.71) + 2.0(0.98)(0) + (1.0(1.47)(0) + 1.0(0.98)(65.02))1.1$$

$$= 154.50\ \text{ksi}\sqrt{in} < 164\ \text{ksi}\sqrt{in}$$

Therefore, the Pressurizer Safety and Relief Nozzles meet the requirement of Appendix G.

Upper Shell:

In the original fatigue evaluation of the pressurizer upper shell, all water from the spray nozzle was assumed to strike the vessel wall. This assumption is overly conservative, and a more reasonable assumption would be that the pressurizer spray does not impact the pressurizer wall during operation except for the heatup and cooldown transients (Reference 3). These assumptions remove the thermal shock stresses from all but the heatup and cooldown transients. Since the governing transient for the pressurizer upper shell is Inadvertant Auxiliary Spray (WNET-130, Volume 16, "Model D Series 84 pressurizer stress report: fracture mechanics analysis", May 1, 1978), no analysis is necessary for the pressurizer upper shell for the IP2 SPU. Therefore the fracture toughness results from WNET-130 remain valid.

<u>Response 4b:</u>

Yes, the analysis performed satisfies the requirements of Article G-2220 of Section XI of the ASME Code. Structural factors, i.e. a factor of 2 for normal and upset conditions, and a factor of 1.5 for test conditions, were applied to the primary stresses as specified in Section XI of the ASME Code.

Pressure Vessel Materials RAIs

Response 4c:

Safety and Relief Nozzle:

The IP2 Pressurizer has three Code Safety Inner Radius Nozzles (PZRN-3, PZRN-4, & PZRN-5); and one (1) Power Operated Relief Inner Radius Nozzle PZRN-2. These nozzles are ASME Category B-D, Item B3.20. These nozzles require volumetric examinations per ASME Section XI, 1989 Code Edition. However, for the Third 10-year Interval, which ends in April 2006, Entergy submitted Relief Request No. 9, Rev. 1 to perform a remote visual (VT-1) with color capability on each of the nozzle inner radius sections. The NRC approved this relief request on June 3, 1997 (TAC No. M88559).

Upper Shell:

The Pressurizer upper shell has two circular welds (PZRC-4 & PZRC-5), and one longitudinal weld (PZRL-4). These welds are ASME Category B-B, Item B2.11 & B2.12. PZRC-4 is a shell-to-shell weld and is exempted from NDE. Table IWB-2500-1 Category B-B, Note 4 requires the volumetric examination coverage stipulated by Figures IWB-2500-1 and 2 be performed on 100% of the Code Class 1 circumferential welds and the adjoining 1 foot section of the longitudinal welds. The upper circumferential (PZRC-5) and longitudinal (PZRL-4) welds are enclosed in a biological and missile shield and are therefore completely inaccessible for volumetric examination (NDE). Therefore, Entergy submitted for the Third 10-year Interval, which ends in April 2006, Relief Request No. 7 on the basis that compliance with the Code requirement is impractical. Thus as an alternative, the welds will be visually examined (VT-2) during each refueling outage for evidence of leakage during system pressure tests performed in accordance with IWB-2500, Category B-P, and Code Case N-498. The NRC approved this relief request on June 3, 1997 (TAC No. M88559).

Pressure Vessel Materials RAIs

Response 4d:

The PODs for the safety and relief nozzle and the upper shell are taken from EPRI Report, "Justification for the Reduction of Inspection Requirements for the Boiling Water Reactor Nozzle-to-Vessel Shell Welds And Nozzle Blend Radii (VIP-108)", R. Carter, June 2002. This report is deemed applicable as the shell thickness and nozzle diameters are similar. As shown in the following figure the PODs of flaws with a depth of 0.50-inch for the safety and relief nozzle and 0.15-inch for the upper shell are 99.9% and 85%, respectively.

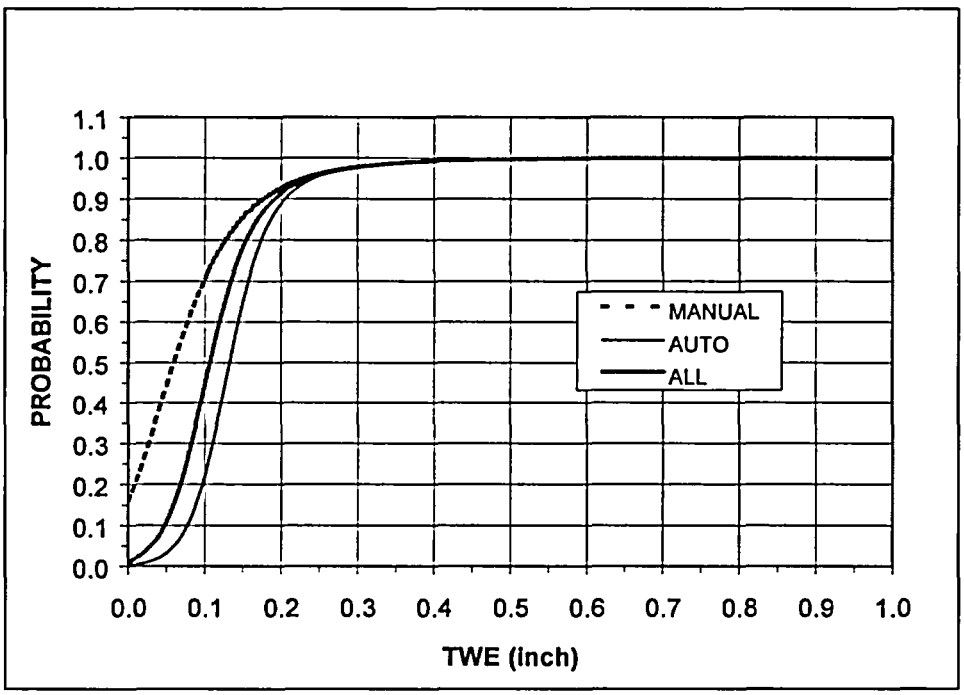

Figure PVM-2-9:
Probability of Correct Rejection/Reporting (PCR) Considering Only Passed Candidates, Appendix VIII from the Outside Surface. Reporting Criterion A' = 0.15 inch.]*

- EPRI Report, "Justification for the Reduction of Inspection Requirements for the Boiling Water Reactor Nozzle-to-Vessel Shell Welds And Nozzle Blend Radii (VIP-108)", R. Carter, June 2002.

Reactor Systems and Analyses RAIs

Question 1:

Provide a table listing the computer codes and evaluation methodologies used in the re-analysis of non-loss-of-coolant accident (non-LOCA) transients. The table should include the NRC-approval status, conditions and limitations, and how they are satisfied for SPU application at IP2.

Response:

The computer codes and methodologies used in each of the non-LOCA transient analyses are listed in Table RAI 1-1. As indicated by Tables RAI 1-2 through RAI 1-5, the NRC staff has approved all codes that were used in the non-LOCA transient analyses for IP2. As for the applicable non-LOCA transient analysis methodologies, these have been reviewed and approved by the NRC staff via transient-specific topical reports (WCAPs) and/or through the review and approval of plant-specific safety analysis reports. Code and methodology restrictions are specified in applicable SERs. Tables RAI 1-2 through RAI 1-6 provide SER conditions and restriction information for computer codes and application for events listed in Table RAI 1-1. Similarly, Tables RAI 1-7 and RAI 1-8 identify the SER conditions and restrictions for each analysis methodology that has an approved topical report associated with it. Tables RAI 1-2 through RAI 1-8 also provide the justifications for how each SER condition/restriction is satisfied in the IP2 analyses.

Reactor Systems and Analyses RAIs

Table RAI 1-1: Computer Codes and Methodologies Used in Non-LOCA Transient Analyses for IP2

UFSAR Section	Event Description	Applicable Code(s)	Applicable Methodology
14.1.1	Uncontrolled RCCA Withdrawal from a Subcritical or Low-Power Startup Condition	TWINKLE FACTRAN VIPRE	SAR submittals
14.1.2	Uncontrolled RCCA Withdrawal at Power	RETRAN	SAR submittals WCAP-14882-P-A
14.1.3	Incorrect Positioning Of Part-Length Rods	N/A	Not Applicable to IP2
14.1.4	RCCA Drop/Misoperation	LOFTRAN VIPRE	WCAP-11394-P-A
14.1.5	Chemical and Volume Control System Malfunction	N/A	SAR submittals
14.1.6	Loss of Reactor Coolant Flow	RETRAN VIPRE	SAR submittals WCAP-14882-P-A
14.1.6	Locked Rotor	RETRAN VIPRE	SAR submittals WCAP-14882-P-A
14.1.7	Startup of an Inactive Reactor Coolant Loop	N/A	Event precluded by Tech Specs
14.1.8	Loss of External Electrical Load	RETRAN	SAR submittals
14.1.9	Loss of Normal Feedwater	RETRAN	SAR submittals
14.1.10	Excessive Heat Removal Due to Feedwater System Malfunctions	RETRAN VIPRE	SAR submittals
14.1.11	Excessive Load Increase Incident	N/A	SAR submittals
14.1.12	Loss of AC Power to the Plant Auxiliaries	RETRAN	SAR submittals
14.2.5	Steam Line Break	RETRAN VIPRE	SAR submittals
14.2.6	Rupture of a Control Rod Drive Mechanism Housing (RCCA Ejection)	TWINKLE FACTRAN	WCAP-7588, Rev. 1-A
14.4	Anticipated Transients Without Scram	LOFTRAN	NS-TMA-2182

Code Approval	Methodology Approvals
TWINKLE WCAP-7979-P-A	As applicable to Transient/Code
FACTRAN WCAP-7908-A	As applicable to Transient/Code
LOFTRAN WCAP-7907-P-A	As applicable to Transient/Code
RETRAN (EPRI) NP-1850-CCM-A	WCAP-14882-P-A
VIPRE (EPRI) NP-2511-CCM-A	WCAP-14565-P-A

Reactor Systems and Analyses RAIs

Table RAI 1-2: Approval Status & SER Requirements for Non-LOCA Transient Analysis Codes – RETRAN

Computer Code: Transients:	RETRAN Various
Computer Code Acceptance: **Licensing Topical Report:** **Date of NRC Acceptance:**	RETRAN-02 Mod 005.0, Thadani (NRC), Boatwright (Texas Utilities Electric Co., November 1, 1991 (Code Restrictions addressed in WCAP-14882-P-A). WCAP-14882-P-A, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," April 1999. February 11, 1999 (SER from F. Akstulewicz (NRC) to H. Sepp (Westinghouse))

Safety Evaluation Report (SER) Conditions & Justification for IP2

1. ***"The transients and accidents that Westinghouse proposes to analyze with RETRAN are listed in this SER (Table 1) and the NRC staff review of RETRAN usage by Westinghouse was limited to this set. Use of the code for other analytical purposes will require additional justification."***

Justification

The transients listed in Table 1 of the SER are:

1 Feedwater system malfunctions,
2 Excessive increase in steam flow,
3 Inadvertent opening of a steam generator relief or safety valve,
4 Steam line break,
5 Loss of external load/turbine trip,
6 Loss of offsite power,
7 Loss of normal feedwater flow,
8 Feedwater line rupture,
9 Loss of forced reactor coolant flow,
10 Locked reactor coolant pump rotor/sheared shaft,
11 Control rod cluster withdrawal at power,
12 Dropped control rod cluster/dropped control bank,
13 Inadvertent increase in coolant inventory,
14 Inadvertent opening of a pressurizer relief or safety valve,
15 Steam generator tube rupture.

The transients analyzed for IP2 using RETRAN are:

Uncontrolled RCCA withdrawal at power (UFSAR 14.1.2), (#11 above)
Loss of reactor coolant flow (UFSAR 14.1.6), (#9 above)
Locked rotor (UFSAR 14.1.6), (#10 above)
Loss of external electrical load (UFSAR 14.1.8), (#5 above)
Loss of normal feedwater (UFSAR 14.1.9), (#7 above)
Excessive heat removal due to feedwater system malfunctions (UFSAR 14.1.10), (#1 above)
Loss of AC power to the plant auxiliaries (UFSAR 14.1.12), (#6 above)
Steam line break (UFSAR 14.2.5) (#4 above)

Each transient analyzed for IP2 using RETRAN is included in Table 1 of WCAP-14882-P-A.

Reactor Systems and Analyses RAIs

Table RAI 1-2: Approval Status & SER Requirements for Non-LOCA Transient Analysis Codes – RETRAN

2.	***"WCAP-14882 describes modeling of Westinghouse designed 4-, 3, and 2-loop plants of the type that are currently operating. Use of the code to analyze other designs, including the Westinghouse AP600, will require additional justification."*** **Justification** IP2 is a 4-loop Westinghouse-designed plant that was "currently operating" at the time the SER was written (February 11, 1999). Therefore, additional justification is not required.
3.	***"Conservative safety analyses using RETRAN are dependent on the selection of conservative input. Acceptable methodology for developing plant-specific input is discussed in WCAP-14882 and in Reference 14 [WCAP-9272-P-A]. Licensing applications using RETRAN should include the source of and justification for the input data used in the analysis."*** **Justification** The input data used in the RETRAN analyses performed by Westinghouse came from both Entergy Nuclear Northeast (ENN) and Westinghouse sources. A quality assurance program is in place that required documentation of the input data sources and justification for use. Consistent with the Westinghouse Reload Evaluation Methodology described in WCAP-9272-P-A, the safety analysis input values used in the IP2 analyses were selected to conservatively bound the values expected in subsequent operating cycles.

Table RAI 1-3: Approval Status & SER Requirements for Non-LOCA Transient Analysis Codes – TWINKLE

Computer Code:	TWINKLE
Licensing Topical Report:	WCAP-7979-P-A, "TWINKLE – A Multidimensional Neutron Kinetics Computer Code," January 1975.
Date of NRC Acceptance:	July 29, 1974 (SER from D. B. Vassallo (U.S. Atomic Energy Commission) to R. Salvatori (Westinghouse))
Safety Evaluation Report (SER) Conditions & Justification for IP2	
There are no conditions, restrictions, or limitations cited in the TWINKLE SER. **Justification** Not Applicable	

Reactor Systems and Analyses RAIs

Table RAI 1-4: Approval Status & SER Requirements for Non-LOCA Transient Analysis Codes – FACTRAN

Computer Code:	FACTRAN
Licensing Topical Report:	WCAP-7908-A, "FACTRAN – A FORTRAN IV Code for Thermal Transients in a UO_2 Fuel Rod," December 1989.
Date of NRC Acceptance:	September 30, 1986 (SER from C. E. Rossi (NRC) to E. P. Rahe (Westinghouse))

Safety Evaluation Report (SER) Conditions & Justification for IP2

1. ***"The fuel volume-averaged temperature or surface temperature can be chosen at a desired value which includes conservatisms reviewed and approved by the NRC."***

   Justification

   The FACTRAN code was used in the analyses of the following transients for IP2: Uncontrolled RCCA Withdrawal from a Subcritical or Low Power Condition (UFSAR 14.1.1) and RCCA Ejection (UFSAR 14.2.6). Conservative initial fuel temperatures were used as FACTRAN input in the RCCA Ejection analyses. The bounding fuel temperatures for these transients were calculated using the PAD 4.0 computer code (see WCAP-15063-P-A). As indicated in WCAP-15063-P-A, the method of determining uncertainties for PAD 4.0 fuel temperatures has been approved by the NRC.

2. ***"Table 2 presents the guidelines used to select initial temperatures."***

   Justification

   In summary, Table 2 of the SER specifies that the initial fuel temperatures assumed in the FACTRAN analyses of the following transients should be "High" and include uncertainties: Loss of Flow, Locked Rotor, and Rod Ejection. As discussed above, fuel temperatures were used as input to the FACTRAN code in the RCCA Ejection analyses for IP2. The assumed fuel temperatures, which were based on bounding temperatures calculated using the PAD 4.0 computer code (see WCAP-15063-P-A), include uncertainties and are conservatively high.

3. ***"The gap heat transfer coefficient may be held at the initial constant value or can be varied as a function of time as specified in the input."***

   Justification

   The gap heat transfer coefficients applied in the FACTRAN analyses are consistent with SER Table 2. For the RCCA Withdrawal from a Subcritical Condition transient, the gap heat transfer coefficient is kept at a conservative constant value throughout the transient; a high constant value is assumed to maximize the peak heat flux (for DNB concerns) and a low constant value is assumed to maximize transient fuel temperatures. For the RCCA Ejection transients, the initial gap heat transfer coefficient is based on the predicted initial fuel surface temperature, and is ramped rapidly to a very high value at the beginning of the transient to simulate clad collapse onto the fuel pellet.

4. ***"...the Bishop-Sandberg-Tong correlation is sufficiently conservative and can be used in the FACTRAN code. It should be cautioned that since these correlations are applicable for local conditions only, it is necessary to use input to the FACTRAN code which reflects the local conditions. If the input values reflecting average conditions are used, there must be sufficient conservatism in the input values to make the overall method conservative."***

   Justification

   Local conditions related to temperature, heat flux, peaking factors and channel information were input to FACTRAN for each transient analyzed for IP2 (RCCA Withdrawal from a Subcritical Condition (UFSAR 14.1.1) and RCCA Ejection (UFSAR 14.2.6)).

Reactor Systems and Analyses RAIs

Table RAI 1-4: Approval Status & SER Requirements for Non-LOCA Transient Analysis Codes – FACTRAN

Computer Code:	FACTRAN
Licensing Topical Report:	WCAP-7908-A, "FACTRAN – A FORTRAN IV Code for Thermal Transients in a UO_2 Fuel Rod," December 1989.
Date of NRC Acceptance:	September 30, 1986 (SER from C. E. Rossi (NRC) to E. P. Rahe (Westinghouse))

Safety Evaluation Report (SER) Conditions & Justification for IP2

5. ***"The fuel rod is divided into a number of concentric rings. The maximum number of rings used to represent the fuel is 10. Based on our audit calculations we require that the minimum of 6 should be used in the analyses."***

Justification

At least 6 concentric rings were assumed in FACTRAN for each transient analyzed for IP2 (RCCA Withdrawal from a Subcritical Condition (UFSAR 14.1.1) and RCCA Ejection (UFSAR 14.2.6)).

6. ***"Although time-independent mechanical behavior (e.g., thermal expansion, elastic deformation) of the cladding are considered in FACTRAN, time-dependent mechanical behavior (e.g., plastic deformation) is not considered in the code. ...for those events in which the FACTRAN code is applied (see Table 1), significant time-dependent deformation of the cladding is not expected to occur due to the short duration of these events or low cladding temperatures involved (where DNBR Limits apply), or the gap heat transfer coefficient is adjusted to a high value to simulate clad collapse onto the fuel pellet."***

Justification

The two transients that were analyzed with FACTRAN for IP2 (RCCA Withdrawal from a Subcritical Condition (UFSAR 14.1.1) and RCCA Ejection (UFSAR 14.2.6)) are included in the list of transients provided in Table 1 of the SER; each of these transients is of short duration. For the RCCA Withdrawal from a Subcritical Condition transient, relatively low cladding temperatures are involved, and the gap heat transfer coefficient is kept constant throughout the transient. For the RCCA Ejection transient, a high gap heat transfer coefficient is applied to simulate clad collapse onto the fuel pellet. The gap heat transfer coefficients applied in the FACTRAN analyses are consistent with SER Table 2.

7. ***"The one group diffusion theory model in the FACTRAN code slightly overestimates at beginning of life (BOL) and underestimates at end of life (EOL) the magnitude of flux depression in the fuel when compared to the LASER code predictions for the same fuel enrichment. The LASER code uses transport theory. There is a difference of about 3 percent in the flux depression calculated using these two codes. When [T(centerline) – T(Surface)] is on the order of 3000°F, which can occur at the hot spot, the difference between the two codes will give an error of 100°F. When the fuel surface temperature is fixed, this will result in a 100°F lower prediction of the centerline temperature in FACTRAN. We have indicated this apparent nonconservatism to Westinghouse. In the letter NS-TMA-2026, dated January 12, 1979, Westinghouse proposed to incorporate the LASER-calculated power distribution shapes in FACTRAN to eliminate this non-conservatism. We find the use of the LASER-calculated power distribution in the FACTRAN code acceptable."***

Justification

The condition of concern (T(centerline – T(surface) on the order of 3000°F) is expected for transients that reach, or come close to, the fuel melt temperature. As this applies only to the RCCA ejection transient, the LASER-calculated power distributions were used in the FACTRAN analysis of the RCCA ejection transient for IP2.

Reactor Systems and Analyses RAIs

Table RAI 1-5: Approval Status & SER Requirements for Non-LOCA Transient Analysis Codes – LOFTRAN

Computer Code:	LOFTRAN
Licensing Topical Report:	WCAP-7907-P-A, "LOFTRAN Code Description," April 1984.
Date of NRC Acceptance:	July 29, 1983 (SER from C. O. Thomas (NRC) to E. P. Rahe (Westinghouse))

Safety Evaluation Report (SER) Conditions & Justification for IP2

1. ***"LOFTRAN is used to simulate plant response to many of the postulated events reported in Chapter 14 of FSARs, to simulate anticipated transients without scram, for equipment sizing studies, and to define mass/energy releases for containment pressure analysis. The Chapter 14 events analyzed with LOFTRAN are:***

   1- Feedwater System Malfunction
   2- Excessive Increase in Steam Flow
   3- Inadvertent Opening of a Steam Generator Relief or Safety Valve
   4- Steamline Break
   5- Loss of External Load
   6- Loss of Offsite Power
   7- Loss of Normal Feedwater
   8- Feedwater Line Rupture
   9- Loss of Forced Reactor Coolant Flow
   10- Locked Pump Rotor
   11- Rod Withdrawal at Power
   12- Rod Drop
   13- Startup of an Inactive Pump
   14- Inadvertent ECCS Actuation
   15- Inadvertent Opening of a Pressurizer Relief or Safety Valve

   This review is limited to the use of LOFTRAN for the licensee safety analyses of the Chapter 15 events listed above, and for a steam generator tube rupture..."

   Justification

   The LOFTRAN code was only used in the analysis of the Rod Drop transient (USAR 14.1.3) for IP2. As this transient matches #12 of the transients listed above.

Reactor Systems and Analyses RAIs

Table RAI 1-6: Approval Status & SER Requirements for Non-LOCA Transient Analysis Codes – VIPRE

Computer Code:	VIPRE
Licensing Topical Report:	WCAP-14565-P-A/WCAP-15306-NP-A, VIPRE-01 *Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis*, Y. Sung, et al., October 1999.
Date of NRC Acceptance:	Letter from T. H. Essig (NRC) to H. Sepp (Westinghouse), "Acceptance for Referencing of Licensing Topical Report WCAP-14565, 'VIPRE-01 *Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal/Hydraulic Safety Analysis,' (TAC No. M98666),*" *January 19, 1999.*

Safety Evaluation Report (SER) Conditions & Justification for IP2

1. *"Selection of the appropriate CHF correlation, DNBR limit, engineered hot channel factors for enthalpy rise and other fuel-dependent parameters for a specific plant application should be justified with each submittal."*

Justification

The NRC-approved WRB-1 correlation was used in the DNBR analyses. Justification of the WRB-1 correlation limit of 1.17 with the VIPRE code is provided in WCAP-14565-P-A.

For the IP2 SPU DNBR analyses, the plant specific hot channel factors for enthalpy rise and other fuel-dependent parameters that have been previously approved by the NRC have been assumed in these analyses.

2. *"Reactor core boundary conditions determined using other computer codes are generally input into VIPRE for reactor transient analyses. These inputs include core inlet coolant flow and enthalpy, core average power, power shape and nuclear peaking factors. These inputs should be justified as conservative for each use of VIPRE."*

Justification

The core boundary conditions for the VIPRE calculations are all generated from NRC-approved methodologies and computer codes, such as RETRAN and ANC. Conservative reactor core boundary conditions were justified for use as input to VIPRE as discussed in the safety evaluations. Continued applicability of the input assumptions is verified on a cycle-by-cycle basis using the Westinghouse reload methodology described in WCAP-9272/9273.

3. *"The NRC Staff's generic SER for VIPRE (Reference 2 of the SER) set requirements for use of new CHF correlations with VIPRE. Westinghouse has met these requirements for using WRB-1, WRB-2 and WRB-2M correlations. The DNBR limit for WRB-1 and WRB-2 is 1.17. The WRB-2M correlation has a DNBR limit of 1.14. Use of other CHF correlations not currently included in VIPRE will require additional justification."*

Justification

Justification on use of the WRB-1 correlation with the VIPRE code is provided in WCAP-14565-P-A. There is no new DNB correlation used for the IP2 SPU.

Reactor Systems and Analyses RAIs

Table RAI 1-6: Approval Status & SER Requirements for Non-LOCA Transient Analysis Codes – VIPRE

Computer Code:	VIPRE
Licensing Topical Report:	WCAP-14565-P-A/WCAP-15306-NP-A, VIPRE-01 *Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis*, Y. Sung, et al., October 1999.
Date of NRC Acceptance:	Letter from T. H. Essig (NRC) to H. Sepp (Westinghouse), "Acceptance for Referencing of Licensing Topical Report WCAP-14565, 'VIPRE-01 *Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal/Hydraulic Safety Analysis,' (TAC No. M98666),*" *January 19, 1999.*

Safety Evaluation Report (SER) Conditions & Justification for IP2

4. *"Westinghouse proposes to use the VIPRE code to evaluate fuel performance following postulated design-basis accidents, including beyond-CHF heat transfer conditions. These evaluations are necessary to evaluate the extent of core damage and to ensure that the core maintains a coolable geometry in the evaluation of certain accident scenarios. The NRC Staff's generic review of VIPRE (Reference 2 of the SER) did not extent to post CHF calculations. VIPRE does not model the time-dependent physical changes that may occur within the fuel rods at elevated temperatures. Westinghouse proposes to use conservative input in order to account for these effects. The NRC Staff requires that appropriate justification be submitted with each usage of VIPRE in the post-CHF region to ensure that conservative results are obtained."*

Justification

For the IP2 SPU analyses, the use of VIPRE in the post-CHF region is limited to the peak clad temperature calculations for the locked rotor transient. The calculation demonstrated that the peak clad temperature in the reactor core is well below the allowable limit to prevent clad embrittlement. VIPRE modeling of the fuel rod is consistent with the model described in WCAP-14565-P-A and included the following conservative assumptions:

- DNB was assumed to occur at the beginning of the transient;
- Film boiling was calculated using the Bishop-Sandberg-Tong correlation;
- The Baker-Just correlation accounted for heat generation in fuel cladding due to zirconium-water reaction.

Conservative results were further ensured with the following inputs:

- Fuel rod input based on the maximum fuel temperature at the given power;
- The hot spot power factor was equal to or greater than the design linear heat rate;
- Uncertainties were applied to the initial operating conditions in the limiting direction.

Reactor Systems and Analyses RAIs

Table RAI 1-7: Approval Status & SER Requirements for Non-LOCA Transient Analysis Methods – Dropped Rod

Transient:	RCCA Misalignment (Dropped Rod)
Licensing Topical Report:	WCAP-11394-P-A, "Methodology for the Analysis of the Dropped Rod Event," January 1990.
Date of NRC Acceptance:	October 23, 1989 (SER from A. C. Thadani (NRC) to R. A. Newton (WOG))
Safety Evaluation Report (SER) Conditions & Justification for IP2	
1.	***"The Westinghouse analysis, results and comparisons are reactor and cycle specific. No credit is taken for any direct reactor trip due to dropped RCCA(s). Also, the analysis assumes no automatic power reduction features are actuated by the dropped RCCA(s). A further review by the staff (for each cycle) is not necessary, given the utility assertion that the analysis described by Westinghouse has been performed and the required comparisons have been made with favorable results."*** **Justification** For the reference cycle assumed in the IP2 SPU program, it is affirmed that the methodology described in WCAP-11394-P-A was performed and the required comparisons have been made with acceptable results (DNB limits are not exceeded).

Reactor Systems and Analyses RAIs

Table RAI 1-8: Approval Status & SER Requirements for Non-LOCA Transient Analysis Methods – RCCA Ejection

Transient:	RCCA Ejection
Licensing Topical Report:	WCAP-7588 Rev. 1-A, "An Evaluation of the Rod Ejection Accident in Westinghouse Pressurized Water Reactors Using Spatial Kinetics Methods," January 1975.
Date of NRC Acceptance:	August 28, 1973 (SER from D. B. Vassallo (AEC) to R. Salvatori (Westinghouse))

Safety Evaluation Report (SER) Conditions & Justification for IP2

1. ***"The staff position, as well as that of the reactor vendors over the last several years, has been to limit the average fuel pellet enthalpy at the hot spot following a rod ejection accident to 280 cal/gm. This was based primarily on the results of the SPERT tests which showed that, in general, fuel failure consequences for UO_2 have been insignificant below 300 cal/gm for both irradiated and unirradiated fuel rods as far as rapid fragmentation and dispersal of fuel and cladding into the coolant are concerned. In this report, Westinghouse has decreased their limiting fuel failure criterion from 280 cal/gm (somewhat less than the threshold of significant conversion of the fuel thermal energy to mechanical energy) to 225 cal/gm for unirradiated rods and 200 cal/gm for irradiated rods. Since this is a conservative revision on the side of safety, the staff concludes that it is an acceptable fuel failure criterion."***

   Justification
   The maximum fuel pellet enthalpy at the hot spot calculated for each IP2-specific RCCA Ejection case is less than 200 cal/gm. These results satisfy the fuel failure criterion accepted by the staff.

2. ***"Westinghouse proposes a clad temperature limitation of 2700°F as the temperature above which clad embrittlement may be expected. Although this is several hundred degrees above the maximum clad temperature limitation imposed in the AEC ECCS Interim Acceptance Criteria, this is felt to be adequate in view of the relatively short time at temperature and the highly localized effect of a reactivity transient."***

   Justification
   As discussed in Westinghouse letter NS-NRC-89-3466 written to the NRC (W. J. Johnson to R. C. Jones, dated October 23, 1989), the 2700°F clad temperature limit was historically applied by Westinghouse to demonstrate that the core remains in a coolable geometry during an RCCA ejection transient. This limit was never used to demonstrate compliance with fuel failure limits and is no longer used to demonstrate core coolability. The RCCA ejection acceptance criteria applied by Westinghouse to demonstrate long term core coolability and compliance with applicable offsite dose requirements are those defined in the suggested revisions to the IP2 UFSAR Section 14.2.6 (fuel pellet enthalpy, RCS pressure, and fuel melt).

Reactor Systems and Analyses RAIs

Question 2:

In its re-analysis of the non-LOCA transients for the SPU, the NRC-approved RETRAN Code (WCAP-14482-P-A) was used for the first time.

a. Explain the quality assurance process used to verify RETRAN was adequately used at IP2.

b. Show that the IP2 nodalization modeling is consistent with the Westinghouse 4-loop plant nodalization model of WCAP-14882-P-A. If the modeling of IP2 deviated from the plant model in the WCAP-14882-P-A, explain why and how these deviations were addressed.

Response 2a:

The Westinghouse Quality Assurance Program computer software development, maintenance and configuration control process is in accordance with procedures and instructions that comply with ASME NQA-1 and ISO 9001 and is required for all safety-related applications.

The RETRAN-02 computer code approved for use in performing Westinghouse safety analyses (WCAP-14882-P-A) is validated and documented under the Westinghouse software configuration control process governed by the NRC-Approved Westinghouse Quality Management System (QMS).

When documenting the non-LOCA safety analyses, analysts document the software code input and version used in performing the event analysis calculations. The event analysis verification includes confirming that the validated/verified version of RETRAN-02 is appropriately applied to the event analysis calculations performed for each event as was done for IP2.

Response 2b:

A pre-processor is used to generate a RETRAN deck with the modeling scheme (i.e. nodalization) approved for use in WCAP-14882-P-A. The pre-processor computer code is validated and documented under the Westinghouse software configuration control process governed by the NRC-Approved Westinghouse Quality Management System (QMS).

In performing the IP2 non-LOCA safety analyses, verified/validated versions of the RETRAN-02 pre-processor and RETRAN-02 computer codes were documented and used based on IP2 plant specific data. By using controlled and configured versions of RETRAN-02 and the RETRAN-02 pre-processor computer codes, the 4-loop modeling scheme used in performing the IP2 non-LOCA safety analyses calculations are consistent with the 4-loop nodalization model approved for use in WCAP-14882-P-A. Therefore, the IP2 non-LOCA analyses did not deviate from the plant model documented in WCAP-14882-P-A.

Reactor Systems and Analyses RAIs

Question 3:

The NRC staff is interested in the degradation of margin to the regulatory limits for the SPU at IP2. With regard to the non-LOCA transient re-analyses, provide a table listing each event and its corresponding acceptance criteria. In this table, also quantify the change in calculated results relative to current operation.

Response:

The response this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments II and III, respectively.

Question 4:

In Table 2.1-2 the application report, the core bypass flow for the SPU is the same as the current plant parameter. Note 3 of this table states that the core bypass flow includes 2.0 percent due to thimble plug removal and intermediate flow mixing (IFM) grids. Provide an explanation for whether the 2.0 percent value was accounted for previously, and if not, how is it accounted for in the uprated power condition.

Response:

Currently, there are no thimble plugs in the IP2 reactor core. 2.0% additional design bypass flow was previously included as part of the total design core bypass flow fraction to reflect this current configuration and the IFM grids used in the current fuel product. The design bypass flow has been accounted for in previous and current IP2 safety analyses pertinent to the current plant configuration without fuel assembly thimble plugs. This same design bypass flow assumption has been maintained for the various SPU analyses assuming that IP2 CY17 will start without the use of fuel assembly thimble plugs. This is conservative for analyses for DNB, since the use of thimble plugs would reduce the bypass flow and increase core cooling flow.

Question 5:

Provide the technical justification for the reduction in the design limit departure from nucleate boiling ratio (DNBR) from its current value of 1.26 to the SPU value of 1.22 for both the typical flow channel and the thimble flow channel.

Response:

The response this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments II and III, respectively.

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Question 6:

As a result of the increased core thermal power for the SPU, the safety analysis limit DNBR and core thermal safety limits were revised. Specifically, the safety analysis limit (SAL) DNBR was revised from 1.58 to 1.48. Provide the technical justification for the revision of the DNBR from 1.58 to 1.48.

Response:

The response this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments II and III, respectively.

Question 7:

Provide a table listing the DNBR margin summary. The values would include the DNBR correlation limit, DNBR design limit, SAL DNBR, DNBR retained margin, rod bow DNBR penalty, transition core DNBR penalty, and available DNBR margin left after the uprate.

Response:

The response this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments II and III, respectively.

Question 8:

In the uncontrolled rod cluster control assembly (RCCA) withdrawal from a subcritical or low power startup condition transient, the minimum DNBR remained above the SAL. Provide the DNBR quantitative result which shows the minimum DNBR remained above the SAL for the SPU analysis.

Response:

The response this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments II and III, respectively.

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Question 9:

Regarding the re-analysis of the uncontrolled RCCA withdrawal at power transient:

a. RETRAN (a system code) rather than a subchannel code such as VIPRE is used for the DNBR analysis. The use of the RETRAN DNBR model requires certain user-input values (not listed here because this is shown as proprietary on page 55 of WCAP-14882-P-A). Discuss how this user-input was determined for IP2.

b. One of the acceptance criteria for this event is that fuel centerline temperature remains less than the melting temperature. Provide the quantitative result which demonstrates the fuel centerline temperature acceptance criteria is met.

Response :

The response this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments II and III, respectively.

Question 10:

Regarding the RCCA drop/misoperation transient re-analysis:

a. The licensee states automatic rod withdrawal has been physically disabled at IP2. Provide the technical justification for this statement and how it affects the transient analysis.

b. The licensee states generic transient statepoints designed to bound specific plant types were examined and found to be applicable to IP2 at SPU conditions. Please reference the document from which these generic statepoints were derived from and explain how these are applicable to IP2.

c. Provide the quantitative results demonstrating the minimum DNBR remained above the SAL DNBR and the peak fuel centerline melt temperature criteria is met for the RCCA dropped event at SPU conditions in section 6.3.4.5.

d. The licensee addressed the misaligned RCCA transient and stated the DNBR did not fall below the SAL value when analyzed at the SPU conditions. Provide the quantitative analysis that shows DNBR did not fall below the SAL when analyzed at the SPU conditions for one RCCA fully withdrawn and one RCCA fully inserted.

e. Provide the analytical justification that shows the resulting linear heat generation rate was below that which would cause fuel melting in the RCCA misalignment transient analysis.

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Response 10a:

The automatic rod withdrawal portion of the automatic rod control system has been defeated at IP2 for many years. This prevents spurious withdrawal of the rods, which could cause flux variations and decreasing average temperature, thus defeating the possibility of an inadvertent reactivity excursion event. Only the automatic function of insertion of rods has been maintained, which always tends towards a reduction in power.

Assumptions regarding rod withdrawal during the RCCA drop (Drop Rod) event affect the limiting DNB transient conditions of the event as described below.

RCCA drop (Drop Rod) event is initiated by a electrical/mechanical failure allowing various combination of RCCA(s) to drop to the bottom of the core. The resulting negative reactivity insertion causes nuclear power to decrease rapidly, which leads to a reduction in system pressure. Nuclear power is then reestablished by reactivity feedback and, potentially, control bank withdrawal (depending on the rod control system characteristics). The combination of the reduced pressure conditions with the return to power may lead to limiting DNBR conditions.

For the IP2 design, the rod control system is able to insert (automatically), but not withdraw control rods. Following a dropped RCCA(s) at IP2, the effects of reactivity feedback will allow the plant to achieve a new equilibrium condition. The new (reestablished) equilibrium condition is dependent on the combination of dropped RCCA(s) (negative reactivity insertion) and the amount of reactivity feedback modeled. As noted in licensing report Section 6.3.4.2, various combinations of dropped RCCA(s) worth (negative reactivity insertion) and reactivity feedback conditions are modeled which bound the possible dropped RCCA/reactivity feedback combinations that are applicable to IP2. From each combination of cases examined, the most limiting (DNB) transient (statepoint) conditions are used in the DNBR analysis.

Response 10b:

The methodology for the dropped rod event, WCAP-11394 (Reference 7 of licensing report Section 6.3.16) is based on establishing bounding sets of generic dropped rod statepoints dependent on the plant type being analyzed. This method was developed for Westinghouse plants (i.e., 2-loop, 3-loop and 4-loop plants) having Westinghouse designed rod control and protection systems. The methodology addresses three analysis areas, 1) the statepoints, i.e., the reactor power, temperature and pressure at the most limiting time in the transient (transient analysis), 2) the DNB (thermal-hydraulic) analysis performed at the conditions established by the first step which determines limiting ($F\Delta H$) conditions which must be met which will exceed DNBR limits, and 3) the nuclear analysis which verified that the potential combinations of dropped rods, over the core life, will not result in exceeding the limiting ($F\Delta H$) conditions (established in step 2).

All three analyses are performed using a parametric approach so that cycle dependent conditions can be determined. While the nuclear analysis and thermal-hydraulic analyses are performed at plant specific (and cycle dependent) conditions, the transient analysis statepoints are performed on a generic basis (i.e., intended to bound cycle-specific variations).

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As part of the WCAP-11394 Drop Rod Methodology (NRC approval dated October 23, 1989), a series of generic transient analysis statepoints were generated with conservative assumptions designed to bound 2-loop, 3-loop or 4-loop Westinghouse plants. The statepoints used for IP2 are based on a 4-loop plant having a 12 ft. (height) core while assuming the automatic rod withdrawal feature of the rod control system is disabled, similar to the conditions of IP2. The generic statepoints are generated for a range of dropped rod worths and moderator temperature coefficients that bound the range of parameters applicable to IP2.

Response 10c:

The response this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments II and III, respectively.

Response 10d:

The response this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments II and III, respectively.

Response 10e:

The response this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments II and III, respectively.

Question 11:

Regarding the chemical volume control system malfunction re-analysis, define what the interim operating procedures are, and how they address dilution during hot and cold shutdown.

Response:

The response this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments II and III, respectively.

Question 12:

Regarding the loss of normal feedwater (LONF) transient analysis:

a. In the analysis of record, the turbine driven auxiliary feedwater (TDAFW) pump is not credited to mitigate this transient. What is the consequence on the plant if the TDAFW pump is not aligned and there is less auxiliary feedwater (AFW) being fed to the system under the SPU? Provide the technical justification to show there is sufficient heat sink provided for the SPU condition. Also provide the justification to show 10 minutes is adequate time for the operator to align the TDAFW pump. Demonstrate the operators are capable of performing this action in 10 minutes and how plant procedures have been updated to address the operator action.

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b. The licensee states with respect to DNB, the LONF transient is bounded by the loss of load transient. Provide the technical basis for this statement and provide the quantitative result demonstrating the DNBR limit remains above the SAL and is bounded by the loss of load transient in the RCCA drop/misoperation transient analysis.

Response 12a:

IP2 has 2 MDAFW pumps and 1 TDAFW pump. All three of these automatically start on a trip signal such as low SG level. However, the TDAFW pump needs to be manually aligned by opening its discharge valves to deliver flow to the SGs. The analysis of record for the LONF/LOAC transients assumes the failure of one MD AFW pump. Consequently, only one MDAFW pump would be available initially and would supply two steam generators. For the SPU analysis, credit is now taken for operator action to initiate additional AFW flow to the SGs from either the TD AFW pump or from the other MDAFW pump at 10 minutes. This additional flow is only equivalent to that which the other motor-driven AFW pump can supply (the TD AFW pump has twice the capacity of the MDAFW pump). This assumption bounds the possibility of a failure in one of the motor-driven AFW pumps or in the turbine-driven AFW pump.

Using Licensing assumptions, the additional AFW flow at 10 minutes is needed to prevent the pressurizer from going water solid. Preventing the pressurizer from going solid is a conservative criterion to assure that a Condition II event, an incident of moderate frequency, does not result in a more serious plant condition without other faults occurring independently. Even if the TD AFW pump is not aligned, the pressurizer water solid condition occurs late in the event and would result in the PORVs discharging water for some period of time, with the transient being terminated when the decay heat drops to the level where available AFW flow is sufficient to remove it. EPRI testing has shown that the PORVs are capable of reseating following liquid discharge. Thus the water solid pressurizer will not result in a more serious plant condition for this event.

As noted, the above discussion is pertinent to the "licensing" transient scenario. A near "best-estimate" LONF analysis that assumes nominal conditions was performed and shows that in the event of a complete LONF transient (and LOAC), the AFW system is sufficiently sized, assuming only one motor-driven AFW pump, to remove decay heat and pump heat and preclude a pressurizer water-solid condition. Nevertheless, Emergency Operating Procedure (EOP) E-O, "Reactor Trip or Safety Injection" is being changed to reflect the "licensing" transient scenario.

EOP E-O provides actions to verify proper response of the automatic protection systems following manual or automatic actuation of a reactor trip or safety injection, to assess plant conditions, and to identify the appropriate recovery procedure. The AFW verification is performed very early in this Procedure (at Step 4). Verification of the operator response time was performed on the plant simulator and operator response time to complete step 4 was 3 minutes and 45 seconds.

Response 12b:

The response this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments II and III, respectively.

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Question 13:

Regarding the loss of AC power (LOAC) to the station auxiliaries transient analysis:

a. The licensee states the TDAFW pump needs to be manually aligned before AFW can be delivered to the steam generators. How is this addressed in the plant procedures and what is the technical basis for the 10-minute completion time?

b. Provide the DNBR value which demonstrates the minimum DNBR remained above the SAL and the technical justification demonstrating the minimum DNBR for LOAC is bounded by the complete loss of flow transient.

Response 13a:

IP2 Emergency Operating Procedure E-O provides actions to verify proper response of the automatic protection systems following manual or automatic actuation of a reactor trip or safety injection, to assess plant conditions, and to identify the appropriate recovery procedure. The AFW verification is performed very early in this Procedure (at Step 4). Verification of the operator response time was performed on the plant simulator and operator response time to complete step 4 was 3 minutes and 45 seconds.

Response 13b:

The response this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments II and III, respectively.

Question 14:

Regarding the excessive heat removal due to feedwater system malfunction re-analysis, the licensee states the case initiated at hot zero power (HZP) conditions with manual rod control was less limiting than the HZP steamline break analysis. Provide the technical basis for this statement.

Response:

The response this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments II and III, respectively.

Question 15:

Regarding the excessive load increase incident, the analysis of record states the LOFTRAN computer code was used to analyze this transient. The application report does not describe how this incident was analyzed. State the methodology used to analyze this transient and provide the results obtained, including pressurizer pressure, nuclear power, DNB ratio and core average temperature over time which show the acceptance criteria is met.

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Response:

The response this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments II and III, respectively.

Question 16:

Westinghouse Report, NS-TMA-2182, "Anticipated Transients Without Scram [ATWS] for Westinghouse Plants, December 1979," was used in performing ATWS analysis. Provide the technical justification that demonstrates there is a linear correlation in going from 10 percent to 60 percent in reduced AFW flow which yields a 76 psi increase in peak RCS pressure. In addition, provide the technical justification that demonstrates the moderator temperature coefficient is valid for 95 percent core life under uprate conditions and that the power uprate remains limited by the ATWS analysis of NS-TMA-2182.

Response:

Part 1 – AFW flow sensitivity and power uprate

The RCS pressure penalty estimated for a 60% reduction in AFW flow is based on the sensitivities documented in NS-TMA-2182 (Reference 3 of Section 6.8.2 of Licensing Report). The intent of NS-TMA-2182 is to establish a baseline maximum RCS pressure applicable to plants having specific SG types, and to provide sensitivities that could be used to assess the impact different operating conditions has on the baseline RCS pressure. The sensitivities documented in NS-TMA-2182 indicate that an AFW flow reduction of 50% results in a maximum RCS pressure increase (from the reference case) of 64 psi. An additional sensitivity indicates that an AFW flow reduction of 10% results in a maximum RCS pressure increase (from the reference case) of 12 psi. As a result of an accumulative AFW flow reduction of 60% (as evaluated for IP2), an accumulated RCS pressure penalty of 76psi was used in the IP2 ATWS evaluation. Note that the total RCS pressure penalty is not an extrapolation from a 10%AFW flow reduction but is taken from a 50% AFW flow reduction sensitivity plus an additional penalty for a 10% AFW flow reduction.

In assessing various affects of the uprate for IP2 (i.e., power increase, AFW flow, etc.), an additional explicit ATWS run was performed verifying that the estimated method used in the IP2 ATWS evaluation is indeed conservative for the IP2 uprate conditions.

Part 2 - MTC applicability

The IP2 Technical Specifications (Section 3.1.3) indicate the MTC upper limit shall be $< 0\ \Delta k/k/^{\circ}F$ (0 pcm/°F) at hot zero power. This "negative" MTC requirement (limit) is currently applicable to IP2 and is being retained for the uprate. At startup, Low Power Physics testing is performed to verify the accuracy of the core design, which includes a zero power MTC measurement that ensures the MTC upper limit Tech Spec is satisfied. If the measured MTC is not within the upper limit, administrative withdrawal limits for control banks to maintain a MTC

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within the limit must be established. This measurement criterion ensures that a negative MTC condition is met.

The ATWS methodology is based on assuming the MTC will be more negative than -7 pcm/°F for 99% and more negative than -8 pcm/°F for 95% of the time that the core power is greater than 80%. This methodology is based on conservative assumptions that a plant measuring a negative (non-positive) MTC at zero power (no xenon conditions) will result in a reduced MTC at hot full power, equilibrium xenon conditions of at least -8 pcm/°F. This is based on the assumption that with higher fuel average temperatures at full power and a reduced boron concentration due to xenon, the MTC is conservatively assumed to be lower by (at least) 8 pcm/°F when going from zero power (no xenon) to full power equilibrium xenon conditions. This assumption bounds the calculated MTC result for IP2 which is on the order of an 8.5 pcm/°F MTC reduction when going from zero power (no xenon) to full power equilibrium xenon conditions.

As part of the SPU analyses, specific calculations were done examining the MTC conditions for future uprate cycles. These calculations show that the fuel performance characteristics for future cycles will result in a zero power (no xenon) MTC of no more than 0 pcm/°F throughout core life. These checks have been performed for the uprate and are addressed each cycle as part of the Westinghouse Reload Safety Evaluation Methodology that is employed for IP2 (Reference 2 of Section 6.3.16). Based on the SPU calculations and a MTC reduction to full power equilibrium xenon conditions, the MTC at uprate conditions will be ≤ 8 pcm/°F for the entire core life of future cycles. To ensure that the MTC upper limit Tech Spec will continue to be met for each future operating cycle, the MTC upper limit is included with the limiting conditions examined for every cycle as part of the Westinghouse Reload Safety Evaluation Methodology.

Therefore the basis for the ATWS rule, as applied to IP2, is preserved through Tech Spec requirements, physics testing and design basis change controls (i.e., Reload Safety Evaluation Methodology, 50.59 process) which ensures that the ATWS analysis methodology of NS-TMA-2182 is applicable for SPU uprate conditions and will be checked and confirmed for future cycles. In the event an increase to the zero power MTC Tech Spec Limit is considered such that the ATWS MTC assumptions are no longer met, the ATWS analysis and methodology will be revised and approval through the NRC will be required.

Question 17:

Describe the measures taken to ensure that: (a) the operators will be able to terminate the break flow from the faulted steam generator within the 60 minutes LOFTTR2 analyzed time, (b) no overfilling occurs, and (c) the radioactivity release will remain within regulatory limits. Provide the results of the steam generator tube rupture thermal-hydraulic analysis over time to demonstrate that the steam generator will not overfill during this event for the 60-minute analyzed condition.

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Response 17a:

Operators are currently required to terminate break flow within 45 minutes. This is required to be demonstrated on the plant simulator as part of operator training. Thus, achieving termination in 60 minutes is assured.

Response 17b:

In addition to analyses needed to support the licensing basis for IP2, detailed thermal-hydraulic analyses have also been performed for the SPU with the LOFTTR2 code to evaluate the effect on the radiological consequences, and on the potential for steam generator overfill, of steam generator tube rupture (SGTR) break flow continuing longer than the 30 minutes considered in the licensing basis analysis. Since these analyses are performed to support operator training, nominal operating conditions were assumed.

The sequence of events for the LOFTTR2 margin-to-overfill evaluation is presented in the following Table RSA 17-1. Figures showing the pressurizer pressure, intact and ruptured steam generators' pressures, break flow, and ruptured steam generator water volume transients are provided in the following Figures RSA 17-1 through RSA 17-4, respectively. As shown in Figure 17-4, SG overfilling will not occur if the break flow is terminated by 60 minutes

Response 17c:

Tables RSA 17-3 and RSA 17-4 provide a comparison of the offsite and control room doses calculated using the licensing basis analysis and calculated using the LOFTTR2 thermal hydraulic analysis. As shown in these Tables, the LOFTTR2 dose consequences are bounded by the 'licensing' analysis, and are well within regulatory limits.

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TABLE RSA 17-1

SEQUENCE OF EVENTS
Margin to Steam Generator Overfill Analysis

Event	Time, seconds
SGTR	0
Reactor Trip (Overtemperature-ΔT)	162
AFW Initiated	177
SI Actuated (Low Pressurizer Pressure)	478
Ruptured Steam Generator AFW Flow Isolated	1080
Ruptured Steam Generator Steamline Isolated	1082
RCS Cooldown Initiated	1,562
RCS Cooldown Terminated	2,284
RCS Depressurization Initiated	2,614
RCS Depressurization Terminated	2,694
ECCS Flow Terminated	2,934
Break Flow Termination	3,764

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TABLE RSA 17-2

PRE-ACCIDENT IODINE SPIKE RADIOLOGICAL CONSEQUENCE RESULTS COMPARISON

Total Effective Dose Equivalent (TEDE) Results	Licensing Basis 30-Minute Hand Calculation	LOFTTR2 60-Minute Calculation
Exclusion Area Boundary TEDE (rem)	3.24	1.17
Low Population Zone TEDE (rem)	1.52	0.55
Control Room TEDE (rem)	1.36	0.59

TABLE 17-3

ACCIDENT INITITATED IODINE SPIKE RADIOLOGICAL CONSEQUENCE RESULTS COMPARISON

Total Effective Dose Equivalent (TEDE) Results	Licensing Basis 30-Minute Hand Calculation	LOFTTR2 60-Minute Calculation
Exclusion Area Boundary TEDE (rem)	1.12	0.46
Low Population Zone TEDE (rem)	0.55	0.24
Control Room TEDE (rem)	0.48	0.25

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FIGURE RSA 17-1: Primary Pressure

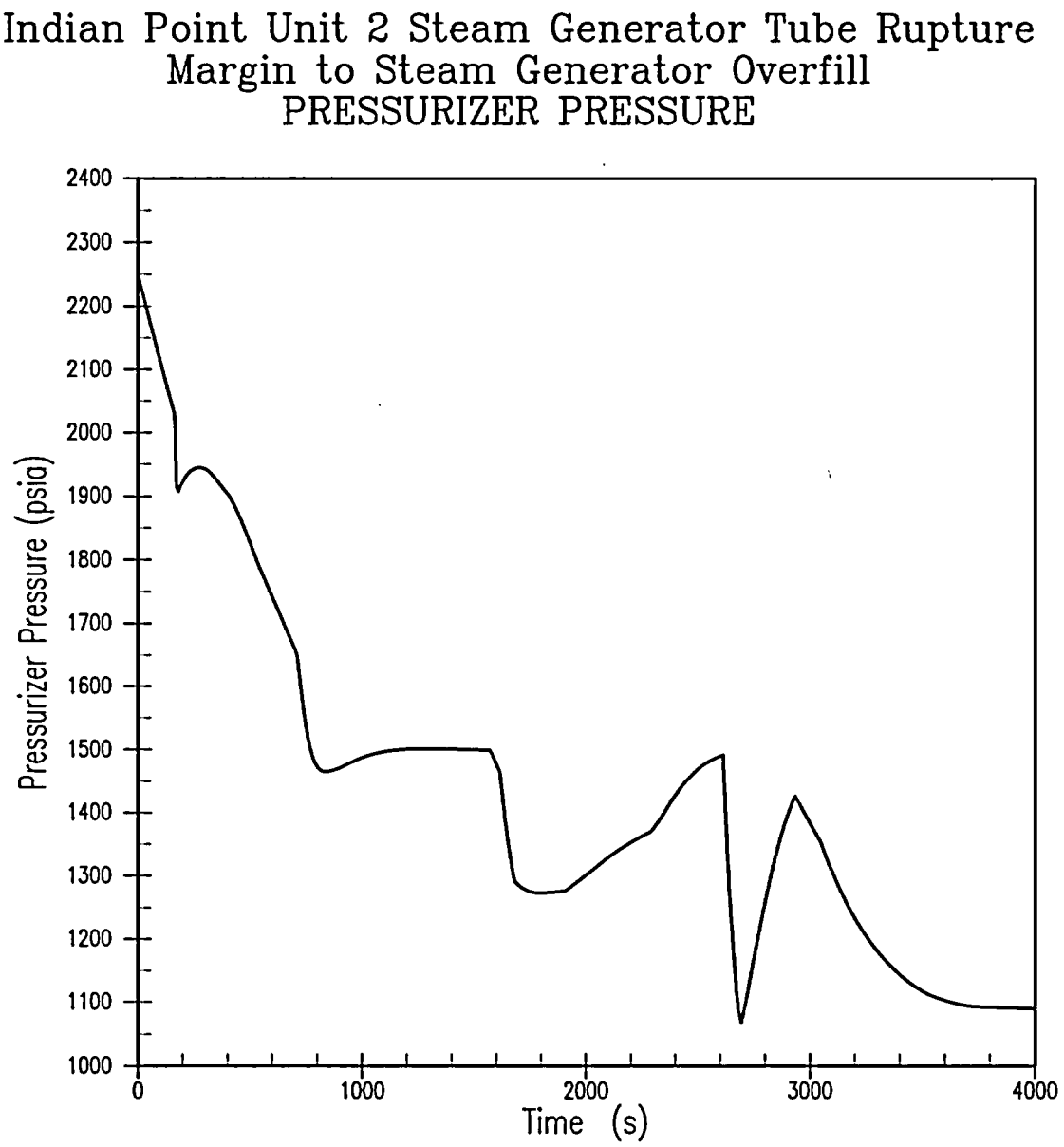

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FIGURE RSA 17-2: Secondary Pressures

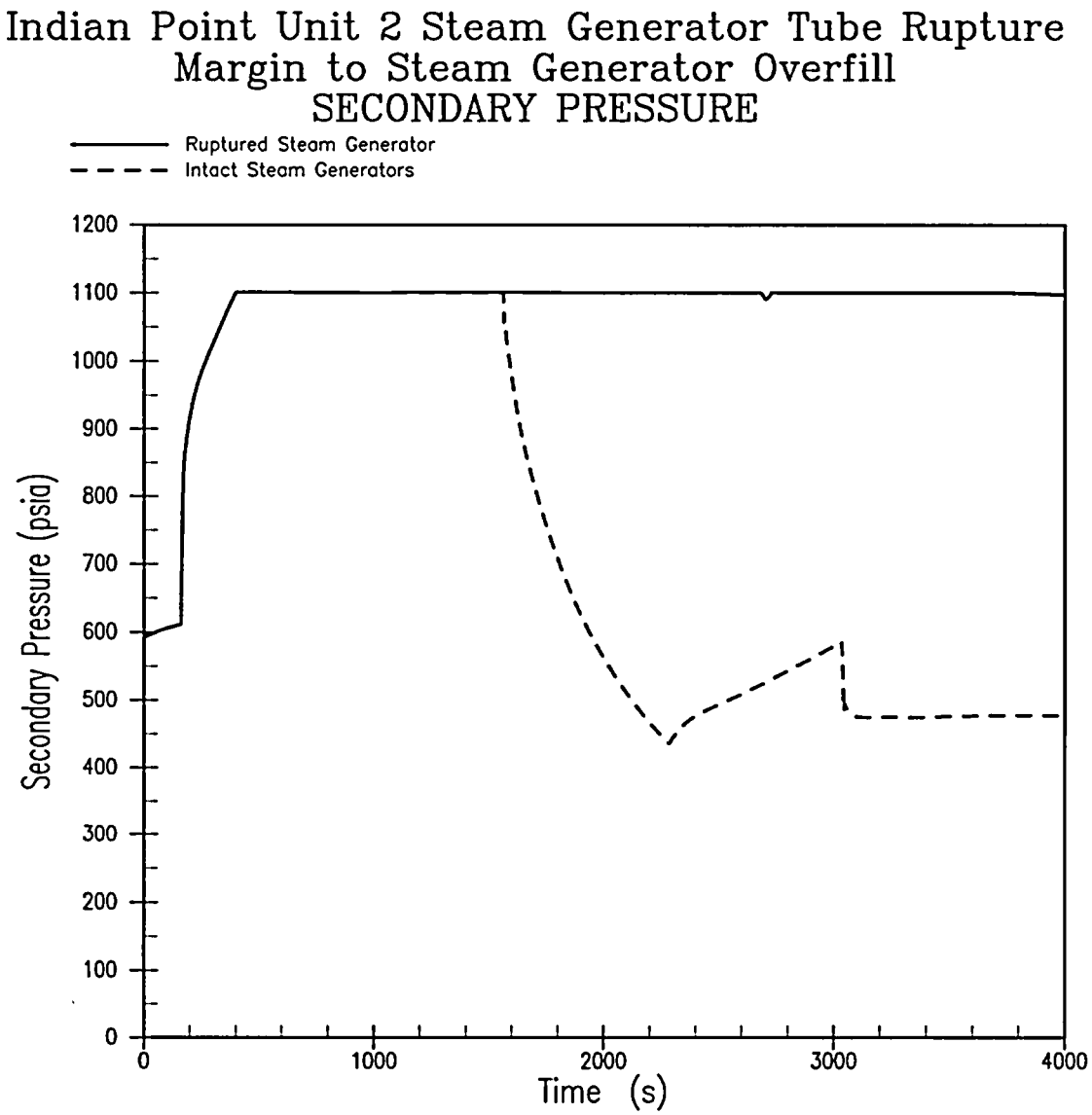

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FIGURE RSA 17-3: Primary-to-Secondary Break Flow

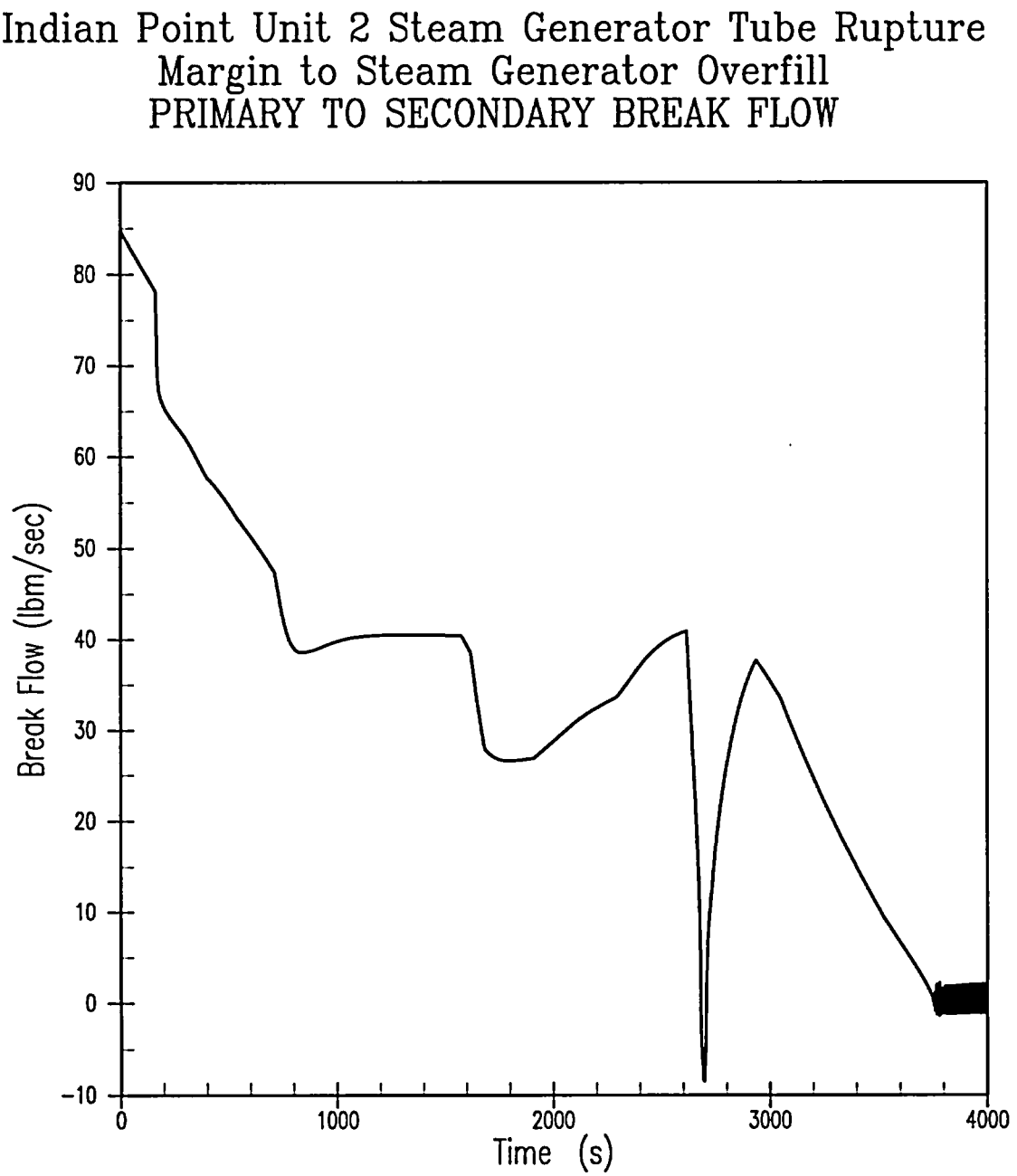

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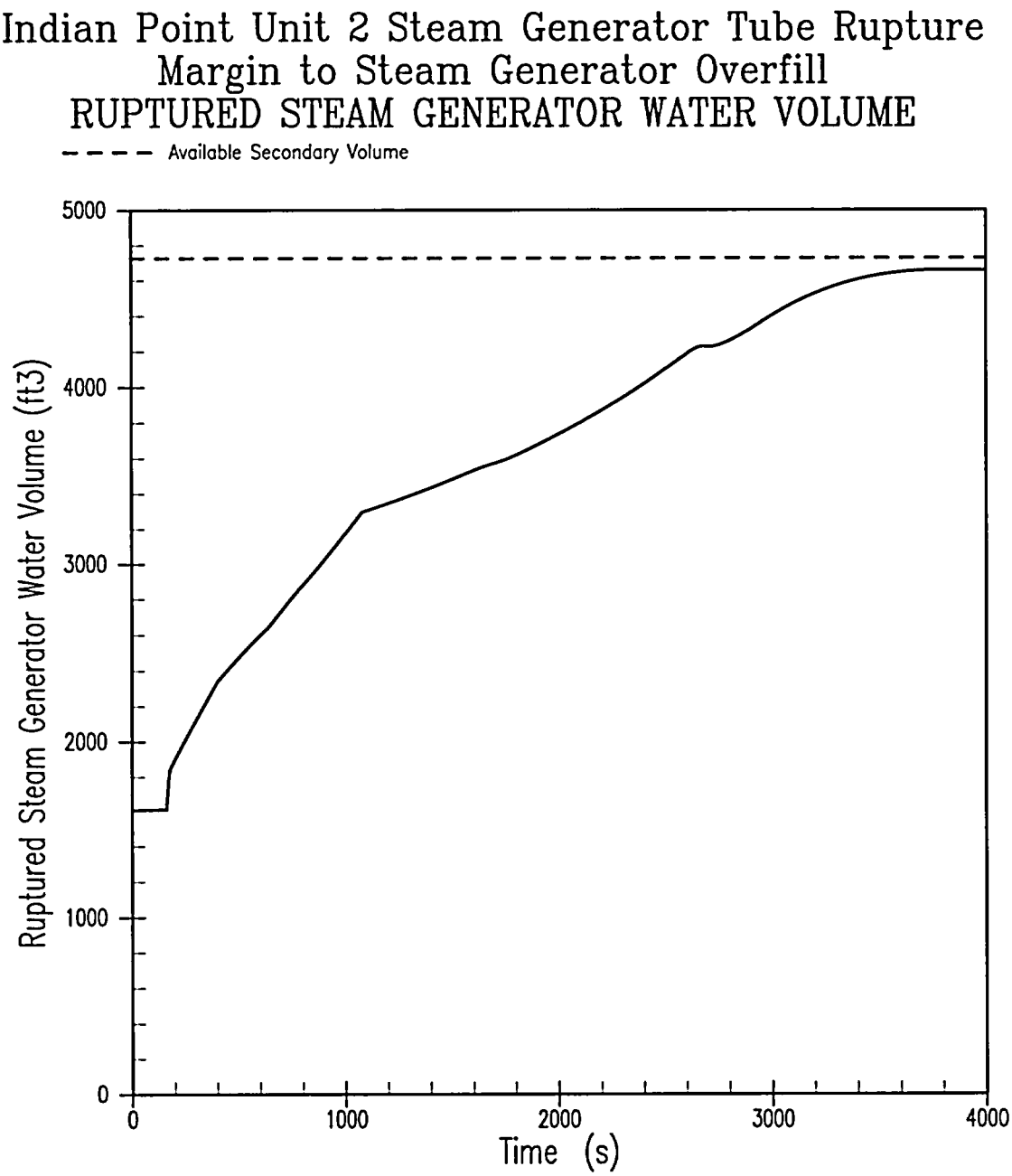
FIGURE RSA 17-4: Ruptured Steam Generator Water Volume



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Question 18:

The licensee states the volume of water in the condensate storage tank (CST) required for 8 hours of decay heat removal and primary system cooldown was determined to be acceptable in a station blackout (SBO) for the SPU. Provide the volume of the CST and the margin available between the actual volume and minimum TS limit which shows IP2 remains above the minimum TS requirement during an SBO for the SPU.

Response:

The condensate inventory for decay heat removal was determined using the methodology in NUMARC 87-00, Section 7.2.1, which provides a bounding analysis for assessing condensate inventory. For the stretch power uprate (3230 MWt NSSS power), the volume of water required for 8 hours of decay heat removal and primary system cooldown to 325°F was determined to be nominally 150,000 gallons. Technical Specification 3.7.6 requires that a minimum of 360,000 gallons of water must be available in the Condensate Storage Tank (CST) during plant operation above 350°F. Accordingly, there is a large margin between the minimum required volume of water in the CST and the volume of water required for coping with an SBO event.

The design basis for IP2 is hot shutdown. The design basis for the CST volume is the CST inventory required to maintain the plant at hot shutdown for 24 hours following a reactor trip. Since the duration of the SBO event is less than 24 hours, it is bounded by maintaining hot shutdown for 24 hours. This is assured by the TS requirement of a minimum CST inventory of 360,000 gallons. The analysis of Section 4.2.4.1 demonstrates that SPU would require an increase from 284,000 to 291,381 gallons (based on 0.6% power uncertainty) or to 295,150 gallons (based on 2.0% power uncertainty) to satisfy the design basis requirement. Thus, considering the unavailable volume and other margins for the CST, the design basis requirement remains satisfied by the existing TS CST volume of 360,000 gallons.

The auxiliary feedwater pumps can draw from an alternative supply of water to provide for long-term cooling. This alternative supply is from the 1.5 million gallon city water storage tank. This supply is manually aligned to the auxiliary feedwater pumps in the event of unavailability of the condensate storage tank and the city water system.

Question 19:

Entergy proposed to change the AVs of several reactor protection system (RPS) trip functions and engineered safety feature actuation system (ESFAS) actuation functions specified in Tables 3.3.1-1 and 3.3.2-1, respectively. For each of those RPS and ESFAS functions that is proposed to have its AV changed, please provide the calculation of the channel statistical allowance for instrumentation uncertainties, and the current and revised (if revised) safety analysis limits (SAL) and nominal setpoint values.

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Response:

Please refer to the response to I&C Question 4, which provides the Westinghouse setpoint methodology uncertainty calculation tables for all protection system trip functions affected by the uprate, the calculation of the allowable values based on Entergy specification FIX-95-A-001, Rev. 1, and a summary table which identifies the current and revised SALs, nominal trip setpoints, and allowable values.

Question 20:

Many cycle-specific parameters have been relocated to the core operating limits report (COLR), which was not submitted with the SPU application. These include the values of the constants in the over-temperature and over-power ΔT functions, respectively (Notes 1 and 2 in Table 3.3.1-1), and the DNBR limiting values of the pressurizer pressure, RCS average temperature, and RCS total flow rate (LCO 3.4.1). Provide either the COLR or the values of these parameters.

Response:

The IP2 Licensing Report (Attachment III of NL-04-5) provides the values for DNB-related constants and limiting values in Section 6.3.1 on pages 6.3-3 through 6.3-6. Additional information regarding the limiting Safety Analysis Limits (SALs) and Nominal Trip Setpoints (NTSs) is provided in Table 6.10-1 for those items that changed as a result of the SPU. Items not listed in Table 6.10-1 were not changed by the SPU. Additional comparative information is also provided in the response to I&C item IC-4 Table IC-1 which provides comparison of before and after values for the RPS and ESFAS parameters that changed as a result of the SPU.

The cycle-specific values for the COLR are not yet available (the reload design process will complete the revised COLR in September 2004), but will be bounded by the SAL and NTS values provided in Table 6.10-1. The preliminary COLR values for pressurizer pressure, RCS average temperature, and RCS total flow rate are pressurizer pressure of ≥ 2216 psia, RCS average T_{avg} temperature of ≤ 565.1°F and highest loop T_{avg} of ≤ 568.1°F, and RCS total flow rate of ≥ 348,300 gpm.

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Table 6.10-1 IP2 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	≤109% rated thermal power (RTP)	116% RTP	≤110.6% RTP
Overtemperature ΔT Reactor Trip			≤4.9%ΔT span above computed setpoint
K_1 Max		1.42	
K_1 Nominal	≤1.22		
K_2	0.020 /°F	0.020 /°F	
K_3	0.00070 /psi	0.00070 /psi	
f(ΔI) Function Between (-30% and +7%)	0	0	
Positive Slope (ΔI>7%)	2.25% RTP/%ΔI	2.25% RTP/%ΔI	
Negative Slope (ΔI<-30%)	1.97% RTP/%ΔI	1.97% RTP/%ΔI	
Overpower ΔT Reactor Trip			≤2.4% ΔT span above computed setpoint
K_4 Max		1.164	
K_4 Nominal	≤1.074		
K_5 (decreasing T_{avg})	0	0	
K_5 (increasing T_{avg})	0.0188/°F	0.0188/°F	
K_6 (T≥T")	0.0015/°F	0.0015/°F	
K_6 (T<T")	0	0	
RCS Flow Low Reactor Trip	≥92% loop flow	85.0% flow	≥88.7% loop flow
Steam Generator Water Level – Low-Low Reactor Trip	≥7% span	0% span	≥3.4% span
Steam Generator Water Level – High-High Feedwater Isolation	≤73% span	90% span	≤88.3% span
Steamline Pressure Low (safety injection/steamline [SI/SL] actuation)	≥565.3 psig	515.3 psig	≥540.3 psig

Environmental Considerations RAIs

Question 1:

Section 5.7 of the application report states that the "original environmental evaluations were conducted at 3216.5 MWt (AEC SER dated 10/19/1970)." Confirm the correctness of this statement.

Response:

The statement contains a typographical error in the date of the reference. The correct date is November 16, 1970. An additional reference to NRC SER dated March 7, 1990 (pages 23 and 24) will provide reference to NRC Staff statements.

Question 2:

Section 5.7 states that no environmental impact statement or environmental evaluation was required for the 1990 power uprate. On December 6, 1989, the NRC staff published an environmental assessment (see 54 FR 50459) for the March 3, 1990, power uprate. Provide a change to the statement in Section 5.7.

Response:

See response to RAI No. 1 above. The characterization was made because the staff stated that the uprate was within the bounds of the original at 3216.5 MWt. Licensee is well aware that the required environmental assessment was performed as documented in 54FR 50459 to 50460 and did not intend to imply otherwise.

Question 3:

Section 5.7 states that the current power uprate qualifies for a categorical exclusion under 10 CFR 51.22(c)(9). Provide the environmental evaluation performed for the proposed power uprate in accordance with Appendix B of the facility operating license. The response should include a discussion of the radiological and non-radiological impacts of the proposed uprate.

Response:

Introduction

The environmental evaluation of the impact of the IP2 Stretch Power Uprate (SPU) is provided in the IP2 SPU Licensing Submittal Attachment 3 in accordance with Appendix B of the Facility Operating License. The evaluation concludes that the proposed license amendment to increase rated thermal power to 3216 MWt and 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 10CFR51.22(c)(9).

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The radiological analysis for annual radwaste effluent releases estimates the impact of uprate on normal operation offsite doses using scaling techniques. The system parameters for uprated conditions reflect the flow rates and coolant masses at a NSSS power level of 3228.5 MWt and a core power level of 3280 MWt. The evaluation utilizes offsite doses based on an average 5 yr set of organ and whole body doses calculated from effluent reports for the years 1997 through 2001 including the associated average annual core power level extrapolated to 100% availability. Releases occurring during periods of Unit shutdown are conservatively lumped with operational releases and included in the doses scaled for 100% availability.

The qualitative assessment is based on methodology and equations found in NUREG-0017 Rev. 1 (Ref 1) with the plant specific parameters for the core uprate case calculated. Relative changes in the noble gas activity inventory in the reactor coolant are also calculated; this is necessary for those releases, which are based on coolant inventory such as noble gas released during shutdown operations. To estimate an upper bound impact on off-site doses, the highest factor found for any chemical group of radioisotopes pertinent to the release pathway is applied to the average doses previously determined as representative of operation at pre-uprate conditions (at 100% availability) to estimate the maximum potential increase in effluent doses due to the uprate and demonstrate that the estimated off-site doses following uprate, although increased, will continue to remain below regulatory limits.

The criteria used in the evaluation include a liquid and gaseous radwaste systems' design capable of maintaining normal operation offsite releases and doses within the requirements of 10CFR50, Appendix I (Ref. 2) following power uprate. (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 Technical Specifications and the Offsite Dose Calculation Manual.) The non-radiological impact of the IP2 SPU to 3216MWt was reviewed and evaluated considering the information contained in the Final Environmental Statement (FES) (Ref. 3) for the station. Section 1 of Appendix B of the Facility Operating License requires environmental concerns identified in the FES that relate to water quality matters to be regulated by way of the State Pollutant Discharge Elimination System (SPDES) permit (Ref. 4) limits. The Indian Point SPDES restrictions on discharge temperatures and discharge flow rates for the station were evaluated along with the flow limits set forth in IP2 Consent Order (Ref. 5).
The criteria used in the evaluation required that the environmental impacts associated with the proposed changes be within the existing regulatory release permits.

Uprate Evaluation

Radiological Effects

The power uprate has no significant impact on the expected annual radwaste effluent releases/doses (i.e. all doses remain a small percentage of allowable Appendix I doses) as summarized below. The estimated impact of uprate on normal operation radwaste effluents is documented in Ref. 6 and is summarized below.

Environmental Considerations RAIs

1. Expected Reactor Coolant Source Terms

The requested SPU is 3.26% reactor power and the source term would increase by the same amount. However, based on a comparison of base vs. power uprate input parameters, and the methodology outlined in NUREG 0017, the effective power increase is 1.115. From this the maximum expected increase in the reactor coolant source is calculated. This increase is well within the uncertainty of the existing (NUREG 0017 based) expected reactor coolant isotopic inventory used for radwaste effluent analyses.

2. Estimated Impact on Effluent Doses due to Uprate

Gaseous Effluents:

(1) Pathways (Gaseous)	Total Body mrem	Skin Mrem	Thyroid mrem	Bone mrem
a) Noble Gas Immersion	1.10E-02	3.09E-02	N/A	N/A
b) Inhalation	1.16E-02	N/A	1.13E-02	5.29E-02
c) Ground Deposition	1.41E-02	1.65E-02	1.41E-02	1.37E-02
d) Milk Ingestion	7.57E-02	N/A	8.39E-02	3.56E-01
e) Meat Ingestion	1.31E-02	N/A	1.31E-02	6.53E-02
f) Vegetable Ingestion	2.67E-01	N/A	2.69E-01	1.33E+00

Liquid Effluents:

SKIN	BONE	LIVER	TOTAL BODY	THYROID	KIDNEY	LUNG	GI-LLI
mrem	mrem	mrem	mrem	mrem	mrem	mrem	mrem
8.10E-03	2.48E-01	2.22E-01	1.40E-01	8.25E-03	7.95E-02	3.27E-02	1.46E-01

The estimated doses due to uprate are presented above and are a fraction of that allowable under Appendix I.

3. Solid Radioactive Waste

Though solid radwaste is not specifically addressed in 10 CFR 50, Appendix I, for completeness relative to radwaste assessments, the impact of core uprate 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 would not be expected to increase proportionally, since the power uprate neither appreciably impacts 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

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increase proportionately to the increase in long half-life coolant activity bounded by maximum increase in power.

Therefore, following uprate, the liquid and gaseous radwaste effluent treatment system will remain capable of maintaining normal operation offsite doses within the requirements of 10 CFR 50 Appendix I. Only minor, if any, changes in solid waste generation volume are expected.

Non-Radiological Effects

The IP2 FES that was approved by the AEC in September 1972 for a maximum calculated thermal power of 3,216 MWt envelops the SPU condition. Increased heat rejection to the plant systems is expected to result in a nominal calculated increase in discharge temperature to the Hudson River. This temperature increase falls within the applicable SPDES permit thermal limits for Indian Point.

Final Environmental Statement (FES)

The environmental issues associated with the issuance of an operating license for Indian Point Unit 2 were originally evaluated in the Indian Point Unit 2 FES that was approved by the AEC in September 1972. The AEC approved Final Environmental Statement (FES) relates to operation of Indian Point Nuclear Generating Plant Unit No. 2 (Volume 1, page I-1 Section I) and has addressed plant operation up to a maximum calculated thermal power of 3,216.5 MWt. The SPU does not significantly change the types or the amount of any effluents that may be released offsite that have not already been evaluated and approved in the FES for a power rating of 3,216.5 MWt. Since the AEC approved FES has already addressed plant operation up to a maximum calculated thermal power of 3,216.5 MWt, the SPU has been determined to not significantly impact the FES.

State Pollutant Discharge Elimination System (SPDES) Permit and Consent Order Flows

The State Pollutant Discharge Elimination System (SPDES) permit places restrictions on discharge temperatures and discharge flow rates to the river for the station. The Indian Point SPDES restrictions on discharge temperatures and discharge flow rates for the station were evaluated along with the flow limits set forth in Indian Point 2 Consent Order.

IP2 operation at the SPU 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 Circulating Water System (CWS) to the Hudson River. The SPU evaluation assumes the existing CWS pumps are not modified and continue to operate at the same flow rates. Since the CW inlet temperatures from the Hudson River are not affected by the SPU and circulating flow is unchanged, the CW discharge temperature to the Hudson River will increase. Heat load increases due to SPU in the Normal and Emergency Service Water System (SWS) will also result in increase in the SWS discharge temperature to the Hudson River.

The SPDES permit has the following limitations that regulate the discharge temperature:

The maximum discharge temperature from DSN001 shall not exceed 110°F (43.3°F), and

Environmental Considerations RAIs

Between April 15 and June 30 the daily average discharge temperature from DSN001 shall not exceed 93.2°F (34°C) for an average of more than 10 consecutive days per year during the term of the permit beginning with 1981; provided that in no event shall the daily average discharge temperature at DSN001 exceed 93.2°F on more than 15 days between April 15 and June 30.

Increased heat rejection to the CWS and SWS is expected to result in a nominal calculated increase in discharge temperature to the river of approximately 17.5°F. The discharge temperatures were evaluated in Ref. 5 using the heat balance model. The temperature rise across each condenser from the model was tuned based on plant data from July 28, 2003. Consent order flows were used as input to the PEPSI model and outlet circulating water temperatures calculated. A 0.5°F value was added to the calculated temperature to account for miscellaneous plant cooling to determine plant discharge temperature. Plant historic data for the river water inlet temperature was iterated so as to result in the maximum plant discharge temperature as dictated by the permit.

Increased heat rejection to the CWS and SWS is expected to result in a nominal calculated increase in plant discharge temperature to the river of approximately 18°F. This temperature increase falls within the applicable SPDES permit thermal limits for the Station.

References

1. NUREG 0017, Rev. 1, April 1985, "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors"

2. Code of Federal Regulations Title 10, Part 50, 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".

3. Final Environmental Statement Related to Operation of Indian Point Nuclear Generating Plant Unit No. 2, Consolidated Edison Company of New York, Inc. Docket No. 50-247, September 1972, Volume 1

4. New York State Department of Environmental Conservation, State Pollutant Discharge Elimination System (SPDES) Discharge Permit, 11/90

5. Fourth Amended Stipulation of Settlement and Judicial Consent Order, Index No. 6570-91, RJI No. 0191-ST3251

6. NL-02-065, Indian Point Units 1 and 2 Docket No. 50-3 and No. 50-247 "Annual Effluent and Waste Disposal Report for 2001", May 1, 2002

Flow-Accelerated Corrosion Program RAIs

Question 1:

Section 10.3 addresses the flow-accelerated corrosion (FAC) program for IP2. The program consists of inspecting selected components and using the inspection results to qualify all the FAC-susceptible components for further service. In order to evaluate the FAC program, the staff requests that the applicant provide the following additional information:

a. Describe the program used in evaluating FAC for IP2. Specify the predictive code used and its application in the FAC program.

b. Describe the criteria used in the FAC program for selecting components for inspection.

c. Describe the criteria for repair or replacement of components that become damaged as a result of FAC.

d. For the five components most susceptible to FAC, provide the changes in velocity and temperature that result from the SPU.

e. For the five components most susceptible to FAC, provide the changes in predicted wear rate that result from the SPU.

Response 1a:

The program used in evaluating FAC for IP2 is described in SE-SQ-12.318, Flow Accelerated Corrosion Program Plan. This plan was established to consolidate information and plans concerning wet steam corrosion issues in a single umbrella document. It implements the inspection program cited in the UFSAR Section 10.4. The predictive code used in the FAC program is EPRI Checworks Flow Accelerated Corrosion Application Version 1.0G.

The approach of this program is based on a comprehensive and continual engineering review of the plant design, available technical information, and experience at Indian Point 2 and other plants. The program was developed consistent with the guidelines provided by INPO, NRC, and EPRI and includes the following:

Identification of susceptible systems – A detailed engineering review was performed to identify all FAC susceptible piping systems. Screening criteria used to exclude non-susceptible piping segments from further FAC analysis include: low temperature, piping material other than carbon steel, systems other than water or wet steam, raw water systems, and systems with no flow or operate less than 2% of operating time.

Checworks Modeling – EPRI's Checworks computer model is used for pipe wear predictions when the piping can be modeled. Input to the model includes heat balance information, steam cycle data, water chemistry, operating time, and piping and component data to analytically identify trouble areas for inspection. When the Checworks model accurately reflects the plant, inspection results are added into the model. A wear rate analysis is performed to generate predicted FAC rates and calculated life expectancies of uninspected components. Inspection

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results are compared to predicted results to ensure accurate model calibration. Results that do not fall within specified limits as per the Checworks user guide are investigated as to the reason and to determine if an updated FAC analysis should be performed and/or additional inspection locations specified.

Large Bore Non-Checworks (LBNCW) Systems – These systems are large bore (>2") FAC susceptible systems that are not suitable for Checworks modeling (i.e. vent lines, gland steam, aux. steam, recirculation lines, high level dump lines, bypass lines, etc.) In general, these systems have usage and flow rates that cannot be accurately quantified because demand and operating conditions greatly vary or are controlled by a remote level, pressure, or temperature signal. LBNCW FAC susceptible systems are determined through the screening process described above. The intent of this methodology is to ensure adequate inspection coverage of LBNCW FAC susceptible systems and assure the structural adequacy of uninspected components.

Typically the most susceptible components include, but are not limited to:

- Downstream of Control Valves
- Vent Lines
- High Level Dump Lines
- Bypass lines
- Discharge Nozzles
- Orifices
- Areas with Concentrated Geometry Changes (i.e. fitting bound elbows, etc.)
- Drain Tanks, Shells of MSR's, Feedwater Heaters, etc.
- Normally closed valves with a potential for leakage.

Small-Bore Systems – These systems are small bore (<2") FAC susceptible systems that are determined by the screening process previously described. These systems include socket welded piping that cannot be accurately modeled using Checworks due to the many uncertainties such as unknown operating conditions, percent of usage and fit-up gaps between the piping and sockets. Systems determined to be high wear are considered for complete replacement with a FAC resistant material.

Component Reinspection, UT Trending – Components that have been inspected are re-examined at a frequency consistent with the calculated component remaining service life based on the inspection results. Components are also reinspected for other reasons, including suspect or questionable inspection results, predicted life is less than the time to the next refueling outage, baseline inspection after component repair or replacement, and monitoring of component wear at a specified time interval. A computerized database is utilized to record historical component inspection data, help schedule components for reinspection and record other important component information.

Closed and Low Usage Boundary Valves – Industry experience has identified seat leakage problems with valves that are closed or see very low usage during normal operation. The leakage can cause FAC in lines that were previously screened out of the FAC program due to

Flow-Accelerated Corrosion Program RAIs

low usage. A review was performed to identify all valves that are closed during normal operation and which act as a FAC susceptibility boundary.

Plant and Industry Experience – Plant specific experience is taken into consideration in the identification of susceptible systems and components. Plant experience considered includes: historical UT data, maintenance records, repair and replacement data, and interviews with plant personnel to solicit specific operational and maintenance information. Industry experience is obtained directly from an industry source such as the Checworks Users Group (CHUG) or INPO. It is also obtained from discussions with peer engineers at other nuclear facilities. Documents that contain industry experience include USNRC Information Notices, EPRI Reports, and Nuclear Network Reports.

The inspection points derived from the above are used to ultimately produce a "Master Inspection List" of inspection points for a particular inspection period.

Response 1b:

The FAC program draws on the following sources to determine the components selected for inspection.

Large Bore Components from Checworks Analysis - Checworks inspection locations are selected based on the following criteria:

Components predicted to have a service life less than the time to the next inspection interval. These include components identified for reinspection, as well as components with a negative "time to t_{crit}" ranking in the Checworks Pass 2 analysis.
At least one of the highest wear components inspected during the previous inspection interval.
Additional high wear components predicted by Checworks.

Large Bore Non-Checworks Systems - LBNCW inspection locations are selected based on the following criteria:

Potential for susceptibility is based on FAC engineering judgment, plant experience, and industry experience. In addition, a review of historical inspection and replacement data is performed to ensure the most susceptible components are inspected.

If the most susceptible component(s) has been previously inspected, select the next highest ranked component for inspection. Relative susceptibility as determined by the FAC engineer normally includes materials, operational, plant experience, industry experience, and FAC judgment considerations.

Additional locations are considered for inspection on sub-segments where it is determined that there are an insufficient number of inspections to adequately identify susceptibility or if there have been a number of replacements on the segment.

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Discussions are held with the operations/systems/maintenance personnel regarding susceptible systems to determine current operational/functional parameters. This may identify specific locations that are highly susceptible which should be added as inspection points.

Determine whether the line or similar lines in a parallel train have had any historical component operational failures such as oscillating control valves or eroded orifices. This may greatly influence flow velocities and conditions and is considered in the selection of inspection locations.

Small Bore Systems *– Small bore piping system inspection locations are based on the following criteria:*

The inspection location selection process consists of a review of the susceptible systems including review of the isometric drawing(s) and flow diagrams for each small bore system to ensure adequate coverage of highly susceptible areas. Highly susceptible areas include, but are not limited to:

- Control Valves
- Discharge Nozzles
- Orifices
- Steam Traps
- Areas with Concentrated Geometry Changes
- Normally closed valves with leakage potential

As with the Large Bore Non-Checworks systems, inspections are based on FAC engineering judgment, plant experience, and industry experience, and a review of historical inspection and replacement data is performed to ensure the most susceptible components are inspected.

Based on the amount of piping, the operating conditions, the extent of coverage of susceptible areas and previous inspection results, a judgment is made as to the adequacy of inspection coverage.

On lines with adequate inspection coverage, a judgment is made as to the susceptibility of the line as either high or low. Repeat inspection of several components may be required before an accurate judgment of susceptibility can be made.

Systems that lack coverage of highly susceptible components have additional locations specified to determine the level of susceptibility. The inspection sample should include the areas detailed above and as many other locations as necessary to adequately judge the susceptibility of the system.

Systems determined to be high wear should be considered for complete replacement with a FAC resistant material as soon as reasonably possible. If replacement cannot be performed before the unit is returned to service, inspection will be expanded to quantify the extent of wear in the system. Additional inspection should be performed in future outages until replacement can be completed.

Flow-Accelerated Corrosion Program RAIs

Systems determined to be low wear require minimal future monitoring of the highest ranked components to ensure the level of susceptibility does not change. If significant wear is found during future inspections, the system should be reclassified as high wear.

Prior to each inspection interval, the susceptible systems are discussed with representatives from operations, maintenance and system engineering to determine current operational/functional parameters. The discussions may identify specific locations that are highly susceptible which should be added as inspection points. Consideration is also given to areas where industry experience has demonstrated a potential for susceptibility.

Component Reinspection Considerations - Components are scheduled for reinspection for several reasons:

- Suspect or questionable inspection results, which require confirmation.
- The predicted life is less than the time to the next RFO (i.e., prior to replacement).
- Baseline inspection after component repair or replacement.
- Monitoring of component wear at a specified time interval.

Prior to each refueling outage, all inspection data taken during the most recent refueling outage is incorporated into a spreadsheet with new locations specified as necessary. The spreadsheet contains all the mathematical computations to determine the next inspection interval.

A component is scheduled for reinspection based on the time of component inspection, the calculated remaining service life and the refueling outage schedule for the plant. The time of reinspection (T_{reinsp}) is determined by the sum of the time of the component inspection and the calculated remaining service life. The component will be reinspected prior to the calculated T_{reinsp}.

Closed and Low Usage Boundary Valves - A review is performed to identify all valves that are closed during normal operation and which act as a FAC susceptibility boundary. The list of valves was then screened against the following criteria to develop the final closed and low usage boundary list. From this list the components with the highest susceptibility are selected for inspection.

- All valve types except safety relief and check valves are reviewed.
- Only closed valves on lines >2" are included on the list.
- Valves on dry steam lines are included on the list because of potential changes in steam quality.
- Valves on lines that are capped are not included on the list.
- Valves on lines < 200°F are not included on the list unless there is a potential for flashing flow.
- Valves on the heating steam, auxiliary steam and auxiliary condensate systems are not included on the list due to a low consequence of failure.
- Valves on the auxiliary feedwater system are not included on the list as the system operates less than 2% of the total operating time.
- Valves on lines constructed of stainless steel or chrome-moly are not included on the list.
- Double isolation valve configurations are not included on the list.

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Prior to each refueling outage, a trouble report search encompassing the previous operating cycle is performed to identify seat leakage on all valves on the closed and low usage boundary list. All valves identified with seat leakage are considered for inspection during the next refueling outage.

Plant and Industry Experience - The nature and criteria for any particular review cannot be codified in advance. A form entitled "Plant and Industry Experience" is filled out to maintain a consistent process. Various actions may be required as a result of the evaluation process on any given topic. The following are some examples:

Inspection Plan Modification – A specific location identified as a potential problem area may be added to the inspection scope for the next refueling outage to determine FAC susceptibility. The results of the inspection will determine the need for future inspection consideration.

Checworks Model Modification – The Checworks model for a system or portion of a system determined to be operated differently than currently modeled would be updated to determine the potential effects on FAC.

Susceptibility Screening Update – A system or portion of a system currently screened out of scope that is identified as having an operational change, which may affect FAC potential will be considered for inclusion in the FAC program.

Response 1c:

Using the inspection results, the wear rate and predicted thickness at a future inspection date, usually the next refueling outage, is calculated. If the predicted thickness is greater or equal to 87 ½% of the component nominal thickness (Tnom), the component is acceptable for continued service. The 87 ½ % of Tnom represents the thinnest pipe wall allowed by the pipe manufacturers tolerances (± 12 ½ % T nom). If the predicted thickness is less than or equal to 30% of Tnom, the component is to be repaired or replaced.

For instances when the predicted thickness is between the two extreme cases (87 ½% and 30% of Tnom), a structural evaluation is required. The structural evaluation is to satisfy the pipe code stress requirements for both hoop and axial directions. Based on the structural evaluation, if the component meets both the hoop and axial stress requirements, for the predicted wall thickness at the end of the operating cycle, the component is acceptable for continued operation. For localized defects, a local wall thinning evaluation, using the methods described in the applicable ASME Code Cases may also be performed to determine the structural capabilities of the thinned component using the predicted wall thickness for the end of the operating cycle. Components that are found to be unacceptable for continued operation by either of the above two methods, are repaired or replaced prior to continued operation.

Response 1d and 1e:

A review was performed of the Checworks model wear rate analyses based on the current operating conditions. The Checworks runs showing the highest average wear rates and lowest average remaining service life were selected. From these runs, five components with the

Flow-Accelerated Corrosion Program RAIs

highest current wear rate were selected for analysis as the most susceptible to FAC under the SPU conditions.

The results of this analysis indicate that the impact of SPU on the velocity, temperature and wear rate of these components was less than 10%. IP2 will be updating the Checworks model to determine the impact of the SPU on all other components. Should the update identify other components with higher wear rates, they will be inspected at a frequency required to detect and correct wall thinning prior to challenging the structural integrity of the system.

Protective Coatings Program RAIs

Question 1:

Discuss how the SPU affects the protective coatings program at IP2. If changes in the protective coatings program occur, describe them in detail and explain what steps are taken to address them. The discussion should include:

a. How the qualification of the Service Level 1 coatings are impacted by SPU temperature and pressure conditions.

b. Whether the qualification parameters (e.g., temperature, pressure, etc.) for Service Level 1 coatings will continue to be bounded by SPU design-basis accident (DBA) conditions.

c. Actions that will be taken if the qualification of Service Level 1 coatings are not bounded by the SPU/DBA conditions, since coating failure could threaten performance of the ECCS sump after a LOCA.

Response 1a:

The SPU temperature and pressure conditions are below or bounded by the DBA test parameters in ANSI N101.2. Since the Service Level I coatings used at IP2 have been tested to ANSI N101.2 there is no impact from the SPU temperature and pressure conditions.

Response 1b:

The Service Level 1 coatings at IP2 will continue to be bounded by the DBA parameters specified in ANSI N101.2.

Response 1c:

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

Steam Generator Structural Integrity Evaluation RAIs

Question 1:

Section 5.6 (Results) of the application report (page 5.6-7) states "The results of the evaluation show that all components analyzed meet ASME Code Section III limits for a 40-year design life." However, the results table (Table 5.6-2) indicate that the fatigue usage factor for the secondary manway bolts increases from 0.979 to 1.165 (the design limit is 1.0) as a result of the SPU, and a footnote on the table states that the bolts "... must be replaced after 34 years of operation, or sooner."

Provide a technical basis for the 34-year target for replacement of the secondary manway bolts. Describe how the bolt replacement target will be incorporated into your plant maintenance procedures.

Response:

The IP2 replacement steam generators use studs, not bolts. Although an analysis was performed for both studs and bolts, the bolt analysis is not applicable and is not needed for the proposed uprate.

Question 2:

With regard to mechanical plugs, the application report states on page 5.6-10 (Conclusions) that, "... both the long and short mechanical plug designs satisfy all applicable stress and retention acceptance criteria at the SPU condition with up to 10-percent tube plugging.", and that, "... mechanical plugs have been previously qualified for the SPU condition with up to 25-percent tube plugging." The licensee states on page 5.6-10 (Results) that, "The plug meets the Class 1 fatigue exemption requirements per N-415.1 of the ASME Code..."

a. Provide a table (similar to Table 5.6-2 for the primary and secondary side components) which summarizes the load conditions, stress categories, ASME allowables, and all applicable stress- and fatigue-related calculation results that support your conclusions for the mechanical plugs. Show the calculation results which indicate that ASME allowables were met.

b. Provide calculation results which show that the mechanical plugs are qualified for the SPU condition with up to 25% tube plugging.

c. Provide the basis and calculation results (if any) for satisfying the ASME Class 1 fatigue exemption requirements

Steam Generator Structural Integrity Evaluation RAIs

Response 2a:

The response this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments II and III, respectively.

Response 2b:

The analysis performed for the mechanical plugs covered two power uprate projects. The first being a 1.4% MUR plant uprate with a 25% tube plugging. The second is the 3.26% SPU condition with a 10% tube plugging. The values that are presented in the responses to RAI #2A and #2C envelop both IP2 uprates. The work performed for the 3.26% SPU project does not cover tube plugging greater than 10%.

Response 2c:

The response this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments II and III, respectively.

Question 3:

With regard to shop weld plugs, the licensee states on page 5.6-11 (Conclusions) that, "All primary stresses are satisfied for the weld between the weld plug and the tubesheet cladding.", and, "The overall maximum primary-plus-secondary stresses for the enveloping transient case of 'steady-state fluctuation' were determined to be acceptable.", and, "It was determined that the fatigue exemption rules were met, and, therefore, fatigue conditions are acceptable."

a. Provide a table (similar to Table 5.6-2 for the primary and secondary side components) which summarizes the load conditions, stress categories, ASME Code allowables, and all applicable stress- and fatigue-related calculation results that support your conclusions for the shop weld plugs. Show the calculation results which indicate that ASME allowables were met.

b. Provide the basis and calculation results (if any) for satisfying the ASME fatigue exemption requirements.

Response 3a:

The response this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments II and III, respectively.

Response 3b:

The response this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments II and III, respectively.

Steam Generator Structural Integrity Evaluation RAIs

Question 4:

With regard to the tube undercut qualification, the licensee states on page 5.6-12 (Conclusions) that, "The results of the stress evaluation of the IP2 model 44F steam generators determined that the stresses are within ASME Code allowable values. Also, fatigue usage factors were determined to remain less than 1.0."

Provide a table (similar to Table 5.6-2 for the primary and secondary side components) which summarizes the load conditions, stress categories, ASME allowables, and all applicable stress- and fatigue-related calculation results that support your conclusions for the tube undercut qualification. Show the calculation results which indicate that ASME allowables were met.

Response:

The response this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments II and III, respectively.

Question 5:

In Section 5.6.5 (RG 1.121 Analysis), the licensee summarized the results of an analysis that was performed to define the structural limits for various regions of the steam generator tube. The licensee also refers to RG 1.121 as providing guidance on calculating the allowable tube repair limit (i.e., utilizing the structural limit, a growth allowance, and eddy current measurement uncertainty allowance). However, the licensee did not conclude whether the revised structural limits support the tube repair limit currently in the TSs.

Confirm that the existing tube repair limit remains appropriate for operation under SPU conditions, and discuss your technical basis for reaching this conclusion. If the tube repair limit currently documented in the TSs needs to be modified, submit an appropriate TS change.

Response:

The existing tube repair limit of 40% remains appropriate under the proposed SPU conditions. During the first ISI for the replacement steam generators at IP2, Entergy inspected 100% of the tubes. The only detected degradation was wear at some anti-vibration bar (AVB) contact points. The wear was identified in 13 tubes and measured from 9 to 20% through wall (TW). The wear was not expected due to the design enhancements made in the U-bend region. The indications were considered anomalous and attributed to the fabrication process. The remaining AVB contact points had no detectable wear as predicted in the post fabrication stress report. The detection limit for wear at AVB intersections is 5% TW or less so it can be assumed that the maximum growth rate for AVB wear for the tubes remaining in service is 5% TW per cycle.

RG 1.121 provides guidance on calculating the allowable tube repair limit that takes into account operational degradation and measurement uncertainty. Under SPU conditions the tube structural limits for the Straight Leg, AVB, FDB and TSP provided in Table 5.6-3 of WCAP-16157-P are reduced slightly for the High T_{avg} conditions while they remain unchanged for the Low T_{avg} conditions. The Low T_{avg} limits are bounding. The eddy current uncertainty of 5%

Steam Generator Structural Integrity Evaluation RAIs

(Technique plus Analyst) is unaffected by the SPU. Calculations for the SPU have estimated the potential increase in wear due to changes in thermal/hydraulic conditions to be 46%. If that change is applied to the maximum AVB growth of less than 5% per cycle for the tubes remaining in service the resulting potential growth rates under SPU conditions is 7.5% TW per cycle. In accordance with improved technical specifications, the steam generators must be inspected after every refueling cycle. However, Entergy has applied for an extension to the inspection interval for two fuel cycles. In addition, there are proposed generic technical specifications that would allow routine inspection intervals of two cycles. Therefore, the operational degradation should encompass two cycles of operations. The maximum expected growth in AVB wear for two cycles is 15% under SPU conditions. When this growth and the 5% measurement uncertainty are subtracted from the tube structural limit at AVB supports, the resulting tube repair limit is above the improved technical specification limit of 40% TW.

For the remaining locations in the steam generator, no degradation has been found and the industry has found none to very limited degradation. In addition, the conditions for SPU will have a negligible effect on those areas. Therefore, the margin between the tube structural limits under SPU conditions and the current technical specification repair limit does not change and remains adequate. The tube repair limit of 40% currently documented in ITS 5.5.7.a.1.a remains appropriate for operation under SPU conditions and does not need to be modified.

Question 6:

In Section 5.5.6 (Tube Vibration and Wear), the licensee described the potential effects of the SPU on steam generator tube vibration and wear. Discuss the potential effects of the SPU on other modes of steam generator tube degradation (e.g., axial and/or circumferential cracking, pitting, etc.).

Response:

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 IP2 steam generators due to the SPU is discussed below.

The IP2 steam generators are Model 44F steam generators that use Alloy 600TT (thermally treated) tubes, and other design features (discussed below) that minimize the potential for tube degradation. Comparative studies (for example, EPRI TR-108501) of the performance of Alloy 600TT and Alloy 600MA have shown Alloy 600TT has superior resistance to corrosion compared to Alloy 600MA. Plants using Alloy 600TT have operated without evidence of PWSCC for over 15 effective full-power years (EFPYs) at hot leg operating temperatures of up to 618°F. The IP2 hot leg operating temperature is expected to be limited to 605.8°F (reduced from the currently approved temperature of 611.7°F) following an NSSS power uprating to 3230 MWt.

Steam Generator Structural Integrity Evaluation RAIs

Secondary side steam generator chemistry has contributed to tube cracking in some units. Concentration of caustic solutions in areas of stress concentration aids the initiation of cracking. Stress corrosion cracking of Alloy 600 tubing is believed to follow an Arrhenius relationship, therefore, the reduction of maximum temperatures in the steam generator (T_{hot}) should decrease the propensity for development of stress corrosion cracking.

ODSCC was reported in a plant with Alloy 600TT tubing in May 2002 after about 9.7 EFPYs of operation. The cause for the ODSCC in that plant has not yet been confirmed, but is believed to be attributed to an off-nominal tube material condition. The presence of the condition is believed to be observable using bobbin-coil eddy current inspection. Thus, if any tubes in the IP2 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 IP2 steam generators use design features that have been shown to effectively reduce the potential for stress corrosion cracking (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 9 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 decreasing the crevice area. Supplemental thermal treatment of the row 1 through 9 U-bends following bending is expected to reduce residual stresses to near straight leg region levels. In response to rapid PWSCC initiation in small-radius U-bends in plants with Alloy 600MA tubing, an in situ heat treatment process was developed in the 1980s. Application of this process in plants prior to operation has resulted in a greatly reduced potential for PWSCC initiation. Some of these plants (with MA tubing) have operated for up to 11 EFPYs at hot leg temperatures up to 620°F with no evidence of PWSCC initiation. The supplemental thermal treatment process, performed in the manufacturing phase for the IP2 steam generators, is expected to result in a more effective treatment compared to the in situ heat treatment process. The existing steam generator eddy current inspection program is in place to detect SCC. The condition monitoring assessment is used to confirm adequate tube integrity has been maintained since the prior inspection meeting the performance criteria. The operational assessment demonstrates reasonable assurance that the tube integrity performance criteria will be met throughout the period prior to the next scheduled tube inspection.

Question 7:

In Section 5.5.6 (Tube Vibration and Wear), the licensee states that thirteen tubes were identified with anti-vibration bar (AVB) wear during the steam generator inspections for refueling outage 15 (RFO-15), and that these thirteen tubes were administratively plugged. The licensee stated that, "The small number of tubes with AVB wear were judged to be outliers and not typical of the general tube behavior." In fact, the licensee's steam generator inservice inspection report for RFO-15 (ADAMS Accession No. ML023580031) stated that three of the

Steam Generator Structural Integrity Evaluation RAIs

plugged tubes experienced 20% through wall wear in three locations over two tubes.

Discuss the likely reasons for the anomalous wear in these two tubes, and discuss how increased vibrations due to SPU conditions might influence similar anomalously high AVB wear rates in tubes during future SPU operation

Response:

The flow-induced vibration analysis results referenced in the uprate analysis addresses the expected wear of the general population of steam generator tubes given the construction tolerances, geometry, and flow characteristics of the steam generators. The fact that 13 out of approximately 12,900 tubes (0.1% of the total population) exhibit wear in excess of what analysis predicts should not detract from the fact that the general population of tubes show no wear after one cycle of operation. It is not unexpected that some tubes may exist with local conditions that lie outside of expected parameters that will show wear outside of predicted limits. Although a few additional tubes with wear outside of the predicted performance may be anticipated, the wear conditions actually observed are expected to be the worst case from the initiation and growth perspective. The following discussion provides additional details in support of this position.

The driving mechanism for AVB wear, fluidelastic excitation of the u-bends resulting from cross-flow over the tubes, has been considered in the design of all models of Westinghouse steam generators, as evidenced the installation of anti-vibration bars (AVB) in the u-bend region. Nevertheless, the observation of significant AVB wear in the Model 51 steam generators led to a detailed study in the early to mid-1980s of the conditions leading to the wear. This study concluded that the dimensions of the tubes and AVBs, together with the limitations of the assembly methods could lead to local conditions where the AVBs might not provide support at one, or more, tube to AVB intersections. Indeed, a field replacement of AVBs was implemented in numerous steam generators, which eliminated as much of the clearance between the tubes and the AVBs as practicable. This field repair was very successful in eliminating AVB wear.

The same design objective – elimination, to the extent possible, of gap between tubes and AVBs – was implemented in second-generation replacement steam generators. Although the design of the u-bend structure in the IP2 replacement steam generators is nominally the same as that of the predecessor steam generators, the key difference lies in the dimensions and tolerances of the AVBs and tubes, resulting in a design with very small theoretical gaps between the tubes and the AVBs. As in any design process, the performance predictions are based on conservative assumptions of tolerances for the limiting conditions of the design, since the actual conditions after manufacturing cannot be precisely anticipated. This performance prediction concluded that very limited wear would occur among all tubes in general for the design dimensions and tolerances of the IP2 replacement steam generators. The subsequent uprating report concluded that a 46% increase in the predicted wear could occur due to the SPU conditions, resulting in a final prediction of about 2 mils wear over the 40 year lifetime of the steam generators. This conclusion applies for both the 1.4% Measurement Uncertainty Recapture uprate and the 3.26% SPU.

Anecdotal data indicate that the extremely tight tolerances of the design led to unanticipated difficulties during u-bend assembly. Thus, it is not unexpected that some local conditions may exist where wear greater than predicted in the design performance predictions could occur.

Steam Generator Structural Integrity Evaluation RAIs

This is similar to the original steam generators in which the practical limitation of the manufacturing process resulted in local conditions conducive to wear in an overall successful design for the bulk of the tubes. Although a few additional occurrences of wear greater than the performance predictions may be anticipated, the wear conditions actually observed are expected to be the worst case from the initiation and growth perspective.

Dose Assessment RAIs

Question 1:

For the fuel handling accident (FHA) the licensee assumed gap fractions from RG 1.25, which are higher than those in RG 1.183, because it could not ensure that all fuel would meet the limitations in Footnote 11 to RG 1.183 Table 3. However, RG 1.183 Table 3 gap fractions were utilized in the analysis of the locked rotor accident. Explain the basis for the different treatment of the fuel gap activity between the two accident analyses. Also, explain why the fuel subject to the FHA is not ensured to meet the RG 1.183 Table 3 footnote.

Response:

Analysis of the IP2 core shows that with the 15 x 15 fuel design, combined with the current fuel cycle length and the stretch power uprate, it can be expected that there will be high-burnup fuel that does not meet the limitations identified in Footnote 11 of RG 1.183 regarding the applicability of the Table 3 gap fractions. The analysis indicates that certain fuel assemblies may have all fuel rods outside the Footnote 11 guidelines of ≤6.3 kw/ft peak rod average power combined with a burnup >54,000 MWD/Mtu. The FHA analysis may involve any fuel assembly in the core and thus needs to consider the possibility that the accident may involve an assembly that has a burnup in excess of 54,000 MWD/Mtu together with peak rod average power >6.3 kw/ft.

For the locked rotor accident the fuel rods that would potentially be damaged due to violation of the DNB limit are those fuel rods operating at high power levels relative to core average. The high-burnup fuel rods would not be among the fuel rods operating at high power levels. Thus, it is appropriate to use the gap fractions from Table 3 of RG 1.183 for the locked rotor accident. For IP2 there is no predicted fuel damage. The assumption of 5% fuel damage has been adopted for the radiological consequences analysis in order to provide an analysis that would bound possible future changes. It is noted that if a large fraction of the core were predicted to fail, this argument would need to be examined further to confirm continued applicability.

Question 2:

The FHA is analyzed for fuel that has decayed 84 hours. By what means is an FHA prevented before that time?

Response:

IP2 Technical Specification basis page B 3.9.3-2 currently states "(i.e., fuel has decayed for greater than 100 hours)". As part of the Stretch Power Uprate, this page will be revised to change the 100 hours to 84 hours. Facility administrative controls will be revised to assure compliance with Technical Specifications and Bases.

Dose Assessment RAIs

Question 3:

The steam generator alkali metal partition coefficient (0.0025) used in several analyses is based on the steam generator moisture carryover percentage. How was the moisture carryover determined?

Response:

As stated in Section 5.6 of the report, the performance of steam generator 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 moisture carryover as a function of SP is used to predict the moisture carryover at defined conditions. The SP values for the IP2 SPU conditions were calculated using the results of the GENF program. The moisture carryover was calculated at the SPU conditions with 10-percent steam generator tube plugging and was determined to have a maximum value below the 0.25 percent design limit.

Question 4:

How were the LOCA dose emergency core cooling system (ECCS) leakage iodine airborne fractions determined? Provide a detailed explanation of the calculation or the calculation itself.

Response:

The calculations utilized the same methodology as contained in the Polestar calculations provided in the supplemental IP2 AST Pilot Program submittal provided April 13, 2000 in response to NRC Requests for Additional Information. As discussed in that submittal, the calculations determined iodine partition coefficients both with and without credit for boundary layer effects.

For the SPU application, the calculation inputs were revised to reflect an earlier switchover time to hot-leg recirculation (i.e. bringing ECCS recirculation fluid outside containment at 6.5 hours as opposed to the 24 hours assumed previously) including changes in fluid temperature. The results presented in the SPU LAR do not credit the boundary layer effect. As presented in the April 13, 2000 submittal, crediting boundary layer effect produces an additional DF of 10, reducing the resultant dose from ECCS leakage by a factor of 10.

Dose Assessment RAIs

Question 5:

For the volume control tank, gas decay tank and holdup tank failure dose analyses, the results were compared to a criterion of 0.5 rem total effective dose equivalent (TEDE). If a licensee chooses to change to a TEDE dose criterion for these non-design-basis accidents, the NRC staff's position is that these systems are evaluated against the dose limits for individual members of the public in 10 CFR 20.1301, and the regulatory dose criterion should be 0.1 rem TEDE. If the licensee would prefer to remain in its current licensing basis, the dose criterion remains 0.5 rem whole body. If Entergy chooses to update the licensing basis to TEDE for these analyses, the current analyses do not meet the regulatory criteria. Discuss how this issue is being addressed.

Response:

The NRC approval of the AST Pilot Program in 2000 did not address tank failures. These non-design basis accidents will not report TEDE doses, but will report thyroid, whole body and beta-skin (control room only) doses. Therefore, the doses for the three events are:

	Gas Decay Tank Doses (rem)			Volume Control Tank Doses (rem)			Holdup Tank Doses (rem)		
	Whole Body	Thyroid	Beta-Skin	Whole Body	Thyroid	Beta-Skin	Whole Body	Thyroid	Beta-Skin
Site boundary	0.14	NA	NA	0.30	2.7	NA	0.40	0.06	NA
LPZ	0.07	NA	NA	0.14	1.3	NA	0.19	0.03	NA
Control Room	0.05	NA	0.63	0.05	2.3	0.91	0.06	0.05	1.3

The offsite whole body doses are below the 0.5 rem limit defined in RG 1.26. The thyroid dose equivalent to 0.5 rem whole body is determined based on the organ dose-weighting factor of 0.03; this results in a thyroid dose limit of 16.7 rem. The offsite thyroid doses are all below this value.

The control room whole body doses are below the 5.0 rem limit defined in GDC 19. The thyroid and beta-skin dose limits in the control room have been defined in Section 6.4 of the SRP as 30 rem. The control room thyroid and beta-skin doses are below this value.

ATTACHMENT III TO NL-04-073

REPLY TO NRC REQUEST FOR ADDITIONAL INFORMATION REGARDING

PROPOSED LICENSE AMENDMENT REQUEST FOR

INDIAN POINT 2 STRETCH POWER UPRATE

Non-Proprietary version of responses containing proprietary information
(from Westinghouse transmittal PU2-W-04-024)

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 2
DOCKET NO. 50-247

I&C Question 4:

Provide setpoint calculation documents for the following protection system trip functions listed in Table 6.10-1 of application report:

- Overtemperature T Reactor Trip and Overpower T Reactor Trip functions.
- Reactor Coolant System (RCS) Flow Low Reactor Trip function.
- Steam Generator Water Level-Low-Low Reactor Trip function.
- Steam Generator Water Level-High-High Feedwater Isolation function.
- Steamline Pressure Low (safety injection/steamline [SI/SL] actuation).
- Steam Flow in Two Steamline-High (SI/SL actuation)
- T_{avg}-Low (SI/SL actuation).

Response:

The Westinghouse setpoint methodology uncertainty calculation tables for all protection system trip functions affected by the uprate are attached (Tables 2 – 13). Each Westinghouse setpoint methodology uncertainty calculation table includes the calculation of the allowable value, based on Entergy specification FIX-95-A-001, Rev. 1. These tables are preceded by Table 1, which summarizes the existing and uprate values for the safety analysis limits, nominal trip setpoints, technical specification allowable values, as well as the uncertainty calculation total allowance (TA), channel statistical allowance (CSA), and Margin for the SPU.

Westinghouse Non-Proprietary Class 3

TABLE 1: INDIAN POINT UNIT 2 STRETCH POWER UPRATE COMPARISON OF EXISTING AND UPRATED RPS/ESFAS PARAMETERS

Protection Function	Safety Analysis Limit		Nominal Trip Setpoint		TA	CSA	Margin	TS Allowable Value	
	Existing	SPU	Existing	SPU	SPU			+a,c Existing	SPU
NIS Power Range Reactor Trip High Setpoint	118% RTP	116% RTP	109% RTP	109% RTP				≤112.6% RTP	≤110.6% RTP
Overtemperature Delta T Reactor Trip								≤3.3% ΔT span above computed setpoint	≤4.9% ΔT span above computed setpoint
K1 max	1.40	1.42							
K1 nominal			1.22	1.22					
Overpower Delta T Reactor Trip								≤2.3% ΔT span above computed setpoint	≤2.4% ΔT span above computed setpoint
K4 max	1.154	1.164							
K4 nominal			1.074	1.074					
RCS Flow Low Reactor Trip	85.0% flow	85.0% flow	92% flow	92% flow				≥88.8% flow	≥88.7% flow
Steam Generator Water Level - Low Low Reactor Trip	0% span	0% span	7% span	7% span				≥3.7% span	≥3.4% span
Steam Generator Water Level - High-High Feedwater Isolation	80% span	90% span	73% span	73% span				≤77.7% span	≤88.3% span
Steamline Pressure Low (SI/SL Actuation)	400 psig	515.3 psig	525 psig	565.3 psig				≥425 psig	≥540.3 psig
Steam Flow in Two Steamlines – High (SI/SL Actuation)	(1)	(2)	(3)	(3)				(4)	(5)
Tavg – Low (SI/SL Actuation)	N/A	537°F	540°F	542°F				≥540.75°F	≥540.5°F

(1) 74% full flow between 0 and 20% load, increasing linearly to 144% full flow at 100% load
(2) 64% full flow between 0 and 20% load, increasing linearly to 144% full flow at 100% load
(3) 40% full flow between 0 and 20% load, increasing linearly to 110% full flow at 100% load
(4) ≤53.7% full flow between 0 and 20% load, increasing linearly to ≤110.8% full flow at 100% load
(5) ≤45.9% full flow between 0 and 20% load, increasing linearly to ≤122% full flow at 100% load

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TABLE 2

NIS POWER RANGE NEUTRON FLUX – HIGH

Parameter	**Allowance ***
Process Measurement Accuracy	[ ]+a,c
[ ]+a,c	
Primary Element Accuracy	
Sensor Calibration Accuracy	
[ ]+a,c	
Sensor Reference Accuracy	
Sensor Measurement & Test Equipment Accuracy	
Sensor Pressure Effects	
Sensor Temperature Effects	
Sensor Drift	
[ ]+a,c	
Environmental Allowance	
Rack Calibration Accuracy	
Rack Measurement & Test Equipment Accuracy	
Rack Temperature Effects	
Rack Drift	

* In % span (120% RTP)

Channel Statistical Allowance =

[ ]+a,c

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Allowable Value Calculation based on ENN Specification FIX-95-A-001, Rev. 1

$$NIS\_CSA := \sqrt{\begin{array}{l} NIS\_pma_1^2 + NIS\_pma_2^2 + NIS\_pea^2 \ldots \\ +(NIS\_smte + NIS\_sca)^2 + NIS\_sra^2 + (NIS\_smte + NIS\_sd)^2 + NIS\_spe^2 + NIS\_ste^2 \ldots \\ +(NIS\_rmte + NIS\_rca)^2 + (NIS\_rmte + NIS\_rd)^2 + NIS\_rte^2 \end{array}} \ldots$$
$$+ NIS\_EA$$

$NIS\_CSA = \lceil 4.8\%span \rceil$

$NIS\_CSA := NIS\_CSA \cdot Span\_to\_Power \qquad NIS\_CSA = \lceil 5.8\%RTP \rceil$

$$\varepsilon_{T\_s} := \sqrt{\begin{array}{l} NIS\_sra^2 + (NIS\_smte + NIS\_sca)^2 + (NIS\_smte + NIS\_sd)^2 + (NIS\_rmte + NIS\_rca)^2 \ldots \\ +(NIS\_rmte + NIS\_rd)^2 \end{array}}$$

$\varepsilon_{T\_s} = 1.7\%span$

$\varepsilon_T := \varepsilon_{T\_s} \cdot Span\_to\_Power \qquad \varepsilon_T = 2.0\%RTP$

$$H\varepsilon_{X\_s} := \sqrt{NIS\_pea^2 + NIS\_ste^2 + NIS\_rte^2 + NIS\_spe^2 + NIS\_pma_1^2 + NIS\_pma_2^2}$$

$H\varepsilon_{X\_s} = 4.5\%span$

$H\varepsilon_X := H\varepsilon_{X\_s} \cdot Span\_to\_Power \qquad H\varepsilon_X = 5.4\%RTP$

$NIS\_SAL_H := 116.0\%RTP$

$High\_AV_0 := NIS\_SAL_H - NIS\_CSA + \varepsilon_T$

Method 1 based on equation 5.12.2.4, page 62 of specification FIX-95-A-001, Rev. 1

$High\_AV_0 = 112.2\%RTP$

$High\_AV_1 := NIS\_SAL_H - H\varepsilon_X$

Check for infringement on AV based on last paragraph of Section 5.12.2, page 62, of specification FIX-95-A-001, Rev. 1

$High\_AV_1 = 110.6\%RTP$

$High\_Allowable\_Value := \min(High\_AV)$

AV is defined as the more conservative of the two values

$High\_Allowable\_Value = 110.6\%RTP$

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TABLE 3

OVERTEMPERATURE ΔT REACTOR TRIP

Parameter	Allowance *
Process Measurement Accuracy	[ ]+a,c
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
Primary Element Accuracy	
Sensor Calibration Accuracy	
[ ]+a,c	
[ ]+a,c	
Sensor Reference Accuracy	
[ ]+a,c	
[ ]+a,c	
Sensor Measurement & Test Equipment Accuracy	
[ ]+a,c	
[ ]+a,c	
Sensor Pressure Effects	
Sensor Temperature Effects	
[ ]+a,c	
Sensor Drift	
[ ]+a,c	
[ ]+a,c	
Environmental Allowance	
Bias	
[ ]+a,c	

* In % ΔT span (75°F)

** Span: R/E Th - 130°F, R/E Tc - 90°F; Tavg - 75°F; Pressure - 800 psig; Power - 150.0% RTP; ΔI - 120% ΔI

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TABLE 3 (continued)

OVERTEMPERATURE ΔT REACTOR TRIP

Parameter	**Allowance ***
Rack Calibration Accuracy	[ ]+a,c
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
Rack Measurement & Test Equipment Accuracy	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
Rack Temperature Effects	
[ ]+a,c	
[ ]+a,c	
Rack Drift	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	

* In % ΔT span (75°F)

** Span: R/E Th - 130°F, R/E Tc - 90°F; Tavg - 75°F; Pressure - 800 psig; Power - 150.0% RTP; ΔI - 120% ΔI

TABLE 3 (continued)

OVERTEMPERATURE ΔT REACTOR TRIP

Channel Statistical Allowance =

[ ] +a,c

Westinghouse Non-Proprietary Class 3

Allowable Value Calculation based on ENN Specification FIX-95-A-001, Rev. 1

$$CSA\_OT\Delta T := \sqrt{\begin{array}{l} pma_{Th}^2 + pma_{\Delta I\_1}^2 + pma_{\Delta I\_2}^2 + pma_{pwr\_cal}^2 + pea^2 \ldots \\ + \left[\sqrt{\dfrac{(smte\_rtd + sca\_rtd)^2 + sra\_rtd^2 + (smte\_rtd + sd\_rtd)^2}{N_H} \ldots + \dfrac{(smte\_rtd + sca\_rtd)^2 + sra\_rtd^2 + (smte\_rtd + sd\_rtd)^2}{N_C}}\right]^2 \ldots \\ + (smte\_pp + sca\_pp)^2 + sra\_pp^2 + (smte\_pp + sd\_pp)^2 + ste\_pp^2 \ldots \\ + \left[\sqrt{\dfrac{(re\_th\_mte + re\_th\_cal)^2 + (re\_th\_mte + re\_th\_drift)^2}{N_H} \ldots + \dfrac{(re\_tc\_mte + re\_tc\_cal)^2 + (re\_tc\_mte + re\_tc\_drift)^2}{N_C}}\right]^2 \ldots \\ + (dt\_rmte + dt\_rca)^2 + (dt\_rmte + dt\_rd)^2 + dt\_rte^2 \ldots \\ + (rmte\_Tavg + rca\_Tavg)^2 + (rmte\_Tavg + rd\_Tavg)^2 \ldots \\ + (rmte\_pp + rca\_pp)^2 + (rmte\_pp + rd\_pp)^2 \ldots \\ + (rmte\_NIS + rca\_NIS)^2 + (rmte\_NIS + rd\_NIS)^2 + rte\_NIS^2 \ldots \\ + (rmte\_\Delta I + rca\_\Delta I)^2 + (rmte\_\Delta I + rd\_\Delta I)^2 \\ + Bias\_pp + pma_{Tc} + pma_{budt} + pma_{butavg} + pma_{Tp\_Tr} + EA \end{array}}$$

$$CSA\_OI\Delta T = [\quad\quad]$$

$$OT\varepsilon_T := \sqrt{\begin{array}{l} \left[\sqrt{\dfrac{(smte\_rtd + sca\_rtd)^2 + sra\_rtd^2 + (smte\_rtd + sd\_rtd)^2}{N_H} \ldots + \dfrac{(smte\_rtd + sca\_rtd)^2 + sra\_rtd^2 + (smte\_rtd + sd\_rtd)^2}{N_C}}\right]^2 \ldots \\ + \left[\sqrt{\dfrac{(re\_th\_mte + re\_th\_cal)^2 + (re\_th\_mte + re\_th\_drift)^2}{N_H} \ldots + \dfrac{(re\_tc\_mte + re\_tc\_cal)^2 + (re\_tc\_mte + re\_tc\_drift)^2}{N_C}}\right]^2 \ldots \\ + (rmte\_Tavg + rca\_Tavg)^2 + (rmte\_Tavg + rd\_Tavg)^2 + (dt\_rmte + dt\_rca)^2 + (dt\_rmte + dt\_rd)^2 \ldots \\ + sra\_pp^2 + (smte\_pp + sca\_pp)^2 + (smte\_pp + sd\_pp)^2 + (rmte\_pp + rca\_pp)^2 + (rmte\_pp + rd\_pp)^2 \ldots \\ + (rmte\_NIS + rca\_NIS)^2 + (rmte\_NIS + rd\_NIS)^2 + (rmte\_\Delta I + rca\_\Delta I)^2 + (rmte\_\Delta I + rd\_\Delta I)^2 \end{array}}$$

$$OT\varepsilon_T = 6.7\%\Delta T$$

$$OT\varepsilon_X := \sqrt{pma_{Th}^2 + pma_{\Delta I\_1}^2 + pma_{\Delta I\_2}^2 + pma_{pwr\_cal}^2 + pea^2 + ste\_pp^2 + dt\_rte^2 + rte\_NIS^2 \ldots} + Bias\_pp + pma_{Tc} + pma_{budt} + pma_{butavg} + pma_{Tp\_Tr} + EA$$

$$OT\varepsilon_X = 8.4\%\Delta T$$

$OTDT\_SAL = 142.0\%RTP$

$K_{1.nom} = 122.0\%RTP$

$OTDT\_AV_1 := OTDT\_SAL + \Delta T_{span\_pwr} \cdot (-CSA\_OT\Delta T + OT\varepsilon_T)$

Method 1 based on equation 5.12.2.4, page 62 of specification FIX-95-A-001, Rev. 1

$OTDT\_AV_1 = 134.5\%RTP$

$OTDT\_AV_2 := OTDT\_SAL - (OT\varepsilon_X) \cdot \Delta T_{span\_pwr}$

Check for infringement on AV based on last paragraph of Section 5.12.2, page 62, of specification FIX-95-A-001, Rev. 1

$OTDT\_AV_2 = 129.4\%RTP$

$OT\_Allowable\_Value := \min(OTDT\_AV)$

AV is defined as the more conservative of the two values

$OT\_Allowable\_Value = 129.4\%RTP$

$$OT\_AV := \frac{OT\_Allowable\_Value - K_{1.nom}}{\Delta T_{span\_pwr}}$$

Convert to ΔT Units

$OT\_AV = 4.9\%\Delta T$

TABLE 4

OVERPOWER ΔT REACTOR TRIP

Parameter	**Allowance ***
Process Measurement Accuracy	[ ]+a,c
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
Primary Element Accuracy	
Sensor Calibration Accuracy	
[ ]+a,c	
Sensor Reference Accuracy	
[ ]+a,c	
Sensor Measurement & Test Equipment Accuracy	
[ ]+a,c	
Sensor Pressure Effects	
Sensor Temperature Effects	
Sensor Drift	
[ ]+a,c	
Environmental Allowance	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	

* In % ΔT span (75°F)

** Span: R/E Th - 130°F, R/E Tc - 90°F; Tavg - 75°F; Power - 150.0% RTP

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TABLE 4 (continued)

OVERPOWER ΔT REACTOR TRIP

Parameter	**Allowance ***
	[ ]+a,c
Rack Calibration Accuracy	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
Rack Measurement & Test Equipment Accuracy	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
Rack Temperature Effects	
[ ]+a,c	
Rack Drift	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	

* In % ΔT span (75°F)

** Span: R/E Th - 130°F, R/E Tc - 90°F; Tavg - 75°F; Power - 150.0% RTP

Channel Statistical Allowance =

[ ]+a,c

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Allowable Value Calculation based on ENN Specification FIX-95-A-001, Rev. 1

$$CSA\_O\Delta T := \sqrt{\begin{array}{l} pmTh^2 + pmpwr\_cal^2 + pe^2 \ldots \\ + \left[\sqrt{\dfrac{(smte\_rt + sca\_rt)^2 + sra\_rt^2 + (smte\_rt + sd\_rt)^2}{N_H} \ldots + \dfrac{(smte\_rt + sca\_rt)^2 + sra\_rt^2 + (smte\_rt + sd\_rt)^2}{N_C}}\right]^2 \ldots \\ + \left[\sqrt{\dfrac{(re\_th\_mt + re\_th\_c)^2 + (re\_th\_mt + re\_th\_dri)^2}{N_H} \ldots + \dfrac{(re\_tc\_mt + re\_tc\_c)^2 + (re\_tc\_mt + re\_tc\_dri)^2}{N_C}}\right]^2 \ldots \\ + (dt\_rmt + dt\_rc)^2 + (dt\_rmt + dt\_rd)^2 + dt\_rt^2 \ldots \\ + (rmte\_Tav + rca\_Tavg)^2 + (rmte\_Tav + rd\_Tavg)^2 \ldots \\ + (rmte\_Tav + rca\_Tavg)^2 + (rmte\_Tav + rd\_Tavg)^2 \end{array}} \ldots$$

$$+ pmTc + pmbudt + pmbutavg + pmTp\_Tr + EA\_d + EA\_Tav$$

$$CSA\_O\Delta T = \left[\qquad\right]$$

$$OP\varepsilon_T := \sqrt{\begin{array}{l} \left[\sqrt{\dfrac{(smte\_rtd + sca\_rtd)^2 + sra\_rtd^2 + (smte\_rtd + sd\_rtd)^2}{N_H} \ldots + \dfrac{(smte\_rtd + sca\_rtd)^2 + sra\_rtd^2 + (smte\_rtd + sd\_rtd)^2}{N_C}}\right]^2 \ldots \\ + \left[\sqrt{\dfrac{(re\_th\_mte + re\_th\_cal)^2 + (re\_th\_mte + re\_th\_drift)^2}{N_H} \ldots + \dfrac{(re\_tc\_mte + re\_tc\_cal)^2 + (re\_tc\_mte + re\_tc\_drift)^2}{N_C}}\right]^2 \ldots \\ + (dt\_rmte + dt\_rca)^2 + (dt\_rmte + dt\_rd)^2 + (rmte\_Tavg1 + rca\_Tavg1)^2 + (rmte\_Tavg1 + rd\_Tavg1)^2 \ldots \\ + (rmte\_Tavg2 + rca\_Tavg2)^2 + (rmte\_Tavg2 + rd\_Tavg2)^2 \end{array}}$$

$$OP\varepsilon_T = 3.2\%\Delta T$$

$$OP\varepsilon_X := \sqrt{pma_{Th}^2 + pma_{pwr\_cal}^2 + pea^2 + dt\_rte^2 \ldots} + pma_{Tc} + pma_{budt} + pma_{butavg} + pma_{Tp\_Tr} + EA\_dt + EA\_Tavg$$

$$OP\varepsilon_X = 3.6\%\Delta T$$

$OPDT\_SAL = 116.4\%RTP$

$K_{4.nom} = 107.4\%RTP$

$OPDT\_AV_1 := OPDT\_SAL + \Delta T_{span\_pwr} \cdot (-CSA\_OP\Delta T + OP\varepsilon_T)$

$OPDT\_AV_1 = 112.7\%RTP$

Method 1 based on equation 5.12.2.4, page 62 of specification FIX-95-A-001, Rev. 1

$OPDT\_AV_2 := OPDT\_SAL - (OP\varepsilon_X) \cdot \Delta T_{span\_pwr}$

$OPDT\_AV_2 = 111.0\%RTP$

Check for infringement on AV based on last paragraph of Section 5.12.2, page 62, of specification FIX-95-A-001, Rev. 1

$OP\_Allowable\_Value := \min(OPDT\_AV)$

$OP\_Allowable\_Value = 111.0\%\Delta T$

AV is defined as the more conservative of the two values

$$OP\_AV := \frac{OP\_Allowable\_Value - K_{4.nom}}{\Delta T_{span\_pwr}}$$

$OP\_AV = 2.4\%\Delta T$

Convert to ΔT Units

TABLE 5

REACTOR COOLANT FLOW – LOW

Parameter		Allowance *
Process Measurement Accuracy		[ ]+a,c
[	]+a,c	
[	]+a,c	
Primary Element Accuracy		
Sensor Calibration Accuracy		
Sensor Reference Accuracy		
Sensor Measurement & Test Equipment Accuracy		
Sensor Pressure Effects		
Sensor Temperature Effects		
Sensor Drift		
Environmental Allowance		
Bias		
[	]+a,c	
Rack Calibration Accuracy		
Rack Measurement & Test Equipment Accuracy		
Rack Temperature Effects		
Rack Drift		

* In % span (120% flow)

Channel Statistical Allowance =

[ ]+a,c

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Allowable Value Calculation based on ENN Specification FIX-95-A-001, Rev. 1

$$RCSF\_CSA\_:= \sqrt{\begin{array}{l}(RCSF\_PM)^2 + (RCS)^2 + RCSF\_RE^2 \ldots \\ + (RCSF\_SMT + RCSF\_SC)^2 + RCSF\_SR^2 \ldots \\ + (RCSF\_SMT + RCSF\_S)^2 + RCSF\_SP^2 + RCSF\_ST^2 \ldots \\ + (RCSF\_RMT + RCSF\_RC)^2 + (RCSF\_RMT + RCSF\_R)^2 + (RCSF\_RT)^2 \\ + RCSF\_BIA\end{array}} \ldots$$

$$RCSF\_CSA\_=[\qquad\qquad]$$

$$\varepsilon T\_100:= \sqrt{\begin{array}{l}(RCSF\_SMT + RCSF\_SC)^2 + RCSF\_SR^2 \ldots \\ + (RCSF\_SMT + RCSF\_S)^2 \ldots \\ + (RCSF\_RMT + RCSF\_RC)^2 + (RCSF\_RMT + RCSF\_R)^2\end{array}}$$

$\varepsilon T\_100 = 1.6\%flowspa$

$$H\varepsilon X := \sqrt{\begin{array}{l}(RCSF\_PM)^2 + (RCS)^2 + RCSF\_PE^2 \ldots \ldots \\ + RCSF\_SP^2 + RCSF\_ST^2 \ldots \\ + (RCSF\_RT)^2 \\ + RCSF\_BIA\end{array}}$$

$H\varepsilon X = 2.9\%flowspa$

$RCSF\_SAL\_L = 85.0\%$

$RCSF\_Span = 120.0\%flow$

$AV_0 := RCSF\_SAL\_L + (RCSF\_CSA\_L - \varepsilon T\_100) \cdot RCSF\_Span$

Method 1 based on equation 5.12.2.4, page 62 of specification FIX-95-A-001, Rev. 1

$AV_0 = 87.1\%flow$

$AV_1 := RCSF\_SAL\_L + H\varepsilon X \cdot RCSF\_Span$

Check for infringement on AV based on last paragraph of Section 5.12.2, page 62, of specification FIX-95-A-001, Rev. 1

$AV_1 = 88.5\%flow$

$Allowable\_Value := \max(AV)$

AV is defined as the more conservative of the two values

$Allowable\_Value = 88.5\%flow$

Note: Submitted value of 88.7% flow, which is based on earlier calculation, is more limiting.

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TABLE 6

STEAM GENERATOR WATER LEVEL – LOW-LOW

Parameter	Allowance *
Process Measurement Accuracy	[ ]+a,c
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
Primary Element Accuracy	
Sensor Calibration Accuracy	
Sensor Reference Accuracy	
Sensor Measurement & Test Equipment Accuracy	
Sensor Pressure Effects	
Sensor Temperature Effects	
Sensor Drift	
Environmental Allowance	
Bias	
[ ]+a,c	
[ ]+a,c	
Rack Calibration Accuracy	
Rack Measurement & Test Equipment Accuracy	
Rack Temperature Effects	
Rack Drift	

* In % span (100%)

(1) The PMA values noted represent the most limiting sum of PMA terms and may not be the most limiting individual value for this term.

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TABLE 6 (continued)

STEAM GENERATOR WATER LEVEL – LOW-LOW

Channel Statistical Allowance =

+a,c

Allowable Value Calculation based on ENN Specification FIX-95-A-001, Rev. 1

$$CSA\_Lo\_Lo = \left[\sqrt{SGL\_pe^2 + (SGL\_smt + SGL\_sc)^2 + SGL\_sr^2 + (SGL\_smt + SGL\_s)^2 + SGL\_sp^2 + SGL\_st^2 + (SGL\_rmt + SGL\_rc)^2 + (SGL\_rmt + SGL\_r)^2 + SGL\_rt^2} + BIAS1 + BIAS2 + BIAS3 + EA1\right]$$

$$CSA\_Lo\_Lo =$$

$$\varepsilon_T := \sqrt{SGL\_sr^2 + (SGL\_smt + SGL\_sc)^2 + (SGL\_smt + SGL\_s)^2 + (SGL\_rmt + SGL\_rc)^2 + (SGL\_rmt + SGL\_r)^2}$$

$\varepsilon_T = 3.9\%$

$$LL\varepsilon_X := \sqrt{SGL\_pe^2 + SGL\_st^2 + SGL\_rt^2 + SGL\_sp^2} + BIAS1 + BIAS2 + BIAS3 + EA1$$

$LL\varepsilon_X = 3.4\%$

SGL_SAL_LL= 0.0%

$LL\_AV_0 := SGL\_SAL\_LL + CSA\_Lo\_Lo - \varepsilon_T$

Method 1 based on equation 5.12.2.4, page 62 of specification FIX-95-A-001, Rev. 1

$LL\_AV_0 = 2.6\%$

$LL\_AV_1 := SGL\_SAL\_LL + LL\varepsilon_X$

Check for infringement on AV based on last paragraph of Section 5.12.2, page 62, of specification FIX-95-A-001, Rev. 1

$LL\_AV_1 = 3.4\%$

SG_LL_Allowable_Value:= max(LL_AV)

AV is defined as the more conservative of the two values

SG_LL_Allowable_Value= 3.4%

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TABLE 7

STEAM GENERATOR WATER LEVEL – HIGH

Parameter	Allowance *
Process Measurement Accuracy	[ ]+a,c
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
Primary Element Accuracy	
Sensor Calibration Accuracy	
Sensor Reference Accuracy	
Sensor Measurement & Test Equipment Accuracy	
Sensor Pressure Effects	
Sensor Temperature Effects	
Sensor Drift	
Environmental Allowance	
Bias	
Rack Calibration Accuracy	
Rack Measurement & Test Equipment Accuracy	
Rack Temperature Effects	
Rack Drift	

* In % span (100%)

(1) The PMA values noted represent the most limiting sum of PMA terms and may not be the most limiting individual value for this term.

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TABLE 7 (continued)

STEAM GENERATOR WATER LEVEL – HIGH

Channel Statistical Allowance =

[ ]+a,c

Allowable Value Calculation based on ENN Specification FIX-95-A-001, Rev. 1

$$CSA\_Hi := \left[\sqrt{SGL\_pe^2 + (SGL\_smt + SGL\_sc)^2 + SGL\_sr^2 + (SGL\_smt + SGL\_sd)^2 + SGL\_sp^2 + SGL\_st^2 + (SGL\_rmt + SGL\_rc)^2 + (SGL\_rmt + SGL\_rd)^2 + SGL\_rt^2} + BIAS4 + EA1\right]$$

$CSA\_Hi = [\quad]$

$$\varepsilon_T := \sqrt{SGL\_sr^2 + (SGL\_smt + SGL\_sc)^2 + (SGL\_smt + SGL\_sd)^2 + (SGL\_rmt + SGL\_rc)^2 + (SGL\_rmt + SGL\_rd)^2}$$

$\varepsilon_T = 3.9\%$

$$H\varepsilon_X := \sqrt{SGL\_pe^2 + SGL\_st^2 + SGL\_rt^2 + SGL\_sp^2} + BIAS4 + EA1$$

$H\varepsilon_X = 1.7\%$

$SGL\_SAL\_H = 90.0\%$

$Hi\_AV_0 := SGL\_SAL\_H - CSA\_Hi + \varepsilon_T$

Method 1 based on equation 5.12.2.4, page 62 of specification FIX-95-A-001, Rev. 1

$Hi\_AV_0 = 89.0\%$

$Hi\_AV_1 := SGL\_SAL\_H - H\varepsilon_X$

Check for infringement on AV based on last paragraph of Section 5.12.2, page 62, of specification FIX-95-A-001, Rev. 1

$Hi\_AV_1 = 88.3\%$

$SG\_Hi\_Allowable\_Value := \min(Hi\_AV)$

AV is defined as the more conservative of the two .

$SG\_Hi\_Allowable\_Value = 88.3\%$

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TABLE 8

STEAMLINE PRESSURE – LOW SI

Parameter	**Allowance ***
Process Measurement Accuracy	[ ]+a,c
Primary Element Accuracy	
Sensor Calibration Accuracy	
Sensor Reference Accuracy	
Sensor Measurement & Test Equipment Accuracy	
Sensor Pressure Effects	
Sensor Temperature Effects	
Sensor Drift	
Environmental Allowance	
Bias [ ]+a,c	
Rack Calibration Accuracy	
Rack Measurement & Test Equipment Accuracy	
Rack Temperature Effects	
Rack Drift	

* In % span (1400 psig)

Channel Statistical Allowance =

[ ]+a,c

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Allowable Value Calculation based on ENN Specification FIX-95-A-001, Rev. 1

$$SP\_csa\_ := \left[\sqrt{\begin{array}{l} SP\_p^{\,2} + SP\_pe^2 \ldots \\ +(SP\_sm + SP\_sd)^2 + SP\_sr^2 + (SP\_sm + SP\_s)^2 + SP\_sp^2 + SP\_st^2 \\ +(SP\_rmt + SP\_rd)^2 + (SP\_rmt + SP\_r)^2 + SP\_rt^2 \end{array}}\right] \ldots$$
$$+ SP\_Bias\_ + SP\_E$$

$SP\_csa\_ =$

$SP\_csa\_Lo := SP\_csa\_ \cdot SP\_Sp$ $\qquad SP\_csa\_Lo = \left[\quad\right]$

$$\varepsilon T := \sqrt{SP\_sr^2 + (SP\_sm + SP\_sd)^2 + (SP\_sm + SP\_s)^2 + (SP\_rmt + SP\_rd)^2 + (SP\_rmt + SP\_r)^2}$$

$\varepsilon T = 2.\ \%$

$span\varepsilon T := \varepsilon T \cdot SP\_Sp$ $\qquad span\varepsilon T = 37.\ psi$

$$\varepsilon X := \sqrt{SP\_pe^2 + SP\_st^2 + SP\_rt^2 + SP\_sp^2 + SP\_p^{\,2}} + SP\_E + SP\_Bias\_$$

$\varepsilon X = 1.\ \%$

$span\varepsilon X := \varepsilon X \cdot SP\_Sp$ $\qquad span\varepsilon X = 25.\ psi$

$SP\_SAL\_Lo := 515.3 psig$

$High\_AV_0 := SP\_SAL\_Lo + SP\_csa\_Lo\_u - span\_\varepsilon_T$

Method 1 based on equation 5.12.2.4, page 62 of specification FIX-95-A-001, Rev. 1

$High\_AV_0 = 524.9 psig$

$High\_AV_1 := SP\_SAL\_Lo + span\_\varepsilon_X$

Check for infringement on AV based on last paragraph of Section 5.12.2, page 62, of specification FIX-95-A-001, Rev. 1

$High\_AV_1 = 540.3 psig$

$SP\_Allowable\_Value := max(High\_AV)$

AV is defined as the more conservative of the two values

$SP\_Allowable\_Value = 540.3 psig$

TABLE 9

T_{AVG} – LOW

Parameter	Allowance *
Process Measurement Accuracy	[ ]+a,c
[ ]+a,c	
Primary Element Accuracy	
Sensor Calibration Accuracy	
Sensor Reference Accuracy	
Sensor Measurement & Test Equipment Accuracy	
Sensor Pressure Effects	
Sensor Temperature Effects	
Sensor Drift	
Environmental Allowance	
Bias	
[ ]+a,c	
[ ]+a,c	
Rack Calibration Accuracy	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
Rack Measurement & Test Equipment Accuracy	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	
Rack Temperature Effects	
Rack Drift	
[ ]+a,c	
[ ]+a,c	
[ ]+a,c	

* In % span (75°F)

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TABLE 9 (continued)

T_{AVG} – LOW

Channel Statistical Allowance =

[ ] +a,c

Channel Statistical Allowance (without the PMA terms)=

[ ] +a,c

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Allowable Value Calculation based on ENN Specification FIX-95-A-001, Rev. 1

$$CSA\_Tavg\_Lo := \sqrt{pma_{th}^2 + \left[\frac{\sqrt{\frac{(smte\_rtd + sca\_rtd)^2 + sra\_rtd^2 + (smte\_rtd + sd\_rtd)^2}{N_H} + \frac{(smte\_rtd + sca\_rtd)^2 + sra\_rtd^2 + (smte\_rtd + sd\_rtd)^2}{N_C}}}{2}\right]^2 + \left[\frac{\sqrt{\frac{(re\_th\_mte + re\_th\_ca)^2 + (re\_th\_mte + re\_th\_drift)^2}{N_H} + \frac{(re\_tc\_mte + re\_tc\_ca)^2 + (re\_tc\_mte + re\_tc\_drift)^2}{N_C}}}{2}\right]^2 + \left[\frac{\sqrt{\frac{(Tavg\_T\_th\_rmte + Tavg\_T\_th\_rca)^2}{N_H} + \frac{(Tavg\_T\_tc\_rmte + Tavg\_T\_tc\_rca)^2}{N_C}}}{2}\right]^2 + (Tavg\_T\_th\_rmte + Tavg\_T\_rd)^2 + Tavg\_T\_rte^2 + Bias\_T\_pma_{th} + Bias\_T\_pma_{tc} + EA\_Tavg}$$

$CSA\_Tavg\_Lo =$ [ ]

$CSA\_Tavg\_Lo\_u := CSA\_Tavg\_Lo Tavg\_Span$ $\quad CSA\_Tavg\_Lo\_u =$ [ ]

$$\varepsilon_T := \sqrt{\left[\frac{\sqrt{\frac{(smte\_rtd + sca\_rtd)^2 + sra\_rtd^2 + (smte\_rtd + sd\_rtd)^2}{N_H} + \frac{(smte\_rtd + sca\_rtd)^2 + sra\_rtd^2 + (smte\_rtd + sd\_rtd)^2}{N_C}}}{2}\right]^2 + \left[\frac{\sqrt{\frac{(re\_th\_mte + re\_th\_cal)^2 + (re\_th\_mte + re\_th\_drift)^2}{N_H} + \frac{(re\_tc\_mte + re\_tc\_cal)^2 + (re\_tc\_mte + re\_tc\_drift)^2}{N_C}}}{2}\right]^2 + \left[\frac{\sqrt{\frac{(Tavg\_T\_th\_rmte + Tavg\_T\_th\_rca)^2}{N_H} + \frac{(Tavg\_T\_tc\_rmte + Tavg\_T\_tc\_rca)^2}{N_C}}}{2}\right]^2 + (Tavg\_T\_th\_rmte + Tavg\_T\_rd)^2}$$

$\varepsilon_T = 1.7\%Tavg$

$\varepsilon_{T\_u} := \varepsilon_T \cdot Tavg\_Span$ $\quad \varepsilon_{T\_u} = 1.3degF$

$\varepsilon_X := \sqrt{pma_{th}^2 + Tavg\_T\_rte^2} + Bias\_T\_pma_{th} + Bias\_T\_pma_{tc} + EA\_Tavg$ $\quad \varepsilon_X = 2.7\%Tavg$

$\varepsilon_{X\_u} := \varepsilon_X \cdot Tavg\_Span$ $\quad \varepsilon_{X\_u} = 2.1degF$

$Tavg\_SAL\_Lo = 537.0degF$

$AV_0 := Tavg\_SAL\_Lo + CSA\_Tavg\_Lo\_u - \varepsilon_{T\_u}$

$AV_0 = 538.2degF$

Method 1 based on equation 5.12.2.4, page 62 of specification FIX-95-A-001, Rev. 1

$AV_1 := Tavg\_SAL\_Lo + \varepsilon_{X\_u}$

$AV_1 = 539.1degF$

Check for infringement on AV based on last paragraph of Section 5.12.2, page 62, of specification FIX-95-A-001, Rev. 1

$Allowable\_Value := \max(AV)$

$Allowable\_Value = 539.1degF$

AV is defined as the more conservative of the two values

Per ENN letter PU2-E-03-044, the Allowable Value should be established to be within the design range of the instrument loop. Therefore, AV = 540.0 deg F.

Note: Submitted value of 540.5 deg F, which is based on pre-RTD replacement calculations, is more limiting

TABLE 10

STEAM FLOW IN TWO STEAMLINES – HIGH (High Setpoint at 100 % Power)

Parameter		Allowance *
		[ ]+a,c
Process Measurement Accuracy		
[	]+a,c	
[	]+a,c	
[	]+a,c	
[	]+a,c	
Primary Element Accuracy		
[	]+a,c	
[	]+a,c	
Sensor Calibration Accuracy		
[	]+a,c	
[	]+a,c	
Sensor Reference Accuracy		
[	]+a,c	
[	]+a,c	
Sensor Measurement & Test Equipment Accuracy		
[	]+a,c	
[	]+a,c	
Sensor Pressure Effects		
[	]+a,c	
Sensor Temperature Effects		
[	]+a,c	
[	]+a,c	
Sensor Drift		
[	]+a,c	
[	]+a,c	
Environmental Allowance		
[	]+a,c	
[	]+a,c	
Bias		
[	]+a,c	
[	]+a,c	

* In % span (122 % flow) Percent of d/p span converted to flow span where F_{max} = 122 %, F_N = 110 %

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TABLE 10 (continued)

STEAM FLOW IN TWO STEAMLINES – HIGH (High Setpoint at 100 % Power)

Parameter		**Allowance ***
Rack Calibration Accuracy		[ ]+a,c
[	]+a,c	
[	]+a,c	
Rack Measurement & Test Equipment Accuracy		
[	]+a,c	
[	]+a,c	
Rack Temperature Effects		
[	]+a,c	
[	]+a,c	
Rack Drift		
[	]+a,c	
[	]+a,c	

* In % span (122 % flow) Percent of d/p span converted to flow span where F_{max} = 122 %, F_N = 110 %

Channel Statistical Allowance =

[ ]+a,c

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Allowable Value Calculation based on ENN Specification FIX-95-A-001, Rev. 1

$$SF\_csa_{H100} := \sqrt{\begin{array}{l} SF\_pma1\_100^2 + SF\_pma2\_100^2 + SF\_pma3\_100^2 + SF\_pea^2 \ldots \\ + (SF\_smte + SF\_sca)^2 + SF\_sra^2 + (SF\_smte + SF\_sd)^2 + SF\_spe^2 + SF\_ste^2 \ldots \\ + (SF\_rmte + SF\_rca)^2 + (SF\_rmte + SF\_rd)^2 + SF\_rte^2 \ldots \\ + TP\_pma^2 + TP\_pea^2 \ldots \\ + (TP\_smte + TP\_sca)^2 + TP\_sra^2 + (TP\_smte + TP\_sd)^2 + TP\_ste^2 \ldots \\ + (TP\_rmte + TP\_rca)^2 + TP\_rte^2 \end{array}} \ldots$$
$$+ |SF\_bias| + |TP\_bias| + SF\_ea + TP\_ea$$

$$SF\_csa_{H100} = \left[\qquad \right]$$

$$\varepsilon T\_100 := \sqrt{\begin{array}{l} SF\_sra^2 + TP\_sra^2 + (SF\_smte + SF\_sca)^2 + (TP\_smte + TP\_sca)^2 \ldots \\ + (SF\_smte + SF\_sd)^2 + (TP\_smte + TP\_sd)^2 + (SF\_rmte + SF\_rca)^2 + (TP\_rmte + TP\_rca)^2 \ldots \\ + (SF\_rmte + SF\_rd)^2 \end{array}}$$

$\varepsilon T\_100 = 2.3\%flow\_span$

$$H\varepsilon X := \sqrt{\begin{array}{l} SF\_pma1\_100^2 + SF\_pma2\_100^2 + SF\_pma3\_100^2 + TP\_pma^2 \ldots \\ + SF\_pea^2 + TP\_pea^2 + SF\_ste^2 + TP\_ste^2 + SF\_rte^2 + TP\_rte^2 + SF\_spe^2 \end{array}} \ldots$$
$$+ |SF\_bias| + |TP\_bias| + SF\_ea + TP\_ea$$

$H\varepsilon X = 8.4\%flow\_span$

$SF\_SAL_{H100} = 144.0\%full\_steam\_flow$

$SF\_Span = 122.0\%full\_steam\_flow$

$High\_AV_0 := SF\_SAL_{H100} - (SF\_csa_{H100} - \varepsilon T\_100) \cdot SF\_Span$

Method 1 based on equation 5.12.2.4, page 62 of specification FIX-95-A-001, Rev. 1

$High\_AV_0 = 135.9\%full\_steam\_flow$

$High\_AV_1 := SF\_SAL_{H100} - H\varepsilon X \cdot SF\_Span$

Check for infringement on AV based on last paragraph of Section 5.12.2, page 62, of specification FIX-95-A-001, Rev. 1

$High\_AV_1 = 133.8\%full\_steam\_flow$

$High\_Allowable\_Value := \min(High\_AV)$

AV is defined as the more conservative of the two values.

$High\_Allowable\_Value = 133.8\%full\_steam\_flow$

Since the calculated AV is off-span high, Westinghouse will follow ENN guidance and set the AV to the top-of-span value of 122% full steam flow.

TABLE 11

STEAM FLOW IN TWO STEAMLINES – HIGH (Low Setpoint at 20 % Power)

Parameter		Allowance *
Process Measurement Accuracy		[ ]+a,c
[	]+a,c	
[	]+a,c	
[	]+a,c	
[	]+a,c	
Primary Element Accuracy		
[	]+a,c	
[	]+a,c	
Sensor Calibration Accuracy		
[	]+a,c	
[	]+a,c	
Sensor Reference Accuracy		
[	]+a,c	
[	]+a,c	
Sensor Measurement & Test Equipment Accuracy		
[	]+a,c	
[	]+a,c	
Sensor Pressure Effects		
[	]+a,c	
Sensor Temperature Effects		
[	]+a,c	
[	]+a,c	
Sensor Drift		
[	]+a,c	
[	]+a,c	
Environmental Allowance		
[	]+a,c	
[	]+a,c	

* In % span (122 % flow) Percent of d/p span converted to flow span where F_{max} = 122 %, F_N = 40 %

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TABLE 11 (continued)

STEAM FLOW IN TWO STEAMLINES – HIGH (Low Setpoint at 20 % Power)

Parameter		**Allowance ***
Bias		[ ]+a,c
[	]+a,c	
[	]+a,c	
[	]+a,c	
Rack Calibration Accuracy		
[	]+a,c	
[	]+a,c	
Rack Measurement & Test Equipment Accuracy		
[	]+a,c	
[	]+a,c	
Rack Temperature Effects		
[	]+a,c	
[	]+a,c	
Rack Drift		
[	]+a,c	
[	]+a,c	

* In % span (122 % flow) Percent of d/p span converted to flow span where F_{max} = 122 %, F_N = 40 %

Channel Statistical Allowance =

[ ]+a,c

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Allowable Value Calculation based on ENN Specification FIX-95-A-001, Rev. 1

$$SF\_csa_{H20} := \sqrt{\begin{array}{l} SF\_pma1\_20^2 + SF\_pma2\_20^2 + SF\_pma3\_20^2 + SF\_pea^2 \ldots \\ + (SF\_smte + SF\_sca)^2 + SF\_sra^2 + (SF\_smte + SF\_sd)^2 + SF\_spe^2 + SF\_ste^2 \ldots \\ + (SF\_rmte + SF\_rca)^2 + (SF\_rmte + SF\_rd)^2 + SF\_rte^2 \ldots \\ + TP\_pma^2 + TP\_pea^2 \ldots \\ + (TP\_smte + TP\_sca)^2 + TP\_sra^2 + (TP\_smte + TP\_sd)^2 + TP\_ste^2 \ldots \\ + (TP\_rmte + TP\_rca)^2 + TP\_rte^2 \end{array}} \ldots$$
$$+ |SF\_bias\_seismic| + |SF\_bias\_spe| + |TP\_bias| + SF\_ea + TP\_ea$$

$SF\_csa_{H20} = [\qquad\qquad]$

$$\varepsilon_{T\_20} := \sqrt{\begin{array}{l} SF\_sra^2 + TP\_sra^2 + (SF\_smte + SF\_sca)^2 + (TP\_smte + TP\_sca)^2 \ldots \\ + (SF\_smte + SF\_sd)^2 + (TP\_smte + TP\_sd)^2 + (SF\_rmte + SF\_rca)^2 + (TP\_rmte + TP\_rca)^2 \ldots \\ + (SF\_rmte + SF\_rd)^2 \end{array}}$$

$\varepsilon_{T\_20} = 6.3\%flow\_span$

$$H\varepsilon_{X\_20} := \sqrt{\begin{array}{l} SF\_pma1\_20^2 + SF\_pma2\_20^2 + SF\_pma3\_20^2 + TP\_pma^2 \ldots \\ + SF\_pea^2 + TP\_pea^2 + SF\_ste^2 + TP\_ste^2 + SF\_rte^2 + TP\_rte^2 + SF\_spe^2 \end{array}} \ldots$$
$$+ |SF\_bias\_seismic| + |SF\_bias\_spe| + |TP\_bias| + SF\_ea + TP\_ea$$

$H\varepsilon_{X\_20} = 14.8\%flow\_span$

$SF\_SAL_{H20} = 64.0\%full\_steam\_flow$

$SF\_Span = 122.00\%full\_steam\_flow$

$High\_AV_0 := SF\_SAL_{H20} - (SF\_csa_{H20} - \varepsilon_{T\_20}) \cdot SF\_Span$

Method 1 based on equation 5.12.2.4, page 62 of specification FIX-95-A-001, Rev. 1

$High\_AV_0 = 49.3\%full\_steam\_flow$

$High\_AV_1 := SF\_SAL_{H20} - H\varepsilon_{X\_20} \cdot SF\_Span$

Check for infringement on AV based on last paragraph of Section 5.12.2, page 62, of specification FIX-95-A-001, Rev. 1

$High\_AV_1 = 45.9\%full\_steam\_flow$

$High\_Allowable\_Value := \min(High\_AV)$

AV is defined as the more conservative of the two values

$High\_Allowable\_Value = 45.9\%full\_steam\_flow$

TABLE 12

OVERTEMPERATURE ΔT CALCULATIONS

The equation for Overtemperature ΔT is :

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

K_1 (nominal)	=	1.22	Value specified in the COLR, Attachment 1
K_1 (max)	=	1.42	Analysis value
K_2	=	0.020/°F	Value specified in the COLR, Attachment 1
K_3	=	0.00070/psi	Value specified in the COLR, Attachment 1
ΔT	=	50.0°F	Smallest ΔT based on extrapolation of previous value
ΔI gain	=	2.25% RTP/% ΔI	Value specified in the COLR, Attachment 1

PMA conversions:

ΔT	=	[ ]+a,c
Tavg	=	
ΔI	=	
ΔI	=	
Power Cal.	=	
Pressure gain	=	[ ]+a,c
Pressure (SCA_P)	=	
Pressure (SRA_P)	=	
Pressure ($SMTE_P$)	=	
Pressure (STE_P)	=	
Pressure (SD_P)	=	
Pressure ($Bias_P$)	=	
NIS and ΔI conversion	=	[ ]+a,c
NIS (RCA_{NIS})	=	
NIS ($RMTE_{NIS}$)	=	
NIS (RTE_{NIS})	=	
NIS (RD_{NIS})	=	
ΔI ($RCA_{\Delta I}$)	=	
ΔI ($RMTE_{\Delta I}$)	=	
ΔI ($RD_{\Delta I}$)	=	
Tavg conversion	=	[ ]+a,c
Tavg (RCA_{Tavg})	=	
Tavg ($RMTE_{Tavg}$)	=	
Tavg (RD_{Tavg})	=	

Total Allowance = [ ]+a,c = 13.3% ΔT span

TABLE 13

OVERPOWER ΔT CALCULATIONS

The equation for Overpower ΔT is :

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

K_4 (nominal)	=	1.074	Value specified in the COLR, Attachment 1
K_4 (max)	=	1.164	Analysis value
K_5	=	0.0188/°F	Value specified in the COLR, Attachment 1
K_6	=	0.0015/°F	Value specified in the COLR, Attachment 1
ΔT	=	50.0°F	Smallest ΔT based on extrapolation of previous value

PMA conversions:

ΔT	=	[ ]+a,c
Tavg	=	
Power Cal.	=	

EA conversions:

ΔT	=	[ ]+a,c
Tavg	=	

Tavg conversion	=	[ ]+a,c
Tavg (RCA_{Tavg-1})	=	
Tavg ($RMTE_{Tavg-1}$)	=	
Tavg (RD_{Tavg-1})	=	
Tavg (RCA_{Tavg-2})	=	
Tavg ($RMTE_{Tavg-2}$)	=	
Tavg (RD_{Tavg-2})	=	

Total Allowance = [ ]+a,c = 6.0% ΔT span

I&C Question 5:

In Table 2, "Cross-Map of Technical Specification Changes to WCAP-16157-P Analyses," of Attachment I to April 12 letter, the comments on Function 9, "Reactor Coolant Flow - low," and Function 13, "Steam Generator water level - low-low," stated that "since one of the non-tested uncertainties (process measurement accuracy) changed slightly for the SPU, a revised allowable value was calculated." Provide a further explanation of the uncertainty and the revised value.

Response:

For Reactor Coolant Flow – Low the SAL remained at 85% for the SPU. However, since the Allowable Value (AV) is based on the SAL and the non-tested uncertainties, and since one of the non-tested uncertainties (process measurement accuracy or PMA) changed slightly for the SPU, a revised allowable value was calculated. The PMA value that changed is the RCS flow calorimetric uncertainty allowance which accounts for the accuracy of the beginning of cycle reference flow to which the RCS Low Flow trip is normalized. The SPU value for this parameter is [ ]^{a,c} (corresponds to approximately [ ]^{a,c}) as identified in Table IC-5 of the response to I&C RAI #4. The previous value for this parameter is [ ]^{a,c} (corresponds to approximately [ ]^{a,c}). The small change in PMA from [ ]^{a,c} to [ ]^{a,c} was the result of revised calculations performed for the SPU conditions which reflect plant processes, procedures, and instrumentation. Thus, incorporation of the reduced PMA value resulted in a 0.1% span relaxation in the AV.

For Steam Generator water level – low-low the SAL remained at 0% level for the SPU. However, since the allowable value (AV) is based on the SAL and the non-tested uncertainties, and since one of the non-tested uncertainties (process measurement accuracy or PMA) changed slightly for the SPU, a revised allowable value was calculated. The PMA value that changed is noted on Table IC-6 of the response to I&C RAI #4 as the sum of the various level related PMA terms. For the SPU this sum is approximately [ ]^{a,c}, whereas the previous value for this sum is approximately [ ]^{a,c} span. The change in PMA from [ ]^{a,c} to [ ]^{a,c} was the result of revised calculations performed for the SPU conditions which addressed the generic Steam Generator Water Level measurement uncertainty issues referenced in Section 6.10 of WCAP-16157. Therefore, incorporation of the reduced PMA value resulted in a 0.3% span relaxation in the AV.

Reactor Systems Question 3:

The NRC staff is interested in the degradation of margin to the regulatory limits for the SPU at IP2. With regard to the non-LOCA transient re-analyses, provide a table listing each event and its corresponding acceptance criteria. In this table, also quantify the change in calculated results relative to current operation.

Response:

The Table RAI 3-1 summarizes the acceptance criteria and limiting analysis results for each non-LOCA event analyzed for the IP2 SPU. Included are the current operation analysis results. The changes in limiting event conditions and acceptance criteria between the SPU and current analysis are primarily due to differences in input assumptions for the analyses (i.e. operating Tavg range, maximum steam generator plugging level, etc. - see LAR section 2)

Table RAI 3-1: Non-LOCA Analysis Limits and Results

Licensing Report Section	Event Description	Result Parameter	Uprate Analysis Results		Current Analysis Limiting Case Result
			Analysis Limit	Limiting Case Result	
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)			
		Minimum DNBR above first mixing vane grid (non-RTDP, WRB-1 correlation)			
		Maximum fuel centerline temperature, °F			
6.3.3	Uncontrolled RCCA Withdrawal at Power	Minimum DNBR (RTDP, WRB-1)			
		Peak RCS pressure, psia			
		Peak main steam system pressure, psia			
6.3.4	RCCA Drop/Misoperation	Minimum DNBR (RTDP, WRB-1)			
		Peak linear heat generation (kW/ft)			
		Max F_dH (static rod misalignment) (Rod fully withdrawn)			
		Max F_dH (static rod misalignment) (Rod fully inserted)			
6.3.5	CVCS Malfunction - Mode 1 (manual) - Mode 1 (auto) - Mode 2 - Mode 6	Minimum time to loss of shutdown margin, minutes			
6.3.6	Loss of External Electrical Load	Minimum DNBR (RTDP, WRB-1)			
		Peak RCS pressure, psia			
		Peak main steam system pressure, psia			

+a, c

Table RAI 3-1: Non-LOCA Analysis Limits and Results (cont.)

Licensing Report Section	Event Description	Result Parameter	Uprate Analysis Results		Current Analysis Results (Limiting Case)
			Analysis Limit	Limiting Case	
6.3.7	LONF	Maximum pressurizer mixture volume, ft^3			
6.3.8	LOAC to the Station Auxiliaries	Maximum pressurizer mixture volume, ft^3			
6.3.9	Excessive Heat Removal Due to Feedwater System Malfunctions	Minimum DNBR (RTDP, WRB-1)			
6.3.10	Excessive Load Increase Incident	Minimum DNBR (RTDP, WRB-1)			
6.3.11	Rupture of a Steam Pipe	Minimum DNBR (non-RTDP, W-3)			
6.3.12	Partial Loss of Reactor Coolant Flow	Minimum DNBR (RTDP, WRB-1)			
6.3.13	Complete Loss of Reactor Coolant Flow: - Undervoltage - Frequency Decay	Minimum DNBR (RTDP, WRB-1)			

+a,c

Table RAI 3-1: Non-LOCA Analysis Limits and Results (cont.)

Licensing Report Section	Event Description	Result Parameter	Analysis Result		Current Analysis Results (Limiting Case)
			Analysis Limit	Limiting Case	
6.3.14	Locked Rotor Accident	Maximum Clad Temperature at Core Hot Spot, °F			
		Maximum Zr-H_2O Reaction at Core Hot Spot, wt. %			
		Maximum RCS Pressure, psia			
		Rods-in-DNB			
6.3.15	Rupture of a Control Rod Drive Mechanism Housing – RCCA Ejection	Maximum fuel pellet average enthalpy, Btu/lb (cal/gm)			
		Maximum fuel melt, %			
		Maximum RCS pressure, psia			

a.c

Notes:

1. Bounded by zero power steam line break.
2. Bound by rod withdrawal from subcritical

Reactor Systems Question 5:

Provide the technical justification for the reduction in the design limit departure from nucleate boiling ratio (DNBR) from its current value of 1.26 to the SPU value of 1.22 for both the typical flow channel and the thimble flow channel.

Response:

The difference in the design limit DNBR values resulted from the different treatments of the measurement bias in pressure and temperature (**Notes:** (1) The pressure and temperature bias are applicable for both the SPU and current operation (i.e. 1.4% power uprate). (2) A power bias is applicable for the SPU only). The power, pressure, and temperature bias are not considered in the design limit DNBR calculations for the IP2 SPU. Instead, DNBR penalties regarding these biases have been offset by available DNBR margin between the design limit DNBR and the SAL DNBR as shown in the DNBR summary table in the response section of RSA RAI #7. However, pressure and temperature bias effects were built into the previous design limit DNBRs of [ ]^{a,c} (Thimble/Typical cells) for the 1.4% power uprate.

Reactor Systems Question 6:

As a result of the increased core thermal power for the SPU, the safety analysis limit DNBR and core thermal safety limits were revised. Specifically, the safety analysis limit (SAL) DNBR was revised from 1.58 to 1.48. Provide the technical justification for the revision of the DNBR from 1.58 to 1.48.

Response:

For the IP2 SPU, the SAL DNBR has been revised from [ ]^{a,c} in support of the proposed OTΔT trip setpoint revisions.

Sufficient DNBR margin has been maintained by performing the safety analyses to a SAL DNBR of [ ]^{a,c}, which retains [ ]^{a,c} DNBR margin as shown in the DNBR summary table provided in the response section for RSA RAI #7. Sufficient DNBR margin was conservatively maintained in the SAL DNBR to offset the rod bow, potential transition core, and plant operating parameter bias DNBR penalties.

Reactor Systems Question 7:

Provide a table listing the DNBR margin summary. The values would include the DNBR correlation limit, DNBR design limit, SAL DNBR, DNBR retained margin, rod bow DNBR penalty, transition core DNBR penalty, and available DNBR margin left after the uprate.

Response:

The DNBR margin summary table for IP2 SPU is provided in the following table, which includes the DNBR correlation limit, DNBR design limit, SAL DNBR, DNBR retained margin, different DNBR penalties, and available DNBR margin after the SPU.

DNBR Margin Summary for IP2 SPU RTDP Analyses	
DNB Correlation	WRB-1
DNB Correlation Limit	1.17
Design Limit DNBR Typical Cell Thimble Cell	 1.22 1.22
Safety Analysis Limit DNBR Typical Cell Thimble Cell	[ ] a,c
DNBR Margin (between design and safety analysis limit DNBR) Typical Cell Thimble Cell	
DNBR Penalties Power Bias Pressure Bias Temperature Bias Rod Bow[1] Transition Core[2]	
Net DNBR Margin after SPU (minimum)	

Notes: 1. Applicable to the grid spans without IFM grids.
2. DNBR margin is reserved to offset the potential transition core DNBR penalty if the upgraded fuel is used with the VANTAGE+ fuel.

Reactor Systems Question 8:

In the uncontrolled rod cluster control assembly (RCCA) withdrawal from a subcritical or low power startup condition transient, the minimum DNBR remained above the SAL. Provide the DNBR quantitative result which shows the minimum DNBR remained above the SAL for the SPU analysis.

Response:

As shown below, the calculated minimum DNBR at SPU conditions is above the SAL established for the Uncontrolled RCCA Withdrawal from a Subcritical or Low-Power Startup Condition (RWFS) event.

Event - Location	Calculated Minimum DNBR at SPU conditions	SAL DNBR Limit
RWFS – Below Span 1	[	] a,c
RWFS – Above Span 1	]	

Reactor Systems Question 9:

Regarding the re-analysis of the uncontrolled RCCA withdrawal at power transient:

a. RETRAN (a system code) rather than a subchannel code such as VIPRE is used for the DNBR analysis. The use of the RETRAN DNBR model requires certain user-input values (not listed here because this is shown as proprietary on page 55 of WCAP-14882-P-A). Discuss how this user-input was determined for IP2.

b. One of the acceptance criteria for this event is that fuel centerline temperature remains less than the melting temperature. Provide the quantitative result which demonstrates the fuel centerline temperature acceptance criteria is met.

Response 9a:

a, c

[ ]

Response 9b:

The basis for the fuel centerline temperature acceptance criterion is described in WCAP-8745-P-A. As long as the maximum power level of the core limit does not exceed a prescribed heat flux limit ([ ]^{a,c} of rated thermal power as described above) for a wide range of reactivity insertion rates, initial power levels and minimum / maximum reactivity feedback conditions, the fuel centerline temperature acceptance criterion will be satisfied. The peak heat flux calculated in the Uncontrolled RCCA Withdrawal at Power analysis is [ ]^{a,c}, which is less than the prescribed limit.

Reactor Systems Question 10:

Regarding the RCCA drop/misoperation transient re-analysis:

a. The licensee states automatic rod withdrawal has been physically disabled at IP2. Provide the technical justification for this statement and how it affects the transient analysis.

b. The licensee states generic transient statepoints designed to bound specific plant types were examined and found to be applicable to IP2 at SPU conditions. Please reference the document from which these generic statepoints were derived from and explain how these are applicable to IP2.

c. Provide the quantitative results demonstrating the minimum DNBR remained above the SAL DNBR and the peak fuel centerline melt temperature criteria is met for the RCCA dropped event at SPU conditions in section 6.3.4.5.

d. The licensee addressed the misaligned RCCA transient and stated the DNBR did not fall below the SAL value when analyzed at the SPU conditions. Provide the quantitative analysis that shows DNBR did not fall below the SAL when analyzed at the SPU conditions for one RCCA fully withdrawn and one RCCA fully inserted.

e. Provide the analytical justification that shows the resulting linear heat generation rate was below that which would cause fuel melting in the RCCA misalignment transient analysis.

Response 10a and 10b:

Refer to Attachment I

Response 10c:

The Westinghouse method for analysis of the dropped rod event confirms that the DNBR design basis is met by verifying that the conditions associated with the limiting pre-drop FΔH value are prevented by the initial conditions permitted by the technical specification FΔH value during a dropped rod event. The limiting pre-drop FΔH value during a dropped rod event includes the effects of the SPU conditions, through the use of plant-specific DNB limit lines, which would result in safety analysis limit DNBR being reached at the technical specification RTDP FΔH limit. These methods are more fully described in WCAP-11394-P-A, and have been approved. The limiting pre-drop FΔH value during a dropped rod event was calculated to be [ ]^{a,c} during the SPU analysis. The Technical Specification FΔH limit is 1.70 (which corresponds to a RTDP FΔH limit of 1.635 and a best-estimate FΔH limit of 1.574 when appropriate uncertainty factors are applied). Since the Technical Specification FΔH limit would prevent a pre-drop FΔH value reaching [ ]^{a,c}, the minimum DNBR during the dropped RCCA event remains above the SAL DNBR.

In addition, the maximum calculated linear heat rate for the dropped rod event was determined to be [ ]^{a,c} kW/ft, which is less than the fuel centerline melt limit of [ ]^{a,c} kW/ft at SPU conditions. Therefore, the peak fuel centerline melt temperature criterion is confirmed to be met.

Response 10d:

There were no explicit DNBR calculations performed for the static misaligned rod event. Instead, an allowable FΔH limit was calculated that would result in the safety analysis DNBR limit being reached, and this was then compared to actual calculated FΔH values corresponding to misaligned rod conditions. The allowable FΔH limit which would result in safety analysis limit DNBR being reached, was calculated to be 2.10. The maximum calculated FΔH for one RCCA fully withdrawn was [ ]^{a,c} (including uncertainty). The maximum calculated FΔH for one RCCA fully inserted was [ ]^{a,c} (including uncertainty). Since both values are less than the FΔH limit of 2.10, this demonstrates that the minimum DNBR for the static misaligned rod event is above the SAL DNBR.

Response 10e:

The maximum calculated linear heat rate for the dropped rod or RCCA misalignment transient is [ ]^{a,c} kW/ft. This is less than the fuel centerline melt limit of [ ]^{a,c} kW/ft, which was established during the SPU analysis. The [ ]^{a,c} kW/ft limit was developed using the NRC approved PAD 4.0 code (WCAP-15063-P-A), and will maintain the fuel centerline temperature below the UO_2 fuel melt limit (5080°F, decreasing by 58°F per 10,000 MWD/MTU, WCAP-12610-P-A).

Reactor Systems Question 11:

Regarding the chemical volume control system malfunction re-analysis, define what the interim operating procedures are, and how they address dilution during hot and cold shutdown.

Response:

Boron Dilution Interim Operating Procedures are administrative procedures designed to address an inadvertent boron dilution in Modes 4 and 5 for plants that have received their SER prior to the issuance of Regulatory Guide 1.70 Revision 2 (previously the boron dilution analysis only addressed Modes 1, 2 and 6, i.e., IP2). The procedures have been generated in response to Westinghouse concerns regarding the change in regulatory guidance. Notification of this procedure was issued to the Nuclear Regulatory Commission and applicable Westinghouse plants (i.e. IP2) in Westinghouse letter NS-TMA-2273 (July 8, 1980).

The Boron Dilution Interim Operating Procedure addresses inadvertent boron dilution during plant shutdown (hot and cold, Modes 4 and 5, respectively). The operating procedure is based upon a generic boron dilution analysis assuming active RCS and RHR volumes which are conservative with respect to IP2. Additionally, the operating procedure accommodates mid-loop cold shutdown operations. The operating procedure is applicable for maximum dilution flowrates up to [ ]^{a,c} gal/min and minimum RHR flowrates of [ ]^{a,c} gal/min. In the event of a boron dilution accident during plant shutdown, use of the operating procedure provides the plant operator with sufficient information to maintain an appropriate boron concentration while will conservatively assure (at least) [ ]^{a,c} minutes will be available for operator action to terminate the dilution, prior to the reactor reaching a critical condition (hence, mitigating the consequences of the event).

Reactor Systems Question 12:

Regarding the loss of normal feedwater (LONF) transient analysis:

a. In the analysis of record, the turbine driven auxiliary feedwater (TDAFW) pump is not credited to mitigate this transient. What is the consequence on the plant if the TDAFW pump is not aligned and there is less auxiliary feedwater (AFW) being fed to the system under the SPU? Provide the technical justification to show there is sufficient heat sink provided for the SPU condition. Also provide the justification to show 10 minutes is adequate time for the operator to align the TDAFW pump. Demonstrate the operators are capable of performing this action in 10 minutes and how plant procedures have been updated to address the operator action.

b. The licensee states with respect to DNB, the LONF transient is bounded by the loss of load transient. Provide the technical basis for this statement and provide the quantitative result demonstrating the DNBR limit remains above the SAL and is bounded by the loss of load transient in the RCCA drop/misoperation transient analysis.

Response 12a:

Refer to Attachment I

Response 12b: a, c

Reactor Systems Question 13:

Regarding the loss of AC power (LOAC) to the station auxiliaries transient analysis:

a. The licensee states the TDAFW pump needs to be manually aligned before AFW can be delivered to the steam generators. How is this addressed in the plant procedures and what is the technical basis for the 10-minute completion time?

b. Provide the DNBR value which demonstrates the minimum DNBR remained above the SAL and the technical justification demonstrating the minimum DNBR for LOAC is bounded by the complete loss of flow transient.

Response 13a:

Refer to Attachment I

Response 13b:

a, c

[ ]

Reactor Systems Question 14:

Regarding the excessive heat removal due to feedwater system malfunction re-analysis, the licensee states the case initiated at hot zero power (HZP) conditions with manual rod control was less limiting than the HZP steamline break analysis. Provide the technical basis for this statement.

Response:

It has been demonstrated that the DNB related statepoint parameters (i.e. pressure, heat flux fraction, flow, and inlet temperature) for the most limiting case of Feedwater Malfunction (FWM) event are less limiting than those for the most limiting case of HZP steamline break (SLB) event. The following table compares the key limiting parameters between the FWM event and the analyzed HZP SLB events. This table shows that the HZP SLB event results in a higher return to power level and significantly lower RCS pressures, which will cause a much larger DNBR penalty than the DNBR benefit gained due to a larger cooldown. The HZP SLB event also results in larger differences between hot and cold loop inlet temperatures, which would tend to increase power distribution asymmetries. Therefore, the FWM event is less limiting than the HZP SLB.

Key Parameter Comparisons between FWM and HZP SLB

Parameter	FWM	HZP SLB-1 (with offsite power)	HZP SLB-2 (without offsite power)
Pressure (psia)	[		]
Coldest Inlet Temp (°F)			
Hottest Inlet Temp (°F)			
Heat Flux Fraction			
Core Flow Fraction			

a,c

Reactor Systems Question 15:

Regarding the excessive load increase incident, the analysis of record states the LOFTRAN computer code was used to analyze this transient. The application report does not describe how this incident was analyzed. State the methodology used to analyze this transient and provide the results obtained, including pressurizer pressure, nuclear power, DNB ratio and core average temperature over time which show the acceptance criteria is met.

Response:

The Excessive Load Increase Incident was evaluated using a simplified method developed to determine whether a reanalysis is required. This method applies conservatively bounding conditions in generating statepoints that are compared directly to the IP2 SPU core limits. If the minimum DNBR statepoint conditions remain above the SPU safety analysis DNBR limit, no further analysis is required. For the SPU, the IP2 initial (SPU) conditions when applying conservatively bounding conditions for the Excessive Load Increase Incident found that the corresponding minimum DNBR statepoint conditions were above the SPU safety analysis DNBR limit. A summary of the method follows.

Bounding initial conditions for plant parameters which impact DNBR conditions (i.e., power, temperature, pressure and flow) were determined for IP2 at SPU conditions consistent with RTDP DNB methods employed for IP2. The initial conditions were the licensed uprate core power (3216 MWt), high nominal Tavg temperature (572°F), nominal RCS pressure (2250 psia) and minimum measured flow (348,300 gpm), consistent with the RTDP DNB methods.

Conservatively bounding deviations in plant parameters are applied to the IP2 initial conditions. The deviations are derived from a bounding set of plant analysis results with appropriate conservatisms applied. By applying these deviations to the IP2 initial conditions, a conservative set of statepoints are generated for each case examined. The following shows the deviations applied to the initial conditions that address various cases examined (note that a constant RCS flow rate is assumed).

Case	Feedback	Rod Control	Core Power	Vessel Average Temperature	Pressurizer Pressure
1	Minimum	Manual	[		]
2	Maximum	Manual			
3/4	Min and Max	Automatic			

a,c

The combined IP2 SPU initial conditions and bounding deviations (i.e. statepoints) were compared directly to the IP2 SPU limiting DNB core limit lines that represent the limiting DNBR conditions for the uprate. The comparison showed that margin exists between the bounding statepoint conditions and DNB core limits which demonstrates that the minimum DNBR conditions associated with an Excessive Load Increase Incident for IP2 at SPU conditions meet SPU safety analysis DNBR limit.

SG Structural Question 2:

With regard to mechanical plugs, the application report states on page 5.6-10 (Conclusions) that, "... both the long and short mechanical plug designs satisfy all applicable stress and retention acceptance criteria at the SPU condition with up to 10-percent tube plugging.", and that, "... mechanical plugs have been previously qualified for the SPU condition with up to 25-percent tube plugging." The licensee states on page 5.6-10 (Results) that, "The plug meets the Class 1 fatigue exemption requirements per N-415.1 of the ASME Code..."

a. Provide a table (similar to Table 5.6-2 for the primary and secondary side components) which summarizes the load conditions, stress categories, ASME allowables, and all applicable stress- and fatigue-related calculation results that support your conclusions for the mechanical plugs. Show the calculation results which indicate that ASME allowables were met.

b. Provide calculation results which show that the mechanical plugs are qualified for the SPU condition with up to 25% tube plugging.

c. Provide the basis and calculation results (if any) for satisfying the ASME Class 1 fatigue exemption requirements

Response 2a:

The requested tables are provided as follows. The results show that the allowables were met.

Table SG-1
Mechanical Plug Stress Summary

Condition	Stress Intensity Classification	Calculated Value	ASME Code Allowable
Design	P_m	[ ]a,c	Sm = 23.3 ksi
	P_L+P_b		1.5Sm = 34.95 ksi
Faulted (Feedwater Line Break)	P_m		0.7Su = 56.0 ksi
	P_L+P_b		1.05 Su = 84.0 ksi
Test (Primary Side Hydrostatic)	P_m		0.9Sy = 0.9x35.0 = 31.5 ksi
	P_L+P_b		1.35Sy = 1.35x35.0 = 47.3 ksi

Note: Normal, and abnormal conditions are enveloped by design conditions. Maximum allowed delta-P across tubesheet is 1700 psi (Per Steam Generator Specification). Design case is based on applying a primary pressure of 2485 psi across tubesheet. The maximum ΔP across the tubesheet is [ ]^{a,c} psi for normal conditions, and [ ]^{a,c} psi for upset conditions. Also, the ASME Code limit for normal and upset condition is $3S_m$ = 3x23.3 = 69.9 ksi.

Table SG-2

Mechanical Plug Retention

Condition	Dislodging Stress (psi)	Bearing Stress (psi)	Total (Dislodging plus bearing stress) (psi)	Allowable Unloading Stress (psi)
Primary Side Hydrostatic Test	[		] a,c	[25660]+ac (With plug expander in place)
Secondary Side Hydrostatic Test				[25660]+ac (With plug expander in place)

Note: The hydrostatic tests bound all subsequent service conditions (normal, abnormal, test) for plug retention.

Response 2b:

Refer to Attachment I

Response 2c:

The following table provides the basis and results for satisfying the ASME Class 1 fatigue exemption requirements.

Table SG-3

Mechanical Plug Fatigue Evaluation based on Fatigue Exemption rules of ASME code Section N-474-1

N-474-1 Fatigue Condition	Description	Limits	Actual
1	Comparison of Transients with Atmospheric to Service Pressure Cycles	Allowable number of cycles for this condition is [ ]^{a,c}.	Actual number of cycles for this condition is [ ]^{a,c}.
2	Comparison of transients with significant pressure fluctuations	Allowable limiting pressure range for this condition is [ ]^{a,c} psi	Maximum service pressure range was found to be [ ]^{a,c} psi.
3	Temperature difference startup and shutdown	Allowable ΔT is 407°F between any two regions.	The startup and shutdown transient is limited to < 100°F/hr. Therefore, metal temperature between any two regions will be lower than the permitted limit.
4	Temperature difference normal service (Exclusive of startup and shutdown)	Allowable ΔT is 276°F.	Largest change in temperature was found for the Loss of Flow transient, which is 115°F.
5	Temperature difference dissimilar materials	The significant ΔT for temperature fluctuations was found to be 642°F.	
6	Non-pressure external mechanical loads.	There are no non-pressure external mechanical loads on the plugs.	

SG Structural Question 3 :

With regard to shop weld plugs, the licensee states on page 5.6-11 (Conclusions) that, "All primary stresses are satisfied for the weld between the weld plug and the tubesheet cladding.", and, "The overall maximum primary-plus-secondary stresses for the enveloping transient case of 'steady-state fluctuation' were determined to be acceptable.", and, "It was determined that the fatigue exemption rules were met, and, therefore, fatigue conditions are acceptable."

a. Provide a table (similar to Table 5.6-2 for the primary and secondary side components) which summarizes the load conditions, stress categories, ASME Code allowables, and all applicable stress- and fatigue-related calculation results that support your conclusions for the shop weld plugs. Show the calculation results which indicate that ASME allowables were met.

b. Provide the basis and calculation results (if any) for satisfying the ASME fatigue exemption requirements.

Response 3a:

The requested table is provided as follows.

Table SG-4A

Stress Summary for Shop Welded Plugs

Loading Condition	Calculated Maximum Stress Intensity (psi)	ASME Code Limit (psi)
Design	[ ] a,c	0.5Sm = 0.5x23,300 = 15,750 psi 0.5(1.5Sm) = 0.5x1.5x23,300 = 23,625 psi
Operating (Normal and Upset Conditions)		0.5(3.0Sm) = 0.5x3.0x23,300 = 34,950 psi
Test		0.5(0.9Sy) = 0.5x0.9x35,000 = 15,750 psi 0.5(1.35Sy) = 0.5x1.35x35,000 = 23,625 psi 0.5(3.0Sm) = 0.5x3.0x23,300 = 34,950 psi

Response 3b:

The following table provides the basis and results for satisfying the ASME fatigue exemption requirements.

Table SG-4B

Shop Welded Plug Fatigue Evaluation based on Fatigue Exemption rules of ASME code Section N-474-1

N-474-1 Fatigue Condition	Description	Limits	Actual
1	Comparison of Transients with Atmospheric to Service Pressure Cycles	Allowable number of cycles for this condition is [ ]^{a,c}.	Actual number of cycles for this condition is [ ]^{a,c}.
2	Comparison of transients with significant pressure fluctuations	Allowable limiting pressure range for this condition is [ ]^{a,c} psi.	Maximum service pressure range was found to be [ ]^{a,c} psi.
3	Temperature difference startup and shutdown	Allowable ΔT is 413°F between any two regions.	The startup and shutdown transient is limited to < 100°F/hr. Therefore, metal temperature between any two regions will be lower than the permitted limit.
4	Temperature difference normal service (Exclusive of startup and shutdown)	Allowable ΔT is 272°F.	Largest change in temperature was found for the Loss of Flow transient, which is 115°F.
5	Temperature difference dissimilar materials	The significant ΔT for temperature fluctuations was found to be 202°F.	
6	Non-pressure external mechanical loads.	There are no non-pressure external mechanical loads on the plugs.	

SG Structural Question 4:

With regard to the tube undercut qualification, the licensee states on page 5.6-12 (Conclusions) that, "The results of the stress evaluation of the IP2 model 44F steam generators determined that the stresses are within ASME Code allowable values. Also, fatigue usage factors were determined to remain less than 1.0."

Provide a table (similar to Table 5.6-2 for the primary and secondary side components) which summarizes the load conditions, stress categories, ASME allowables, and all applicable stress- and fatigue-related calculation results that support your conclusions for the tube undercut qualification. Show the calculation results which indicate that ASME allowables were met.

Response:

Stress evaluation results of IP2 Model 44F series steam generator tube end machining are all found to be within allowable limits. Also, the fatigue usage values have been found to be less than the 1.0 fatigue limit. Summary results for the maximum normal design condition are provided in Table SG-5, and results for fatigue are provided in Table SG-6.

Table SG-5
Indian Point Unit 2 Steam generators

Summary of Maximum Normal Design Stresses

Maximum Normal Operation Primary Pressure – Secondary Pressure = 1700 Psi												
Location	PM (Ksi)	ASME Allow Sm (Ksi)	Ratio	PI+Pb (Ksi)	ASME Allow 1.5Sm (Ksi)	Ratio	Triaxial Stress P1+P2+P3 (Ksi)	ASME Allow 4Sm (Ksi)	Ratio	Max Shear (Bending) (Ksi)	ASME Allow 0.6Sm (Ksi)	Ratio
Horizontal section between the end of tube and the weld	[ ]	26.6	[ ]	[ ]	39.9	[ ]	[ ]	106.4	[ ]	[ ]	15.96	[ ]
Vertical section between the weld and cladding/ tubesheet	[ ]	26.6	[ ]	[ ]	39.9	[ ]	[ ]	106.4	[ ]	[ ]	15.96	[ ]

a,c

Table SG-6
Indian Point Unit 2 Steam Generators

Summary of Fatigue Usage Factors

Location	Surface	Usage Factor
Horizontal section between the end of tube and the weld	Inside (Weld Root)	[ ]a,c
Vertical section between the weld and cladding/ tubesheet	Inside (Weld Root)	[ ]a,c

Note: Maximum usage factor occurs at a point that is common to both sections.