FPL Energy Point Beach, LLC, 6590 Nuclear Road, Two Rivers, WI 54241

FPL Energy.

Point Beach Nuclear Plant

April 7, 2009

NRC 2009-0030
10 CFR 50.90

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

Point Beach Nuclear Plant, Units 1 and 2
Dockets 50-266 and 50-301
Renewed License Nos. DPR-24 and DPR-27

License Amendment Request 261
Extended Power Uprate

Pursuant to 10 CFR 50.90, FPL Energy Point Beach, LLC (FPL Energy Point Beach) hereby requests an amendment to Renewed Facility Operating Licenses DPR-24 and DPR-27 for Point Beach Nuclear Plant (PBNP) Units 1 and 2, respectively. The proposed amendment would increase each unit's licensed core power level from 1540 megawatts thermal (MWt) to 1800 MWt reactor core power, and revise the Technical Specifications to support operation at this increased core thermal power level. This is an approximate 17% increase in core thermal power compared to current licensed core thermal power in the facility operating licenses, and therefore, is defined as an Extended Power Uprate (EPU). The increase in core thermal power is planned to be accomplished following the Spring 2010 Unit 1 refueling outage beginning with Cycle 33, and following the Spring 2011 Unit 2 refueling outage beginning with Cycle 32.

This planned license amendment request was the topic of public meetings between the NRC staff and FPL Energy Point Beach on September 8, 2008 (ML086280110) and January 22, 2009 (ML090410636).

This amendment request fulfills the information requirements of RS-001, Review Standard for Extended Power Uprates, Revision 0, dated December 2003, insofar as the guidance and/or criteria of RS-001 applies to the design bases of PBNP. In addition, technical information beyond the specific guidance of RS-001 is provided in the attached EPU Licensing Report.

A001
NRR

FPL Energy Point Beach has developed this license amendment request consistent with the format and content contained in the R. E. Ginna Nuclear Power Plant license amendment request for an extended power uprate (ML051950123). R. E. Ginna is a two-loop Westinghouse PWR similar in design to the Point Beach Nuclear Plant units. The Ginna 17% extended power uprate was approved and implemented in 2006.

Plant modifications required by the power uprate are being implemented over time. Modifications that do not require prior NRC approval and do not prevent safe operation at the current licensed power level, have already been made or will be made in accordance with 10 CFR 50.59 while the plant is on line, or no later than the planned refueling outage in the Spring 2010 for Unit 1 and Spring 2011 for Unit 2. The remaining power uprate-related modifications are dependent upon the Commission's approval of the enclosed license amendment request. These modifications are planned to be made during the Spring 2010 refueling outage for Unit 1 and the Spring 2011 refueling outage for Unit 2. A list of planned plant major modifications associated with EPU is provided in the Licensing Report, Attachment 5, Section 1.0, Introduction.

Two additional license amendment requests are required in support of this EPU submittal. These requests are as following:

- PBNP LAR 241 – Alternative Source Term, dated December 8, 2008 (ML083450683).
- PBNP LAR 258 – Incorporate Best Estimate Large Break Loss of Coolant Accident (LOCA) Analyses Using ASTRUM, dated November 25, 2008 (ML083330160).

These license amendment requests were individually submitted. The approval of the EPU submittal is contingent upon the approval of these additional submittals.

Approval of this LAR will satisfy an FPL Energy Point Beach Regulatory Commitment to provide revised setpoints for the reactor protection system (RPS) instrumentation and the engineered safety feature actuation system (ESFAS) instrumentation Allowable Values in Technical Specification Tables 3.3.1-1 and 3.3.2-1, respectively. In October of 2005, it was identified that certain Technical Specification (TS) allowable values for these instruments were less restrictive than the corresponding calculated values. The Regulatory Commitment to submit a license amendment request to revise these setpoints was docketed via letter dated November 16, 2006 (ML063250487) from the Nuclear Management Company, LLC, former license holder for PBNP Units 1 and 2, to the Commission. The Regulatory Commitment was subsequently revised via letter dated August 8, 2007 (ML072210998) to defer submittal of the request until completion of the site's calculation review and reconstitution project. That project is now complete. This license amendment request fulfills the Regulatory Commitment made with respect to the RPS/ESFAS setpoint changes.

In addition, this license amendment request fully implements Technical Specification Task Force Traveler (TSTF)-491, Revision 2, "Removal of the Main Steam and Main

Feedwater Valve Isolation Time from Technical Specifications." This Consolidated Line Item Improvement Process (CLIIP) had been submitted to the Commission via License Amendment Request 255 dated June 29, 2007 (ML071800512). At that time, the CLIIP only had direct applicability for PBNP for the main steam isolation valves (MSIVs), so partial adoption of the CLIIP was requested. (TAC Nos. MD6079 and MD6080 were assigned to this application.) The Commission approved the proposed changes via letter and accompanying safety evaluation dated November 16, 2007 (ML0742410104). The letter issued Amendments 230 and 235 for Units 1 and 2, respectively. Since the proposed EPU installs main feedwater isolation valves, FPL Energy Point Beach now requests full adoption of TSTF-491, Revision 2 with respect to the proposed Technical Specification changes for these new valves.

Attachment 1 contains descriptions and technical justifications for the proposed changes to the Facility Operating Licenses, Technical Specifications, and current licensing bases (CLB), and proposed plant modifications. Attachment 1 also contains a No Significant Hazards Consideration. In accordance with 10 CFR 50.91(a)(1), FPL Energy Point Beach has performed a No Significant Hazards Consideration analysis and concludes that the changes proposed by this license amendment request present no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

Attachment 2 contains the affected Facility Operating Licenses and Technical Specification marked up pages to facilitate identifying the proposed changes.

Attachment 3 identifies the associated changes (marked up pages) to the Technical Specification Bases. These changes are provided for information only. Following approval of the requested Facility Operating Licenses and Technical Specification changes, the Technical Specification Bases will be revised.

Attachment 4 contains a summary of Regulatory Commitments related to this submittal.

Attachment 5 contains the Licensing Report, which contains the technical assessment of the EPU per the guidance of RS-001 including: description, system and component evaluations, design transients, nuclear fuel, accident analyses, and environmental considerations. For plant design features and analyses affected by the EPU, the Licensing Report describes PBNP's CLB, and the methods, margins or operating limits, and results of the evaluations that have been performed to determine the impacts of EPU on the CLB. This Licensing Report demonstrates acceptable facility operation at the increased core thermal power. The Licensing Report is supported by five appendices: Appendix A - Safety Evaluation Report Compliance; Appendix B - Additional Codes and Methodologies; Appendix C – Scope and Associated Technical Review Guidance; Appendix D – Supplemental Environmental Report; and Appendix E - Supplement to LR Section 2.4.1.

Attachment 6 contains the application for withholding the proprietary information contained in the Licensing Report, Attachment 5, from public disclosure. As Attachment 5 contains information proprietary to Westinghouse Electric Company, LLC (Westinghouse), it is supported by an affidavit signed by Westinghouse, the owner of the information. The affidavit sets forth the basis for which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b) (4) of § 2.390 of the Commission's' regulations: Accordingly, it is respectfully requested that the information which is proprietary to Westinghouse be withheld from public disclosure in accordance with 10 CFR 2.390 of the Commission's regulations.

Attachment 7 provides topical report WCAP-14787, Revision 3, Revised Thermal Design Procedure Instrument Uncertainty Methodology for Point Beach Power Uprate, (1775 MWt Core Power with Feedwater Venturis, or 1800 MWt-Core Power with LEFM on Feedwater Header).

Attachment 8 contains the application for withholding the proprietary information contained in WCAP-14787, Attachment 7 from public disclosure. As Attachment 7 contains information proprietary to Westinghouse, it is supported by an affidavit signed by Westinghouse, the owner of the information. The affidavit sets forth the basis for which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b) (4) of § 2.390 of the Commission's' regulations: Accordingly, it is respectfully requested that the information which is proprietary to Westinghouse be withheld from public disclosure in accordance with 10 CFR 2.390 of the Commission's regulations.

Correspondence with respect to the copyright or proprietary aspects of the items listed above or the supporting Westinghouse affidavits should reference CAW-09-2537 or CAW-09-2530 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.

Attachments 5 and 7 contain proprietary information. A non-proprietary license amendment request will be submitted that replaces Attachment 5 Licensing Report with a non-proprietary Licensing Report, and replaces Attachment 7, WCAP-14787 with WCAP-14788, the non-proprietary version of WCAP-14787.

In accordance with 10 CFR 50.91, a copy of this application is being provided to the designated Wisconsin official.

FPL Energy Point Beach has evaluated the proposed amendment and has determined that it does not involve a significant hazards consideration pursuant to 10 CFR 50.92. The PBNP Plant Operations Review Committee has reviewed the proposed license amendment request.

Approval of this application is requested by April 7, 2010, to allow implementation of the extended power uprate during the Spring 2010 Unit 1 refueling outage and the Spring 2011 Unit 2 refueling outage.

Should you have questions regarding the information in this submittal, please contact Mr. Steve Hale, Point Beach Extended Power Uprate Licensing Manager, at 561-904-3205.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on April 7, 2009

Very truly yours,

FPL Energy Point Beach, LLC

Larry Meyer
Site Vice President

Attachments (8)

cc: Administrator, Region III, USNRC
Project Manager, Point Beach Nuclear Plant, USNRC
Resident Inspector, Point Beach Nuclear Plant, USNRC
PSCW

Westinghouse

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Proj letter ref WEP-09-26
Our ref: CAW-09-2537

February 23, 2009

APPLICATION FOR WITHHOLDING PROPRIETARY
INFORMATION FROM PUBLIC DISCLOSURE

Subject: "Attachment 5 to Point Beach Units 1 and 2 Extended Power Uprate Amendment Request"

The proprietary information for which withholding is being requested in the above-referenced report is further identified in Affidavit CAW-09-2537 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 FPL Energy.

Correspondence with respect to the proprietary aspects of the application for withholding or the Westinghouse affidavit should reference this letter, CAW-09-2537, 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: George Bacuta (NRC OWFN 12E-1)

bcc: J. A. Gresham (ECE 4-7A) 1L
R. Bastien, 1L (Nivelles, Belgium)
C. Brinkman, 1L (Westinghouse Electric Co., 12300 Twinbrook Parkway, Suite 330, Rockville, MD 20852)
RCPL Administrative Aide (ECE 4-7A) 1L, 1A (letter and affidavit only)
B. Gergos (ECE 4-7A) 1L, 1A
R. Morrison (ECE 4-16A) 1L, 1A
P. Vaughn (ECE 3-19J) 1L, 1A

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 & Plant Licensing

Sworn to and subscribed before me
this 23rd day of February, 2009

Sharon L. Markle
Notary Public

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Sharon L. Markle, Notary Public
Monroeville Boro, Allegheny County
My Commission Expires Jan. 29, 2011
Member, Pennsylvania Association of Notaries

(1) I am Manager, Regulatory Compliance & 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 as "Attachment 5 to Point Beach Units 1 and 2 Extended Power Uprate Amendment Request," being transmitted by FPL Energy 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 Point Beach Units 1 and 2 is expected to be applicable for other licensee submittals in response to certain NRC requirements for extended power uprate submittals.

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

(a) Provide input to the Nuclear Regulatory Commission for review of the Point Beach extended power uprate.

(b) Provide results of customer specific calculations.

(c) Provide licensing 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 extended power uprates.

(b) Westinghouse can sell support and defense of the technology to its customer 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 information 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).

Should you have questions regarding the information in this submittal, please contact Mr. Steve Hale, Point Beach Extended Power Uprate Licensing Manager, at 561-904-3205.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on April 7, 2009

Very truly yours,

FPL Energy Point Beach, LLC

Larry Meyer
Site Vice President

Attachments (8)

cc: Administrator, Region III, USNRC
Project Manager, Point Beach Nuclear Plant, USNRC
Resident Inspector, Point Beach Nuclear Plant, USNRC
PSCW

Attachment 1

FPL Energy Point Beach, LLC
Point Beach Nuclear Plant Units 1 and 2

License Amendment Request 261
Extended Power Uprate

Description and Technical Justifications
for the Renewed Facility Operating License
and Technical Specification and Licensing Basis Changes

47 Pages to Follow

DESCRIPTION AND TECHNICAL JUSTIFICATIONS FOR THE RENEWED FACILITY OPERATING LICENSE , TECHNICAL SPECIFICATION AND LICENSING BASIS CHANGES

1.0 Description

FPL Energy Point Beach, LLC (FPL Energy Point Beach) is proposing to amend Renewed Facility Operating License Nos. DPR-24 and DPR-27 for the Point Beach Nuclear Plant (PBNP), Units 1 and 2, respectively.

The proposed license amendment request (LAR) will revise the Facility Operating Licenses to permit PBNP to operate at a maximum steady-state reactor core thermal power of 1800 megawatts thermal (MWt). The requested increase constitutes an Extended Power Uprate (EPU) and is requested to provide greater unit electrical generating capacity. FPL Energy Point Beach developed this LAR in accordance with the guidance provided in NRC Review Standard (RS)-001, Review Standard for Extended Power Uprate (Reference 1). Once approved, the amendment implementation is planned following the refueling outages in the Spring 2010 for Unit 1 and the Spring 2011 for Unit 2. Operation at the increased power level will occur in Cycle 33 for Unit 1 and Cycle 32 for Unit 2.

FPL Energy Point Beach has submitted two license amendment requests that are associated with the EPU and are necessary to implement the EPU: PBNP LAR 258, Incorporate Best Estimate Large Break Loss of Coolant Accident (LOCA) Analyses Using ASTRUM, dated November 25, 2008 (ML083330160), and PBNP LAR 241, Alternative Source Term, dated December 8, 2008 (ML083450683), (Reference 2 and Reference 3, respectively).

FPL Energy Point Beach has reviewed the Renewed Facility Operating Licenses, Technical Specifications and current licensing basis and has determined that no revisions to these documents other than those addressed below (or in the previously referenced submittals) are required to properly control plant operations and configuration under EPU conditions. Note that the Function 6.e, AFW Pump Suction Transfer on Suction Pressure Low, is being added to Function 6, Auxiliary Feedwater. This setpoint is being implemented to eliminate the need for a manual transfer of the AFW pump suction from the condensate storage tank (CST) to the safety related service water source and to implement an automatic suction transfer upon a low suction pressure signal. The [TBD] setpoint will be determined with the final design of the AFW system upgrade. Therefore, this setpoint is not included in the change description or the No Significant Hazards Determination contained in this attachment. The NRC staff has requested this setpoint information to be provided on a specific schedule. FPL Energy Point Beach will provide the setpoint, the change description and a No Significant Hazards Determination in a supplement to this LAR by July 30, 2009. Attachment 4, Item 1, lists the regulatory commitment associated with this item.

Mark-ups of the proposed Renewed Facility Operating Licenses and Technical Specification changes are provided in Attachment 2. Note that the proposed mark-ups of the Technical Specification Bases are provided in Attachment 3 for information. In addition, the regulatory commitments identified in Attachment 4 are required to be completed as stated or prior to implementation of the EPU for each unit.

2.0 Background

This LAR would authorize FPL Energy Point Beach to operate PBNP Units 1 and 2 at 1800 MWt, an approximate 17% increase in licensed reactor core thermal power. PBNP Units 1 and 2 are currently licensed at a rated reactor core thermal power of 1540 MWt for Renewed Facility Operating Licenses Nos. DPR-24 and DPR-27, for Units 1 and 2, respectively. Due to the magnitude of this increase in licensed thermal power, this power uprate is defined as an extended power uprate (EPU).

FPL Energy Point Beach has evaluated the impact of the 17% power uprate for the applicable systems, structures, components, and safety analyses at PBNP. The results of this evaluation are described in Attachment 5, EPU Licensing Report (LR). The EPU Licensing Report provides the details that support the requested Operating License amendments, Technical Specification changes, Licensing Basis changes and plant modifications, and Attachment 5 works in concert with the other attachments of the LAR to provide a comprehensive evaluation of the effects of the proposed EPU.

3.0 Proposed Changes

3.1 License and Technical Specification Changes

The requested changes involve one revision to each Renewed Facility Operating License and changes to the Technical Specifications and Licensing Basis.

FPL Energy Point Beach has reviewed the Renewed Facility Operating Licenses, Technical Specifications and current licensing basis and has determined that no revisions other than those noted below (or in the referenced LAR 241 and LAR 258 submittals) are required to properly control plant operations and configuration under EPU conditions. An additional supplement to this LAR will be submited to provide the Table 3.3.2-1 Function 6.e. Limiting Safety System Settings (LSSS) and the associated no significant hazards determentation by July 30, 2009. In addition, the commitments identified in Attachment 4 are required to be completed, as stated for implementation of the EPU for each respective unit.

1 Renewed Operating License Condition 4. A. (DPR-24 and DPR-27)

The maximum reactor core power level was revised from 1540 MWt to 1800 MWt.

<u>Licensing Report Sections</u>: Section 1.0, Introduction to the Point Beach Nuclear Plant Units 1 and 2 Extended Power Uprate Licensing Report, and LR Section 1.1, Nuclear Steam Supply System Parameters.

<u>Basis for the change</u>: The results of the analyses and evaluations performed and discussed in the EPU Licensing Report (Attachment 5) demonstrate that the proposed increase in power can be safely and acceptably achieved by satisfying all applicable acceptance criteria, provided the regulatory commitments in Attachment 4 are completed as stated.

2 Technical Specification 1.1, Definitions, Rated Thermal Power (RTP)

The rated thermal power (RTP) was revised from 1540 MWt to 1800 MWt.

Licensing Report Sections: Section 1.0, Introduction to the PBNP Units 1 and 2 EPU Licensing Report, and LR Section 1.1, Nuclear Steam Supply System Parameters.

Basis for the change: The results of the analyses and evaluations performed and discussed in the EPU LR (Attachment 5) demonstrate that the proposed increase in power can be safely and acceptably achieved by satisfying all applicable acceptance criteria, provided the regulatory commitments in Attachment 4 are completed as stated.

3 Technical Specification 2.1.1, Reactor Core SLs

a. The typical/thimble design limit for the departure from nucleate boiling ratio (DNBR) values for cores not containing 422V+ fuel was deleted.

The clarifier that the 1.22/1.21 typical/thimble design limit DNBR values are applicable for cores not containing 422V+ fuel was deleted.

The clarifier that the 1.24/1.23 typical/thimble design limit DNBR values are applicable for cores containing 422V+ fuel was deleted.

The OR was deleted.

Licensing Report Sections: Section 1.1, Nuclear Steam Supply System Parameters, and Section 2.8.5.0, Non LOCA Analyses Introduction.

Basis for the change: The Nuclear Steam Supply System (NSSS) design parameters provide the reactor coolant system (RCS) and secondary side system conditions (thermal power, temperatures, pressures, and flows) that are used as the basis for the design transients, systems, structures, components, accidents, and fuel analyses and evaluations. One of the major input parameters and assumptions used in the calculation of the four cases of NSSS design parameters established for the PBNP Units 1 and 2 EPU is 14x14 422V+ fuel. Therefore, this fuel type is the only fuel that has been evaluated for the EPU.

The OR is not required since only the three remaining cited DNB limits apply and are identified by the specific DNB correlation.

The typical/thimble design limit DNBR values for cores containing 422V+ fuel and for cores not containing 422V+ fuel were deleted because the EPU analysis only supports 422V+ fuel, and the DNB correlation limit value for the WRB-1 correlation was added below for the EPU analyses. The change of adding the limit for the WRB-1 DNB correlation is consistent with NUREG-1431, and makes it consistent with the DNB correlation limits that are currently presented for the W-3 DNB correlation.

b. The limit of $\geq$ 1.17 for the WRB-1 departure from nucleate boiling (DNB) correlation was added.

Licensing Report Sections: Section 2.8.3.2.2.2, DNB Methodology, and Section 2.8.3.2.2.2.1, DNB Correlation and Limits.

Basis for the change: The Standard Thermal Design Procedure (STDP) is used for those analyses where the Revised Thermal Design Procedure (RTDP) is not applicable. The DNBR limit for the STDP is the appropriate DNB correlation limit increased by sufficient margin to offset the applicable DNBR penalties. For analyses where STDP is used, the DNBR correlation limit is ≥ 1.17 for the WRB-1 correlation.

4 Technical Specification 3.2.1, Heat Flux Hot Channel Factor ($F_Q(Z)$)

The second COMPLETION TIME for REQUIRED ACTION A.4 was deleted.

REQUIRED ACTION B.1, was revised to delete "AFD limits" and insert "THERMAL POWER," and insert "RTP" after the first 1% such that it reads, "Reduce THERMAL POWER ≥ 1% RTP for each 1% $F^W{}_Q(Z)$ exceeds limit."

REQUIRED ACTION B.2, was revised to delete "that the maximum allowable power of the AFD limits is reduced" and insert "$F^W{}_Q(Z)$ exceeds limits."

REQUIRED ACTION B.3 was revised.to delete "that the maximum allowable power of the AFD limits is reduced" and insert "$F^W{}_Q(Z)$ exceeds limits."

The COMPLETION TIME for REQUIRED ACTION B.4 was revised to delete, "the maximum allowable power of the AFD limits" and insert "limit of Required Action B.1."

Licensing Report Sections: LR Section 2.8.1, Fuel System Design

Basis for the change: The changes are consistent with Technical Specification 3.2.1.C, Heat Flux Hot Channel Factor ($F_Q(Z)$ (CAOC-W(Z) Methodology), in NUREG-1431, Standard Technical Specifications Westinghouse Plants, (Reference 4). The changes are necessary to change from a Relaxed Axial Offset Control (RAOC) operating strategy to a Constant Axial Offset Control (CAOC) operating strategy. This change adds clarity to the Technical Specification.

5. Technical Specification 3.2.3, Axial Flux Difference (AFD)

The RAOC Technical Specification 3.2.3 was deleted and replaced with a CAOC Technical Specification 3.2.3.

Licensing Report Sections: Section 2.8.1, Fuel System Design, and Section 2.8.2, Nuclear Design.

Basis for the change: The CAOC methodology provides additional analytical margin, and is reflected in the referenced fuel rod design analysis. The Axial Offset limits must be reduced to offset the impact of EPU on the core thermal hydraulics and fuel rod performance. The change is consistent with Technical Specification 3.2.3A, Axial Flux Difference (AFD) (Constant Axial Offset Control CAOC) Methodology) in NUREG-1431, Standard Technical Specifications Westinghouse Plants. See Reference 17 and Reference 18.

6. Technical Specification 3.3.1, RPS Instrumentation.

This section contains changes to Limiting Safety System Settings (LSSS) for RPS setpoints. In summary, Technical Specification Table 3.3.1-1 (RPS Instrumentation) is being revised to:

1) Change the column heading now titled "ALLOWABLE VALUE" to "LIMITING SAFETY SYSTEM SETTINGS." Values in this column are revised to reflect changes resulting from

EPU and are revised to provide a conservative setpoint that includes instrument uncertainty and to replace existing values that are not consistent with the LSSS calculations and presentation in this submittal.

2) Two notes are added to the Table to specify Operability criteria and to require that out-of-tolerance conditions detected during surveillance be entered into the corrective action process; and

3) Change the LSSS values in the tables for individual Functions identified below.

a. Table 3.3.1-1 change the 6th column heading previously identified as ALLOWABLE VALUES to LIMITING SAFETY SYSTEM SETTINGS with a reference to footnote (m). The footnote (m) insertion reads, "Table 3.3.1-1 Notes 3 and 4 are applicable with the exception of those listed as "NA."

Licensing Report Sections: Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems

Basis for the change: As defined in 10 CFR 50.36, LSSS are settings for automatic protective devices related to those variables having significant safety functions. 10 CFR 50.36 requires that these limiting settings be included in the Technical Specifications. The heading change is consistent with this requirement.

The LSSS for trip functions in the above table are calculated based on limits from the safety analyses, process limits for the instrumentation, and instrument loop uncertainties calculated with 95% probability and 95% confidence to industry standard methodology. The LSSS for reactor trip system interlocks are calculated based on nominal setpoints used in the analyses and as-found acceptance criteria. The methods used to determine LSSS values and summaries of calculations are provided in Appendix E, Supplement to LR Section 2.4.1.

The LSSS values proposed for TS Table 3.3.1-1 are limiting values for the nominal trip setpoint and are calculated such that there is 95% probability and 95% confidence that the trip will occur prior to the process variable exceeding the established limit. For interlocks, the LSSS value insures the interlock, permissive or block function will occur in accordance with the assumptions of the analyses. Therefore, the assumptions of the safety analyses and results are protected by proposed LSSS values.

Table 1.0-1 identifies functions for which the LSSS values were affected by EPU and the functions for which LSSS values are changed to obtain consistency in the application of LSSS values in TS Table 3.3.1-1. These LSSS values have been evaluated using the methods described in Appendix E, Supplement to LR Section 2.4.1. Four RPS functions that are shown in the table (Reactor Coolant Flow Low (single loop and two loops), Undervoltage Bus A01 & A02, and Underfrequency Bus A01 & A02), have been evaluated using the methods described in Appendix E, Supplement to LR Section 2.4.1 and have shown that no change to the LSSS is required for these functions.

The heading change is consistent with the 10 CFR 50.36 requirement. The change is also consistent with the 16.8 Percent Power Uprate, License Amendment approved for R. E. Ginna on August 7, 2006 (ML061380103).

Footnote (m), and therefore, Notes 3 and 4, applies to all functions that do not have an "NA" as a value in the LIMITING SAFETY SYSTEM SETTINGS column.

Notes 3 and 4 are added to Table 3.3.1-1 consistent with the guidance contained in RIS 2006-17 and LIMITING SAFETY SYSTEM SETTING are revised to provide a conservative setpoint that includes instrument uncertainty. The setpoint changes are being made also to resolve setpoint LSSS required changes that were identified during the PBNP calculation reconstitution project.

b Notes 3 and 4

Notes 3 and 4 are added to Table 3.3.1-1 and LIMITING SAFETY SYSTEM SETTINGS are revised to provide a setpoint that includes instrument uncertainty. The setpoint changes resolve LSSSs needing correction that were identified during the PBNP calculation reconstitution project.

Note 3 states:

"A channel is OPERABLE when both of the following conditions are met:

a. The as-found Field Trip Setpoint (FTSP) is within the COT acceptance criteria for the as-found value. The method used to determine the COT acceptance criteria is described in FSAR Section 7.2.

b. The as-left FTSP is reset to a value that is within the as-left tolerance at the completion of the surveillance. The channel is considered operable even if the as-left FTSP is non-conservative with respect to the LSSS provided that the as-left FTSP is within the established as-left tolerance band. The method used to determine the as-left tolerance is described in FSAR Section 7.2."

Note 4 states:

"If the as-found FTSP is outside its predefined as-found acceptance criteria:

a. Evaluation of corrective measures necessary to return the channel to service is implemented in applicable plant maintenance and operating procedures.

b. The out-of-tolerance condition shall be entered into the Corrective Action Process."

Both notes will apply to each of those RPS Functions that contain specific values in the LSSS column in marked-up Tables 3.3.1-1 for surveillances where a specific value is measured (i.e., COT or channel calibration). The notes will not apply to those Functions that contain "NA" in the column.

Notes 3 and 4 will be applied to the following functions as indicated:

Table 1.0-1 Reactor Protection System LSSS TS Changes and Notes 3 and 4 Application

Item Number	Function	Notes 3 & 4 Apply	EPU Related	LSSS Change
2.a.	Power Range Neutron Flux – High	X	X	X
2.b.	Power Range Neutron Flux – Low	X		X
3.	Intermediate Range Neutron Flux	X		X
4.	Source Range Neutron Flux	X		
5.	Overtemperature ΔT	X	X	
6.	Overpower ΔT	X	X	
7.a.	Pressurizer Pressure – Low	X	X	
7.b.	Pressurizer Pressure – High	X	X	
8.	Pressurizer Water Level – High	X		X
9.a.	Reactor Coolant Flow Low - Single Loop	X		
9.b.	Reactor Coolant Flow Low - Two Loops	X		
11.	Undervoltage Bus A01 & A02	X		
12.	Underfrequency Bus A01 & A02	X		
13.	Steam Generator Water Level – Low Low	X	X	X
14.	Steam Generator Water Level – Low– Coincident with Steam Flow/Feedwater Flow Mismatch	X		X
17.	Reactor Trip System Interlocks	-	-	-
17.a.	Intermediate Range Neutron Flux, P-6	X		X
17.b.(1).	Low Power Reactor Trip Block, P-7, Power Range Neutron Flux	X		X
17.b.(2)	Low Power Reactor Trip Block, P-7, Turbine Impulse Pressure	X		X
17.c.	Power Range Neutron Flux, P-8	X	X	X
17.d.	Power Range Neutron Flux, P-9	X	X	X
17.e.	Power Range Neutron Flux, P10	X		X

Licensing Report Sections: Section 2.4.1, Reactor Protection, Engineered Safety Features and Control Systems, and Appendix E, Supplement to LR Section 2.4.1, LAR Attachment 5.

Basis for the change: Surveillance limits are established to verify that reactor protection system instrumentation with an LSSS in TS Table 3.3.1-1 operate within the boundaries of applicable instrument uncertainty calculations. These limits are implemented in plant procedures in accordance with Notes 3 and 4 above. The determination of as-left setting tolerance and as-found criteria is described in Appendix E, Supplement to LR Section 2.4.1.

The implementation of as-left and as-found limits verifies that the instrument loops are performing in accordance with uncertainty calculation assumptions and that out-of-tolerance conditions are evaluated. If a channel cannot be set within the as-left tolerance band the channel is declared inoperble and Notes 3 and 4 apply. FSAR Section 7.2 will be revised during implementation of these changes.

Footnote (m) and therefore, Notes 3 and 4, applies to all functions that do not have an "NA" as a value in the LSSS column.

c Function 2a, Power Range Neutron Flux - High

The LSSS is revised from ≤ 108% RTP to ≤ 109% RTP.

Licensing Report Sections: Section 2.8.5.4.2, Uncontrolled Rod Withdrawal at Power, LR Section 2.4.1.2.3.2.1, Reactor Protection, Engineered Safety Features and Control Systems, and Appendix E, Supplement to LR Section 2.4.1.

Basis for the change: This change is being implemented to support operation at EPU conditions. The uncontrolled rod withdrawal at power event for EPU assumes that the RPS is actuated at a conservative value of 116% of nominal full power. The LSSS is established by calculation to avoid exceeding the new analytical limit, taking all instrument uncertainties into account.

d. Function 2b, Power Range Neutron Flux - Low

The LSSS is revised from ≤ 25% RTP to ≤ 28% RTP.

Licensing Report Sections: Section 2.4.1.2.3.2.1, Reactor Protection, Engineered Safety Features and Control Systems, and Appendix E, Supplement to LR Section 2.4.1.

Basis for the change: This change is being made to replace existing values that are not consistent with the LSSS calculations and presentation in this submittal. The subcritical rod withdrawal, rod ejection, and steam line break outside containment analyses assume trip actuation at 35% RTP. This analytical limit is applicable at EPU and current conditions. The LSSS is established by calculation to avoid exceeding the new analytical limit, taking all instrument uncertainties into account.

e. Function 3, Intermediate Range Neutron Flux

1) The LSSS is revised from ≤ 40% RTP to ≤ 43% RTP.

Licensing Report Sections: Section 2.4.1.2.3.2.1, Reactor Protection, Engineered Safety Features and Control Systems, and Appendix E, Supplement to LR Section 2.4.1.

Basis for the change: This change is being made to replace existing values that are not consistent with the LSSS calculations and presentation in this submittal. The LSSS is calculated based on the nominal setpoint and as-found tolerance values and is valid at current and EPU conditions.

2) Footnote (b) - "interlocks" is revised to "interlock."

Licensing Report Sections: None

Basis for the change: This is an administrative change. There is only one interlock addressed by this Note.

f. Function 5, Overtemperature ΔT, Note 1

1) Note 1 states that the T', P', K_1, K_2, and K_3 values are applicable for operation at both 2000 psia and 2250 psia. The differentiation of these values for cores containing 422V+ fuel assemblies and cores not containing 422V+ fuel assemblies were deleted. The differentiation between 2000 psia and 2250 psia operation was deleted.

Licensing Report Sections: Section 1.1, Nuclear Steam Supply System Parameters, Section 2.4.1.2.3.2.1, Reactor Protection, Engineered Safety Features and Control Systems, and Section 2.8.5.0, Non-LOCA Analyses Introduction.

Basis for the change: The NSSS design parameters provide the RCS and secondary side system conditions (thermal power, temperatures, pressures, and flows) that are used as the basis for the design transients, systems, structures, components, accidents, and fuel analyses and evaluations. One of the major input parameters and assumptions used in the calculation of the four cases of NSSS design parameters established for PBNP Units 1 and 2 EPU is 14x14 422V+ Fuel. Therefore, this fuel type is the only fuel that has been evaluated for the EPU. In addition, 2000 psia operation was not analyzed and will not be allowed under EPU conditions.

2) The f(ΔI) function description was revised to delete the following.

"and f(ΔI) is an even function of the indicated difference between top and bottom detectors of the power-range nuclear ion chambers; with gains to be selected based on measured instrument response during plant startup tests, where q_t and q_b are the percent power in the top and bottom halves of the core respectively, and $q_t + q_b$ is total core power in percent of rated power, such that:

a.) for $q_t - q_b$ within -[*], +[*] percent, f(ΔI) = 0 for cores not containing 422V+ fuel assemblies; for $q_t - q_b$ within -[*], +[*] percent, f(ΔI) = 0 for cores containing 422V+ fuel assemblies.

b.) for each percent that the magnitude of $q_t - q_b$ exceeds +[*] percent, the ΔT trip setpoint shall be automatically reduced by an equivalent of [*] percent of rated power for cores not containing 422V+ fuel assemblies and reduced by an equivalent of [*] percent of rated power for cores containing 422V+ fuel assemblies."

And add the following:

"f (ΔI) = [*] {[*] - ($q_t - q_b$)}	when $q_t - q_b \leq$ [*]% RTP
0% of RTP	when [*]% RTP < $q_t - q_b \leq$ [*]% RTP
[*] {($q_t - q_b$) - [*]}	when $q_t - q_b$ > [*]% RTP

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

Licensing Report Sections: None

Basis for the change: The f (ΔI) description is being modified to delete references to a fuel type that has not been evaluated for use at EPU conditions. This results in the PBNP TS being identical to NUREG-1431, Standard Technical Specification Westinghouse Plants, for f(ΔI).

3) An * was added prior to the note that reads "The values denoted within [*] are specified in the COLR."

Licensing Report Sections: None

Basis for the change: This is an administrative change. The * is added to be consistent with Standard Technical Specifications.

4) The differentiation of the Rosemont or equivalent and Sostman or equivalent RTDs for τ_3 and τ_4 was deleted.

Licensing Report Sections: None

Basis for the change: Only Rosemont RTDs are used at PBNP.

5) Note (c) for f (ΔI) was deleted.

Licensing Report Sections: Section 1.1, Nuclear Steam Supply System Parameters, and Section 2.8.5.0, Non-LOCA Analyses Introduction.

Basis for the change: The NSSS design parameters provide the RCS and secondary side system conditions (thermal power, temperatures, pressures, and flows) that are used as the basis for the design transients, systems, structures, components, accidents, and fuel analyses and evaluations. One of the major input parameters and assumptions used in the calculation of the four cases of NSSS design parameters established for the PBNP Units 1 and 2 EPU is 14x14 422V+ fuel. This note was removed as part of the removal of notes (a) and (b) above. This fuel type is the only fuel that has been evaluated for use for the EPU.

g. Function 6, Overpower ΔT, Note 2

1) Note 2 states that the T', K_4, and K_6 values are applicable for operation at both 2000 psia and 2250 psia operation. Differentiation of these values for cores containing 422V+ fuel assemblies and cores not containing 422V+ fuel assemblies and differentiation between 2000 psia and 2250 psia operation was deleted. PBNP operates at 2250 psia with 422V+ fuel being the only fuel type evaluated for EPU operation.

Licensing Report Sections: Section 1.1, Nuclear Steam Supply System Parameters, Section 2.8.5.0, Non LOCA Analyses Introduction, and Section 2.4.1.2.3.2.1, Reactor Protection, Engineered Safety Features and Control Systems.

Basis for the change: The NSSS design parameters provide the RCS and secondary side system conditions (thermal power, temperatures, pressures, and flows) that are used as the basis for the design transients, systems, structures, components, accidents, and fuel analyses and evaluations. One of the major input parameters and assumptions used in the calculation of the four cases of NSSS design parameters established for PBNP Units 1 and 2

EPU is 14x14 422V+ fuel. Therefore, this fuel type is the only fuel that has been evaluated for the EPU.

The analyses and evaluations performed for the EPU and discussed in the LR Section 1.0 only considered a nominal RCS pressure of 2250 psia.

2) "Rated power" was revised to "RTP" for ΔT_0.

Licensing Report Sections: None

Basis for the change: This is an editorial change.

3) The differentiation of the Rosemont or equivalent and Sostman or equivalent RTDs for τ_3 and τ_4 was deleted.

Licensing Report Sections: None

Basis for the change: Only Rosemont RTDs are used at PBNP.

4) An * was added prior to the note that reads "The values denoted within [*] are specified in the COLR."

Licensing Report Sections: None

Basis for the change: This is an administrative change. The * is added to be consistent with Standard Technical Specifications.

h. Function 7a, Pressurizer Pressure - Low

The LSSS is revised from Footnote (h) ≥ 1905 psig during operation at 2250 psia, or ≥ 1800 psig during operation at 2000 psia to ≥1860 psig. Footnote (h) is deleted and replaced with a new footnote (h) for function 17.d.

Licensing Report Sections: Section 1.1, Nuclear Steam Supply System Parameters, Section 2.4.1.2.3.2.1, Reactor Protection, Engineered Safety Features and Control Systems and Appendix E, Supplement to LR Section 2.4.1, to Attachment 5 of this LAR.

Basis for the change: This change is being implemented to support operation at EPU conditions. Operation at 2000 psia was not analyzed and will not be allowed under EPU conditions. The OPTOAX code analysis assumes that the RPS is actuated at 1840 psig. The LSSS is established by calculation to avoid exceeding the new analytical limit, taking all instrument uncertainties into account.

i. Function 7b, Pressurizer Pressure - High

The LSSS is revised from Footnote (i) which states "≤ 2385 psig during operation at 2250 psia, or ≤ 2210 psig during operation at 2000 psia," to ≤ 2385 psig. Footnote (i) is deleted.

Licensing Report Sections: Section 1.1, Nuclear Steam Supply System Parameters, Section 2.4.1.2.3.2.1, Reactor Protection, Engineered Safety Features and Control Systems, and Appendix E, Supplement to LR Section 2.4.1.

Basis for the change: This change is being implemented to support operation at EPU conditions. Operation at 2000 psia was not analyzed and will not be allowed under EPU conditions. The Loss of External Load / Turbine Trip analysis assumes that the RPS is actuated at 2403 psig. The LSSS is established by calculation to avoid exceeding the new analytical limit, taking all instrument uncertainties into account.

j. Function 8, Pressurizer Water Level - High

The LSSS is revised from ≤ 95% of span to ≤ 85% of span.

Licensing Report Sections: Appendix E, Supplement to LR Section 2.4.1, Attachment 5, and Section 2.4.1.2.3.2.1, Reactor Protection, Engineered Safety Features and Control Systems.

Basis for the change: This change is being made to replace existing values that are not consistent with the LSSS calculations and presentation in this submittal. A process limit of 100% of instrument span is used in the calculation of LSSS taking all instrument uncertainties into account. This value is applicable at EPU and at current conditions.

k. Function 13, Steam Generator (SG) Water Level - Low Low

The LSSS for Function 13, Steam Generator Water Level - Low Low, was revised from ≥ 20% of span to ≥ 29.3% of span.

Licensing Report Sections: Section 2.4.1.2.3.2.1, Reactor Protection, Safety Features Actuation, and Control Systems, Section 2.8.5.2.3, Loss of Normal Feedwater Flow and Appendix E, Supplement to LR Section 2.4.1.

Basis for the change: This change is being implemented to support operation at EPU conditions. The Loss of Normal Feedwater Flow/Loss of All AC Power analyses assume that the RPS is actuated at 20% of the narrow range span. The LSSS is established by calculation to avoid exceeding the new analytical limit, taking all instrument uncertainties into account.

l. Function 14, Steam Generator Water Level - Low Coincident with Steam Flow/Feedwater Flow Mismatch

The LSSS for Steam Generator Water Level - Low is revised from NA to ≥ 10% of span.

Licensing Report Sections: Section 2.4.1.2.3.2.1, Reactor Protection, Safety Features Actuation, and Control Systems, and Appendix E, Supplement to LR Section 2.4.1.

Basis for the change: This change is being made to replace existing values that are not consistent with the LSSS calculations and presentation in this submittal. A process limit of 0% of instrument span is used in the calculation of LSSS taking all instrument uncertainties into account. This value is applicable at EPU and at current conditions.

m. Function 17, Reactor Trip System Interlocks

1.) 17.a Intermediate Range Neutron Flux, P-6 - LSSS is revised from >1E-10 amp to ≥ 4E-11 amp.

17.b. (1) Low Power Reactor Trip Block, P-7, (1) Power Range Neutron Flux - LSSS is revised from < 10% RTP to ≤ 13% RTP.

17.b. (2) Low Power Reactor Trip Block, P-7, (2) Turbine Impulse Pressure - LSSS is revised from < 10% turbine power to ≤13% turbine power.

Licensing Report Sections: Section 2.4.1.2.3.2.1, Reactor Protection, Safety Features Actuation, and Control Systems, and Appendix E, Supplement to LR Section 2.4.1.

Basis for the change: These changes are being made to replace existing values that are not consistent with the LSSS calculations and presentation in this submittal. The LSSSs are calculated based on the nominal setpoint and as-found tolerance values and are valid at current and EPU conditions.

2.) Function 17.c, Power Range Neutron Flux, P-8

The LSSS for the P-8 function is revised from ≤ 50% RTP to ≤ 38% RTP.

Licensing Report Sections: Section 2.4.1.2.3.2.1, Reactor Protection, Safety Features Actuation, and Control Systems, and Section 2.4.2.1, Plant Operability.

Basis for the change: The P-8 permissive setpoint was changed by EPU to the nominal steady-state power level the reactor can operate with one RCS loop inactive without violating core thermal limits at uprated conditions. The LSSS is calculated based on the nominal setpoint and as-found tolerance values.

3.) Function 17.d, Power Range Neutron Flux, P-9

The LSSS for the P-9 function is revised from < 50% RTP to ≤ 38% RTP when full power T_{avg} is < 572°F and ≤ 53% when full power T_{avg} is ≥ 572°F. New Note (h) will read " ≤ 38% RTP for full power T_{avg} < 572°F or ≤ 53% RTP for full power T_{avg} ≥ 572°F. For EOC coastdown, P-9 is not reset if T_{avg} decreases to < 572°F."

Licensing Report Sections: LR Section 2.4.1.2.3.2.1, Reactor Protection, Safety Features Actuation, and Control Systems, LR Section 2.4.2.1, Plant Operability, and Appendix E, and Supplement to LR Section 2.4.1.

Basis for the change: The permissive nominal setpoint to reinstate two reactor trips on turbine trips was changed by EPU. The LSSS is calculated based on the nominal setpoint and as-found tolerance values. The addition of the word design is to clarify that the note is not referring to a specific operating point but rather an operating condition based on a nominal T_{avg} at 100% power.

4.) Function 17.e, Power Range Neutron Flux, P-10

The LSSS for the P-10 function is revised from "≥ 8% RTP and ≤ 10% RTP" to "≥ 6% RTP and ≤ 12% RTP, respectively."

Licensing Report Sections: LR Section 2.4.1.2.3.2.1, Reactor Protection, Safety Features Actuation, and Control Systems, LR Section 2.4.2.1, Plant Operability, and Appendix E, and Supplement to LR Section 2.4.1.

Basis for the change: The LSSS range for the P-10 permissive is revised to coincide with the upper and lower as-found limits for a nominal setpoint of 9% (decreasing) as allowed during a Channel Operational Test (COT). Both limits are listed to be consistent with the STS, although only the lower limit provides the LSSS for the P-10 safety function of automatically clearing the reactor trip bypass on decreasing power.

7 Technical Specification 3.3.2, ESFAS Instrumentation

TS Table 3.3.2-1 is revised to change the column heading of "ALLOWABLE VALUE" to "LIMITING SAFETY SYSTEM SETTINGS." Values in this column are revised to reflect changes resulting from EPU and to replace existing values that are not consistent with the LSSS calculations and presentation in this submittal.

1) Change the column heading now titled "ALLOWABLE VALUE" to "LIMITING SAFETY SYSTEM SETTING."

2) Added two new Notes to be applied to those ESFAS Functions that have LSSS values; and to specify operability criteria and to require that out-of-tolerance conditions detected during surveillance be entered into the corrective action process.

3) Change the LSSS values in the tables for individual Functions identified below.

a. 6th Column heading is changed from ALLOWABLE VALUES to LIMITING SAFETY SYSTEM SETTING with a reference to footnote (f). The footnote (f) insertion reads, "Table 3.3.2-1 Notes 1 and 2 are applicable with the exception of those listed as "NA."

Licensing Report Sections: Section 2.4.1.2.3.2.1, Reactor Protection, Safety Features Actuation, and Control Systems, and Appendix E, Supplement to LR Section 2.4.1.

Basis for the change: As defined in 10 CFR 50.36, LSSS are settings for automatic protective devices related to those variables having significant safety functions. 10 CFR 50.36 requires that these limiting settings be included in the Technical Specifications. The heading change is consistent with this requirement.

The LSSS for ESFAS function initiations in the above table are calculated based on limits from the safety analyses, process limits for the instrumentation, and instrument loop uncertainties calculated with 95% probability and 95% confidence to industry standard methodology. The LSSS for the Low T_{avg} Interlock and SI Block functions are calculated based on nominal setpoints used in the analyses and as-found acceptance criteria. The methods used to determine LSSS values and summaries of calculations are provided in Appendix E, Supplement to LR Section 2.4.1.

The LSSS values proposed for TS Table 3.3.2-1 are limiting values for the nominal field setpoint and are calculated such that there is 95% probability and 95% confidence that the trip will occur prior to the process variable exceeding the established limit. For the interlock and block, the LSSS value ensures the interlock, permissive or block function will occur in accordance with the assumptions of the analyses. Therefore, the assumptions of the safety analyses and results are protected by proposed LSSS values.

Table 1.0-2 below identifies functions for which the LSSS values were affected by EPU and the functions for which LSSS values are changed to obtain consistency in the application of LSSS values in TS Table 3.3.2-1. The one ESFAS function shown in the table, Auxiliary Feedwater actuation on Undervoltage Bus A01 & A02, has been evaluated using the methods described in Appendix E, Supplement to LR Section 2.4.1. No change to the LSSS is required for this function.

The column heading previously identified in TS Table 3.3.2-1 as ALLOWABLE VALUE is being changed to LSSS to be consistent with 10 CFR 50.36. As defined in 10 CFR 50.36, LSSS are settings for automatic protective devices related to those variables having significant safety functions. 10 CFR 50.36 requires that LSSS be included in the Technical Specifications. The heading change is consistent with the requirement. The change is also consistent with the 16.8 Percent Power Uprate, License Amendment approved for R. E. Ginna on August 7, 2006 (ML061380103).

Footnote (f) applies to all functions that do not have an "NA" as a value in the LIMITING SAFETY SYSTEM SETTING column.

b. Notes 1 and 2

Notes 1 and 2 are added to Table 3.3.2-1 consistent with the guidance contained in RIS 2006-17 and LSSS are revised to provide a conservative setpoint that includes instrument uncertainty. The setpoint changes being made also resolve setpoint LSSSs needing change that were identified during the PBNP calculation reconstitution project.

Note 1 states:

"A channel is OPERABLE when both of the following conditions are met:

a. The as-found Field Trip Setpoint (FTSP) is within the COT acceptance criteria for the as-found value. The method used to determine the COT acceptance criteria is described in FSAR Section 7.2.

b. The as-left FTSP is reset to a value that is within the as-left tolerance at the completion of the surveillance. The channel is considered operable even if the as-left FTSP is non-conservative with respect to the LSSS provided that the as-left FTSP is within the established as-left tolerance band. The method used to determine the as-left tolerance is described in FSAR Section 7.2."

Note 2 states:

"If the as-found FTSP is outside its predefined as-found acceptance criteria:

a. Evaluation of corrective measures necessary to return the channel to service is implemented in applicable plant maintenance and operating procedures.

b. The out-of-tolerance condition shall be entered into the Corrective Action Process."

Footnote (f) was added to LIMITED SAFETY SYSTEM SETPOINT Column of Table 3.3.2-1 for the LSSSs setpoints with values. Footnote (f) does not apply to those LSSSs that have an N/A in the column. Footnote (f) identifies that for the surveillances that measure values being performed for the function with values in the column, Notes 1 and 2 are applicable. In addition, the LSSSs for each of these Functions that are being revised to include the instrument uncertainty are determined by the setpoint methodology discussed in Appendix E, Supplement to LR Section 2.4.1, of Attachment 5.

Both notes will apply to each of those ESFAS Functions that contain specific values in the LSSS column in marked-up Tables 3.3.2-1 for surveillances where a specific value is measured (i.e., COT or channel calibration). The notes will not apply to those Functions that contain "NA" in the column.

Notes 1 and 2 will be applied to the following functions as indicated:

Table 1.0-2 ESFAS Instrumentation Notes 1 and 2 Application

Item Number	Function	Notes 1 & 2 Apply	EPU Related	LSSS Change
1.c.	Safety Injection on Containment Pressure- High	X		X
1.d.	Safety Injection on Pressurizer Pressure- Low	X		X
1.e. and note (c)	Safety Injection on Steam Line Pressure- Low	X	X	
2.c.	Containment Spray on Containment Pressure - High High	X		X
4.c.	Steam Line Isolation – Containment Pressure – High High	X		X
4.d.	Steam Line Isolation on High Steam Flow Coincident with Safety Injection and T_{avg}- Low	X	X	X
4.e.	Steam Line Isolation on High High Steam Flow Coincident with Safety Injection	X	X	X
5.b.	Feedwater Isolation on SG Water Level – High	X		X
6.b.	Auxiliary Feedwater on SG Water Level- Low Low	X	X	X
6.d.	Undervoltage Bus A01 and A02	X		
6.e.	AFW Pump Suction Transfer on Suction Pressure Low	X	X	
8	SI Block-Pressurizer Pressure	X		X

Licensing Report Sections: Section 2.4.1, Reactor Protection, Engineered Safety Features and Control Systems, and Appendix E, Supplement to LR Section 2.4.1, to LAR Attachment 5.

Basis for the change: Surveillance limits are established to verify that engineered safety function actuation system instrumentation with an LSSS in TS Table 3.3.2-1 operate within the boundaries of applicable instrument uncertainty calculations. These limits are implemented in plant procedures in accordance with Notes 1 and 2 above. The determination of as-left setting tolerance and as-found criteria is described in Appendix E, Supplement to LR Section 2.4.1. The implementation of as-left and as-found limits verifies that the instrument loops are performing in accordance with uncertainty calculation assumptions and that out-of tolerance conditions get evaluated. If a channel cannot be set within the as-left tolerance band the channel is declared inoperble and Notes 1 and 2 apply. FSAR Section 7.2 will be revised during implementation.

Footnote (f) and therefore, Notes 1 and 2, applies to all functions that do not have an "NA" as a value in the LSSS column.

c. Function 1.c, Safety Injection - Containment Pressure - High

The LSSS is revised from ≤ 6 psig to ≤ 5.3 psig.

Licensing Report Sections: Section 2.4.1.2.3.2.2, Reactor Protection, Safety Features Actuation, and Control Systems, and Appendix E, Supplement to LR Section 2.4.1.

Basis for the change: This change is being made to replace existing values that are not consistent with the LSSS calculations and presentation in this submittal. An analytical limit of 6 psig for the steam line break inside containment analysis is used in the calculation of LSSS taking all instrument uncertainties into account. This value is applicable at EPU and at current conditions.

d. Function 1.d, Safety Injection - Pressurizer Pressure - Low

1) The LSSS is revised from ≥1715 psig to ≥ 1725 psig.

Licensing Report Sections: Section 2.4.1.2.3.2.2, Reactor Protection, Safety Features Actuation, and Control Systems, and Appendix E, Supplement to LR Section 2.4.1

Basis for the change: This change is being made to replace existing values that are not consistent with the LSSS calculations and presentation in this submittal. A process limit of 0% of the instrument span is used in the calculation of LSSS taking all instrument uncertainties into account. This value is applicable at EPU and at current conditions.

2) Note a: The pressurizer pressure at which the Safety Injection Pressurizer Pressure Low function applies in MODES 1, 2, and 3 is revised from > 1800 psig to > 2000 psig.

Licensing Report Sections: Section 2.4.1.2.3.2.2, Reactor Protection, Safety Features Actuation, and Control Systems, and Appendix E, Supplement to LR Section 2.4.1.

Basis for the change: The change from > 1800 psig to > 2000 psig is being made to coincide with the change in the SI Block - Pressurizer Pressure function (Function 8 in Table 3.3.2-1) LSSS value from ≥ 1800 psig to ≥ 2005 psig. The previous 1800 psig value in Note a was based on the previous normal plant operating pressure of 1985 psig and an SI Block setpoint of 1800 psig (decreasing) that allowed manual bypass of the SI signal on low pressurizer pressure below 1800 psig during a normal plant shutdown/cooldown. The new 2000 psig value in Note "a" is based on the current normal plant operating pressure of 2235 psig and a revised SI Block setting of 2000 psig (decreasing). Below this pressurizer pressure, the manual SI Block function prevents the SI Pressurizer Pressure Low signal from occurring.

e. Function 1.e., Safety Injection - Steam Line Pressure- Low

1) The LSSS is revised from ≥ 500[(c)] psig to ≥ 520[(c)] psig.

Licensing Report Sections: Section 2.8.5.1.2, Steam System Piping Failures Inside and Outside Containment, Section 2.4.1.2.3.2.2, Reactor Protection, Safety Features Actuation, and Control Systems, and Appendix E, Supplement to LR Section 2.4.1.

Basis for the change: This change is being implemented to support operation at EPU conditions. The steam line failure at hot zero power and full power analysis assumes that SI actuation would occur at 395.3 psig. The LSSS is established by calculation to avoid exceeding the new analytical limit, taking all instrument uncertainties into account.

2) Note b: The pressurizer pressure at which the Safety Injection Steam Line Pressure Low function applies in MODES 1, 2, and 3 is revised from > 1800 psig to > 2000 psig.

Licensing Report Sections: Section 2.4.1.2.3.2.2, Reactor Protection, Safety Features Actuation, and Control Systems, and Appendix E, Supplement to LR Section 2.4.1.

Basis for the change: The change from > 1800 psig to > 2000 psig is being made to coincide with the change in the SI Block - Pressurizer Pressure function (Function 8 in Table 3.3.2-1) LSSS value from ≥ 1800 psig to ≥ 2005 psig. The previous 1800 psig value in Note "a" was based on the previous normal plant operating pressure of 1985 psig and an SI Block setpoint of 1800 psig (decreasing) that allowed manual bypass of the SI signal on steam line pressure low below 1800 psig during a normal plant shutdown/cooldown. The new 2000 psig value in Note "a" is based on the current normal plant operating pressure of 2235 psig and a revised SI Block setting of 2000 psig (decreasing). Below this pressurizer pressure, the manual SI Block function prevents the SI Steam Line Pressure Low signal from occurring.

3) Note c: The lead time constant (t_1) was revised from ≥ 12 seconds to ≥ 18 seconds.

Licensing Report Sections: Section 2.8.5.1.2.2.2, Steam System Piping Failures Inside and Outside Containment .

Basis for the change: The lead dynamic compensation time constant (t_1) for Safety Injection on Steam Line Pressure - Low was revised from ≥ 12 seconds to ≥18 seconds in the Steam System Piping Failure at Hot Full Power safety analysis. This change is being implemented to allow operation at EPU conditions.

In order to obtain acceptable results for the steam system piping failure at hot full power analysis for the EPU, protection system setpoint changes are necessary. The low steam line pressure – Safety Injection safety analysis setpoint is changed from 335 psia to 410 psia, and the associated lead/lag dynamic compensation time constants are changed from 12 sec/2 sec to 18 sec/2 sec.

f. Function 2.c, Containment Spray - Containment Pressure - High High

The LSSS is revised from ≤ 30 psig to ≤ 28 psig.

Licensing Report Sections: Section 2.4.1.2.3.2.2, Reactor Protection, Safety Features Actuation, and Control Systems, and Appendix E, Supplement to LR Section 2.4.1.

Basis for the change: This change is being made to replace existing values that are not consistent with the LSSS calculations and presentation in this submittal. A process limit of 30 psig is established in the steam line break inside containment analysis and used in the calculation of LSSS taking all instrument uncertainties into account. This value is applicable at EPU and at current conditions.

g. Function 4.c, Steam Line Isolation - Containment Pressure - High High

The LSSS is revised from ≤ 20 psig to ≤ 18 psig.

Licensing Report Sections:Section 2.4.1.2.3.2.2, Reactor Protection, Safety Features Actuation, and Control Systems, and Appendix E, Supplement to LR Section 2.4.1.

Basis for the change: This change is being made to replace existing values that are not consistent with the LSSS calculations and presentation in this submittal. A process limit of 20 psig has been established and is used in the calculation of LSSS taking all instrument uncertainties into account. This value is applicable at EPU and at current conditions.

h. Function 4.d., Steam Line Isolation on High Steam Flow Coincident with Safety Injection and T_{avg} - Low, and Function 4.e., Steam Line Isolation on High High Steam Flow Coincident with Safety Injection.

The LSSS for Function 4. d., Steam Line Isolation on High Steam Flow Coincident with Safety Injection and T_{avg}- Low, was revised from ≤ ΔP corresponding to 0.66×10^6 lb/hr at 1005 psig to 0.8×10^6 lbm/hr at 1005 psig and Coincident with Safety Injection and T_{avg}- Low was revised from ≥ 540°F to ≥ 542°F.

The LSSS for Function 4. e., Steam Line Isolation on High High Steam Flow Coincident with Safety Injection, was revised from ≤ ΔP corresponding to 4×10^6 lb/hr at 806 psig to 4.9×10^6 lbm/hr at 586 psig.

Licensing Report Sections: Section 2.4.1.2.3.2.2, Reactor Protection, Safety Features Actuation, and Control System, and Section 2.8.5.1.2, Steam System Piping Failures Inside and Outside Containment and Appendix E, Supplement to LR Section 2.4.1.

Basis for the Change: This change is being implemented to support operation at EPU conditions. The Steamline Break Mass and Energy Releases Outside of Containment analysis assumed that Steam Line Isolation on High Steam Flow Coincident with Safety Injection and T_{avg}- Low was initiated at 1.07×10^6 lb/hr. The Steam line Break Mass and Energy Releases Outside of Containment and Steam line Break (core response) analyses established a process limit for the Steam Line Isolation on High High Steam Flow Coincident with Safety Injection of 5.0×10^6 lb/hr. The LSSS's for these functions are calculated based on the analytical and process limits taking all instrument uncertainties into account. The main steam line flow transmitters are currently calibrated for a range of 0 - 4.0×10^6 lb/hr, which is near the predicted EPU nominal steam flow of 3.7×10^6 lbm/hr at a feedwater temperature of 390°F. The main steam flow transmitters will be recalibrated for a range of 0 - 5.0×10^6 lbm/hr for the EPU. This has been accounted for in the LSSS calculations.

i. Function 5.b, Feedwater Isolation - SG Water Level - High

The LSSS is revised from NA to ≤ 90% of span.

Licensing Report Sections: Section 2.4.1.2.3.2.2, Reactor Protection, Safety Features Actuation, and Control Systems, and Appendix E, Supplement to LR Section 2.4.1.

Basis for the change: This change is being made to replace existing values that are not consistent with the LSSS calculations and presentation in this submittal. A process limit is established based on the maximum reliable indication of the instrument. This process limit is used in the calculation of LSSS taking all instrument uncertainties into account. This value is applicable at EPU and at current conditions.

j. Function 6.b, Auxiliary Feedwater - SG Water Level - Low Low

The LSSS is revised from ≥ 20% to ≥ 29.3% of span.

<u>Licensing Report Sections</u>: LR Section 2.8.5.2.3, Loss of Normal Feedwater Flow, LR Section 2.8.5.2.2, Loss of Non-Emergency AC Power to Station Auxiliaries, Section 2.4.1.2.3.2.2, Reactor Protection, Safety Features Actuation, and Control Systems, and Appendix E, Supplement to LR Section 2.4.1.

<u>Basis for the change</u>: This change is being implemented to support operation at EPU conditions. The loss of normal feedwater flow and the loss of non emergency AC power to station auxiliaries assume that Auxiliary Feedwater is initiated at 20% of span. The LSSS is established by calculation to avoid exceeding this new analytical limit, taking all instrument uncertainties into account.

k. Function 6.e., Auxiliary Feedwater Transfer on Suction Pressure Low

Function 6.e, AFW Pump Suction Transfer on Suction Pressure Low, is being added to Function 6, Auxiliary Feedwater. This setpoint is being implemented to eliminate the need for a manual transfer of the AFW pump suction from the condensate storage tank (CST) to the safety related service water source and to implement an automatic suction transfer upon a low suction pressure signal. The setpoint will be determined with the final design of the AFW system upgrade. Therefore, this setpoint is not included in the change description or the No Significant Hazards Determination.

FPL Energy Point Beach will provide the setpoint, the change description and a revised No Significant Hazards Determination in a supplement to this LAR by July 30, 2009. Attachment 4, lists the Regulatory Commitment associated with this item.

Two channels of the AFW Pump Suction Transfer on Suction Pressure Low are required to be operable in MODEs 1, 2, and 3. If one of the channels is not operable, CONDITION F applies. The REQUIRED ACTION for CONDITION F is the restoration of the channel to OPERABLE status within one hour or to be in MODE 3 in 7 hours and in MODE 4 in 13 hours.

To ensure operability of the channels is maintained, surveillances SR 3.3.2.1, 3.3.2.3 and 3.3.2.8 must be performed. This requires a CHANNEL CHECK to be performed every 12 hours, a COT to be performed every 92 days, and a CHANNEL CALIBRATION to be performed every 18 months.

<u>Licensing Report Sections</u>: Section 2.5.4.5.2, Auxiliary Feedwater.

<u>Basis for the change</u>: The AFW system is being upgraded to increase the capability of the system. A description of the associated Technical Specification changes is provided in the markups for Technical Specification 3.7.5, Auxiliary Feedwater. The AFW system upgrade adds a provision for automatic switchover of pump suction to Service Water on loss of the condensate storage tank (CST) suction source.

l. Function 7, Condensate Isolation

The Condensate Isolation function is being deleted from the Technical Specifications. This Function will be annotated as "Not Used."

Licensing Report Sections: Section 2.6.1.2.4, Containment Response to Main Steam Line Break.

Basis for the change: With the addition of the new Main Feedwater Isolation Valves, the function to isolate condensate upon a Containment Pressure High and the Automatic Actuation Logic and Actuation Relays is no longer credited in the accident analysis for Main Steam Line Break Inside Containment.

m. Function 8, SI Block - Pressurizer Pressure

The LSSS for the SI Block - Pressurizer Pressure, function is being revised from ≤ 1800 psig to ≤ 2005 psig.

Licensing Report Sections: Section 1.1, Nuclear Steam Supply System Parameters, Section 2.4.1.2.3.2.2, Reactor Protection, Safety Features Actuation, and Control Systems, and Appendix E, Supplement to LR Section 2.4.1.

Basis for the change: This change is being made to replace the existing value that is not consistent with the LSSS calculations and presentation in this submittal. The LSSS is calculated based on the nominal setpoint and as-found tolerance values and is valid at current and EPU conditions. PBNP is not analyzed and will not operate at 2000 psia RCS pressure at EPU conditions. The unblock at 1800 psig for 2000 psia operation is no longer applicable.

8 Technical Specification 3.3.4, Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

SR 3.3.4.3.a. is revised from, "with a time delay of ≥ 0.7 seconds and ≤ 1.0 second," to "with a time delay of ≥ 1.8 seconds and ≤ 2.3 seconds (Bus Loss of Voltage Relay) and ≥ 1.95 seconds and ≤ 3.55 seconds (EDG Breaker Close Delay Relay)."

SR 3.3.4.3.c is revised from "with a time delay of ≤ 0.5 seconds" to "with a time delay of ≥ 1.15 seconds and ≤ 1.6 seconds."

Licensing Report Sections: Section 2.3.3, AC Onsite Power System

Basis for the change: The loss of voltage relay settings for the safety related 4160 V and 480 V buses were recalculated to prevent inadvertent relay actuation and to protect the units against loss of voltage due to a grid disturbance. An analysis has been completed to provide the setpoints for each of the time delays. The setpoints are independent of the electrical generator output and bound operation at either 1540 MWt or 1800 MWt. The proposed TS change is consistent with the analysis and demonstrates that the safety function of the associated buses will be maintained.

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

The RCS total flow rate in LCO 3.4.1.c and SR 3.4.1.3 was revised from 182,400 gpm to 178,000 gpm.

Licensing Report Sections: Section 1.1, Nuclear Steam Supply System Parameters.

Basis for the change: The NSSS design parameters provide the RCS and secondary side system conditions (thermal power, temperatures, pressures, and flows) that are used as the basis for the design transients, systems, structures, components, accidents, and fuel analyses and evaluations. One of the major input parameters and assumptions used in the calculation of the four cases of NSSS design parameters established is the thermal design flow (TDF) of 89,000 gpm/loop, for a total RCS flow of 178,000 gpm. The total flow value is included in the Technical Specifications and the minimum measured flow (MMF) value is included in the COLR, so the MMF value can be revised on a cycle-specific basis. The MMF is usually greater than 182,000 gpm.

10 Technical Specification 3.4.9, Pressurizer

The pressurizer water level in LCO 3.4.9 a., and SR 3.4.9.1 was revised from ≤ 50.8% in MODE 1 or ≤ 95% in MODES 2 and 3 to ≤ 52% in MODE 1 or ≤ 88% in MODES 2 and 3.

Licensing Report Sections: Section 2.8.5.2.3, Loss of Normal Feedwater, and Appendix E, Supplement to LR Section 2.4.1.

Basis for the change: This change will provide additional operating margin in MODE 1 during normal plant operations. The limiting Loss of Normal Feedwater event, which is the bounding event for pressurizer overfill, has been analyzed for EPU with an initial pressurizer level of 57%. The Technical Specification value of 52% provides an initial pressurizer level that includes instrument uncertainty. FPL Energy Point Beach has verified that an initial pressurizer level of 57% will not result in overfilling the pressurizer for the design basis accidents with the revised analytical limit at EPU conditions.

The 88% in MODES 2 and 3 provides a setpoint that maintains a steam bubble in the pressurizer, and adjusts the setpoint for instrument uncertainty. The revised setpoints were calculated in accordance with Appendix E, Supplement to LR Section 2.4.1 of Attachment 5.

11 Technical Specification, 3.4.10, Pressurizer Safety Valves

1) LCO 3.4.10, the pressurizer safety valve upper lift setting, was reduced from ≤ 2560 psig to ≤ 2547 psig

Licensing Report Sections: Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum.

Basis for the change: To meet an RCS pressure limit of 2748.5 psia for a Loss of External Electrical Load/Turbine Trip event, the pressurizer safety valve upper lift setting was reduced.

2) SR 3.4.10.1 is being revised from "≥ 2440.71 psig and ≤ 2551.25 psig" to "within ±1%"

Licensing Report Sections: Section 2.8.5.0, Accident and Transient Analyses

Basis for the change: The change to the as-left acceptance criteria provided in SR 3.4.10.1 is to be consistent with the PBNP Inservice Testing Program.

12 Technical Specification 3.5.1, Accumulators

SR 3.5.1.4 is revised from ≥ 2600 ppm to ≥ 2700 ppm minimum boron concentration for the SURVEILLANCE and for the second FREQUENCY.

Licensing Report Sections: Section 2.8.5.6.3.4, Post-LOCA Subcriticality and Long Term Cooling.

Basis for the change: The accumulator minimum boron concentration was increased to ensure that the core will remain subcritical following a LOCA. The resulting sump boron concentration, which is calculated as a function of the pre-LOCA RCS boron concentration, is reviewed for each cycle-specific core design to confirm that adequate boron exists to maintain subcriticality in a long-term post-LOCA environment at EPU conditions.

13 Technical Specification 3.5.4, Refueling Water Storage Tank

The minimum refueling water storage tank boron concentration in SR 3.5.4.3 is increased from ≥ 2700 ppm to ≥ 2800 ppm.

Licensing Report Sections: Section 2.8.5.6.3.4, Post-LOCA Subcriticality and Long Term Cooling.

Basis for the change: The RWST minimum boron concentration was increased to ensure that the core will remain subcritical following a LOCA. The resulting sump boron concentration, which is calculated as a function of the pre-LOCA RCS boron concentration, is reviewed for each cycle-specific core design to confirm that adequate boron exists to maintain subcriticality in the long-term post-LOCA environment at EPU conditions.

14 Technical Specification 3.7.1, Main Steam Safety Valves (MSSVs)

The maximum allowable power in Table 3.7.1-1 for three operable MSSVs was reduced from ≤ 49% RTP to ≤ 39% RTP and for two operable MSSVs was reduced from ≤ 29% RTP to ≤ 22% RTP.

The lift setting for MSSVs MS 2012, 2013, 2007, and 2008 in Table 3.7.1-2 was reduced from 1125 psig to 1105 psig.

Licensing Report Sections: Section 2.8.4.2, Overpressure Protection During Power Operation, and Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip and Loss of Condenser Vacuum.

Basis for the change: To meet a main steam system pressure limit of 1208.5 psia for a Loss of External Electrical Load/Turbine Trip event, the nominal lift settings of MSSVs MS 2012, 2013, 2007, and 2008 were reduced. Lower maximum allowable power levels are required to prevent exceeding a main steam system pressure limit of 1208.5 psia for a Loss of External

Electrical Load/Turbine Trip with less than 4 operable MSSVs per steam generator. There are two cases, one for operation with only 3 operable MSSVs per steam generator and one for operation with only 2 operable MSSVs per steam generator.

15 Technical Specification 3.7.3, Main Feedwater Isolation

Introduction

To mitigate the consequences of a design basis main steam line break (MSLB) in containment at EPU conditions, isolation of feedwater (FW) to the faulted steam generators is required to minimize the mass and energy released to containment. To reduce the mass and energy releases, a new Main Feedwater Isolation Valve (MFIV) with an automatically actuated operator is being added to each main feedwater line just outside containment. This valve location closer to containment reduces the mass and energy release to containment due to the reduced feedwater inventory remaining in the piping to the faulted steam generator.

Change

TS 3.7.3 was revised to add "Valves (MFIVs), Main Feedwater Regulating Valves (MFRVs), and MFRV Bypass Valves," to the title of this TS.

A note was added under the ACTIONS title at the top of the ACTIONS table. The Note reads, "NOTE: Separate Condition entry is allowed for each valve."

CONDITION A was revised to delete "NOTE Separate Condition entry is allowed for each valve."

CONDITION A was revised to delete "Main Feedwater Regulating Valves (MFRVs) or MFRV bypass valves," and to add "(MFIV)."

REQUIRED ACTION A.1 and A.2 were revised to delete "valve," and to add "MFIV."

CONDITION B was revised to delete "NOTE Separate Condition entry is allowed for each pump trip circuit."

CONDITION B was revised to delete "Main Feed Water, Heater Drain Tank, or Condensate pump trip circuits," and to add "MFRVs."

REQUIRED ACTION B.1 was revised to delete "Secure pump from operation," and to add "Close or isolate MFRV."

REQUIRED ACTION B.2 was revised to delete "pump is not operating," and to add "MFRV is closed or isolated."

CONDITION C, REQUIRED ACTIONS C.1 and C.2, and the COMPLETION TIMES associated with REQUIRED ACTIONS C.1 and C.2 were deleted.

A new CONDITION C was added that states: "One or more MFRV Bypass Valves inoperable."

A new REQUIRED ACTION C.1 was added that states: "Close or isolate MFRV Bypass Valve." with a COMPLETION TIME of "72 hours."

A new REQUIRED ACTION C.2 was added that states: "Verify MFRV Bypass Valve is closed or isolated." with a COMPLETION TIME of "Once per 7 days."

New REQUIRED ACTIONS C.1 and C.2 are connected by "AND" to ensure that both actions are performed when CONDITION C is entered.

A new CONDITION D was added that states: "Two valves in the same flow path inoperable."

A new REQUIRED ACTION D.1 was added that states: "Isolate affected flow path." with a COMPLETION TIME of "8 hours."

CONDITION "D," was revised to "E," and REQUIRED ACTIONS "D.1" and "D.2" were revised to "E.1" and "E.2."

SR 3.7.3.1 was revised to delete "associated" and to add "MFIV," and "MFRV."

SR 3.7.3.2 was revised to delete "Main Feedwater pump automatically trips on an actual or simulated actuation signal," and to add "MFIV, MFRV, and MFRV Bypass Valve isolation time is within limits."

SR 3.7.3.2 FREQUENCY was revised to delete "18 months," and to insert "In accordance with the Inservice Testing Program."

SR 3.7.3.3 was deleted.

<u>Licensing Report Sections</u>: Section 2.5.5.4, Condensate and Feedwater, Section 2.6.1, Primary Containment Functional Design, and Section 2.6.3.2, Mass and Energy Release Analysis for Secondary Pipe Ruptures.

<u>Basis for the Change</u>: In order to mitigate the consequences of a design basis main steam line break (MSLB) in containment at EPU conditions, isolation of feedwater (FW) to the faulted steam generators is required to minimize the mass and energy released to containment. To reduce the mass and energy releases, a new Main Feedwater Isolation Valve (MFIV) with an automatically actuated operator is being added to each main feedwater line outside containment. The new MFIVs are designed to fully close in $\leq$ 5 seconds to meet the containment integrity steam line break safety analysis requirements discussed in LR Section 2.6.1, Primary Containment Functional Design. The current containment pressure response analysis in FSAR Chapter 14.2.5, Rupture of a Steam Pipe, credits the Main Feedwater Regulating Valves (MFRVs), and MFRV bypass valves as the primary means of FW isolation and the isolation function of tripping the FW Pump, closure of the FW pump discharge valves and the tripping of the Condensate and HD pumps as the backup means of FW isolation. For the EPU, the new safety related MFIVs will provide the primary means for FW isolation with the MFRVs and MFRV bypass valves as the backup for FW isolation. This is required to minimize the mass and energy release from the FW System following a MSLB inside containment (LR Section 2.6.3.2, Mass and Energy Release Analysis for Secondary System Pipe Ruptures). No credit is taken for the isolation function of tripping the FW Pump, closure of the FW pump discharge valves and the tripping of the Condensate and HD pumps in the mass and energy release analysis for a MSLB.

The Title of TS 3.7.3 was revised to reflect the new design of the Main Feedwater System. The name is consistent with NUREG 1431, Standard Technical Specifications Westinghouse Plants.

The NOTE under the label for the ACTION Table was added to consolidate similar notes in CONDITION A and B. This note location is consistent with NUREG 1431, Standard Technical Specifications Westinghouse Plants.

CONDITION A, B, C, D and E were revised to reflect the addition of the new MFIVs as the primary means for FW isolation, and the MFRVs and MFRV bypass valves as the back-up means for FW isolation and removal of the tripping of the FW pumps, Condensate pumps and HD pumps.

The SR 3.7.3.2 FREQUENCY was revised from a frequency of 18 months to be under licensee control in accordance with the Inservice Testing Program (IST) in accordance with Technical Specifications Task Force (TSTF) 491, Revision 2. This TSTF was partially adopted at PBNP via License Amendment Request 255 for the main steam isolation valves. Since PBNP did not have MFIVs at the time, the TSTF could not be fully adopted. TSTF-491, Revision 2 was communicated as a Consolidated Line Item Improvement Process action via ML063390370. The Notice of Availability was provided in 71 FR 58884, dated October 5, 2006.

10 CFR 50.36 requires the inclusion of the periodic testing of the MFIVs, MFRVs and MFRV bypass valves in the Surveillance Requirements not the actual closure time of the valves. TSTF-491 maintains the periodic testing requirements for MFIVs, MFRVs and MFRV bypass valves in accordance with 10 CFR 50.36.

Based on the requirements of 10 CFR 50.36, 10 CFR 50.59 and the IST Program, the MFIVs, MFRVs, and MFRV bypass valves periodic testing requirements are being relocated to a licensee controlled program.

16 Technical Specification 3.7.5, Auxiliary Feedwater (AFW) System

<u>Introduction</u>

The AFW system will be upgraded to install a new full capacity unitized motor driven pump on each unit and add AFW pump suction auto-switchover to safety related service water upon loss of the condensate storage water source. The construction of the system may proceed under 10 CFR 50.59. The final physical tie-in and implementation require Commision approval. See LR Section 2.5.4.5, Auxiliary Feedwater, for more detail.

<u>Change</u>

The LCO was revised from "... and two motor driven AFW pump systems," to "... and one motor driven AFW pump system."

The LCO NOTE was revised to delete "associated with steam generators relied upon for heat removal are" and replace it with "is," and to revise “systems” to “system.”

The ACTIONS note was revised to add "when entering MODE 1."

CONDITION A was revised to add an additional condition, "OR" "The turbine driven AFW pump system inoperable in MODE 3 following refueling." and a Note for the new CONDITION that states, "Only applicable if MODE 2 has not been entered following refueling."

REQUIRED ACTION A.1 was revised to delete "steam supply," and to add "affected equipment."

CONDITION B. was revised to delete the words "turbine driven."

REQUIRED ACTION B.1 was revised to delete "turbine driven."

CONDITION C, REQUIRED ACTION C.1, and the COMPLETION TIME associated with REQUIRED ACTION C.1 were deleted.

CONDITION "D," was renumbered to "C," and REQUIRED ACTION "D.1" and "D.2" were renumbered to "C.1" and "C.2."

The new CONDITION C was revised to replace "A, B or C" with "A or B" and the second CONDITION was deleted.

The Note for new REQUIRED ACTION C.1 was deleted.

REQUIRED ACTION C.2 Note was revised to delete "one" and to add "the."

CONDITION "E" was renumbered to "D," and REQUIRED ACTION "E.1" was renumbered to "D.1."

New CONDITION D was revised to delete "Three" and to add "Two."

CONDITION "F" was revised to "E," and REQUIRED ACTION "F.1" was revised to "E.1."

New CONDITION E. was revised to delete "One or more" and "systems" and to add "motor driven" and "system" such that the CONDITION now reads "Required motor driven AFW pump system inoperable in MODE 4."

New REQUIRED ACTION E.1 was revised to delete "system(s)" and to add "the motor driven" such that the REQUIRED ACTION now reads, "Initiate action to restore the motor driven AFW pump system to OPERABLE status."

<u>Licensing Report Sections</u>: Section 2.5.4.5, Auxiliary Feedwater.

<u>Basis for the Change</u>: New motor driven AFW (MDAFW) pump systems are being installed to increase the capability of the AFW system. Unit 1 and Unit 2 each will have a single new full-capacity MDAFW pump that will be unit specific. The safety-related portions of each unit-specific AFW system is designed as Seismic Class I, and is capable of withstanding design basis earthquake accelerations without a loss of system performance capability. Each new unit specific MDAFW pump system and current turbine driven AFW (TDAFW) pump system are designed such that a single active failure will not disable more than one MDAFW or TDAFW pump system in each unit. Each of the MDAFW and TDAFW pump systems in each unit has some shared discharge piping with independent instrumentation and controls (I&C) necessary for operation. The two unit-specific MDAFW pump systems (one per unit) share a condensate storage tank (CST) suction header. The two TDAFW pump systems

(one per unit) share a second CST suction header. Each AFW pump suction will automatically transfer from the non-safety related CST to safety related Service Water on low suction pressure, reducing required operator actions.

Each MDAFW and TDAFW pump system will automatically start and deliver adequate AFW flow to maintain adequate steam generator (SG) levels during anticipated plant transients that result in a loss of the main feedwater system. These transients include loss of normal feedwater (LONF) and Loss of non-vital AC power (LOAC) events. The limiting transient with respect to AFW is a LONF without a concurrent LOAC, since the reactor is not tripped, continuing to add 100% power to the reactor coolant, until a low-low SG level reactor trip occurs. Redundancy is provided by 100% capacity MDAFW and 100% capacity TDAFW pump systems using different power sources. The design capacity of each pump system ensures that on the limiting LONF event, with a failure of one AFW system, adequate RCS heat removal will be maintained to prevent the pressurizer from going water solid. The unit-specific MDAFW pump systems eliminate the current manual operator action on dual unit AFW actuations (e.g., LOAC) to balance the MDAFW pump flows between the units.

The AFW pump systems will automatically start and deliver sufficient AFW flow to maintain adequate SG levels for other accidents such as the Steam Generator Tube Rupture (SGTR) and Main Steam Line Break (MSLB). Although operator action is required to isolate the AFW lines to a faulted SG following a MSLB, the addition of flow control valves on the individual MDAFW pump SG discharge headers automatically decreases the maximum flow to the faulted SG, while increasing the flow to the non-faulted SG relative to the pre-EPU system configuration.

TS 3.7.5 was revised to reflect the new unit-specific MDAFW pump system design. The changes to TS 3.7.5 are consistent with TS 3.7.5, Auxiliary Feedwater System, contained in NUREG-1431, Standard Technical Specifications Westinghouse Plants. The terminology "pump systems" contained in the existing PBNP Technical Specifications has been retained, rather than adopting the term "train" when referring to the new pumps. During the conversion of the PBNP Custom Technical Specifications to Improved Technical Specifications, Justification for Deviation (JFD-01) was submitted to the Commission for review in this regard. The rationale for use of the term "pump systems" versus "trains" was that "pump systems" is a more accurate description of the PBNP AFW system since the flow paths associated with the AFW pumps are not associated with a specific ESF safety train. "Pump systems" and "trains" both represent the valves and piping which support the ability of an AFW pump to provide the required accident analysis flow rates. Pump systems more aptly describe the AFW system at 2-loop pressurized water reactor plants. The Commission approved this JFD, as documented in the SE approving the new Improved Technical Specifications dated August 8, 2001 (ML012250504). In addition, similar Technical Specifications for use for the AFW System have been approved for the Prairie Island Nuclear Plant (ML022210054).

17 Technical Specification 3.7.6 Condensate Storage Tank (CST)

SR 3.7.6.1 for the CST minimum level is revised from "level is ≥ 13,000 gallons" to "level is ≥ ** gallons." The CST level value to be inserted into the table will be provided as a supplement to this LAR by July 30, 2009.

Licensing Report Sections: Section 2.3.5, Station Blackout, and Section 2.5.4.5, Auxiliary Feedwater.

Basis for the change: This change assures that sufficient water is available to maintain the unit in MODE 3 for at least one hour concurrent with a loss of all AC power. The new CST level value will take into account vortex shedding and net positive suction head. The volume change will satisfy the higher EPU decay heat requirements for each unit.

18 Technical Specification 5.6.4, Core Operating Limits Report (COLR)

TS 5.6.4, Reference 4, WCAP-14787-P revision number was deleted, and the title was revised to reflect the correct title.

TS 5.6.4, Reference 8, WCAP 10216-P-A was deleted since it is no longer used. It will be replaced with "Not used."

Reference 15, Reference 16, and Reference 17 were added to the TS 5.6.4 Reference section.

TS 5.6.4 References 13 and 14 were previously added as part of LAR 258 (ML083330160) and LAR 241 (ML083450683), respectively.

Licensing Report Sections: Section 1.1, NSSS Parameters, and Section 2.8.5.0, Accident and Transient Analyses.

Basis for the change: These are the references for the Axial Flux Difference control change from RAOC to CAOC and RCS Power, Pressure, Temperature, and Flow instrument uncertainties for DNB COLR Limits.

FPL Energy Point Beach is requesting approval of topical report WCAP 14787-P (proprietary), Revision 3 and WCAP-14788 (non-proprietary) Revision 3, both entitled, Westinghouse Revised Thermal Design Procedure Instrument Uncertainty Methodology for Point Beach Units 1 & 2 Power Uprate (1775 MWt - Core Power with Feedwater Venturis, or 1800 MWt - Core Power with LEFM on Feedwater Header)" (Reference 5 and Reference 6, respectively). Revision 3 includes the design and parameter changes for an extended power uprate to a rated thermal power of 1800 MWt.

TS 5.6.4, Reference 8, WCAP 10216-P-A is no longer being used due to the change from RAOC to CAOC for axial offset control.

Approval to implement TS 5.6.4, Reference 13, WCAP-16009-P-A, Realistic Large Break LOCA Evaluation Methodology Using Automated Statistical Treatment of Uncertainty Method (ASTRUM) is requested in LAR 258 (ML083330160). Therefore, the final TS 5.6.4 markups will not be available until Commission approval of LAR 258. Accordingly, a regulatory commitment has been established in Attachment 4 to supplement this LAR within 45 days of issuance of the Commission's Safety Evaluation that approves LAR 258 to provide final markups of this section.

Approval to implement TS 5.6.4, Reference 14, WCAP-16259-P-A, Westinghouse Methodology for Application of 3-D Transient Neutronics to Non-LOCA Accident Analysis is requested in LAR 241, Alternative Source Term (ML083450683).

3.2 LICENSING BASIS CHANGES

1. Analytical Methodologies

   FPL Energy Point Beach has implemented the following changes in methodologies to support the analyses required for the increase in licensed thermal power to 1800 MWt. Attachment 5, LR Section 2.8.5.0, Non-LOCA Analyses Introduction, contains a description of the methodologies and computer codes used for the PBNP Non-LOCA analyses. Methodologies and computer codes that are being applied at PBNP for the first time are identified below:

   a) The definition of the design basis step-load decrease of 50% is revised to a rapid load decrease equivalent to 50% of the EPU rated thermal power (RTP) at a maximum turbine unloading rate of 200%/minute. Refer to Attachment 5 LR Section Section 2.4.2.1, Plant Operability.

   b) Calculation of containment response following a postulated LOCA or MSLB and calculation of the long-term post-HELB releases outside containment are analyzed using the Gothic computer code, (Reference 7 and Reference 8) (See LR Section 2.6.1, Primary Containment Functional Design and Section 2.5.1.3, Pipe Failures).

   c) The thermal-hydraulic design analyses uses computer code VIPRE-W, and the RAVE Methodology. The RAVE Methodology is used specifically for the Loss of Reactor Coolant Flow and Locked Rotor events. Refer to Attachment 5 LR Section 2.8.3, Thermal and Hydraulic Design, Section 2.8.5.3.1, Loss of Forced Reactor Coolant Flow, and Section 2.8.5.3.2, Reactor Coolant Pump (RCP) Rotor Seizure and RCP Shaft Break.

   d) The overpressure protection at power operation analysis uses the computer code RETRAN. Refer to Attachment 5 LR Section 2.8.4.2, Overpressure Protection During Power Operation.

   e) Steam line break at full power is being analyzed for the first time. The analysis uses computer codes RETRAN, Advanced Nodal Code (ANC), and VIPRE. Refer to Attachment 5 LR Section 2.8.5.1.2, Steam System Piping Failures Inside and Outside Containment.

   f) The loss of external electrical load uses the RETRAN computer code. Refer to Attachment 5, LR Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum.

   g) The loss of offsite AC Power and the loss of normal feedwater flow analyses use the RETRAN computer code, including the RETRAN thick metal mass heat transfer model.

Refer to Attachment 5, LR Section 2.8.5.2.2, Loss of Non-Emergency AC Power to Station Auxiliaries, and Section 2.8.5.2.3, Loss of Normal Feedwater Flow.

h) The uncontrolled rod withdrawal at power analysis uses the RETRAN and VIPRE computer codes. Refer to Attachment 5, LR Section 2.8.5.4.2, Uncontrolled Rod Withdrawal at Power.

i) The steam generator tube rupture analysis uses the LOFTTR2 computer code. Refer to Attachment 5, LR Section 2.8.5.6.2, Steam Generator Tube Rupture.

j) See Attachment 5, Appendix A, Safety Evaluation Report Compliance for a summary of NRC-approved codes and methods used in LR Section 2.8.5.0, Accident and Transient Analyses, for the PBNP Extended Power Uprate. The appendix addresses compliance with the limitations, restrictions and conditions specified in the approving safety evaluation of the applicable codes.

2. High Energy Line Break (HELB)

The PBNP HELB outside containment program has been reconstituted to ensure documentation demonstrates compliance with the plant's license basis.

a) Implementation of NRC Generic Letter (GL) 87-11, Relaxation In Arbitrary Intermediate Pipe Rupture Requirements, dated June 19, 1987 (Reference 9) and Branch Technical Position MEB 3-1, Postulated Rupture Locations in Fluid System Piping Inside and Outside Containment, Revision 2, dated June 1987 (Reference 10).

FPL Energy Point Beach uses the guidance of GL 87-11. The stress thresholds for identifying break and crack locations identified in MEB 3-1 were adopted for the EPU HELB evaluation.

FSAR Appendix A.2 provided discussions for the main steam, feedwater, steam generator blowdown and sample systems. Chemical and Volume Control System (CVCS) letdown and other high energy systems in the Turbine Building were not addressed. These additional high energy systems were addressed in the EPU HELB evaluations.

GL 87-11 relaxed the requirements for arbitrary intermediate breaks and did not require prior NRC approval. It attached Branch Technical Position MEB 3-1, which provided new equations for break and crack selection, deleted longitudinal breaks at terminal ends and provided guidance on how non-analyzed high energy piping was to be handled.

Several calculations evaluated the pipe stress analyses for current or EPU power level operating conditions, by using the criteria contained in GL 87-11. A summary of the results follows:

Arbitrary intermediate break locations were eliminated for all systems that had a seismic pipe stress analysis performed. A few locations exceeded the break stress threshold. The number of locations that exceeded the break stress threshold was greatly reduced. However, both the A. Giambusso, Atomic Energy Commission (AEC) letter to J. G. Quale, Wisconsin Electric Power Company (WEP), dated December 19, 1972 (Reference 11) and MEB 3-1 require postulating a leakage crack at the most adverse location in all high energy piping systems.

Calculations evaluated the available pipe stress analyses retrieved by implementing the guidance contained in GL 87-11 and MEB 3-1. The combined stress values in the stress reports that were available were revised to incorporate ASME Section III, 1986 Edition requirements in lieu of stress intensification factors. The resultant stresses were then compared to the break and crack stress thresholds defined by the equations in MEB 3-1. For those high energy systems that did not have the benefit of having a dynamic seismic analysis, a break was postulated at the weld to every fitting, valve and welded attachment. Rather than determining all of these locations, a break was postulated in every compartment the piping run traversed. In addition, a crack was postulated to occur anywhere along the run of pipe at the most adverse location.

b) Mass and energy released from a HELB

The PBNP HELB reconstitution program addressed the Mass and Energy (M&E) release during HELB event. The EPU and M&E releases were determined using the Fauske - Moody methodology and spectrum of break sizes as determined previously. The remaining M&E releases, except for the component cooling water (CCW) heat exchanger room were also determined using the Fauske - Moody methodology and spectrum of break sizes as determined previously and as described in the manual of Reference 13. The M&E releases in the CCW heat exchanger room were determined using the Fanno line methodology, as done in the past at PBNP.

c) Compartment pressurization transient evaluation following a HELB event

The HELB reconstitution program uses the GOTHIC model (Reference 12). GOTHIC is an industry wide recognized computer program. The GOTHIC analysis assumes that a HELB event can be separated into phases, such that the result of the analysis of one phase serves as the conditions of the time dependent input to the next phase. The calculation accounts for the high energy blowdown characteristics, including the effects of steam superheating due to steam generator tube uncovering.

d) Jet impingement from streams following a HELB event

A detailed analysis using the guidance in ANSI/ANS 58.2-1988, Design Basis for Protection of Light Water Nuclear Power Plants Against the Effects of Postulated Pipe Rupture, (Reference 14) was completed in the HELB reconstitution program. ANSI/ANS 58.2-1988 was used in accordance with Section 3.6.2.III.3.F of NUREG-0800, Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, (Reference 15) and satisfies the six assumptions stated in the NUREG. The analysis determined new jet impingement centerline pressures and temperatures versus distances utilizing the methodology contained in the ANSI standard and the break and crack sizes and operating parameters identified in other EPU HELB calculations. This analysis supersedes the discussion of jet impingement methodology provided in FSAR Appendix A.2, Addendum 1 to reflect changes in methodologies used to determine HELB parameters, including those used for environmental qualifications of equipment outside containment.

e) Operator response time evaluation

Training was performed on the PBNP simulator using two separate operating crews and the Westinghouse Owner Group Emergency Operating Procedures. The scenario chosen was a small main steam line break that would not generate automatic protective action. The mass and energy releases required manual operator action within ten (10) minutes to initiate reactor trip, isolation of feedwater flow to a faulted steam generator and closure of the main steam isolation valves. Both crews successfully accomplished all of those actions within ten minutes.

The review of the HELB outside containment reconstitution program has determined that the program will maintain compliance with the license basis and will be acceptable for EPU conditions.

3. Related License Amendment Requests

The following license amendment requests are required to be implemented prior to operation at EPU conditions. The LARs each contain their own summary of changes and No Significant Hazards evaluation, which is not repeated here.

a) Alternative Source Term

In LAR 241, Alternative Source Term, (Reference 3), FPL Energy Point Beach proposed to continue containment spray operation during the recirculation phase of the accident for dose reduction. The containment integrity analysis for EPU presented in this LAR credits the operation of containment spray during the recirculation phase of the accident. (Attachment 5, LR Section 2.6.1, Primary Containment Functional Design).

b) ASTRUM LBLOCA Analyses

In LAR 258, Incorporate Best Estimate Large Break Loss of Coolant Accident (LOCA) Analyses Using ASTRUM, (Reference 2.) FPL Energy Point Beach proposed the use of the LB BELOCA analysis using the Westinghouse Automated Statistical Treatment of Uncertainties Method (ASTRUM) methodology. (Attachment 5, LR Section 2.8.5.6.3, Emergency Core Cooling System and Loss-of-Coolant Accidents).

4. Post-LOCA Vital Area Access

The vital areas that will remain following EPU are:

a) C59 panel, located in the primary auxiliary building at Elevation 26'.

b) Unit 1 and 2 NaOH discharge line air-operated valves (AOVs) located in the primary auxiliary building Elevation 26'. (Reference 3)

Emergency Operating Procedures (EOPs)

A review was performed of the Emergency Operating Procedures (EOPs) to identify the operational (not security related) vital area access requirements applicable for EPU operations following a design basis LOCA. It was determined that the vital area access requirements identified in the original licensing basis are either:

a) Not required to be evaluated since they are completed prior to the sump water recirculation phase of the LOCA, and thus, do not pose a radiation hazard to the operator or,

b) Not required steps to be performed, but steps that may be performed if the environment is considered acceptable by the PBNP Radiation Protection staff.

As discussed below the vital access area of the PASS is being eliminated for accident mitigation and safe shutdown.

5. Post Accident Sampling System (PASS)

FPL Energy Point Beach is proposing to eliminate its current NUREG- 0737, Item II.3.b requirement to draw and analyze post-accident samples within 3 hours following a large break LOCA. As a result of the above change, the Units 1 and 2 sample rooms are removed from the list of operational vital areas. Justification for elimination of this requirement is presented in Attachment 5, LR Section 2.10.2, Additional Review Areas (Health Physics) which requests approval of WCAP 14986-A, Westinghouse Owners Group Post Accident Sampling System Requirements: A Technical Basis, (Reference 16) and the associated NRC approval of the topical report. Required Licensee Actions (RLAs) identified in Sections 4.1 and 5 of the NRC Safety Evaluation (SE) for WCAP-14986-A (Reference 17) are complete. Detailed discussion of the RLAs and the PBNP implementation of them is provided in LR Section 2.10.2, Additional Review Areas (Health Physics). The plant will remain capable of performing sampling activities following NRC approval to eliminate the 3-hour sampling requirement. These two post accident sample areas will no longer be considered vital areas that require access for accident mitigation and safe shutdown. PASS programatic requirements will remain in the TS.

The PBNP current licensing basis for core damage assessment is based on sample analysis based upon the WOG, Post Accident Core Damage Assessment Methodology Revision 2, dated November 1984. With the approval of this amendment, PBNP requests approval of WCAP 14696-A Revision 1, Westinghouse Owners Group Core Damage Assessment Guidance (CDAG) for use at PBNP for core damage assessment. WCAP 14696-A Revision 1 was approved by the NRC staff on September 2, 1999, for use as a methodology change by Westinghouse plants. This methodology will be implemented prior to uprating PBNP Unit 1 or Unit 2 as a part of implementation of this license amendment.

A 10 CFR 50.54(q) evaluation was completed and the conclusion has been reached that implementation of the revised CDAG should increase the effectiveness of the emergency response organization as stated in the NRC safety evaluation for WCAP 14696-A Revision 1. Therefore, the change to the Emergency Plan does not require prior NRC approval.

3.3 Plant Modification Changes

The following modifications are being made for implementation of the EPU. These modifications may be installed, tested and implemented in accordance with 10 CFR 50.59.

1) Main steam pipe supports will be upgraded to mitigate larger flow induced transient loads.

2) The Steam Generator Moisture separator packages will be modified to maintain steam moisture carry over to less than 0.25%.

3) New Main Generator output breakers will be installed on each unit along with an associated protection scheme for isolation of the generator from the distribution system when generator trips occur.

4) A variable speed drive will be installed on the 1P2C charging pump.

5) The AFW system will be upgraded to install new unitized motor driven pumps and add AFW pump suction auto-switchover to safety related service water upon loss of the condensate storage water source. The construction of the system may proceed under 10 CFR 50.59. The final physical tie-in and implementation will require Commission prior approval.

6) New main feedwater isolation valves (MFIVs) will be installed. Main feedwater piping supports will be installed to withstand the potential stress of an MFIV closure transient.

7) Main steam isolation valve MSIV internals will be upgraded to address flow induced vibration and closure loads at EPU conditions.

8) The pressurizer backup heater actuation on a pressurizer high level deviation signal will be removed.

9) A backup compressed gas supply to the pressurizer auxiliary spray valve will be installed.

10) Local manual action to gag the Motor-Driven and Turbine-Driven AFW pump mini-recirculation valves open will be eliminated. Therefore, reliance on that action will no longer be required.

11) A self-cooled (i.e., air-cooled) air compressor to supply instrument air independent of the need for service water cooling will be installed.

The final installation, testing and implementation of the following modifications will require NRC approval of this LAR.

1) AFW system upgrade final tie-ins and implementation in accordance with the requested TS 3.7.5 changes.

2) Main steam safety valve setpoint changes in accordance with the requested TS 3.7.1 changes.

3) Main feedwater isolation modification implementation in accordance with the requested TS 3.7.3 changes.

4) Nuclear Steam Supply System (NSSS) and Balance of Plant (BOP) final instrumentation setpoint changes and axial flux difference control implementation in accordance with the requested TS 3.2.3, 3.3.1, 3.3.2, and 3.3.4 changes.

In summary, FPL Energy Point Beach has reviewed the Renewed Facility Operating Licenses, Technical Specifications and current licensing basis and has determined that revisions to those documents noted above (or in the previously referenced submittals) are required to properly control plant operations and configuration under EPU conditions. In addition, the Regulatory

Commitments identified in Attachment 4 are required to be completed as noted or prior to implementation of the EPU for each respective unit. Identified changes to the FSAR will be processed as part of the implementation process.

4.0 Technical Analysis

The acceptability of each proposed Renewed Facility Operating License, Technical Specification, and Licensing Basis change is addressed in Attachment 5, EPU Licensing Report. Attachment 5 summarizes the evaluations performed to assure acceptable operation at EPU conditions, and provides technical justification for the EPU related changes.

5.0 Environmental Evaluation

The environmental considerations evaluation is contained in Appendix D, Supplemental Environmental Report to Attachment 5. It concludes that EPU will not result in a significant change in non-radiological impacts on land use, water use, waste discharges, terrestrial and aquatic biota, transmission facilities, or social and economic factors, and will have no non-radiological environmental impacts other than those evaluated in the Environmental Report. The Environmental Report further concludes that EPU will not introduce any new radiological release pathways, will not result in a significant increase in occupational or public radiation exposures, and will not result in significant additional fuel cycle environmental impacts.

FPL Energy Point Beach has determined that operation with the proposed EPU license amendment would not result in any significant change in the types or significant increase in the amounts of any effluent that may be released offsite nor does it involve a significant increase in individual or cumulative occupational radiation exposure. Therefore, the proposed license amendment is eligible for categorical exclusion as set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment is needed in connection with the approval of the proposed license amendment.

6.0 Regulatory Analysis

6.1 Applicable Regulatory Requirements / Criteria

The proposed changes have been evaluated to determine whether applicable regulations and requirements continue to be met.

FPL Energy Point Beach has determined that the proposed changes do not require any exemptions or relief from regulatory requirements and do not affect conformance with any General Design Criterion (GDC) differently than described in the Final Safety Analysis Report (FSAR).

6.2 No Significant Hazards Consideration

FPL Energy Point Beach has evaluated whether or not a significant hazards consideration is involved with the proposed amendments by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No. The proposed changes will not involve a significant increase in the probability or consequences of an accident previously evaluated.

   The proposed modifications, associated changes to the Licenses, Technical Specifications and current licensing bases will ensure that the results of previously evaluated accidents at the uprated conditions remain within the acceptance criteria.

   License and Technical Specification Changes

   Changes to the Renewed Facility Operating Licenses, Technical Specifications and licensing bases are being proposed, including changes to the maximum licensed reactor core thermal power, reactor core safety limits, Constant Axial Offset Control (CAOC) operating strategy, Reactor Protection System (RPS) and Engineered Safety Feature Actuation System (ESFAS) Limited Safety System Settings and diesel generator (DG) start loss of voltage time delays. Additional Technical Specification changes include, Reactor Coolant System (RCS) flow rate, pressurizer operating level, pressurizer safety valve settings, accumulator and refueling water storage tank boron concentrations, main steam safety valve maximum allowable power level and lift settings, new MFIVs, modified AFW system, CST level and Core Operating Limits Report (COLR) references. The safety analyses demonstrated that the applicable acceptance criteria are met at the uprated power conditions, considering the proposed License and Technical Specification changes.

   The fission product barriers (fuel cladding, reactor coolant pressure boundary, and the containment building) remain unchanged. The spectrum of previously analyzed postulated accidents and transients was evaluated, and effects on the fuel, the reactor coolant pressure boundary, and containment were determined. These analyses were performed consistent with the proposed Technical Specification changes. The analysis results demonstrate that existing fuel, reactor coolant pressure boundary and containment limits are met and the effects on the fuel are such that dose consequences meet criteria described in LAR 241, Alternative Source Term (ML083450683), at EPU conditions.

   The proposed RPS and ESFAS setpoint changes provide appropriate values for operation of PBNP at EPU conditions. The revised Technical Specification allowable values have been calculated to account for new EPU analytical limits, instrument uncertainties and drift. The proposed RPS and ESFAS setpoint changes are considered in the safety analyses for the affected RPS and ESFAS functions, and do not significantly increase the probability or consequences of the accidents previously evaluated and the setpoint changes considered in the safety analysis continue to meet the applicable acceptance criteria. The safety analyses for these accidents have been performed at the EPU power level and demonstrated acceptable results.

   Licensing Basis Changes

   The licensing bases are being revised to use methodologies for the safety analyses that had not been previously used at PBNP. These methodology changes incorporate computer codes and methods that have been previously approved for use by the NRC for use at other nuclear power facilities.

The safety analyses have been revised to address operation at the uprated power level. Analyses and evaluations have been performed for Point Beach Nuclear Plant (PBNP) Units 1 and 2 at an uprated reactor core thermal power level of 1800 megawatts thermal (MWt) for evaluation of NSSS and balance of plant (BOP) systems and components, including the nuclear fuel.

The analyses and evaluations of the NSSS and BOP systems, structures and components based on completion of the required modifications, confirm that the systems and components will function as designed and demonstrate that the NSSS and BOP systems and components meet all applicable design and licensing requirements at the uprated power level.

Use of NRC approved computer codes such as RETRAN, VIPRE and RAVE at PBNP for departure from nucleate boiling (DNB) analysis for those FSAR transients and accidents for which DNB might be a concern, will not involve a significant increase in the probability or consequences of an accident for the following reasons. The codes are evaluation tools that are independent of the probability of an accident. Use of the codes establish that DNB limits are met such that core damage will not occur. Consequences of previously evaluated accidents are not increased.

The EPU radiological analysis reflects the application of the Alternative Source Term methodology for operation at a licensed thermal power of 1800 MWt provided in LAR 241 Alternative Source Term (ML083450683), at EPU conditions. The no significant hazards consideration in the LAR 241 application concluded that the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

In LAR 258, Incorporate Best Estimate Large Break Loss of Coolant Accident (LOCA) Analyses Using ASTRUM, (Reference 2) FPL Energy Point Beach proposed the use of the LB BELOCA analysis using the Westinghouse Automated Statistical Treatment of Uncertainties Method (ASTRUM) methodology. Approval at the uprated power level does not alter the conclusion. The no significant hazards consideration in that application concluded that the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

This LAR provides for the elimination of the 3-hour requirement to sample and analyze a post-accident sample as described in WCAP 14986-A, Westinghouse Owners Group Post Accident Sampling System Requirements: A Technical Basis. The implementation of the licensee required actions of WCAP 14986-A have been completed with the exception of the incorporation of the Core Damage Assessment Guideline. Details of the licensee required actions can be found in LR Section 2.10.2, Additional Review Areas (Health Physics). As part of the EPU implementation, PBNP will adopt the core damage assessment guidance (CDAG) described in WCAP 14696-A Revision 1, Westinghouse Owners Group Core Damage Assessment Guidance and has included it as a commitment in Attachment 4. Therefore, the elimination of the 3-hour sample and analyze requirement with the use of the

NRC approved WCAP 14986-A and WCAP 14696 guidance does not involve a significant increase in the probability or consequences of an accident previously evaluated.

HELB evaluations have been reevaluated at EPU conditions using the following:

1) Implementation of NRC Generic Letter (GL) 87-11, Relaxation in Arbitrary Intermediate Pipe Rupture Requirements, dated June 19, 1987 (Reference 9) and Branch Technical Position MEB 3-1, Postulated Rupture Locations in Fluid System Piping Inside and Outside Containment, Revision 2, dated June 1987 (Reference 10)
2) Mass and energy released from a HELB
3) Compartment pressurization transient evaluation following a HELB event
4) Jet impingement from streams following a HELB event
5) Operator response time evaluation

The review of the HELB outside containment reconstitution program has determined that the program will maintain compliance with the license basis and will be acceptable for EPU conditions. The results of these evaluations show that the effects of HELB at EPU do not involve a significant increase in the probability or consequences of an accident previously evaluated.

Modifications

To support operation at the uprated power level, system modifications are required: including a proposed installation of main feedwater isolation valves (MFIVs) that will mitigate accidents to ensure that containment pressure does not exceed safety analysis limits. Also an upgrade to the main steam isolation valves (MSIVs) to improve the reliability of the valves under EPU conditions will be made.

An upgrade to the Auxiliary Feedwater System is being made to support requirements for transients and other accidents at EPU conditions. This modification to the auxiliary feedwater (AFW) system will provide additional capacity and reliability for the system. This modification will incorporate Appendix R and other separation considerations in its design. In addition, an automatic switchover from a Condensate Storage Tank suction source to a safety related Service Water source will be installed for actuation based upon the loss of suction pressure from the CST. A low suction pressure trip of the AFW pumps will also be maintained to ensure pump protection if the suction transfer does not occur.

The proposed changes involve design basis accident or event response. However, they will not significantly increase the probability of any accident previously evaluated. The probability of any evaluated accident or event is not significantly affected by the changes being proposed. The proposed changes will not significantly affect accident initiators or precursors. They will not alter or prevent the ability of systems, structures or components from performing their intended safety function to meet the applicable acceptance limits for the accidents and events.

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

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

   Response: No. The proposed modifications, associated changes to the Licenses, Technical Specifications and current licensing bases do not create the possibility of a new or different kind of accident from any accident previously evaluated.

   License and Technical Specification Changes

   Changes to the Renewed Facility Operating License, Technical Specifications and licensing bases are being proposed, including changes to the maximum licensed reactor core thermal power, reactor core safety limits, Constant Axial Offset Control (CAOC) operating strategy, Reactor Protection System (RPS) and Engineered Safety Feature Actuation System (ESFAS) Limiting Safety System Settings, and diesel generator (DG) start loss of voltage time delays. Additional Technical Specification changes include, Reactor Coolant System (RCS) flow rate, pressurizer operating level, pressurizer safety valve settings, accumulator and refueling water storage tank boron concentrations, main steam safety valves maximum allowable power level and lift settings, new MFIVs, modified AFW system, CST level and Core Operating Limits Report (COLR) references. These analyses and evaluations of the NSSS and BOP based on implementation of the proposed License, Technical Specification changes above confirm that the systems and components meet their design requirements and the transient and accident analyses continue to meet their acceptance criteria. No new or different kind of accident are created by these changes.

   The proposed RPS and ESFAS Limited Safety System Setting changes do not create the possibility of a new or different type of accident due to operation of PBNP at EPU conditions. The revised Technical Specification LSSS values have been calculated to account for new EPU analytical limits, and known instrument uncertainties using industry standard setpoint methodology ISA 67.04. The proposed RPS and ESFAS setpoint changes are used in the safety analyses for the affected RPS and ESFAS functions, and do not significantly affect these accidents or the applicable acceptance criteria.

   Licensing Basis Changes

   The current licensing bases are being revised to use methodologies for the safety analyses that had not been previously used at PBNP. These methodology changes incorporate computer codes and methods that have been previously approved for use by the NRC and used at other nuclear power facilities.

   The analyses and evaluations of the NSSS and BOP systems, structures, and components based on these new methods, confirm that the systems and components will function as designed and demonstrate that the NSSS and BOP systems and components meet all applicable design and licensing requirements at the uprated power level. The possibility of a new or different type of accident is not created.

   Use of computer codes such as RETRAN, VIPRE and RAVE at PBNP for departure from nucleate boiling (DNB) analysis for those FSAR transients and accidents for which DNB might be a concern, will not create the possibility of a new or different kind of accident from any accident previously evaluated since the codes are evaluation tools and are not accident initiators. Use of the codes establish DNB limits such that core damage will not occur.

The EPU radiological analysis reflects the application of the Alternative Source Term methodology for operation at a licensed thermal power of 1800 MWt provided in LAR 241 Alternative Source Term (ML083450683), at EPU conditions. The no significant hazards consideration in that application concluded that the proposed change does not create the possibility of a new or different kind of accident from any previously evaluated.

In LAR 258, Incorporate Best Estimate Large Break Loss of Coolant Accident (LOCA) Analyses Using ASTRUM, (Reference 2) FPL Energy Point Beach proposed the use of the LB BELOCA analysis using the Westinghouse Automated Statistical Treatment of Uncertainties Method (ASTRUM) methodology. The No Significant Hazards Consideration in that application concluded that the use of the new methodology does not alter the nature of events postulated in the FSAR nor do they introduce any unique precursor mechanisms.

HELB evaluations have been reevaluated at EPU conditions using the following:

1) Implementation of NRC Generic Letter (GL) 87-11, Relaxation In Arbitrary Intermediate Pipe Rupture Requirements, dated June 19, 1987 (Reference 9) and Branch Technical Position MEB 3-1, Postulated Rupture Locations In Fluid System Piping Inside And Outside Containment, Revision 2, dated June 1987 (Reference 10)
2) Mass and energy released from a HELB
3) Compartment pressurization transient evaluation following a HELB event
4) Jet impingement from streams following a HELB event
5) Operator response time evaluation

The review of the HELB outside containment reconstitution program has determined that the program will maintain compliance with the license basis and will be acceptable for EPU conditions. The results of these evaluations show that the effects of HELB at EPU do not create the possibility of a new or different kind of accident from any previously evaluated.

<u>Modifications</u>

To support operation at the uprated power level, system modifications are required including a proposed installation of main feedwater isolation valves (MFIVs) that will mitigate accidents to ensure that containment pressure does not exceed safety analysis limits for a steam line break accident. An upgrade to the main steam isolation valves (MSIVs) to improve the reliability of the valves under EPU conditions will also be made.

An upgrade to the Auxiliary Feedwater System is being made to support requirements for transients and other accidents at EPU conditions. This modification to the auxiliary feedwater (AFW) system will provide additional capacity and reliability for the system. This modification will incorporate Appendix R and other separation considerations in its design. In addition, an automatic switchover from a Condensate Storage Tank suction source to a safety related Service Water source will be installed for actuation based upon the loss of suction pressure from the CST. A low suction pressure trip of the AFW pumps will also be maintained to ensure pump protection if the suction transfer does not occur.

The proposed changes involve design basis accident or event response. However, they will not create the possibility of a new accident or event. The proposed changes will not significantly affect accident initiators or precursors. They will not alter or prevent the ability of systems, structures, or components from performing their intended function within the applicable acceptance limits.

Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any previously evaluated.

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

   Response: No. The proposed modifications and associated changes to the Licenses, Technical Specifications and current licensing bases will ensure that the results of postulated accidents at the uprated conditions remain within the acceptance criteria and will not involve a significant reduction in the margin of safety.

   License and Technical Specification Changes

   Changes to the Renewed Facility Operating License, Technical Specifications and licensing bases are being proposed, including changes to the maximum licensed reactor core thermal power, reactor core safety limits, Constant Axial Offset Control (CAOC) operating strategy, Reactor Protection System (RPS) and Engineered Safety Feature Actuation System (ESFAS) Limiting Safety System Settings, and diesel generator (DG) start loss of voltage time delays. Additional Technical Specification changes include Reactor Coolant System (RCS) flow rate, pressurizer operating level, pressurizer safety valve settings, accumulator and refueling water storage tank boron concentrations, main steam safety valves maximum allowable power level and lift settings, new MFIVs, modified AFW system, CST level and Core Operating Limits Report (COLR) references. Analyses and evaluations have been performed for PBNP Units 1 and 2 at the uprated power level of 1800 MWt for the NSSS and BOP systems and components, including the nuclear fuel. Analyses and evaluations of the NSSS and BOP based on these changes, confirm that the systems and components meet their design requirements and the transients and accidents meet their acceptance criteria.

   The proposed changes to Technical Specifications provide adequate margin such that PBNP Units 1 and 2 can be operated in a safe manner at the EPU conditions. These changes will not involve a significant reduction in the margin of safety.

   Current Licensing Bases Changes

   The current licensing bases are being revised to use methodologies for the safety analyses that had not been previously used at PBNP. These methodology changes incorporate methods,computer codes and analyses that have been previously approved for use by the NRC and for use at other nuclear power facilities.

   Use of NRC approved computer codes such as RETRAN, VIPRE and RAVE at PBNP for departure from nucleate boiling (DNB) analysis for those FSAR transients and accidents for which DNB might be a concern, will not involve a significant reduction in a margin of safety, since the code is an evaluation tool that is in many cases is used to verify the maintenance of the margin to safety. Use of the code establishes DNB limits and verifies that core damage will not occur.

The EPU radiological analysis reflects the application of the Alternative Source Term methodology for operation at a licensed thermal power of 1800 MWt provided in LAR 241 Alternative Source Term (ML083450683), at EPU conditions. The no significant hazards consideration in that application concluded that the proposed change does not reduce any margin of safety.

In LAR 258, Incorporate Best Estimate Large Break Loss of Coolant Accident (LOCA) Analyses Using ASTRUM, (LAR 258, Reference 7.2) FPL Energy Point Beach proposed the use of the LB BELOCA analysis using the Westinghouse Automated Statistical Treatment of Uncertainties Method (ASTRUM) methodology. The No Significant Hazards Consideration in that application concluded that the use of the new methodology does not reduce a margin of safety.

The EPU radiological analysis reflects the application of the Alternative Source Term methodology for operation at a rated thermal power of 1800 MWt provided in LAR 241 Alternative Source Term (ML083450683), at EPU conditions. The no significant hazards consideration in that application concluded that the use of the new methodology does not reduce any margin of safety.

This LAR provides for the elimination of the 3-hour requirement to sample and analyze a post accident sample as described in NRC approved WCAP 14986-A, Westinghouse Owners Group Post Accident Sampling System Requirements: A Technical Basis. The implementation of the licensee required actions of WCAP 14986-A, have been completed with the exception of the incorporation of the Core Damage Assessment Guidline. Details of the licensee required actions can be found in LR Section 2.10.2, Additional Review Areas (Health Physics). As part of the implementation PBNP will adopt the core damage assessment guidance (CDAG) described in WCAP 14696-A Revision 1, Westinghouse Owners Group Core Damage Assessment Guidance. Therefore the elimination of the 3-hour sample and analyze requirement with the use of the WCAP 14986-A and WCAP 14696-A guidance does not reduce a margin of safety.

HELB evaluations have been reevaluated at EPU conditions using the following:

1) Implementation of NRC Generic Letter (GL) 87-11, Relaxation In Arbitrary Intermediate Pipe Rupture Requirements, dated June 19, 1987 (Reference 9) and Branch Technical Position MEB 3-1, Postulated Rupture Locations In Fluid System Piping Inside And Outside Containment, Revision 2, dated June 1987 (Reference 10)
2) Mass and energy released from a HELB
3) Compartment pressurization transient evaluation following a HELB event
4) Jet impingement from streams following a HELB event
5) Operator response time evaluation

The review of the HELB outside containment reconstitution program has determined that the program will maintain compliance with the license basis and will be acceptable for EPU conditions. The results of these evaluations show that the effects of HELB at EPU do not involve a significant reduction in a margin of safety.

Modifications

To support operation at the uprated power level, system modifications are required: including a proposed installation of main feedwater isolation valves (MFIVs) that will mitigate accidents to ensure that containment pressure does not exceed safety analysis limits for a steam line break accident. An upgrade to the main steam isolation valves (MSIVs) to improve the reliability of the valves under EPU conditions will also be made.

A modification to the auxiliary feedwater (AFW) system will provide additional capacity and reliability for the system. This modification will incorporate Appendix R and other separation considerations in its design. In addition, an automatic switchover from a Condensate Storage Tank suction source to a safety related Service Water source will be installed for actuation based upon the loss of suction pressure from the CST. A low suction pressure trip of the AFW pumps will also be maintained to ensure pump protection if the suction transfer does not occur.

The analyses and evaluations of the NSSS and BOP systems based on completion of the required modifications, confirm that the systems and components will function as designed and demonstrate that the NSSS and BOP systems and components meet all applicable design and licensing requirements at the uprated power level.

No new accident scenarios, failure mechanisms or single failures are introduced as a result of the proposed modifications. All systems, structures and components previously assumed for the mitigation of an event remain capable of fulfilling their intended design function. The proposed changes will not have any significant effect on the margin to safety.

Therefore, in conclusion, none of the proposed changes involve a significant reduction in a margin of safety.

In accordance with the requirements of 10 CFR 50.90, FPL Energy Point Beach hereby requests an amendment to Renewed Facility Operating Licenses DPR-24 and DPR-27 for PBNP. The purpose of the proposed LAR is to revise the Renewed Facility Operating Licenses and the Technical Specifications to allow operation at an increased licensed core thermal power of 1800 MWt.

FPL Energy Point Beach has evaluated the proposed LAR in accordance with 10 CFR 50.91 against the standards in 10 CFR 50.92 and has determined that the operation of PBNP Units 1 and 2 in accordance with the proposed LAR presents no significant hazards and therefore, a finding of "no significant hazards consideration" is justified.

A comprehensive review of accident analyses, component and system analyses, and radiological dose consequences was performed for the EPU. Analyses met the appropriate criteria, as explained in the no significant hazards determination. Therefore, operation of PBNP Units 1 and 2 in accordance with the proposed amendments will not result in a significant increase in the probability or consequences of any accident previously analyzed; will not result in a new or different kind of an accident from any accident previously analyzed; and will not result in a significant reduction in margin of safety. Therefore, operation of PBNP Units 1 and 2 in accordance with the proposed amendments does not involve a significant hazards consideration.

7.0 References

1 RS-001, Review Standard for Extended Power Uprates, U.S. Nuclear Regulatory Commission, December 2003

2 PBNP LAR 258, Incorporate Best Estimate Large Break Loss Of Coolant Accident (LOCA) Analyses Using ASTRUM, dated November 25, 2008 (ML083330160)

3 PBNP LAR 241 Alternative Source Term, dated December 8, 2008 (ML083450683)

4 NUREG-1431, Revision 3.0, Standard Technical Specifications Westinghouse Plants, dated June 2004 (ML041830612)

5 WCAP-14787-P, Revision 3, Revised Thermal Design Procedure Instrument Uncertainty Methodology for Point Beach Units 1 & 2 (Power Uprate to 1775 MWt Core Power with Feedwater Venturis, or 1800 MWt Core Power with LEFM on Feedwater Header), February 2009

6 WCAP-14788, Revision 3, Revised Thermal Design Procedure Instrument Uncertainty Methodology for Point Beach Units 1 & 2 (Power Uprate to 1775 MWt Core Power with Feedwater Venturis, or 1800 MWt Core Power with LEFM on Feedwater Header), February 2009

7 NAI 8907 06, Revision. 16, GOTHIC Containment Analysis Package Technical Manual, Version 7.2a, January 2006

8 NAI 8907 09, Revision. 9, GOTHIC Containment Analysis Package Qualification Report, Version 7.2a, January 2006

9 NRC Generic Letter (GL) 87-11, Relaxation In Arbitrary Intermediate Pipe Rupture Requirements, dated June 19, 1987

10 MEB 3-1, Postulated Rupture Locations In Fluid System Piping Inside And Outside Containment, Revision 2, dated June 1987

11 Atomic Energy Commission (AEC) letter to Wisconsin Electric Power Company (WEP), dated December 19, 1972

12 NAI 8907-02 Revision 17 GOTHIC Software Version 7.2a (QA) dated 2/20/08 including Gothic Containment Analysis Package User Manual, Version 7.2a(QA), January 2006,

13 Manual of RETRAN-3D --- A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, Volume 1: Theory and Numerics, NP-7450(A), Volume 1, Revision 5, Research Project 889-10 Computer Code Manual, July 2001

14 ANSI/ANS 58.2-1988, Design Basis for Protection of Light Water Nuclear Power Plants Against the Effects of Postulated Pipe Rupture, dated October 6, 1988

15 NUREG-0800, Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, dated March, 2007

16 WCAP 14986-A, Revision 1, Westinghouse Owners Group Post Accident Sampling System Requirements, A Technical Basis, dated October 26, 1998

17 Safety Evaluation Related to Topical Report WCAP 14986-A, Revision 1, Westinghouse Owners Group Post Accident Sampling System Requirements (TAC No. MA4176), dated June 14, 2000 (ML003723268)

18 NS-TMA-2198, Westinghouse to NRC Letter, Operation and Safety Analysis Aspects of an Improved Load Follow Package, dated January 31, 1980

19 NS-CE-687, Westinghouse to NRC Letter, Power Distribution Control Analysis, dated July 16, 1975

ATTACHMENT 2

FPL ENERGY POINT BEACH, LLC
POINT BEACH NUCLEAR PLANT UNITS 1 AND 2

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE

PROPOSED FACILITY OPERATING LICENSES

AND

TECHNICAL SPECIFICATION CHANGES

MARKED UP PAGES

43 Pages Follow

C. Pursuant to the Act and 10 CFR Parts 30, 40 and 70, FPLE Point Beach to receive, possess and use at any time any byproduct, source, and special nuclear material as sealed neutron sources for reactor startup, sealed source for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

D. Pursuant to the Act and 10 CFR Parts 30, 40 and 70, FPLE Point Beach to receive, possess and use in amounts as required any byproduct, source of special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

E. Pursuant to the Act and 10 CFR Parts 30 and 70, FPLE Point Beach to possess such byproduct and special nuclear materials as may be produced by the operation of the facility, but not to separate such materials retained within the fuel cladding.

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

A. Maximum Power Levels

FPLE Point Beach is authorized to operate the facility at reactor core power levels not in excess of ~~1540~~ 1800 megawatts thermal.

B. Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. ~~238~~, are hereby incorporated in the renewed operating license. FPLE Point Beach shall operate the facility in accordance with Technical Specifications.

C. Spent Fuel Pool Modification

The licensee is authorized to modify the spent fuel storage pool to increase its storage capacity from 351 to 1502 assemblies as described in licensee's application dated March 21, 1978, as supplemented and amended. In the event that the on-site verification check for poison material in the poison assemblies discloses any missing boron plates, the NRC shall be notified and an on-site test on every poison assembly shall be performed.

FPL ENERGY POINT BEACH LLC
DOCKET NO. 50-301
RENEWED FACILITY OPERATING LICENSE
Renewed License No. DPR-27

D. Pursuant to the Act and 10 CFR Parts 30, 40 and 70, FPLE Point Beach to receive, possess and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

E. Pursuant to the Act and 10 CFR Parts 30 and 70, FPLE Point Beach to possess such byproduct and special nuclear materials as may be produced by the operation of the facility, but not to separate such materials retained within the fuel cladding.

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

A. Maximum Power Levels

FPLE Point Beach is authorized to operate the facility at reactor core power levels not in excess of ~~1540~~ megawatts thermal.

1800

B. Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. ~~234~~, are hereby incorporated in the renewed operating license. FPLE Point Beach shall operate the facility in accordance with Technical Specifications.

C. Spent Fuel Pool Modification

The licensee is authorized to modify the spent fuel storage pool to increase its storage capacity from 351 to 1502 assemblies as described in licensee's application dated March 21, 1978, as supplemented and amended. In the event that the on-site verification check for poison material in the poison assemblies discloses any missing boron plates, the NRC shall be notified and an on-site test on every poison assembly shall be performed.

FPL ENERGY POINT BEACH LLC
DOCKET NO. 50-266
RENEWED FACILITY OPERATING LICENSE
Renewed License No. DPR-24

1.1 Definitions

RATED THERMAL POWER (RTP)

RTP shall be a total reactor core heat transfer rate to the reactor coolant of ~~1540~~ 1800 MWt.

SHUTDOWN MARGIN (SDM)

SDM shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming:

a. All rod cluster control assemblies (RCCAs) are fully inserted except for the single RCCA of highest reactivity worth, which is assumed to be fully withdrawn. However, with all RCCAs verified fully inserted by two independent means, it is not necessary to account for a stuck RCCA in the SDM calculation;

b. With any RCCA not capable of being fully inserted, the reactivity worth of the RCCA must be accounted for in the determination of SDM; and

c. In MODES 1 and 2, the fuel and moderator temperatures are changed to the nominal zero power design level.

SLAVE RELAY TEST

A SLAVE RELAY TEST shall consist of energizing all slave relays in the channel required for OPERABILITY and verifying the OPERABILITY of each required slave relay. The SLAVE RELAY TEST shall include a continuity check of associated required testable actuation devices. The SLAVE RELAY TEST may be performed by means of any series of sequential, overlapping, or total channel steps.

STAGGERED TEST BASIS

A STAGGERED TEST BASIS shall consist of the testing of one of the systems, subsystems, channels, or other designated components during the interval specified by the Surveillance Frequency, so that all systems, subsystems, channels, or other designated components are tested during n Surveillance Frequency intervals, where n is the total number of systems, subsystems, channels, or other designated components in the associated function.

THERMAL POWER

THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.

2.0 SAFETY LIMITS (SLs)

2.1 SLs

2.1.1 Reactor Core SLs

In MODES 1 and 2, the combination of THERMAL POWER, Reactor Coolant System (RCS) highest loop average temperature, and pressurizer pressure shall not exceed the limits specified in the COLR in order to preserve the following fuel design criteria:

2.1.1.1 The departure from nucleate boiling ratio (DNBR) shall be maintained:

~~≥ 1.22/1.21 (typical/thimble) for the WRB-1 correlation cores not containing 422V+ fuel~~
~~≥ 1.24/1.23 (typical/thimble) for the WRB-1 correlation cores containing 422V+ fuel~~

~~OR~~ ≥ 1.17 for the WRB-1 correlation

≥ 1.30 for the W-3 correlation when system pressure is > 1000 psia
≥ 1.45 for the W-3 correlation when system pressure is ≥ 500 psia and ≤ 1000 psia

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

2.1.2 RCS Pressure SL

In MODES 1, 2, 3, 4, 5, and 6 the RCS pressure shall be maintained ≤ 2735 psig.

2.2 SL Violations

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

2.2.2 If SL 2.1.2 is violated:

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

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.4	Perform SR 3.2.1.1 and SR 3.2.1.2.	Prior to increasing THERMAL POWER above the limit of Required Action A.1 ~~AND~~ ~~Prior to increasing any setpoint that has been reduced above the limits of Required Actions A.2 and A.3~~
-----------NOTE----------- Required Action B.4 shall be completed whenever this Condition is entered. -------------------------------	B.1	Reduce ~~AFD limits~~ THERMAL POWER ≥ 1% RTP for each 1% $F^W_Q(Z)$ exceeds limit.	4 hours
	AND		
B. $F^W_Q(Z)$ not within limits.	B.2	Reduce Power Range Neutron Flux-High trip setpoints ≥ 1% for each 1% ~~that the maximum allowable power of the AFD limits is reduced.~~ $F^W_Q(Z)$ exceeds limits	72 hours
	AND		
			(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued) $F^W_Q(Z)$ exceeds limits.	B.3	Reduce the Overpower ΔT trip setpoints $\geq$ 1% for each 1% ~~that the maximum allowable power of the AFD limits is reduced~~.	72 hours
	<u>AND</u>		
	B.4	Perform SR 3.2.1.1 and SR 3.2.1.2.	Prior to increasing THERMAL POWER above the ~~maximum allowable power of the AFD limits~~.
C. Required Action and associated Completion Time not met.	C.1	Be in MODE 2.	6 hours

limit of Required Action B.1.

REPLACE WITH THE FOLLOWING 3 AFD INSERT PAGES.

3.2 POWER DISTRIBUTION LIMITS

3.2.3 AXIAL FLUX DIFFERENCE (AFD)

LCO 3.2.3 The AFD in % flux difference units shall be maintained within the limits specified in the COLR.

---------------------------------NOTE---------------------------------
The AFD shall be considered outside limits when two or more OPERABLE excore channels indicate AFD to be outside limits.

APPLICABILITY: MODE 1 with THERMAL POWER ≥ 50% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. AFD not within limits.	A.1 Reduce THERMAL POWER to < 50% RTP.	3 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.3.1	Verify AFD within limits for each OPERABLE excore channel.	7 days

3.2 POWER DISTRIBUTION LIMITS

3.2.3A AXIAL FLUX DIFFERENCE (AFD)

LCO 3.2.3 The AFD:

a. Shall be maintained within the target band about the target flux difference. The target band is specified in the COLR.

b. May deviate outside the target band with THERMAL POWER < 90% RTP but ≥ 50% RTP, provided AFD is within the acceptable operation limits and cumulative penalty deviation time is ≤ 1 hour during the previous 24 hours. The acceptable operation limits are specified in the COLR.

c. May deviate outside the target band with THERMAL POWER < 50% RTP.

------------------------------NOTES------------------------------

1. The AFD shall be considered outside the target band when two or more OPERABLE excore channels indicate AFD to be outside the target band.

2. With THERMAL POWER ≥ 50% RTP, penalty deviation time shall be accumulated on the basis of a 1 minute penalty deviation for each 1 minute of power operation with AFD outside the target band.

3. With THERMAL POWER < 50% RTP and > 15 % RTP, penalty deviation time shall be accumulated on the basis of a 0.5 minute penalty deviation for each 1 minute of power operation with AFD outside the target band.

4. A total of 16 hours of operation may be accumulated with AFD outside the target band without penalty deviation time during surveillance of power range channels in accordance with SR 3.3.1.6, provided AFD is maintained within acceptable operation limits.

APPLICABILITY: MODE 1 with THERMAL POWER > 15% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. THERMAL POWER ≥ 90% RTP. AND AFD not within the target band.	A.1 Restore AFD to within target band.	15 minutes
B. Required Action and associated Completion Time of Condition A not met.	B.1 Reduce THERMAL POWER to < 90% RTP.	15 minutes
C. ------------NOTE------------ Required Action C.1 must be completed whenever Condition C is entered. -------------------------------- THERMAL POWER < 90% and ≥ 50% RTP with cumulative penalty deviation time > 1 hour during the previous 24 hours. OR THERMAL POWER < 90% and ≥ 50% RTP with AFD not within the acceptable operation limits.	C.1 Reduce THERMAL POWER to < 50% RTP.	30 minutes
D. Required Action and associated Completion Time for Condition C not met.	D.1 Reduce THERMAL POWER to < 15% RTP.	9 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.2.3.1	Verify AFD is within limits for each OPERABLE excore channel.	7 days
SR 3.2.3.2	Update target flux difference.	Once within 31 EFPD after each refueling <u>AND</u> 31 EFPD thereafter
SR 3.2.3.3	-------------------------NOTE------------------------- The initial target flux difference after each refueling may be determined from design predictions. --- Determine, by measurement, the target flux difference.	 Once within 31 EFPD after each refueling <u>AND</u> 92 EFPD thereafter

LIMITING SAFETY SYSTEM SETTING (m)

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

	FUNCTION	APPLICABLE MODES	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	~~ALLOWABLE VALUE~~
1.	Manual Reactor Trip	1,2	2	B	SR 3.3.1.13	NA
		3(a), 4(a), 5(a)	2	C	SR 3.3.1.13	NA
2.	Power Range Neutron Flux					
	a. High	1,2	4	D	SR 3.3.1.1 SR 3.3.1.2 SR 3.3.1.7 SR 3.3.1.11	≤ 109% ~~≤ 108%~~ RTP
	b. Low	1(b),2	4	D	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	≤ 28% ~~≤ 35%~~ RTP
3.	Intermediate Range Neutron Flux	1(b), 2(c)	2	F,G	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	≤ 43% ~~≤ 40%~~ RTP
4.	Source Range Neutron Flux	2(d)	2	H,I	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	within span of instrumentation
		3(a), 4(a), 5(a)	2	I,J	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.11	within span of instrumentation
5.	Overtemperature ΔT	1,2	4	D	SR 3.3.1.1 SR 3.3.1.3 SR 3.3.1.6 SR 3.3.1.7 SR 3.3.1.11	Refer to Note 1 (Page 3.3.1-18)
6.	Overpower ΔT	1,2	4	D	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.11	Refer to Note 2 (Page 3.3.1-20)

(continued)

(a) With Reactor Trip Breakers (RTBs) closed and Rod Control System capable of rod withdrawal.

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

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

(d) Below the P-6 (Intermediate Range Neutron Flux) interlock.

(m) Table 3.3.1-1 Notes 3 and 4 are applicable with the exception of those listed as "NA".

Table 3.3.1-1 (page 2 of 8)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	LIMITING SAFETY SYSTEM SETTING(m) ~~ALLOWABLE VALUE~~
7. Pressurizer Pressure					
a. Low	$1^{(e)}$	4	K	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.11	≥1860 psig ~~(h)~~
b. High	1,2	3	D	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.11	≤2385 psig ~~(i)~~
8. Pressurizer Water Level — High	$1^{(e)}$	3	K	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.11	≤85% ~~≤ 86%~~ of span
9. Reactor Coolant Flow-Low					
a. Single Loop	$1^{(f)}$	3 per loop	L	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.11	≥90%
b. Two Loops	$1^{(g)}$	3 per loop	K	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.11	≥90%
10. Reactor Coolant Pump (RCP) Breaker Position					
a. Single Loop	$1^{(f)}$	1 per RCP	M	SR 3.3.1.13	NA
b. Two Loops	$1^{(g)}$	1 per RCP	N	SR 3.3.1.13	NA
11. Undervoltage Bus A01 & A02	$1^{(e)}$	2 per bus	K	SR 3.3.1.9 SR 3.3.1.10	≥ 3120 V

(continued)

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

(f) Above the P-8 (Power Range Neutron Flux) interlock.

(g) Above the P-7 (Low Power Reactor Trips Block) interlock and below the P-8 (Power Range Neutron Flux) interlock.

~~(h) ≥ 1905 psig during operation at 2250 psia, or ≥ 1900 psig during operation at 2000 psia.~~

~~(i) ≤ 2385 psig during operation at 2250 psia, or ≤ 2210 psig during operation at 2000 psia.~~

(m) Table 3.3.1-1 Notes 3 and 4 are applicable with the exception of those listed as "NA".

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

FUNCTION	APPLICABLE MODES	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	~~ALLOWABLE VALUE~~ LIMITING SAFETY SYSTEM SETTING (m)
12. Underfrequency Bus A01 & A02	1(e)	2 per bus	E	SR 3.3.1.10	≥ 55.0 Hz
13. Steam Generator (SG) Water Level — Low Low	1,2	3 per SG	D	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.11	≥ 29.3% ~~≥ 20%~~ of span
14. SG Water Level — Low	1,2	2 per SG	D	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.11	≥ 10% of ~~NA~~ span
Coincident with Steam Flow/Feedwater Flow Mismatch	1,2	2 per SG	D	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.11	≤ 1 E6 lbm/hr
15. Turbine Trip					
a. Low Autostop Oil Pressure	1(j)	3	O	SR 3.3.1.14	NA
b. Turbine Stop Valve Closure	1(j)	2	O	SR 3.3.1.14	NA
16. Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS)	1,2	2 trains	P	SR 3.3.1.13	NA

(continued)

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

(j) Above the P-9 (Power Range Neutron Flux) interlock.

(m) Table 3.3.1-1 Notes 3 and 4 are applicable with the exception of those listed as "NA".

Table 3.3.1-1 (page 4 of 8)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	LIMITING SAFETY SYSTEM SETTING(m) ~~ALLOWABLE VALUE~~
17. Reactor Trip System Interlocks					
a. Intermediate Range Neutron Flux, P-6	2(d)	2	R	SR 3.3.1.11 SR 3.3.1.12	≥ 4E-11 ~~≥ 1E-10~~ amp
b. Low Power Reactor Trips Block, P-7					
(1) Power Range Neutron Flux	1	4	S	SR 3.3.1.11 SR 3.3.1.12	≤ 13% ~~≤ 10%~~ RTP
(2) Turbine Impulse Pressure	1	2	S	SR 3.3.1.11 SR 3.3.1.12	≤ 13% ~~≤ 10%~~ turbine power
c. Power Range Neutron Flux, P-8	1	4	S	SR 3.3.1.11 SR 3.3.1.12	≤ 38% ~~≤ 50%~~ RTP
d. Power Range Neutron Flux, P-9	1(k)	4	S	SR 3.3.1.11 SR 3.3.1.12	(h) ~~< 50% RTP~~
e. Power Range Neutron Flux, P-10	1,2	4	R	SR 3.3.1.11 SR 3.3.1.12	≥ 6% ~~≥ 8%~~ RTP and ≤ 12% ~~≤ 10%~~ RTP
18. Reactor Trip Breakers (RTBs)	1,2	2 trains	Q	SR 3.3.1.4	NA
	3(a), 4(a), 5(a)	2 trains	T	SR 3.3.1.4	NA
19. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms	1,2	1 each per RTB	U	SR 3.3.1.4	NA
	3(a), 4(a), 5(a)	1 each per RTB	T	SR 3.3.1.4	NA

(continued)

(a) With the RTBs closed and the Rod Control System capable of rod withdrawal.

(d) Below the P-6 (Intermediate Range Neutron Flux) interlock.

(k) With 1 of 2 circulating water pump breakers closed and condenser vacuum ≥ 22 "Hg.

(h) ≤ 38% RTP for full design power Tavg < 572°F or ≤ 53% RTP for full design power Tavg ≥ 572°F. For EOC coastdown, P-9 is not reset if Tavg decreases to < 572°F.

(m) Table 3.3.1-1 Notes 3 and 4 are applicable with the exception of those listed as "NA."

Table 3.3.1-1 (page 5 of 8)
Reactor Protection System Instrumentation

	FUNCTION	APPLICABLE MODES	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	~~ALLOWABLE VALUE~~ LIMITING SAFETY SYSTEM SETTING[m]
20.	Reactor Trip Bypass Breaker and associated Undervoltage Trip Mechanism	1[l], 2[l]	1	V	SR 3.3.1.4	NA
		3[l], 4[l], 5[l]	1	W	SR 3.3.1.4	NA
21.	Automatic Trip Logic	1, 2,	2 trains	P	SR 3.3.1.5 SR 3.3.1.15	NA
		3[a], 4[a], 5[a]	2 trains	X	SR 3.3.1.5	NA

(a) With RTBs closed and Rod Control System capable of rod withdrawal.

(l) When Reactor Trip Bypass Breakers are racked in and closed and the Rod Control System is capable of rod withdrawal.

(m) Table 3.3.1-1 Notes 3 and 4 are applicable with the exception of those listed as "NA".

Table 3.3.1-1 (page 6 of 8)
Reactor Protection System Instrumentation

Note 1: Overtemperature ΔT

$$\Delta T\left(\frac{1}{1+\tau_3 S}\right) \le \Delta T_o\left(K_1 - K_2\left(T\left(\frac{1}{1+\tau_4 S}\right) - T'\right)\left(\frac{1+\tau_1 S}{1+\tau_2 S}\right) + K_3(P-P') - f(\Delta I)\right)$$

Where:

~~where (values are applicable to operation at both 2000 psia and 2250 psia unless otherwise indicated)~~

ΔT_o	=	indicated ΔT at RTP ~~rated power~~, °F
T	=	average temperature, °F
T'	≤	[*]°F ~~(for cores containing 422V+ fuel assemblies)~~
~~T'~~	~~≤~~	~~[*]°F (for cores not containing 422V+ fuel assemblies)~~
P	=	pressurizer pressure, psig
P'	=	[*] psig ~~(for 2250 psia operation)~~
~~P'~~	~~=~~	~~[*] psig (for 2000 psia operation and cores not containing 422V+ fuel assemblies)~~
K_1	≤	[*] ~~(for 2250 psia operation and cores containing 422V+ fuel assemblies)~~
~~K_1~~	~~≤~~	~~[*] (for 2250 psia operation and cores not containing 422V+ fuel assemblies)~~
~~K_1~~	~~≤~~	~~[*] (for 2000 psia operation and cores not containing 422V+ fuel assemblies)~~
K_2	=	[*] ~~(for 2250 psia operation and cores containing 422V+ fuel assemblies)~~
~~K_2~~	~~=~~	~~[*] (for 2250 psia operation and cores not containing 422V+ fuel assemblies)~~
~~K_2~~	~~=~~	~~[*] (for 2000 psia operation and cores not containing 422V+ fuel assemblies)~~
K_3	=	[*] ~~(for 2250 psia operation and cores containing 422V+ fuel assemblies)~~
~~K_3~~	~~=~~	~~[*] (for 2250 psia operation and cores not containing 422V+ fuel assemblies)~~
~~K_3~~	~~=~~	~~[*] (for 2000 psia operation and cores not containing 422V+ fuel assemblies)~~
τ_1	=	[*] sec
τ_2	=	[*] sec
τ_3	=	[*] sec ~~for Rosemont or equivalent RTD~~
	~~=~~	~~[*] sec for Sostman or equivalent RTD~~
τ_4	=	[*] sec ~~for Rosemont or equivalent RTD~~
	~~=~~	~~[*] sec for Sostman or equivalent RTD~~

~~and f(ΔI) is an even function of the indicated difference between top and bottom detectors of~~ the power-range nuclear ion chambers; with gains to be selected based on measured instrument response during plant startup tests, where q_t and q_b are the percent power in the top and bottom halves of the core respectively, and $q_t + q_b$ is total core power in percent of rated power, such that:

(a) for $q_t - q_b$ within −[*], +[*] percent, $f(\Delta I) = 0$ for cores not containing 422V+ fuel assemblies; for $q_t - q_b$ within −[*], +[*] percent, $f(\Delta I) = 0$ for cores containing 422V+ fuel assemblies.

(b) for each percent that the magnitude of $q_t - q_b$ exceeds +[*] percent, the ΔT trip setpoint shall be automatically reduced by an equivalent of [*] percent of rated power for cores not containing 422V+ fuel assemblies and reduced by an equivalent of [*] percent of ~~rated power for cores containing 422V+ fuel assemblies.~~

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

Note 1: *Overtemperature ΔT (continued)*

~~(e) for cores not containing 422V+ fuel assemblies, for each percent that the magnitude of~~ $q_t - q_b$ exceeds ~~[*] percent~~, the ΔT trip setpoint shall be ~~automatically~~ reduced by an equivalent of [*] percent of ~~rated power; for cores~~ containing 422V+ fuel assemblies, for each ~~percent that the~~ magnitude of $q_t - q_b$ exceeds ~~[*] percent, the ΔT~~ trip setpoint ~~shall be automatically reduced by an equivalent of [*] percent of rated power.~~

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

$f(\Delta I) = [*] \{[*] - (q_t - q_b)\}$ when $q_t - q_b \leq$ [*]% RTP
0% of RTP when [*]% RTP $< q_t - q_b \leq$ [*]% RTP
$[*] \{(q_t - q_b) - [*]\}$ when $q_t - q_b >$ [*]% RTP

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

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

Note 2: Overpower ΔT

$$\Delta T\left(\frac{1}{1+\tau_3 S}\right) \le \Delta T_o\left[K_4 - K_5\left(\frac{\tau_5 S}{\tau_5 S+1}\right)\left(\frac{1}{1+\tau_4 S}\right)T - K_6\left[T\left(\frac{1}{1+\tau_4 S}\right) - T'\right]\right]$$

Where:

~~where (values are applicable to operation at both 2000 psia and 2250 psia)~~

ΔT_o	=	indicated ΔT at ~~rated power,~~ RTP °F
T	=	average temperature, °F
T'	≤	[*]°F ~~(for cores containing 422V+ fuel assemblies)~~
~~T'~~	~~≤~~	~~[*]°F (for cores not containing 422V+ fuel assemblies)~~
K_4	≤	[*] ~~of rated power (for cores containing 422V+ fuel assemblies)~~
~~K_4~~	~~≤~~	~~[*] of rated power (for cores not containing 422V+ fuel assemblies)~~
K_5	=	[*] for increasing T
	=	[*] for decreasing T
K_6	=	[*] for T ≥ T' ~~(for cores containing 422V+ fuel assemblies)~~
~~K_6~~	~~=~~	~~[*] for T ≥ T' (for cores not containing 422V+ fuel assemblies)~~
	=	[*] for T < T'
τ_5	=	[*] sec
τ_3	=	[*] sec ~~for Rosemont or equivalent RTD~~
		~~[*] sec for Sostman or equivalent RTD~~
τ_4	=	[*] sec ~~for Rosemont or equivalent RTD~~
		~~[*] sec for Sostman or equivalent RTD~~

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

Table 3.3.1-1
Reactor Protection System Instrumentation

Note 3:

A channel is OPERABLE when both of the following conditions are met:

a. The as-found Field Trip Setpoint (FTSP) is within the COT acceptance criteria for the as-found value. The method used to determine the COT acceptance criteria is described in FSAR Section 7.2.

b. The as-left FTSP is reset to a value that is within the as-left tolerance at the completion of the surveillance. The channel is considered operable even if the as-left FTSP is non-conservative with respect to the LSSS provided that the as-left FTSP is within the established as-left tolerance band. The method used to determine the as-left tolerance is described in FSAR Section 7.2.

Note 4:

If the as-found FTSP is outside its predefined as-found acceptance criteria:

a. Evaluation of corrective measures necessary to return the channel to service is implemented in applicable plant maintenance and operating procedures.

b. The out-of-tolerance condition shall be entered into the Corrective Action Process.

Table 3.3.2-1 (page 1 of 3)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	LIMITING SAFETY SYSTEM SETTING (f) ~~ALLOWABLE VALUE~~
1. Safety Injection					
a. Manual Initiation	1,2,3,4	2	B	SR 3.3.2.7	NA
b. Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	C	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.5	NA
c. Containment Pressure—High	1,2,3	3	D	SR 3.3.2.1 SR 3.3.2.3 SR 3.3.2.8	≤ 5.3 psig ~~≤ 6.0 psig~~
d. Pressurizer Pressure—Low	1,2,3[a]	3	D	SR 3.3.2.1 SR 3.3.2.3 SR 3.3.2.8	≥ 1725 psig ~~≥ [illegible] psig~~
e. Steam Line Pressure—Low	1,2,3[b]	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.3 SR 3.3.2.8	≥ 520[c] psig ~~≥ 500[c] psig~~
2. Containment Spray					
a. Manual Initiation	1,2,3,4	2	E	SR 3.3.2.7	NA
b. Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	C	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.5	NA
c. Containment Pressure—High High	1,2,3	2 sets of 3	D	SR 3.3.2.1 SR 3.3.2.3 SR 3.3.2.8	≤ 28 psig ~~≤ 30 psig~~

(continued)

(a) Pressurizer Pressure > ~~1800~~ 2000 psig.

(b) Pressurizer Pressure > ~~1800~~ 2000 psig, except during Reactor Coolant System hydrostatic testing.

(c) Time constants used in the lead/lag controller are t_1 ~~[illegible]~~ ≥ 18 seconds and $t_2 \leq 2$ seconds.

(f) Table 3.3.2-1 Notes 1 and 2 are applicable with the exception of those listed as "NA".

Table 3.3.2-1 (page 2 of 3)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	~~ALLOWABLE VALUE~~ LIMITING SAFETY SYSTEM SETTING(f)
3. Containment Isolation					
a. Manual Initiation	1,2,3,4	2	B	SR 3.3.2.7	NA
b. Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	C	SR 3.3.2.4 SR 3.3.2.5	NA
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements, except Manual SI Initiation.				
4. Steam Line Isolation					
a. Manual Initiation	$1,2^{(d)},3^{(d)}$	1/loop	F	SR 3.3.2.7	NA
b. Automatic Actuation Logic and Actuation Relays	$1,2^{(d)},3^{(d)}$	2 trains	G	SR 3.3.2.2 SR 3.3.2.5	NA
c. Containment Pressure—High High	$1,2^{(d)},3^{(d)}$	3	D	SR 3.3.2.1 SR 3.3.2.3 SR 3.3.2.8	≤ 18 psig ~~≤ 20 psig~~
d. High Steam Flow	$1,2^{(d)},3^{(d)}$	2 per steam line	D	SR 3.3.2.1 SR 3.3.2.3 SR 3.3.2.8	0.8 x 10^6 lbm/hr ≤ Δp corresponding to ~~0.66 x 10^6 lb/hr~~ at 1005 psig
Coincident with Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
and					
Coincident with T_{avg}—Low	$1,2^{(d)},3^{(d)}$	3	D	SR 3.3.2.1 SR 3.3.2.3 SR 3.3.2.8	≥ 542°F ~~≥ 540°F~~
e. High High Steam Flow	$1,2^{(d)},3^{(d)}$	2 per steam line	D	SR 3.3.2.1 SR 3.3.2.3 SR 3.3.2.8	4.9 x 10^6 lbm/hr ≤ Δp corresponding to ~~[illegible] x 10^6 lb/hr~~ at ~~696~~ psig 586
Coincident with Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				

(continued)

(d) Except when all MSIVs are closed and de-activated.

(f) Table 3.3.2-1 Notes 1 and 2 are applicable with the exception of those noted as "NA."

Table 3.3.2-1 (page 3 of 3)
Engineered Safety Feature Actuation System Instrumentation Limiting Safety System Setting(f)

FUNCTION	APPLICABLE MODES	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
5. Feedwater Isolation					
a. Automatic Actuation Logic and Actuation Relays	$1,2^{(e)},3^{(e)}$	2 trains	G	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.5	NA
b. SG Water Level—High	$1,2^{(e)},3^{(e)}$	3 per SG	D	SR 3.3.2.1 SR 3.3.2.3 SR 3.3.2.8	~~NA~~ ≤90% of span
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
6. Auxiliary Feedwater					
a. Automatic Actuation Logic and Actuation Relays	1,2,3	2 trains	G	SR 3.3.2.2	NA
b. SG Water Level—Low Low	1,2,3	3 per SG	D	SR 3.3.2.1 SR 3.3.2.3 SR 3.3.2.8	~~≥29%~~ ≥29.3% of span
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
d. Undervoltage Bus A01 and A02	1,2	2 per bus	H	SR 3.3.2.6 SR 3.3.2.8	≥ 3120 V
Add INSERT ESF-A					
7. ~~Condensate Isolation~~ Not Used					
~~a. Containment Pressure—High~~	~~$1,2^{(e)},3^{(e)}$~~	~~3~~	~~D~~	~~SR 3.3.2.1~~ ~~SR 3.3.2.3~~ ~~SR 3.3.2.8~~	~~≤ 6 psig~~
~~b. Automatic Actuation Logic and Actuation Relays~~	~~$1,2^{(e)},3^{(e)}$~~	~~2 trains~~	~~G~~	~~SR 3.3.2.2~~ ~~SR 3.3.2.4~~ ~~SR 3.3.2.5~~	~~NA~~
8. SI Block-Pressurizer Pressure	1,2,3	3	I	SR 3.3.2.1 SR 3.3.2.3 SR 3.3.2.8	≤2005 ~~≤1800~~ psig

(e) Except when all MFIVs, MFRVs and associated bypass valves are closed and de-activated.

(f) Table 3.3.2-1 Notes 1 and 2 are applicable with the exception of those noted as "NA."

* Setpoint details to be provided by July 30, 2009 Supplement.

Insert ESF-A

e.	AFW Pump Suction Transfer on Suction Pressure Low	1,2,3	2	F	SR 3.3.2.1 SR 3.3.2.3 SR 3.3.2.8	[*]

Table 3.3.2-1
Engineered Safety Features Actuation System Instrumentation

Note 1:

A channel is OPERABLE when both of the following conditions are met:

a. The as-found Field Trip Setpoint (FTSP) is within the COT acceptance criteria for the as-found value. The method used to determine the COT acceptance criteria is described in FSAR Section 7.2.

b. The as-left FTSP is reset to a value that is within the as-left tolerance at the completion of the surveillance. The channel is considered operable even if the as-left FTSP is non-conservative with respect to the LSSS provided that the as-left FTSP is within the established as-left tolerance band. The method used to determine the as-left tolerance is described in FSAR Section 7.2.

Note 2:

If the as-found FTSP is outside its predefined as-found acceptance criteria:

a. Evaluation of corrective measures necessary to return the channel to service is implemented in applicable plant maintenance and operating procedures.

b. The out-of-tolerance condition shall be entered into the Corrective Action Process.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.4.3	Perform CHANNEL CALIBRATION with Allowable Value as follows: a. 4.16 kV loss of voltage Allowable Value ≥ 3156 V with a time delay of ~~≥ 0.7 seconds and ≤ 1.0 second.~~ ≥ 1.8 seconds and ≤ 2.3 seconds (Bus Loss of Voltage Relay) and ≥ 1.95 seconds and ≤ 3.55 seconds (EDG Breaker Close Delay Relay.) b. 4.16 kV degraded voltage Allowable Value ≥ 3937 V with a time delay of < 5.68 seconds (bus degraded voltage relay) and < 39.14 seconds (bus time delay relay) c. 480 V loss of voltage Allowable Value 256 V ± 3% with a time delay of ~~≤ 0.5 seconds~~ ≥ 1.15 seconds and ≤ 1.6 seconds.	18 months

3.4 REACTOR COOLANT SYSTEM (RCS)

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

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

a. Pressurizer pressure is greater than or equal to the limits specified in the COLR;

b. RCS average temperature is within the limits specified in the COLR; and

c. RCS total flow rate ≥ ~~182,400~~ 178,000 gpm and greater than or equal to the limit specified in the COLR.

APPLICABILITY: MODE 1.

------------------------------------NOTE------------------------------------

Pressurizer pressure limit does not apply during:

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

b. THERMAL POWER step > 10% RTP.

ACTIONS

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

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.1.1	Verify pressurizer pressure is greater than or equal to the limits specified in the COLR.	12 hours
SR 3.4.1.2	Verify RCS average temperature is within the limits specified in the COLR.	12 hours
SR 3.4.1.3	-------------------NOTE-------------------- Not required to be performed until 24 hours after ≥ 90% RTP. -- Verify by precision heat balance that RCS total flow rate is ≥ ~~182,400~~ 178,000 gpm and greater than or equal to the limit specified in the COLR.	18 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.9 Pressurizer

LCO 3.4.9 The pressurizer shall be OPERABLE with:

a. Pressurizer water level ≤ ~~50.0%~~ 52% in MODE 1 or ≤ ~~85%~~ 88% in MODES 2 and 3; and

b. At least 100 kW of pressurizer heaters capable of being powered from an emergency power supply are OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Pressurizer water level not within limit in MODE 1.	A.1 Restore pressurizer water level to within limit.	1 hour
B. Required pressurizer heaters inoperable.	B.1 Restore required pressurizer heaters to OPERABLE status.	1 hour
C. Required Action and associated Completion Time not met. <u>OR</u> Pressurizer water level not within limit in MODES 2 and 3.	C.1 Be in MODE 3. <u>AND</u> C.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS 88% 52%

SURVEILLANCE		FREQUENCY
SR 3.4.9.1	Verify pressurizer water level is ≤ ~~50.8%~~ in MODE 1 OR ≤ ~~95%~~ in MODES 2 and 3.	12 hours
SR 3.4.9.2	Verify capacity of required pressurizer heaters is ≥ 100 kW.	92 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.10 Pressurizer Safety Valves

LCO 3.4.10 Two pressurizer safety valves shall be OPERABLE with lift settings ≥ 2410 psig and ≤ ~~2560~~ psig.

2547

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 with all RCS cold leg temperatures > the LTOP enabling temperature specified in the PTLR.

-------------------------------------NOTE-------------------------------------
The lift settings are not required to be within the LCO limits during MODES 3 and 4 for the purpose of setting the pressurizer safety valves under ambient (hot) conditions. This exception is allowed for 36 hours following entry into MODE 3 provided a preliminary cold setting was made prior to heatup.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One pressurizer safety valve inoperable.	A.1	Restore valve to OPERABLE status.	15 minutes
B. Required Action and associated Completion Time not met. OR Two pressurizer safety valves inoperable.	B.1 AND B.2	Be in MODE 3. Be in MODE 4 with any RCS cold leg temperature ≤ the LTOP enabling temperature specified in the PTLR.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.10.1	Verify each pressurizer safety valve is OPERABLE in accordance with the Inservice Testing Program. Following testing, lift settings shall be ~~≥ 2440.71 psig and ≤ 2551.25 psig~~. within ±1%.	In accordance with the Inservice Testing Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.1.1	Verify each accumulator isolation valve is fully open.	12 hours
SR 3.5.1.2	Verify borated water volume in each accumulator is $\geq$ 1100 ft^3 and $\leq$ 1136 ft^3.	12 hours
SR 3.5.1.3	Verify nitrogen cover pressure in each accumulator is $\geq$ 700 psig and $\leq$ 800 psig.	12 hours
SR 3.5.1.4	Verify boron concentration in each accumulator is $\geq$ ~~2600~~ 2700 ppm and $\leq$ 3100 ppm.	31 days AND ------NOTE------ Only required to be performed for affected accumulators -------------------- Once within 24 hours after each solution volume increase of $\geq$ 5% of indicated level that is not the result of addition from the refueling water storage tank with boron concentration $\geq$ ~~2600~~ 2700 ppm and $\leq$ 3100 ppm
SR 3.5.1.5	Verify power is removed from each accumulator isolation valve operator when RCS pressure is > 1000 psig.	31 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.4.1	Verify RWST borated water temperature is ≥ 40°F and ≤ 100°F.	24 hours
SR 3.5.4.2	Verify RWST borated water volume is ≥ 275,000 gallons.	7 days
SR 3.5.4.3	Verify RWST boron concentration is ≥ ~~2700~~ 2800 ppm and ≤ 3200 ppm.	7 days

Table 3.7.1-1 (page 1 of 1)
OPERABLE Main Steam Safety Valves versus
Maximum Allowable Power

NUMBER OF OPERABLE MSSVs PER STEAM GENERATOR	MAXIMUM ALLOWABLE POWER (% RTP)
3	≤ ~~40~~ 39
2	≤ ~~20~~ 22

Table 3.7.1-2 (page 1 of 1)
Main Steam Safety Valve Lift Settings

VALVE NUMBER		LIFT SETTING (psig ± 3%)
STEAM GENERATOR		
A	B	
MS 2010	MS 2005	1085
MS 2011	MS 2006	1100
MS 2012	MS 2007	~~1125~~ 1105
MS 2013	MS 2008	~~1125~~

3.7 PLANT SYSTEMS

3.7.3 Main Feedwater Isolation Valves (MFIVs), Main Feedwater Regulating Valves (MFRVs) and MFRV Bypass Valves

LCO 3.7.3 Main Feedwater Isolation shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ------------NOTE------------ Separate Condition entry is allowed for each valve. ------------------------------		
One or more ~~Main Feedwater Regulating Valves (MFRVs) or MFRV bypass valves~~ MFIV inoperable.	A.1 Close or isolate ~~valve~~ MFIV.	72 hours
	AND	
	A.2 Verify ~~valve~~ MFIV is closed or isolated.	Once per 7 days
B. ~~------------NOTE------------ Separate Condition entry is allowed for each pump trip circu~~it. ------------------------------	B.1 ~~Secure pump from operation~~. Close or isolate MFRV.	72 hours
	AND	
One or more ~~Main Feed Water, Heater Drain Tank, or Condensate pump trip circuits~~ MFRVs inoperable.	B.2 Verify ~~pump is not operating.~~ MFRV is closed or isolated.	Once per 7 days
C. One or more MFRV Bypass Valves inoperable.	C.1 Close or isolate MFRV Bypass Valve	72 hours
	AND	
	C.2 Verify MFRV Bypass Valve is closed or isolated.	Once per 7 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Two valves in the same flowpath inoperable. ~~C. One or more unisolated Main Feedwater Regulating Valves (MFRVs) or unisolated bypass valves inoperable.~~ ~~AND~~ ~~One or more operating pumps with inoperable trip circuits.~~	D.1 Isolate affected flowpath. ~~C.1 Restore MFRV or bypass valves to OPERABLE status.~~ ~~OR~~ ~~C.2 Restore pump trip circuits to OPERABLE status.~~	8 hours ~~8 hours~~
E, ~~D~~. Required Action and associated Completion Time not met.	E ~~D~~.1 Be in MODE 3. AND E ~~D~~.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.3.1	Verify each MFIV, MFRV and ~~associated~~ MFRV bypass valve, actuate to the isolation position on an actual or simulated actuation signal.	18 months
SR 3.7.3.2	Verify each ~~Main Feedwater pump automatically trips on an actual or simulated actuation signal.~~ MFIV, MFRV and MFRV Bypass Valve isolation time is within limits.	~~18 months~~ In accordance with the Inservice Testing Program
~~SR 3.7.3.3~~	~~Verify each Condensate and Heater Drain pump automatically trips on an actual or simulated actuation signal.~~	~~18 months~~

3.7 PLANT SYSTEMS

3.7.5 Auxiliary Feedwater (AFW)

one

LCO 3.7.5 The AFW System shall be OPERABLE with; one turbine driven AFW pump system and ~~two~~ motor driven AFW pump system~~s~~.

---NOTE---
Only the motor driven AFW pump system~~s associated with steam generators relied upon for heat removal are~~ required to be OPERABLE in MODE 4.

is

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 when steam generator is relied upon for heat removal.

ACTIONS

when entering MODE 1.

---NOTE---
LCO 3.0.4.b is not applicable

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One steam supply to turbine driven AFW pump system inoperable. OR - - - NOTE - - - Only applicable if MODE 2 has not been entered following refueling - - - - - -	A.1 Restore ~~steam supply~~ affected equipment to OPERABLE status.	7 days AND 10 days from discovery of failure to meet the LCO
B. One ~~turbine driven~~ AFW pump system inoperable in MODE 1, 2 or 3 for reasons other than Condition A. The turbine driven AFW pump system inoperable in MODE 3 following refueling.	B.1 Restore ~~turbine driven~~ AFW pump system to OPERABLE status.	72 hours AND 10 days from discovery of failure to meet the LCO

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~C. One motor driven AFW pump system inoperable in MODE 1, 2 or 3.~~	~~C.1 Restore motor driven AFW pump system to OPERABLE status.~~	~~7 days~~ ~~AND~~ ~~10 days from discovery of failure to meet the LCO~~
C ~~D.~~ Required Action and associated Completion Time for Condition ~~A, B, or C~~ A or B not met. ~~OR~~ ~~Two AFW pump systems inoperable in MODE 1,~~ 2, ~~or 3.~~	C ~~D~~.1 ~~NOTE~~ ~~Each unit may be sequentially placed in MODE 3 within 12 hours when both units are in Condition D concurrently.~~ Be in MODE 3.	6 hours
	AND C ~~D~~.2 -----------NOTE----------- Entry into MODE 4 is not required unless ~~one~~ the motor driven AFW pump system is OPERABLE. ------------------------------ Be in MODE 4.	18 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~E.~~ D Two ~~Three~~ AFW pump systems inoperable in MODE 1, 2, or 3.	~~E~~D.1 -----------NOTE----------- LCO 3.0.3 and all other LCO Required Actions requiring MODE changes are suspended until one AFW pump system is restored to OPERABLE status. ------------------------------	
	Initiate action to restore one AFW pump system to OPERABLE status.	Immediately
~~F.~~ E ~~One or more~~ required motor driven AFW pump system~~s~~ inoperable in MODE 4.	~~F~~E.1 Initiate action to restore the motor driven AFW pump system~~(s)~~ to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.5.1	-------------------------NOTE------------------------- AFW pump system(s) may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually realigned to the AFW mode of operation. --	
	Verify each AFW manual, power operated, and automatic valve in each water flow path, and in both steam supply flow paths to the steam turbine driven pump, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days

(continued)

3.7 PLANT SYSTEMS

3.7.6 Condensate Storage Tank (CST)

LCO 3.7.6 The CST shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 when steam generator is relied upon for heat removal.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. CST inoperable.	A.1 Restore CST to OPERABLE status.	7 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 4, without reliance on steam generator for heat removal.	6 hours 18 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.6.1	Verify the CST level is ≥ ** ~~13,000~~ gallons.	12 hours

** Value to be provided as a supplement to this LAR by July 30, 2009.

Westinghouse

5.6.4 CORE OPERATING LIMITS REPORT (COLR) (continued)

Power Uprate (1775 MWt) Core Power with Feedwater Venturis, or 1800 MWt - Core Power with LEFM on Feedwater Header.

(4) WCAP-14787-P, ~~Rev. 2~~, "Revised Thermal Design Procedure Instrument Uncertainty Methodology for ~~Wisconsin Electric Power Company.~~ Point Beach Units 1 & 2 ~~(Fuel Upgrade & Uprate to 1656 MWt NSSS Power with Feedwater Venturis, or 1679 MWt NSSS Power with LEFM on Feedwater Header), October, 2002 (approved by NRC Safety Evaluation, November 29, 2002).~~

(5) WCAP-10054-P-A, "Westinghouse Small Break ECCS Evaluation Model Using The NOTRUMP Code," August 1985.

(6) WCAP-10054-P-A, "Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model," Addendum 2, Revision 1, July 1997.

(7) WCAP-8745-P-A, "Design Bases for the Thermal Overpower ΔT and Thermal Overtemperature ΔT Trip Functions," September 1986.

Not Used

(8) ~~WCAP-10216-P-A, "Relaxation of Constant Axial Offset Control," Revision 1A, February 1994.~~

(9) WCAP-10924-P-A, "Large Break LOCA Best Estimate Methodology, Volume 2: Application to Two-Loop PWRs Equipped with Upper Plenum Injection," and Addenda, December 1988. (cores not containing 422 V+ fuel)

(10) WCAP-10924-P-A, "LBLOCA Best Estimate Methodology: Model Description and Validation: Model Revisions," Volume 1, Addendum 4, August 1990. (cores not containing 422 V+ fuel)

(11) Caldon, Inc., Engineering Report-80P, "TOPICAL REPORT: Improving Thermal Power Accuracy and Plant Safety While Increasing Operating Power Level Using the LEFM✓™ System," Revision 0, March 1997.

(12) Caldon, Inc., Engineering Report-160P, "Supplement to Topical Report ER-80P: Basis for a Power Uprate With the LEFM✓™ System," Revision 0, May 2000.

INSERT COLR References from next Page

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

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

Previously submitted in linked LAR 258 (ML083330160)

INSERT

Previously submitted in linked LAR 241 (ML083450683)

13. WCAP-16009-P-A, "Realistic Large Break LOCA Evaluation Methodology Using the Automated Statistical Treatment of Uncertainty Method (ASTRUM)," January 2005.

14. WCAP-16259-P-A, "Westinghouse Methodology for Application of 3-D Transient Neutronics to Non-LOCA Analysis," August 2006.

15. WCAP-9403 (nonproprietary), "Power Distribution Control and Load Following Procedures," Westinghouse Electric Corporation," September 1974.

16. NS-TMA-2198, Westinghouse to NRC Letter, Attachment "Operation and Safety Analysis Aspects of Improved Load Follow Package," January 31, 1980.

17. NS-CE-687, Westinghouse to NRC Letter, "Power Distribution Control Analysis," July 16, 1975.

ATTACHMENT 3

FPL ENERGY POINT BEACH, LLC
POINT BEACH NUCLEAR PLANT UNITS 1 AND 2

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE

PROPOSED

TECHNICAL SPECIFICATION BASES CHANGES

MARKED UP PAGES

115 Pages Follow

Deleted
(2000psia Operation No Longer Applicable)

~~For 2000 psia Operation~~

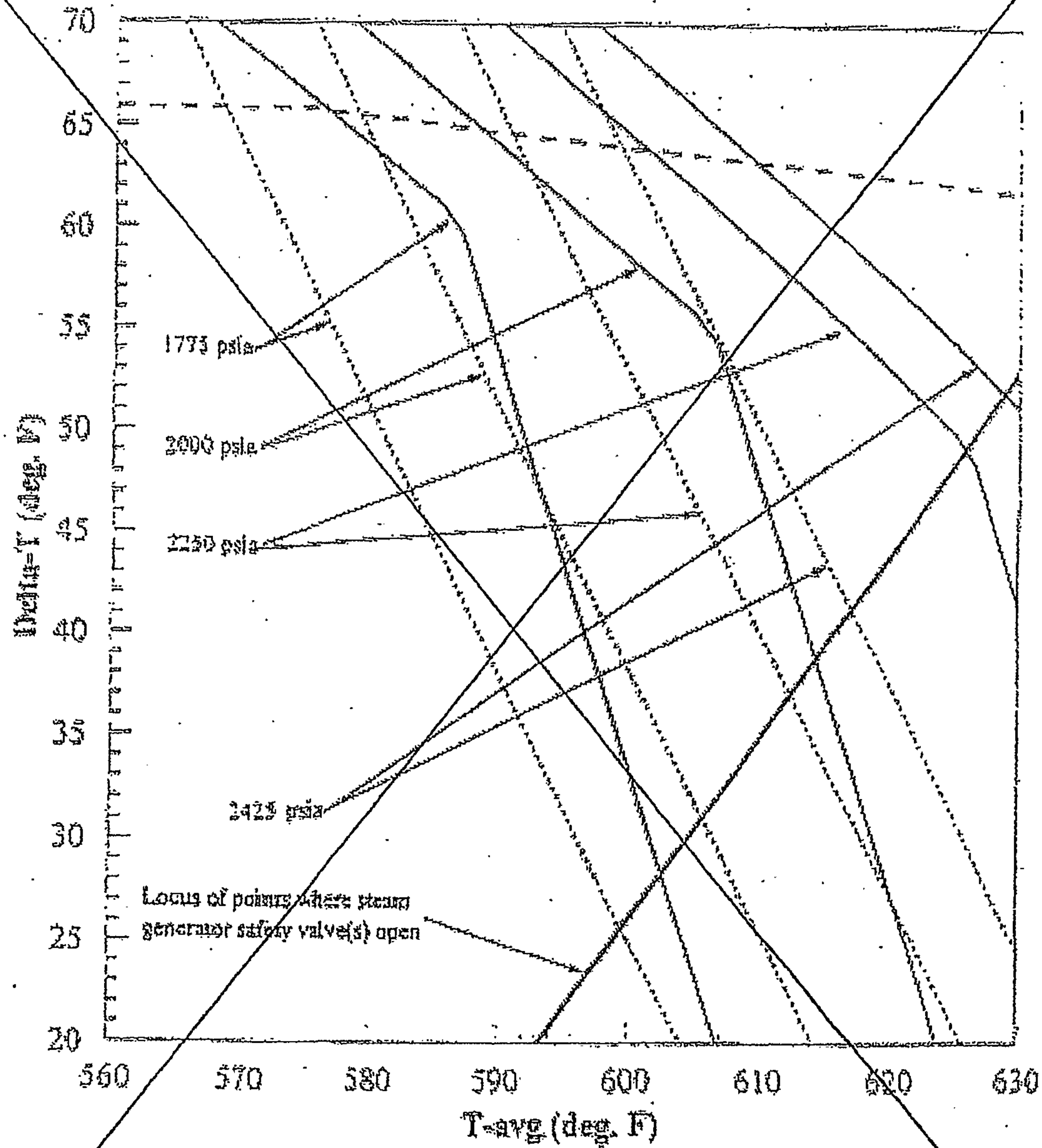

Figure B 2.1.1-1 (page 1 of 2)
Illustration of Overtemperature and Overpower Delta-T Protection
For 2000 psia Operation

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(Figure Included in COLR)

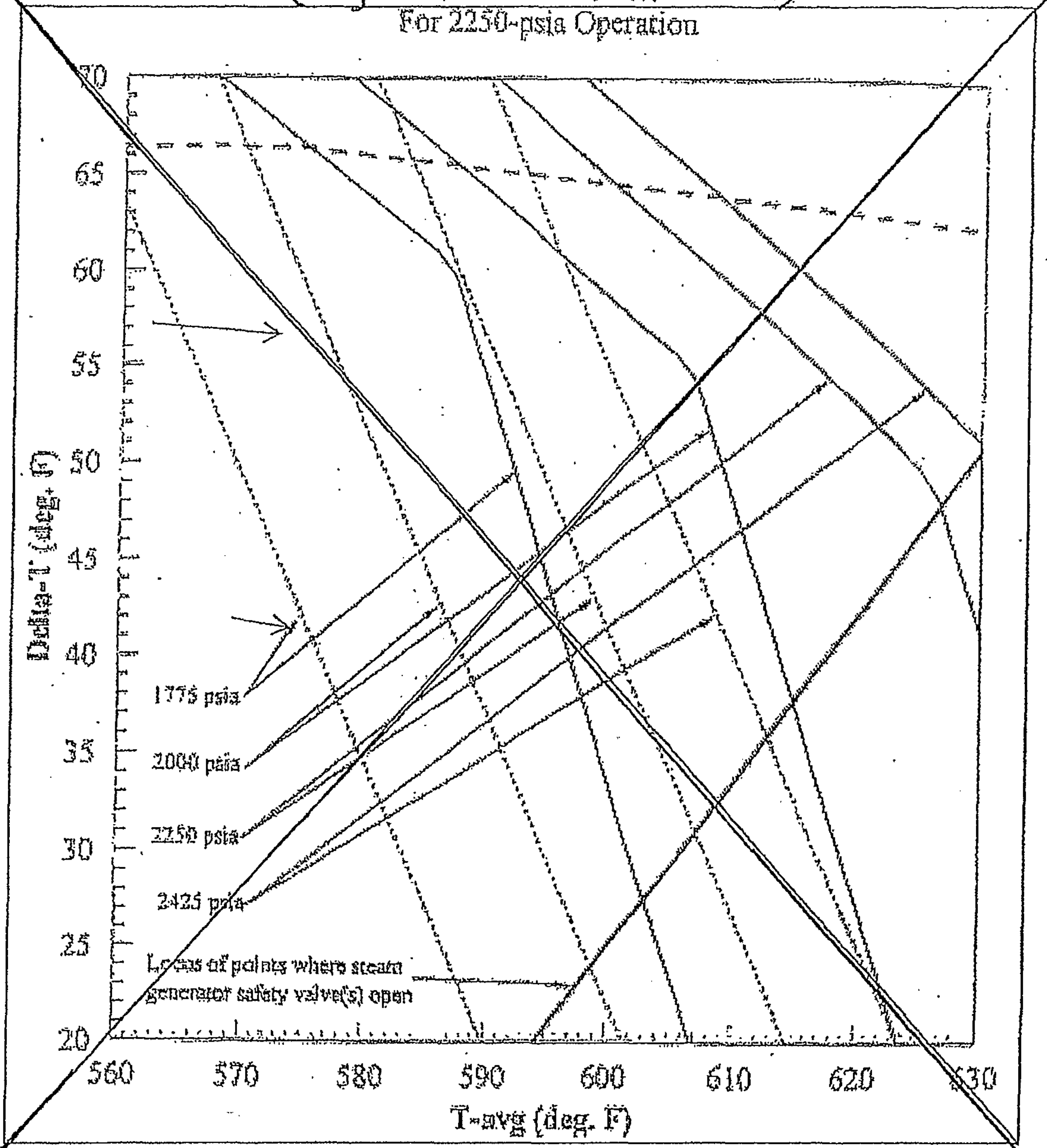

Figure B 2.1.1-1 ~~(page 2 of 2)~~
Illustration of Overtemperature and Overpower Delta-T Protection
For 2250 psia Operation

BASES

LCO

The Heat Flux Hot Channel Factor, $F_Q(Z)$, shall be limited by the following relationships:

$$F_Q(Z) \le \frac{CF_Q}{P} K(Z) \qquad \text{for } P > 0.5$$

$$F_Q(Z) \le \frac{CF_Q}{0.5} K(Z) \qquad \text{for } P \le 0.5$$

where: CF_Q is the $F_Q(Z)$ limit at RTP provided in the COLR,

$K(Z)$ is the normalized $F_Q(Z)$ as a function of core height provided in the COLR, and

$$P = \frac{\text{THERMAL POWER}}{\text{RTP}}$$

2.60

For this facility, the actual values of CF_Q and $K(Z)$ are given in the COLR; however, CF_Q is normally a number on the order of ~~2.50~~, and $K(Z)$ is a function that looks like the one provided in Figure B 3.2.1-1.

Constant

For ~~Relaxed~~ Axial Offset Control operation, $F_Q(Z)$ is approximated by $F^C_Q(Z)$ and $F^W_Q(Z)$. Thus, both $F^C_Q(Z)$ and $F^W_Q(Z)$ must meet the preceding limits on $F_Q(Z)$.

An $F^C_Q(Z)$ evaluation requires obtaining an incore flux map in MODE 1. From the incore flux map results we obtain the measured value ($F^M_Q(Z)$) of $F_Q(Z)$. Then,

$$F^C_Q(Z) = F^M_Q(Z)\ 1.08$$

where 1.08 is a factor that accounts for fuel manufacturing tolerances and flux map measurement uncertainty.

$F^C_Q(Z)$ is an excellent approximation for $F_Q(Z)$ when the reactor is at the steady state power at which the incore flux map was taken.

The expression for $F^W_Q(Z)$ is: $F^W_Q(Z) = F^C_Q(Z)\,W(Z)$

where $W(Z)$ is a cycle dependent function that accounts for power distribution transients encountered during normal operation. $W(Z)$ is included in the COLR. The $F_Q(Z)$ is calculated at equilibrium conditions.

The $F_Q(Z)$ limits define limiting values for core power peaking that precludes peak cladding temperatures above 2200°F during either a large or small break LOCA.

BASES

LCO (continued).

This LCO requires operation within the bounds assumed in the safety analyses. Calculations are performed in the core design process to confirm that the core can be controlled in such a manner during operation that it can stay within the LOCA $F_Q(Z)$ limits. If $F^C_Q(Z)$ cannot be maintained within the LCO limits, reduction of the core power is required~~, and if $F^W_Q(Z)$ cannot be maintained within the LCO limits, reduction of the AFD limits is required. Note that sufficient reduction of the AFD limits will result in a reduction of the core power.~~

Violating the LCO limits for $F_Q(Z)$ produces unacceptable consequences if a design basis event occurs while $F_Q(Z)$ is outside its specified limits.

APPLICABILITY

The $F_Q(Z)$ limits must be maintained in MODE 1 to prevent core power distributions from exceeding the limits assumed in the safety analyses. Applicability in other MODES is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to require a limit on the distribution of core power.

ACTIONS

A.1

Reducing THERMAL POWER by ≥ 1% RTP for each 1% by which $F^C_Q(Z)$ exceeds its limit, maintains an acceptable absolute power density. $F^C_Q(Z)$ is $F^M_Q(Z)$ multiplied by a factor accounting for manufacturing tolerances and measurement uncertainties. $F^M_Q(Z)$ is the measured value of $F_Q(Z)$. The Completion Time of 15 minutes provides an acceptable time to reduce power in an orderly manner and without allowing the plant to remain in an unacceptable condition for an extended period of time. The maximum allowable power level initially determined by Required Action A.1 may be affected by subsequent determinations of F^C_Q (Z) and would require power reductions within 15 minutes of the $F^C_Q(Z)$ determination if necessary to comply with the decreased maximum allowable power level. Decreases in $F^C_Q(Z)$ would allow increasing the maximum allowable power level and increasing power up to this revised limit.

A.2

A reduction of the Power Range Neutron Flux—High trip setpoints by ≥ 1% for each 1% by which $F^C_Q(Z)$ exceeds its limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is

ACTIONS (continued)

sufficient considering the small likelihood of a severe transient in this time period and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1. The maximum allowable Power Range Neutron Flux-High trip setpoints initially determined by required action A.2 may be affected by subsequent determinations of $F^C_Q(Z)$ and would require Power Range Neutron Flux-High trip setpoint reductions within 72 hours of the $F^C_Q(Z)$ determination, if necessary to comply with the decreased maximum allowable Power Range Neutron Flux-High trip setpoints. Decreases in $F^C_Q(Z)$ would allow increasing the maximum allowable Power Range Neutron Flux-High trip setpoints.

A.3

Reduction in the Overpower ΔT trip setpoints (value of K_4) by $\geq$ 1% for each 1% by which $F^C_Q(Z)$ exceeds its limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period, and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1. The maximum allowable Overpower ΔT trip setpoints initially determined by Required Action A.3 may be affected by subsequent determinations of $F^C_Q(Z)$ and would require Overpower ΔT trip setpoint reductions within 72 hours of the $F^C_Q(Z)$ determination, if necessary to comply with the decreased maximum allowable Overpower ΔT trip setpoints. Decreases in $F^C_Q(Z)$ would allow increasing the maximum Overpower ΔT trip setpoints.

A.4

Verification that $F^C_Q(Z)$ has been restored to within its limit, by performing SR 3.2.1.1 and SR 3.2.1.2 prior to increasing THERMAL POWER above the limit imposed by Required Action A.1~~, and prior to increasing any reactor trip setpoint which had been reduced in accordance with Action A.2 or A.3~~, ensures that core conditions during operation at higher power levels and future operation are consistent with safety analyses assumptions.

Condition A is modified by a Note that requires Required Action A.4 to be performed whenever the Condition is entered. This ensures that SR 3.2.1.1 and SR 3.2.1.2 will be performed prior to increasing THERMAL POWER above the limit of Required Action A.1 even when Condition A is exited prior to performing Required Action A.4. Performance of SR 3.2.1.1 and SR 3.2.1.2 are necessary to assure $F_Q(Z)$ is properly evaluated prior to increasing THERMAL POWER.

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THERMAL POWER

ACTIONS (continued) B.1

If it is found that the maximum calculated value of $F_Q(Z)$ that can occur during normal maneuvers, $F^W_Q(Z)$, exceeds its specified limits, there exists a potential for $F^C_Q(Z)$ to become excessively high if a normal operational transient occurs. Reducing the ~~AFD limit~~ RTP by ≥ 1% for each 1% by which $F^W_Q(Z)$ exceeds its limit within the allowed Completion Time of 4 hours, ~~restricts the axial flux distribution such that even if a transient occurred,~~ maintains an acceptable absolute power density such that even if a transient occurred, core peaking factors are not exceeded. ~~For example, if the $F^W_Q(Z)$ limit is exceeded by 2% at 90% of RTP and the COLR AFD limits are −8 and +9 at 90% RTP, the new AFD limits would become −6 and +7 at 90% RTP. Note that complying with this action (of reducing AFD limits) may also result in a reduction of the maximum allowed power (maximum reactor power allowed within the reduced limits), hence the need for B.2, B.3 and B.4. Operation outside the reduced AFD limits would require a power reduction in accordance with LCO 3.2.3, AFD.~~

~~The implicit assumption is that if W(Z) values were recalculated (consistent with reduced AFD limits), then $F^C_Q(Z)$ times the recalculated W(Z) values would meet the $F_Q(Z)$ limit. Therefore, Condition B may be exited upon completion of Required Action B.1 (and Required Actions B.2 and B.3, if required). Required Action B.4 still must be completed.~~

B.2

~~If the reduction of AFD limits required by Required Action B.1 results in a reduction of the maximum allowed power (maximum reactor power allowed within the reduced limits), then the Power Range Neutron Flux-High trip setpoints must be reduced.~~ A reduction of the Power Range Neutron Flux-High trip setpoints by ≥ 1% for each 1% by which the maximum allowable power is reduced, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period and the preceding prompt reduction in THERMAL POWER ~~as a result of reducing AFD limits~~ in accordance with Required Action B.1.

B.3

~~If the reduction of AFD limits required by Required Action B.1 results in a reduction of the maximum allowed power (maximum reactor power allowed within the reduced limits), then the Overpower ΔT trip setpoints must be reduced.~~ Reduction in the Overpower ΔT trip setpoint value of

Unit 1 - Amendment No.
Unit 2 - Amendment No.

$F_Q{}^W(z)$ exceeds its limits

BASES

ACTIONS (continued)

K_4 by ≥ 1% for each 1% by ~~which the maximum allowable power is reduced~~, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period, and the preceding prompt reduction in THERMAL POWER ~~as a result of reducing AFD limits~~ in accordance with Required Action B.1.

B.4

Verification that $F^W_Q(Z)$ has been restored to within its limit, by performing SR 3.2.1.1 and SR 3.2.1.2 prior to increasing THERMAL POWER above the maximum allowable limit imposed by Required Action B.1 ensures that core conditions during operation at higher power levels and future operation are consistent with safety analyses assumptions.

Condition B is modified by a Note that requires Required Action B.4 to be performed whenever the Condition is entered. This ensures that SR 3.2.1.1 and SR 3.2.1.2 will be performed prior to increasing THERMAL POWER above the limit of Required Action B.1, even when Condition B is exited prior to performing Required Action B.4. Performance of SR 3.2.1.1 and SR 3.2.1.2 are necessary to assure $F_Q(Z)$ is properly evaluated prior to increasing THERMAL POWER.

~~Required Action B.4 is also considered satisfied, if reducing the AFD limit per Required Action B.1 does not require a reduction of the maximum power allowed by the reduced AFD limit.~~

C.1

If Required Actions A.1 through A.4 or B.1 through B.4 are not met within their associated Completion Times, the plant must be placed in a mode or condition in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours.

This allowed Completion Time is reasonable based on operating experience regarding the amount of time it takes to reach MODE 2 from full power operation in an orderly manner and without challenging plant systems.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.3 AXIAL FLUX DIFFERENCE (AFD)

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the values of the AFD in order to limit the amount of axial power distribution skewing to either the top or bottom of the core. By limiting the amount of power distribution skewing, core peaking factors are consistent with the assumptions used in the safety analyses. Limiting power distribution skewing over time also minimizes the xenon distribution skewing, which is a significant factor in axial power distribution control.

REPLACE THIS WITH THE FOLLOWING AFD BASES BACKGROUND INSERT PAGE.

RAOC is a calculational procedure that defines the allowed operational space of the AFD versus THERMAL POWER. The AFD limits are selected by considering a range of axial xenon distributions that may occur as a result of large variations of the AFD. Subsequently, power peaking factors and power distributions are examined to ensure that the loss of coolant accident (LOCA), loss of flow accident, and anticipated transient limits are met. Violation of the AFD limits invalidate the conclusions of the accident and transient analyses with regard to fuel cladding integrity.

The AFD is monitored on an automatic basis using the unit process computer, which has an AFD monitor alarm. The computer determines the 1 minute average of each of the OPERABLE excore detector outputs and provides an alarm message immediately if the AFD for two or more OPERABLE excore channels is outside its specified limits.

Although the RAOC defines limits that must be met to satisfy safety analyses, typically an operating scheme, Constant Axial Offset Control (CAOC), is used to control axial power distribution in day to day operation (Ref. 1). CAOC requires that the AFD be controlled within a narrow tolerance band around a burnup dependent target to minimize the variation of axial peaking factors and axial xenon distribution during unit maneuvers.

The CAOC operating space is typically smaller and lies within the RAOC operating space. Control within the CAOC operating space constrains the variation of axial xenon distributions and axial power distributions. RAOC calculations assume a wide range of xenon distributions and then confirm that the resulting power distributions satisfy the requirements of the accident analyses.

AFD BASES BACKGROUND
INSERT PAGE

Constant Axial Offset Control

(CAOC)

The operating scheme used to control the axial power distribution, ~~CAOC~~, involves maintaining the AFD within a tolerance band around a burnup dependent target, known as the target flux difference, to minimize the variation of the axial peaking factor and axial xenon distribution during unit maneuvers.

220

The target flux difference is determined at equilibrium xenon conditions. The control banks must be positioned within the core in accordance with their insertion limits and Control Bank D should be inserted near its normal position (i.e., ≥ ~~216~~ steps withdrawn) for steady state operation at high power levels. The power level should be as near RTP as practical. The value of the target flux difference obtained under these conditions divided by the Fraction of RTP is the target flux difference at RTP for the associated core burnup conditions. Target flux differences for other THERMAL POWER levels are obtained by multiplying the RTP value by the appropriate fractional THERMAL POWER level.

The AFD is monitored on an automatic basis using the unit process computer that has an AFD monitor alarm. The frequency of monitoring the AFD by the computer is once per minute providing an essentially continuous accumulation of penalty deviation time that allows the operator to assess the status of the penalty deviation time. The computer determines the 1 minute average of each of the OPERABLE excore detector outputs and provides an alarm message immediately if the AFDs for two or more OPERABLE excore channels are outside the target band and the THERMAL POWER is > 90% RTP. During operation at THERMAL POWER levels < 90% RTP but > 15% RTP, the computer sends an alarm message when the cumulative penalty deviation time is > 1 hour in the previous 24 hours.

Periodic updating of the target flux difference value is necessary to follow the change of the flux difference at steady state conditions with burnup.

The Nuclear Enthalpy Rise Hot Channel Factor $\cancel{(F^N_{\Delta H})}$ and QPTR LCOs limit the radial component of the peaking factors

$(F^N_{\Delta H})$

BASES

APPLICABLE SAFETY ANALYSES

REPLACE THIS WITH THE FOLLOWING AFD BASES APPLICABLE SAFETY ANALYSES INSERT PAGE.

The AFD is a measure of the axial power distribution skewing to either the top or bottom half of the core. The AFD is sensitive to many core related parameters such as control bank positions, core power level, axial burnup, axial xenon distribution, and, to a lesser extent, reactor coolant temperature and boron concentration.

The allowed range of the AFD is used in the nuclear design process to confirm that operation within these limits produces core peaking factors and axial power distributions that meet safety analysis requirements.

~~The RAOC methodology (Ref. 2) establishes a xenon distribution library with tentatively wide AFD limits. One dimensional axial power distribution calculations are then performed to demonstrate that normal operation power shapes are acceptable for the LOCA and loss of flow accident, and for initial conditions of anticipated transients. The tentative limits are adjusted as necessary to meet the safety analysis requirements.~~

The limits on the AFD ensure that the Heat Flux Hot Channel Factor ($F_Q(Z)$) is not exceeded during either normal operation or in the event of xenon redistribution following power changes. The limits on the AFD also restrict the range of power distributions that are used as initial conditions in the analyses of Condition 2, 3, or 4 events. This ensures that the fuel cladding integrity is maintained for these postulated accidents. The most important Condition 4 event is the LOCA. The most important Condition 3 event is the loss of flow accident. The most important Condition 2 events are uncontrolled bank withdrawal and boration or dilution accidents. Condition 2 accidents simulated to begin from within the AFD limits are used to confirm the adequacy of the Overpower ΔT and Overtemperature ΔT trip setpoints.

10 CFR 50.36(c)2(ii)

The limits on the AFD satisfy Criterion 2 of ~~the NRC Policy Statement.~~

LCO

REPLACE THIS WITH THE FOLLOWING AFD BASES LCO INSERT PAGES.

~~The AFD limits are provided in the COLR. Figure B 3.2.3B-1 shows typical RAOC AFD limits. The AFD limits for RAOC do not depend on the target flux difference. However, the target flux difference may be used to minimize changes in the axial power distribution.~~

~~Violating this LCO on the AFD could produce unacceptable consequences if a Condition 2, 3, or 4 event occurs while the AFD is outside its specified limits.~~

AFD BASES APPLICABLE SAFETY ANALYSES
INSERT PAGE

The CAOC methodology (Refs. 1, 2, and 3) entails:

a. Establishing an envelope of allowed power shapes and power densities,

b. Devising an operating strategy for the cycle that maximizes unit flexibility (maneuvering) and minimizes axial power shape changes,

c. Demonstrating that this strategy does not result in core conditions that violate the envelope of permissible core power characteristics, and

d. Demonstrating that this power distribution control scheme can be effectively supervised with excore detectors.

The shape of the power profile in the axial (i.e., the vertical) direction is largely under the control of the operator, through either the manual operation of the control banks, or automatic motion of control banks responding to temperature deviations resulting from either manual operation of the Chemical and Volume Control System to change boron concentration, or from power level changes.

Signals are available to the operator from the Nuclear Instrumentation System (NIS) excore neutron detectors (Ref. 4). Separate signals are taken from the top and bottom detectors. The AFD is defined as the difference in normalized flux signals between the top and bottom excore detector in each detector well. For convenience, this flux difference is converted to provide flux difference units expressed as a percentage and labeled as %Δ flux or %ΔI.

The required target band varies with axial burnup distribution, which in turn varies with the core average accumulated burnup. The target band defined in the COLR may provide one target band for the entire cycle or more than one band, each to be followed for a specific range of cycle burnup. With THERMAL POWER ≥ 90% RTP, the AFD must be kept within the target band. With the AFD outside the target band with THERMAL POWER ≥ 90% RTP, the assumptions of the accident analyses may be violated.

Violating the LCO on the AFD could produce unacceptable consequences if a Condition 2, 3, or 4 event occurs while the AFD is outside its limits.

Figure B 3.2.3A-1 shows a typical target band and typical AFD acceptable operation limits.

The LCO is modified by four Notes. Note 1 states the conditions necessary for declaring the AFD outside of the target band. Notes 2 and 3 describe how the cumulative penalty deviation time is calculated. It is intended that the unit is operated with the AFD within the target band about the target flux difference. However, during rapid THERMAL POWER reductions, control bank motion may cause the AFD to deviate outside of the target band at reduced THERMAL POWER levels. This deviation does not affect the xenon distribution sufficiently to change the envelope of peaking factors that may be reached on a subsequent return to RTP with the AFD within the target band, provided the time duration of the deviation is limited. Accordingly, while THERMAL POWER is ≥ 50% RTP and < 90% RTP (i.e., Part b of this LCO), a 1 hour cumulative penalty deviation time limit, cumulative during the preceding 24 hours, is allowed during which the unit may be operated outside of the target band but within the acceptable operation limits provided in the COLR (Note 2). This penalty time is accumulated at the rate of 1 minute for each 1 minute of operating time within the power range of Part b of this LCO (i.e., THERMAL POWER ≥ 50% RTP). The cumulative penalty time is the sum of penalty times from Parts b and c of this LCO.

For THERMAL POWER levels > 15% RTP and < 50% RTP (i.e., Part c of this LCO), deviations of the AFD outside of the target band are less significant. Note 3 allows the accumulation of 1/2 minute penalty deviation time per 1 minute of actual time outside the target band and reflects this reduced significance. With THERMAL POWER < 15% RTP, AFD is not a significant parameter in the assumptions used in the safety analysis and, therefore, requires no limits. Because the xenon distribution produced at THERMAL POWER levels less than RTP does affect the power distribution as power is increased, unanalyzed xenon and power distribution is prevented by limiting the accumulated penalty deviation time.

For surveillance of the power range channels performed according to SR 3.3.1.6, Note 4 allows deviation outside the target band for 16 hours and no penalty deviation time accumulated. Some deviation in the AFD is required for doing the NIS calibration with the incore detector system. This calibration is performed every 92 days

Above 50% RTP,

15% RTP.

BASES

APPLICABILITY

REPLACE THIS WITH THE FOLLOWING AFD BASES APPLICABILITY INSERT PAGE.

The AFD requirements are applicable in MODE 1 greater than ~~or equal to 50% RTP when~~ the combination of THERMAL POWER and core peaking factors are of primary importance in safety analysis. (Ref. 1).

the core parameters

e

~~For AFD limits developed using RAOC methodology, the value of the AFD does not affect the limiting accident consequences with THERMAL POWER < 50% RTP and for lower operating power MODES.~~

ACTIONS

REPLACE THIS WITH THE FOLLOWING AFD BASES ACTIONS INSERT PAGES.

~~A.1~~

~~As an alternative to restoring the AFD to within its specified limits, Required Action A.1 requires a THERMAL POWER reduction to < 50% RTP. This places the core in a condition for which the value of the AFD is not important in the applicable safety analyses. A Completion Time of three hours is reasonable, based on operating experience, to reach 50% RTP without challenging plant systems.~~

SURVEILLANCE REQUIREMENTS

REPLACE THIS WITH THE FOLLOWING AFD BASES SURVEILLANCE REQUIREMENTS INSERT PAGES.

SR 3.2.3.1

~~This Surveillance verifies that the AFD, as indicated by the NIS excore channel, is within its specified limits. The Surveillance Frequency of 7 days is adequate considering that the AFD is monitored by a computer and any deviation from requirements is alarmed.~~

REFERENCES

REPLACE THIS WITH THE FOLLOWING AFD BASES REFERENCE INSERT PAGE.

1. WCAP-8403 (nonproprietary), "Power Distribution Control and Load Following Procedures," Westinghouse Electric Corporation, September 1974.

~~2. R. W. Miller et al., "Relaxation of Constant Axial Offset Control: F_Q Surveillance Technical Specification," WCAP-10217(NP), June 1983.~~

4. ~~3.~~ FSAR, Chapter 14.

AFD BASES APPLICABILITY
INSERT PAGE

Between 15% RTP and 90% RTP, this LCO is applicable to ensure that the distributions of xenon are consistent with safety analysis assumptions.

At or below 15% RTP and for lower operating MODES, the stored energy in the fuel and the energy being transferred to the reactor coolant are low. The value of the AFD in these conditions does not affect the consequences of the design basis events.

Low signal levels in the excore channels may preclude obtaining valid AFD signals below 15% RTP.

A.1

With the AFD outside the target band and THERMAL POWER ≥ 90% RTP, the assumptions used in the accident analyses may be violated with respect to the maximum heat generation. Therefore, a Completion Time of 15 minutes is allowed to restore the AFD to within the target band because xenon distributions change little in this relatively short time.

B.1

If the AFD cannot be restored within the target band, then reducing THERMAL POWER to < 90% RTP places the core in a condition that has been analyzed and found to be acceptable, provided that the AFD is within the acceptable operation limits provided in the COLR.

The allowed Completion Time of 15 minutes provides an acceptable time to reduce power to < 90% RTP without allowing the plant to remain in an unanalyzed condition for an extended period of time.

C.1

With THERMAL POWER < 90% RTP but ≥ 50% RTP, operation with the AFD outside the target band is allowed for up to 1 hour if the AFD is within the acceptable operation limits provided in the COLR. With the AFD within these limits, the resulting axial power distribution is acceptable as an initial condition for accident analyses assuming the then existing xenon distributions. The 1 hour cumulative penalty deviation time restricts the extent of xenon redistribution. Without this limitation, unanalyzed xenon axial distributions may result from a different pattern of xenon buildup and decay. The reduction to a power level < 50% RTP puts the reactor at a THERMAL POWER level at which the AFD is not a significant accident analysis parameter.

If the indicated AFD is outside the target band and outside the acceptable operation limits provided in the COLR, the peaking factors assumed in accident analysis may be exceeded with the existing xenon condition. (Any AFD within the target band is acceptable regardless of its relationship to the acceptable operation limits.) The Completion Time of 30 minutes allows for a prompt, yet orderly, reduction in power.

Condition C is modified by a Note that requires that Required Action C.1 must be completed whenever this Condition is entered.

D.1

If Required Action C.1 is not completed within its required Completion Time of 30 minutes, the axial xenon distribution starts to become significantly skewed with the THERMAL POWER ≥ 50% RTP. In this situation, the assumption that a cumulative penalty deviation time of 1 hour or less during the previous 24 hours while the AFD is outside its target band is acceptable at < 50% RTP, is no longer valid.

Reducing the power level to < 15% RTP within the Completion Time of 9 hours and complying with LCO penalty deviation time requirements for subsequent increases in THERMAL POWER ensure that acceptable xenon conditions are restored.

This Required Action must also be implemented either if the cumulative penalty deviation time is > 1 hour during the previous 24 hours, or the AFD is not within the target band and not within the acceptable operation limits.

AFD BASES SURVEILLANCE REQUIREMENTS
INSERT PAGE

SR 3.2.3.1

This Surveillance verifies that the AFD as indicated by the NIS excore channels is within the target band. The Surveillance Frequency of 7 days is adequate because the AFD is controlled by the operator and monitored by the process computer. Furthermore, any deviations of the AFD from the target band that is not alarmed should be readily noticed.

The AFD should be monitored and logged more frequently in periods of operation for which the power level or control bank positions are changing to allow corrective measures when the AFD is more likely to move outside the target band.

SR 3.2.3.2

This Surveillance requires that the target flux difference is updated at a Frequency of 31 effective full power days (EFPD) to account for small changes that may occur in the target flux differences in that period due to burnup by performing SR 3.2.3.3.

Alternatively, linear interpolation between the most recent measurement of the target flux differences and a predicted end of cycle value provides a reasonable update because the AFD changes due to burnup tend toward 0% AFD. When the predicted end of cycle AFD from the cycle nuclear design is different from 0%, it may be a better value for the interpolation.

SR 3.2.3.3

Measurement of the target flux difference is accomplished by taking a flux map when the core is at equilibrium xenon conditions, preferably at high power levels with the control banks nearly withdrawn. This flux map provides the equilibrium xenon axial power distribution from which the target value can be determined. The target flux difference varies slowly with core burnup.

A Frequency of 31 EFPD after each refueling and 92 EFPD thereafter for remeasuring the target flux differences adjusts the target flux difference for each excore channel to the value measured at steady state conditions. This is the basis for the CAOC. Remeasurement at this Surveillance interval also establishes the AFD target flux difference values that account for changes in incore excore calibrations that may have occurred in the interim.

A Note modifies this SR to allow the predicted end of cycle AFD from the cycle nuclear design to be used to determine the initial target flux difference after each refueling.

AFD BASES REFERENCE
INSERT PAGE

2. NS-TMA-2198, Westinghouse to NRC Letter, Attachment "Operation and Safety Analysis Aspects of Improved Load Follow Package," January 31, 1980.

3. NS-CE-687, Westinghouse to NRC Letter, "Power Distribution Control Analysis," July 16, 1975.

This Figure is deleted.

Cycle-specific figure is in the COLR.

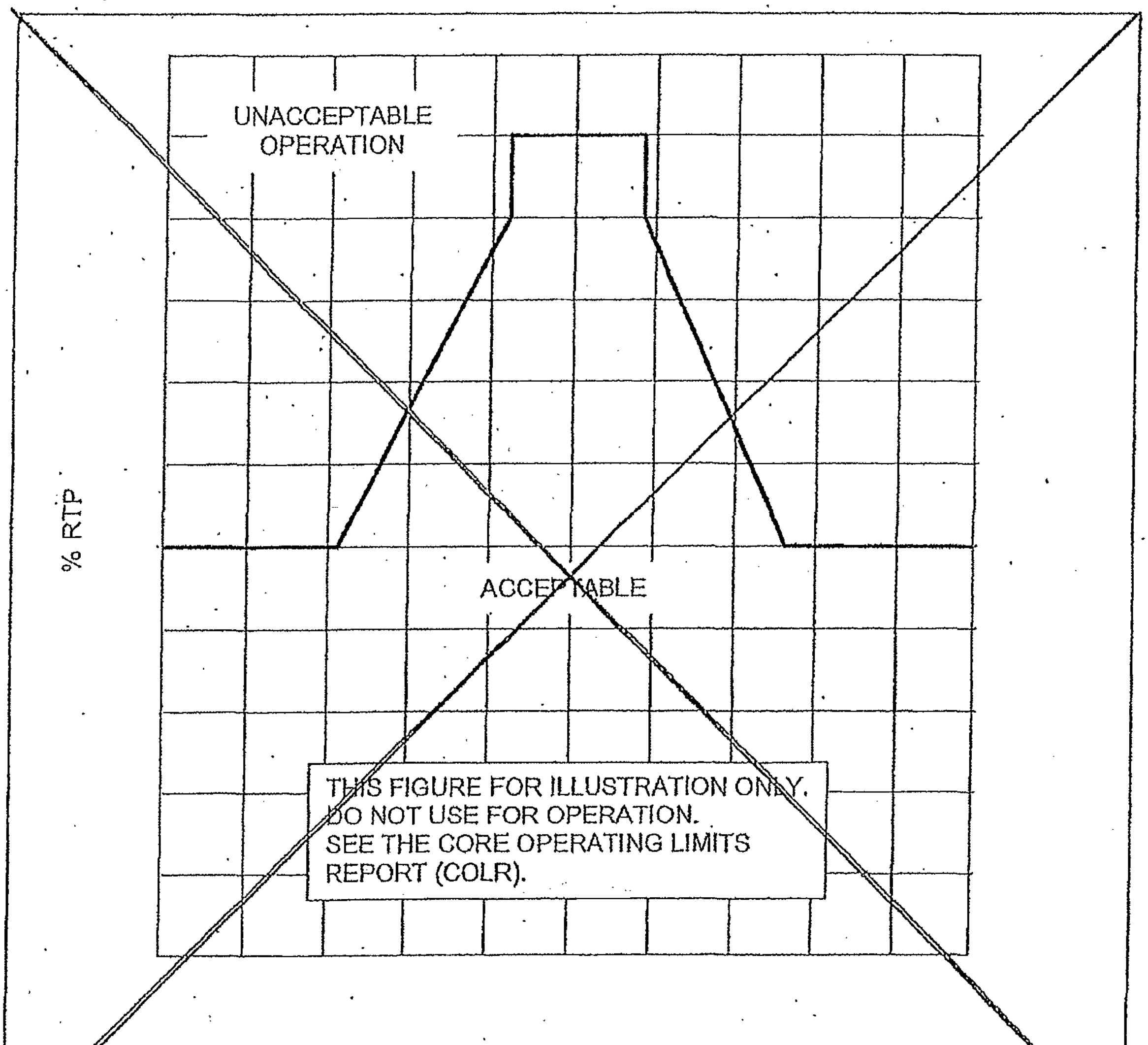

Figure B 3.2.3-1 (page 1 of 1)
AXIAL FLUX DIFFERENCE Acceptable Operation Limits
as a Function of RATED THERMAL POWER

B 3.3 INSTRUMENTATION

B 3.3.1 Reactor Protection System (RPS) Instrumentation

BASES

BACKGROUND

The RPS initiates a unit shutdown, based on the values of selected unit parameters, to protect against violating the core fuel design limits and Reactor Coolant System (RCS) pressure boundary during anticipated operational occurrences (AOOs) and to assist the Engineered Safety Features (ESF) Systems in mitigating accidents.

The protection and monitoring systems have been designed to assure safe operation of the reactor. This is achieved by specifying limiting safety system settings (LSSS) in terms of parameters directly monitored by the RPS, as well as specifying LCO's on other reactor system parameters and equipment performance.

Shown in Table 3.3.1-1

The LSSS, ~~defined in this specification as the Allowable Value Setpoints,~~ in conjunction with the LCOs, establish the threshold for protective system action to prevent exceeding acceptable limits during Design Basis Accidents (DBAs).

During AOOs, which are those events expected to occur one or more times during the unit life, the acceptable limits are:

1. The Departure from Nucleate Boiling Ratio (DNBR) shall be maintained above the Safety Limit (SL) value to prevent departure from nucleate boiling (DNB);

2. Fuel centerline melt shall not occur; and

3. The RCS pressure SL of 2750 psia shall not be exceeded.

Operation within the SLs of Specification 2.0, "Safety Limits (SLs)," also maintains the above values and assures that offsite dose will be within the 10 CFR 50 and 10 CFR 100 criteria during AOOs.

Accidents are events that are analyzed even though they are not expected to occur during the unit life. The acceptable limit during accidents is that offsite dose shall be maintained within an acceptable fraction of 10 CFR 100 limits. Different accident categories are allowed a different fraction of these limits, based on probability of occurrence. Meeting the acceptable dose limit for an accident category is considered having acceptable consequences for that event.

ADD INSERTS RPS-1 and RPS-2

INSERT RPS-1

Limiting Safety System Settings

10 CFR 50.36(c)(1) requires limiting safety system settings to be included in the Technical Specifications.

The following RPS Functions are LSSS that protect safety limits in the accident analyses:

1. Power Range Neutron Flux - High
2. Power Range Neutron Flux - Low
3. Overtemperature ΔT
4. Overpower ΔT
5. Pressurizer Pressure - Low
6. Pressurizer Pressure - High
7. Reactor Coolant Flow - Low
8. Undervoltage Bus A01 & A02
9. Steam Generator Water Level - Low Low

The following RPS Functions are LSSS that are not specifically credited to protect safety limits in the accident analyses:

1. Intermediate Range Neutron Flux
2. Source Range Neutron Flux
3. Pressurizer Water Level - High
4. Underfrequency Bus A01 & A02
5. Steam Generator Water Level – Low
6. Steam Flow/Feedwater Flow Mismatch
7. Intermediate Range Permissive P-6
8. Power Range Permissive P-7 Neutron Flux
9. Turbine Impulse Pressure Permissive P-7
10. Power Range Permissive P-8
11. Power Range Permissive P-9
12. Power Range Permissive P-10

INSERT RPS-2

Limiting Safety System Settings (continued)

A Limiting Safety System Setting is specified in Table 3.3.1-1 for each RPS Function that has an adjustable setpoint, to ensure that the reactor trip protective actions credited in the safety analyses occur within the limits assumed in the analyses.

To account for instrumentation channel uncertainties, including sensor and rack errors, normal instrument drift, and environmental and process errors, the LSSS values in Table 3.3.1-1 are conservative with respect to an Analytical Limit established for the Function in the safety analyses, or a Process Limit if the Function is not specifically credited in the safety analyses. The LSSS value is based on a calculated Limiting Trip Setpoint (LTSP), which is offset from the Analytical or Process Limit by all known uncertainties applicable to the channel. The field sensors and signal processing equipment for these channels are assumed to operate within uncertainties determined at a 95/95 confidence level.

In some cases, an Analytical or Process Limit may not exist for an RPS Function, such as an operating bypass (permissive) that is based on a nominal Field Trip Setpoint (FTSP) that is not specifically credited in the safety analyses. For these cases, the LSSS value is based on an as-found tolerance limit of the nominal FTSP, rather than on a calculated LTSP.

The actual Field Trip Setpoint (FTSP) entered into the channel bistable during calibration is normally more conservative than the LSSS value, which provides design margin beyond the LTSP. This design margin provides further assurance that the RPS Function will operate prior to the process reaching the Analytical Limit or Process Limit for the Function.

Notes 3 and 4

Notes 3 and 4 in Table 3.3.1-1 apply to the LSSS column and address required actions during a Channel Operational Test (COT) surveillance related to as-left and as-found conditions of the RPS Functions that have LSSS values. Note 3 provides two conditions that must be met for the channel to be considered OPERABLE at the completion of the surveillance. These conditions assure that the COT portion of the channel is operating within the uncertainty values applied in the associated setpoint calculation.

Note 4 requires that a channel found outside the COT as-found acceptance criteria be evaluated prior to returning the channel to service. The out-of-tolerance condition will be evaluated under the Corrective Action Process, and may involve review of calibration/surveillance history, component replacement if it is determined a component has failed, cannot be calibrated within its as-left tolerance, the calibration is not repeatable, or there is an adverse performance history.

BASES

BACKGROUND (continued)

The RPS instrumentation is segmented into four distinct but interconnected modules as identified below:

1. Field transmitters or process sensors: provide a measurable electronic signal based upon the physical characteristics of the parameter being measured;

2. Signal Process Control and Protection System, including Analog Protection System, Nuclear Instrumentation System (NIS), field contacts, and protection channel sets: provides signal conditioning, compatible electrical signal output to protection system devices, and control board/control room/miscellaneous indications;

3. Relay Logic System, including input, logic, and output devices: initiates proper unit shutdown in accordance with the defined logic, which is based on bistable, setpoint comparators, or contact outputs from the signal process control and protection systems; and

4. Reactor trip switchgear, including reactor trip breakers (RTBs) and bypass breakers: provides the means to interrupt power to the control rod drive mechanisms (CRDMs) and allows the rod cluster control assemblies (RCCAs), or "rods," to fall into the core and shut down the reactor. The bypass breakers allow testing of the RTBs at power.

Field Transmitters or Sensors

To meet the design demands for redundancy and reliability, more than one, and often as many as four, field transmitters or sensors are used to measure unit parameters. To account for the calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the ~~Allowable Values.~~ LSSS values The OPERABILITY of each transmitter or sensor can be evaluated when its "as found" calibration data are compared against its documented acceptance criteria.

Signal Process Control and Protection System

Generally, three or four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. The process control equipment provides signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with setpoints established by safety analyses. If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable is forwarded to the logic relays.

BASES

BACKGROUND (continued)

REPLACE WITH INSERT RPS-3

Generally, if a parameter is used only for input to the protection circuits, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function is still OPERABLE with a two-out-of-two logic. If one channel fails, such that a partial Function trip occurs, a trip will not occur and the Function is still OPERABLE with a one-out-of-two logic.

Generally, if a parameter is used for input to the relay logic system and a control function, four channels with a two-out-of-four logic are sufficient to provide the required reliability and redundancy. The circuit must be able to withstand both an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Again, a single failure will neither cause nor prevent the protection function actuation. These requirements are described in IEEE-279-1968 (Ref. 3). The actual number of channels required for each unit parameter is specified in Reference 1.

Two logic channels are required to ensure no single random failure of a logic channel will disable the RPS. The logic channels are designed such that testing required while the reactor is at power may be accomplished without causing trip. Provisions to allow removing logic channels from service during maintenance are unnecessary because of the logic system's designed reliability.

Allowable Values

To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those RPS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 4), the Allowable Values specified in Table 3.3.1-1 in the accompanying LCO are conservatively adjusted with respect to the analytical limits. A detailed description of the methodology used to calculate the Trip Setpoints, including their explicit uncertainties, is provided in DG1-01, "Instrument Setpoint Methodology" (Ref. 5). The actual nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT. One example of such a change in measurement error is drift during the surveillance interval. If the measured setpoint does not exceed the Allowable Value, the bistable is considered OPERABLE.

Setpoints in accordance with the Allowable Value ensure that SLs are not violated during AOOs (and that the consequences of DBAs will be acceptable, providing the unit is operated from within the LCOs at the

INSERT RPS-3

Generally, if a parameter is used only for input to the protection circuits, three channels with a two-out-of-three coincidence logic are sufficient to provide the required reliability and redundancy. If one of the three channels fails in a direction that would result in a non-trip of the affected channel, the Function is still OPERABLE with a two-out-of-two coincidence logic on the remaining two channels. If one of the three channels fails in a direction that trips the channel, the failure alone does not cause a reactor trip and the Function is still OPERABLE with a one-out-of-two coincidence logic on the remaining two channels.

Generally, if a parameter is used for input to both protection circuits and a control function, four channels with a two-out-of-four coincidence logic are needed to provide the required reliability and redundancy. Under IEEE 279-1968 (Ref. 3), the control/protection interaction criterion requires that if a control malfunction can prevent protective action of a channel and the control malfunction also requires protective action by the same channel providing the control signal, then the failure of the channel providing the control signal and an additional failure of the remaining protection channels must be considered. With four channels in a two-out-of-four coincidence, the combined control/protection failures will neither cause nor prevent the protective action.

The actual number of channels required for each RPS parameter is specified in Reference 1.

BASES

BACKGROUND (continued)

onset of the AOO or DBA and the equipment functions as designed). Note that in the accompanying LCO 3.3.1, the Allowable Values of Table 3.3.1-1 are the LSSS.

Each channel of the process control equipment can be tested on line to verify that the signal or setpoint accuracy is within the specified allowance requirements. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SRs section.

The Allowable Values listed in Table 3.3.1-1 are based on the methodology described in Reference 5, which incorporates all of the known uncertainties applicable for each channel. The magnitudes of these uncertainties are factored into the determination of each Allowable Value. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

<u>Relay Logic System</u>

The Relay Logic System equipment is used for the decision logic processing of outputs from the signal processing equipment bistables. To meet the redundancy requirements, two trains of Relay Logic System, each performing the same functions, are provided. If one train is taken out of service for maintenance or test purposes, the second train will provide reactor trip for the unit. Each train is packaged in its own cabinet for physical and electrical separation to satisfy separation and independence requirements. The system has been designed to trip in the event of a loss of power, directing the unit to a safe shutdown condition.

The Relay Logic System performs the decision logic for actuating a reactor trip, generates the electrical output signal that will initiate the required trip, and provides the status, permissive, and annunciator output signals to the main control room of the unit.

The bistable outputs from the signal processing equipment are sensed by the Relay Logic System equipment and combined into logic matrices that represent combinations indicative of various unit upset and accident transients. If a required logic matrix combination is completed, the system will initiate a reactor trip. Examples are given in the Applicable Safety Analyses, LCO, and Applicability sections of this Bases.

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY (continued)

four configuration are generally required when one RPS channel is also used as a control system input. This configuration accounts for the possibility of the shared channel failing in such a manner that it creates a transient that requires RPS action. In this case, the RPS will still provide protection, even with random failure of one of the other three protection channels. Three OPERABLE instrumentation channels in a two-out-of-three configuration are generally required when there is no potential for control system and protection system interaction that could simultaneously create a need for RPS trip and disable one RPS channel. The two-out-of-three and two-out-of-four configurations allow one channel to be tripped during maintenance or testing without causing a reactor trip. Specific exceptions to the above general philosophy exist and are discussed below.

Reactor Protection System Functions

The safety analyses and OPERABILITY requirements applicable to each RPS Function are discussed below:

1. Manual Reactor Trip

The Manual Reactor Trip ensures that the control room operator can initiate a reactor trip at any time by using one of four reactor trip switches in the control room. A Manual Reactor Trip accomplishes the same results as any one of the automatic trip Functions. It is used by the reactor operator to shut down the reactor whenever any parameter is rapidly trending toward its ~~Allowable Value.~~ reactor trip setpoint

The LCO requires two Manual Reactor Trip channels to be OPERABLE. Each channel consists of two reactor trip switches (one in each train). Each channel activates the reactor trip breaker in both trains. Two independent channels are required to be OPERABLE so that no single random failure will disable the Manual Reactor Trip Function.

In MODE 1 or 2, manual initiation of a reactor trip must be OPERABLE. These are the MODES in which the shutdown rods and/or control rods are partially or fully withdrawn from the core. In MODE 3, 4, or 5, the manual initiation Function must also be OPERABLE with the RTBs closed and the Rod Control System capable of rod withdrawal. In this condition, inadvertent control rod withdrawal is possible. In MODE 3, 4, or 5, manual initiation of a reactor trip does not have to be OPERABLE if the Rod Control System is not capable of withdrawing the shutdown rods or control rods. If the rods cannot be withdrawn from the core or all of the rods are inserted, there is no need to be able to trip the reactor. In MODE 6, neither the

BASES

APPLICABLE SAFETY ANALYSES, LCO AND APPLICABILITY (continued)

In MODES 3, 4 and 5 with the Rod Control System not capable of rod withdrawal, and in MODE 6, this Function is not required to be OPERABLE. The requirements for the NIS source range detectors to monitor core neutron levels and provide indication of reactivity changes that may occur as a result of events like a boron dilution are addressed in LCO 3.9.2, "Nuclear Instrumentation," for MODE 6.

5. <u>Overtemperature ΔT</u>

The Overtemperature ΔT trip Function is provided to ensure that the design limit DNBR is met. This trip Function also limits the range over which the Overpower ΔT trip Function must provide protection. The inputs to the Overtemperature ΔT trip include ~~all~~ pressure, coolant temperature, axial power distribution, and reactor power as indicated by loop ΔT assuming full reactor coolant flow. Protection from violating the DNBR limit is assured for those transients that are slow with respect to delays from the core to the measurement system. ~~The Function monitors both variation in power and flow since a decrease in flow has the same effect on ΔT as a power increase.~~ The Overtemperature ΔT trip Function uses each loop's ΔT as a measure of reactor power and is compared with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature-the Trip Setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature;
- pressurizer pressure-the Trip Setpoint is varied to correct for changes in system pressure; and
- axial power distribution — f(ΔI), the Trip Setpoint is varied to account for imbalances in the axial power distribution as detected by the NIS upper and lower power range detectors. If axial peaks are greater than the design limit, as indicated by the difference between the upper and lower NIS power range detectors, the Trip Setpoint is reduced in accordance with Note 1 of Table 3.3.1-1.

The Overtemperature ΔT trip Function is calculated for each channel as described in Note 1 of Table 3.3.1-1. Reactor Trip occurs if Overtemperature ΔT is indicated in two channels. Because the pressure and temperature signals are used for other control functions, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Note that this Function

BASES

APPLICABLE SAFETY ANALYSES, LCO AND APPLICABILITY (continued)

also provides a signal to generate a turbine runback prior to reaching the Trip Setpoint. A turbine runback will reduce turbine power and reactor power. A reduction in power will normally alleviate the Overtemperature ΔT condition and may prevent a reactor trip.

The LCO requires all four channels of the Overtemperature ΔT trip Function to be OPERABLE. Note that the Overtemperature ΔT Function receives input from channels shared with other RPS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overtemperature ΔT trip must be OPERABLE to prevent DNB. In MODE 3, 4, 5, or 6, this trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about DNB.

6. Overpower ΔT

The Overpower ΔT trip Function ensures that protection is provided to ensure the integrity of the fuel (i.e., no fuel pellet melting and less than 1% cladding strain) under all possible overpower conditions. This trip Function also limits the required range of the Overtemperature ΔT trip Function and provides a backup to the Power Range Neutron Flux-High Setpoint trip. The Overpower ΔT trip Function ensures that the allowable heat generation rate (kW/ft) of the fuel is not exceeded. It uses the ΔT of each loop as a measure of reactor power with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature — the Trip Setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature; and
- rate of change of reactor coolant average temperature.

The Overpower ΔT trip Function is calculated for each channel as per Note 2 of Table 3.3.1-1. Trip occurs if Overpower ΔT is indicated in two channels. The temperature signals are used for other control functions. The actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation and a single failure in the remaining channels providing the protection function actuation. Note that this Function also provides a signal to generate a turbine runback prior to reaching the ~~Allowable Value~~ reactor trip setpoint. A turbine runback will reduce turbine power and reactor power. A reduction in power

BASES

APPLICABLE SAFETY ANALYSES, LCO AND APPLICABILITY (continued)

b. Pressurizer Pressure-High

The Pressurizer Pressure-High trip Function ensures that protection is provided against overpressurizing the RCS. This trip Function operates in conjunction with the pressurizer relief and safety valves to prevent RCS overpressure conditions.

The LCO requires three channels of the Pressurizer Pressure-High to be OPERABLE.

~~For operation at 2250 psia,~~ the Pressurizer Pressure-High LSSS is selected to be below the pressurizer safety valve actuation pressure and above the power operated relief valve (PORV) setting. This setting minimizes challenges to safety valves while avoiding unnecessary reactor trip for those pressure increases that can be controlled by the PORVs.

~~For operation~~ at 2000 psia, a 50% load rejection with ~~steam~~ dump results ~~in a peak~~ pressure below ~~the Pressurizer~~ Pressure-High LSSS. ~~Therefore,~~ even though the PORV setting is above ~~the reactor~~ trip, the transient ~~will not~~ result in PORV ~~actuation~~ or a reactor trip on high Pressurizer ~~Pressure.~~

In MODE 1 or 2, the Pressurizer Pressure-High trip must be OPERABLE to help prevent RCS overpressurization and minimize challenges to the relief and safety valves. In MODE 3, 4, 5, or 6, the Pressurizer Pressure-High trip Function does not have to be OPERABLE because transients that could cause an overpressure condition will be slow to occur. Therefore, the operator will have sufficient time to evaluate unit conditions and take corrective actions. Additionally, low temperature overpressure protection systems provide overpressure protection when below MODE 4.

8. Pressurizer Water Level—High

The Pressurizer Water Level-High trip Function provides a backup signal for the Pressurizer Pressure-High trip and also provides protection against water relief through the pressurizer safety valves. These valves are designed to pass steam in order to achieve their design energy removal rate. A reactor trip is actuated prior to the pressurizer becoming water solid. The LCO requires three channels of Pressurizer Water Level-High to be OPERABLE. The pressurizer level channels are used as input to the Pressurizer Level Control System. A fourth channel is not required to address control/protection interaction concerns. The level channels do not

BASES

APPLICABLE SAFETY ANALYSES, LCO AND APPLICABILITY (continued)

interlock, this trip and all reactor trips on loss of flow are automatically blocked, because no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 interlock, the Underfrequency Bus A01 and A02 RCP breaker trip is automatically enabled.

13. Steam Generator Water Level—Low Low

REPLACE WITH INSERT RPS-4

~~The SG Water Level—Low Low trip Function ensures that protection is provided against a loss of heat sink and actuates the AFW System prior to uncovering the SG tubes. The SGs are the heat sink for the reactor. In order to act as a heat sink, the SGs must contain a minimum amount of water. A narrow range low low level in any SG is indicative of a loss of heat sink for the reactor. The level transmitters provide input to the SG Level Control System. Therefore, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. This Function also performs the ESFAS function of starting the AFW pumps on low low SG level.~~

~~The LCO requires three channels of SG Water Level—Low Low per SG to be OPERABLE.~~

In MODE 1 or 2, when the reactor requires a heat sink, the SG Water Level—Low Low trip must be OPERABLE. The normal source of water for the SGs is the Main Feedwater (MFW) System (not safety related). The MFW System is only in operation in MODE 1 or 2. The AFW System is the safety related backup source of water to ensure that the SGs remain the heat sink for the reactor. During normal startups and shutdowns, the AFW System provides feedwater to maintain SG level. In MODE 3, 4, 5, or 6, the SG Water Level—Low Low Function does not have to be OPERABLE because the MFW System is not in operation and the reactor is not operating or even critical. Decay heat removal is accomplished by the AFW System in MODE 3 and by the Residual Heat Removal (RHR) System in MODE 4, 5, or 6.

14. Steam Generator Water Level—Low, Coincident With Steam Flow/Feedwater Flow Mismatch

SG Water Level-Low, in conjunction with the Steam Flow/Feedwater Flow Mismatch, ensures that protection is provided against a loss of heat sink. In addition to a decreasing water level in the SG, the difference between feedwater flow and steam flow is evaluated to

INSERT RPS-4

The SG Water Level – Low Low trip Function provides reactor trip protection against a loss of heat sink and also actuates the AFW system (an ESFAS Function) prior to uncovering the SG tubes. The SGs are the heat sink for the reactor. In order to act as a heat sink, the SGs must contain a minimum amount of water. A narrow range low-low level in either SG is indicative of a loss of heat sink for the reactor.

One of the three protection channel level transmitters on each SG provides an input signal to the SG Feedwater Control System. A failure of the level control signal in the high direction would reduce feedwater flow to the affected SG and challenge the low-low level reactor trip Function. Under IEEE 279-1968, the control/protection interaction criterion requires that the protection function be performed coincident with an additional single failure in the remaining channels providing the protective function. Because the low-low level reactor trip function is a two-out-of-three coincidence logic, a control failure in one channel and a concurrent single failure in one of the two remaining protection channels would not satisfy the coincidence logic. Therefore, the IEEE 279 control/protection interaction criterion is not met for the low-low level reactor trip function.

Under the above control failure scenario, the failure would affect only one of the two SGs, with the unaffected SG continuing to provide a heat sink for the reactor. For this scenario, the plant relies on the separate reactor trip provided by the SG Water Level – Low coincident with Steam Flow/Feedwater Flow mismatch for reactor protection. The SG Water Level – Low reactor trip is a one-out-of-two coincidence using the two level channels that do not provide a control signal, and is therefore unaffected by the control failure.

For the loss of heat sink safety analyses, the SG Water Level – Low Low reactor trip is credited as a primary trip without assuming the concurrent control failure scenario discussed above. Loss of Normal Feedwater and Loss of All AC events cause a low-low level condition to occur in both SGs, and the reactor trip logic on a low-low SG level condition is satisfied if the low-low level condition occurs in either SG.

BASES

APPLICABLE SAFETY ANALYSES, LCO AND APPLICABILITY (continued)

determine if feedwater flow is significantly less than steam flow.

With less feedwater flow than steam flow, SG level will decrease at a rate dependent upon the magnitude of the difference in flow rates. There are two SG level channels and two Steam Flow/Feedwater Flow Mismatch channels per SG. One narrow range level channel sensing a low level coincident with one Steam Flow/ Feedwater Flow Mismatch channel sensing flow mismatch (steam flow greater than feed flow) will actuate a reactor trip.

~~Table 3.3.1-1 identifies the Technical Specification Allowable Value for this trip function as not applicable (NA), because LCO 3.3.1, Function 13, Steam Generator Water Level-Low Low, is used to bound the analysis for a loss of feedwater event. The nominal setting required for the Steam Generator Water Level-Low trip function is 30% of span. This nominal setting was developed outside of the setpoint methodology and has been provided by the NSSS supplier.~~

The LCO requires two channels of SG Water Level-Low coincident with Steam Flow/Feedwater Flow Mismatch per SG.

In MODE 1 or 2, when the reactor requires a heat sink, the SG Water Level-Low coincident with Steam Flow/Feedwater Flow Mismatch trip must be OPERABLE. The normal source of water for the SGs is the MFW System (not safety related). The MFW System is only in operation in MODE 1 or 2. The AFW System is the safety related backup source of water to ensure that the SGs remain the heat sink for the reactor. During normal startups and shutdowns, the AFW System provides feedwater to maintain SG level. In MODE 3, 4, 5, or 6, the SG Water Level-Low coincident with Steam Flow/Feedwater Flow Mismatch Function does not have to be OPERABLE because the MFW System is not in operation and the reactor is not operating or even critical. Decay heat removal is accomplished by the AFW System in MODE 3 and by the RHR System in MODE 4, 5, or 6. The MFW System is in operation only in MODE 1 or 2 and, therefore, this trip Function need only be OPERABLE in these MODES.

15. Turbine Trip

a. Turbine Trip-Low Autostop Oil Pressure

The Turbine Trip-Low Autostop Oil Pressure trip Function anticipates the loss of heat removal capabilities of the secondary system following a turbine trip. This trip Function acts to

BASES

APPLICABLE SAFETY ANALYSES, LCO AND APPLICABILITY (continued)

minimize the pressure/temperature transient on the reactor. Any turbine trip from a power level below the P-9 setpoint (approximately 50% power, with at least one circulating water pump breaker closed, and condenser vacuum not high, will not actuate a reactor trip. Three pressure switches monitor the control oil pressure in the Turbine Electrohydraulic Control System. A low pressure condition sensed by two-out-of-three pressure switches will actuate a reactor trip. These pressure switches do not provide any input to the control system. The unit is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the Pressurizer Pressure-High trip Function and RCS integrity is ensured by the pressurizer safety valves.

LSSS value

Table 3.3.1-1 identifies the Technical Specification ~~Allowable Value~~ for this trip function as not applicable (NA). No Analytical Value is assumed in the accident analysis for this function. The nominal setting required for the Turbine Trip – Low Autostop Oil Pressure trip function is 45 psig. This nominal setting was developed outside of the setpoint methodology and has been provided by the NSSS supplier.

The LCO requires three channels of Turbine Trip-Low Autostop Oil Pressure to be OPERABLE in MODE 1 above P-9.

Below the P-9 setpoint, a turbine trip does not actuate a reactor trip. In MODE 2, 3, 4, 5, or 6, there is no potential for a turbine trip, and the Turbine Trip-Low Autostop Oil Pressure trip Function does not need to be OPERABLE.

b. Turbine Trip-Turbine Stop Valve Closure

The Turbine Trip-Turbine Stop Valve Closure trip Function anticipates the loss of heat removal capabilities of the secondary system following a turbine trip. Any turbine trip with from a power level below the P-9 setpoint, approximately 50% power, with at least one circulating water pump breaker closed, and condenser vacuum not high, will not actuate a reactor trip. The trip Function anticipates the loss of secondary heat removal capability that occurs when the stop valves close. Tripping the reactor in anticipation of loss of secondary heat removal acts to minimize the pressure and temperature transient on the reactor. ~~This trip Function will not and is not required to operate in the presence of a single channel failure.~~ The reactor trip on turbine trip is not credited in the safety analyses. The unit is designed to withstand a complete loss of load and not sustain core damage

BASES

APPLICABLE SAFETY ANALYSES, LCO AND APPLICABILITY (continued)

or challenge the RCS pressure limitations. Core protection is provided by the Pressurizer Pressure-High trip Function, and RCS integrity is ensured by the pressurizer safety valves. This trip Function is diverse to the Turbine Trip-Low Autostop Oil Pressure trip Function. Each turbine stop valve is equipped with one limit switch that inputs to the RPS. If both limit switches indicate that the stop valves are all closed, a reactor trip is initiated.

LSSS values are not applicable to this function because the RPS inputs are valve limit switches and not adjustable setpoints.

No analytical value is assumed in the accident analyses for this function. The LCO requires two Turbine Trip-Turbine Stop Valve Closure channels, one per valve, to be OPERABLE in MODE 1 above P-9. Both channels must trip to cause reactor trip.

Below the P-9 setpoint, a load rejection can be accommodated by the Steam Dump System. In MODE 2, 3, 4, 5, or 6, there is no potential for a load rejection, and the Turbine Trip-Stop Valve Closure trip Function does not need to be OPERABLE.

16. Safety Injection Input from Engineered Safety Feature Actuation System

The SI Input from ESFAS ensures that if a reactor trip has not already been generated by the RPS, the ESFAS automatic actuation logic will initiate a reactor trip upon any signal that initiates SI. This is a condition of acceptability for the LOCA. However, other transients and accidents take credit for varying levels of ESF performance and rely upon rod insertion, except for the most reactive rod that is assumed to be fully withdrawn, to ensure reactor shutdown. Therefore, a reactor trip is initiated every time an SI signal is present.

An LSSS value is ~~Allowable Values are~~ not applicable to this Function. The SI Input is provided by relay in the ESFAS. Therefore, there is no measurement signal with which to associate an LSSS.

The LCO requires two trains of SI Input from ESFAS to be OPERABLE in MODE 1 or 2.

A reactor trip is initiated every time an SI signal is present. Therefore, this trip Function must be OPERABLE in MODE 1 or 2, when the reactor is critical, and must be shut down in the event of an accident. In MODE 3, 4, 5, or 6, the reactor is not critical, and this trip Function does not need to be OPERABLE.

BASES

APPLICABLE SAFETY ANALYSES, LCO AND APPLICABILITY (continued)

17. Reactor Protection System Interlocks

Replace with Insert RPS-5

~~Reactor~~ protection interlocks are provided to ensure reactor trips ~~are~~ in the ~~correct~~ configuration for the current unit status. ~~They~~ back up operator actions to ~~ensure~~ protection system ~~Functions~~ are not bypassed during unit conditions ~~under~~ which the safety analysis assumes the Functions ~~are~~ not bypassed. ~~Therefore~~, the interlock Functions ~~do not~~ need to be OPERABLE when the ~~associated~~ ~~reactor~~ trip functions are outside the applicable MODES. These ~~are~~:

a. Intermediate Range Neutron Flux, P-6

The Intermediate Range Neutron Flux, P-6 interlock is actuated when any NIS intermediate range channel goes approximately one decade above the minimum channel reading. If both channels drop below the setpoint, the permissive will automatically be defeated. The LCO requirement for the P-6 interlock ensures that the following Functions are performed:

- on increasing power, the P-6 interlock allows the manual block of the NIS Source Range, Neutron Flux reactor trip. This prevents a premature block of the source range trip and allows the operator to ensure that the intermediate range is OPERABLE prior to leaving the source range. When the source range trip is blocked, the high voltage to the detectors is also removed; and

- on decreasing power, the P-6 interlock automatically energizes the NIS source range detectors and enables the NIS Source Range Neutron Flux reactor trip.

The LCO requires two channels of Intermediate Range Neutron Flux, P-6 interlock to be OPERABLE in MODE 2 when below the P-6 interlock setpoint.

Above the P-6 interlock setpoint, the NIS Source Range Neutron Flux reactor trip will be blocked, and this Function will no longer be necessary.

b. Low Power Reactor Trips Block, P-7

The Low Power Reactor Trips Block, P-7 interlock is actuated by input from either Power Range Neutron Flux or Turbine Impulse Pressure. The LCO requirement for the P-7 interlock ensures that the following Functions are performed:

INSERT RPS-5

Reactor protection system interlocks are provided to ensure reactor trips are in the correct configuration for the unit status. As required by IEEE 279-1968, the interlocks perform a safety function to automatically remove (unblock) operating bypasses of reactor trip Functions to ensure the Functions are enabled under unit conditions when the safety analyses credit the Functions. Therefore, the interlocks need to be OPERABLE when the associated reactor trip Functions are required in the applicable MODES. The interlocks are:

BASES

APPLICABLE SAFETY ANALYSES, LCO AND APPLICABILITY (continued)

(1) on increasing power, the P-7 interlock automatically enables reactor trips on the following Functions:

- Pressurizer Pressure - Low;
- Pressurizer Water Level - High;
- Reactor Coolant Flow - Low (Two Loops);
- RCP Breaker Open (Two Loops); and
- Undervoltage Bus A01 and A02 ~~and~~
- ~~Underfrequency Bus A01 and A02.~~

These reactor trips are only required when operating above the P-7 setpoint ~~(approximately 10% power)~~. The reactor trips provide protection against violating the DNBR limit. Below the P-7 setpoint, the RCS is capable of providing sufficient natural circulation without any RCP running.

(2) on decreasing power, the P-7 interlock automatically blocks reactor trips on the following Functions:

- Pressurizer Pressure - Low;
- Pressurizer Water Level - High;
- Reactor Coolant Flow - Low (Two Loops);
- RCP Breaker Position (Two Loops); and
- Undervoltage Bus A01 and A02; ~~and~~
- ~~Underfrequency Bus A01 and A02.~~

The low power trips are blocked below the P-7 setpoint and unblocked above the P-7 setpoint. In MODE 2, 3, 4, 5 or 6, this Function does not have to be OPERABLE because the interlock performs its Function when power level drops below 10% power, which is in MODE 1.

Power Range Neutron Flux

Power Range Neutron Flux is actuated by two-out-of-four NIS power range channels. The LCO requirement for this Function ensures that this input to the P-7 interlock is available.

The LCO requires four channels of Power Range Neutron Flux to be OPERABLE in MODE 1.

OPERABILITY in MODE 1 ensures the Function is available to perform its increasing power Functions.

BASES

APPLICABLE SAFETY ANALYSES, LCO AND APPLICABILITY (continued)

Turbine Impulse Pressure

The Turbine Impulse Pressure interlock is actuated when the pressure in the first stage of the high pressure turbine is greater than ~~approximately 10% of the rated full power pressure~~ the P-7 setpoint. This is determined by one-out-of-two pressure detectors. The LCO requirement for this Function ensures that one of the inputs to the P-7 interlock is available.

The LCO requires two channels of Turbine Impulse Pressure interlock to be OPERABLE in MODE 1.

The Turbine Impulse Chamber Pressure interlock must be OPERABLE when the turbine generator is operating. The interlock Function is not required OPERABLE in MODE 2, 3, 4, 5, or 6 because the turbine generator is not operating.

c. Power Range Neutron Flux, P-8

The Power Range Neutron Flux, P-8 interlock is actuated ~~at approximately 50% power~~ when power is greater than the P-8 setpoint as determined by two-out-of-four NIS power range detectors.

The P-8 interlock automatically enables the Reactor Coolant Flow-Low (Single Loop) and RCP Breaker Position (Single Loop) reactor trips on increasing power. The LCO requirement for this trip Function ensures that protection is provided against a loss of flow in any RCS loop that could result in DNB conditions in the core when greater than approximately 50% power. On decreasing power, the reactor trip on low flow in any loop is automatically blocked.

The LCO requires four channels of Power Range Neutron Flux, P-8 interlock to be OPERABLE in MODE 1.

In MODE 1, a loss of flow in one RCS loop could result in DNB conditions, so the Power Range Neutron Flux, P-8 interlock must be OPERABLE. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the core is not producing sufficient power to be concerned about DNB conditions.

d. Power Range Neutron Flux, P-9

The Power Range Neutron Flux, P-9 interlock, is actuated ~~at approximately 50% power~~ when power is greater than the P-9 setpoint as determined by two-out-of-four NIS

BASES

APPLICABLE SAFETY ANALYSES, LCO AND APPLICABILITY (continued)

power range detectors, if the Steam Dump System is available. The LCO requirement for this Function ensures that the Turbine Trip-Low Autostop Oil Pressure and Turbine Trip-Turbine Stop Valve Closure reactor trips are enabled above the P-9 setpoint. Above the P-9 setpoint, a turbine trip will cause a load rejection beyond the capacity of the Steam Dump System. A reactor trip is automatically initiated on a turbine trip when it is above the P-9 setpoint to minimize the transient on the reactor.

The LCO requires four channels of Power Range Neutron Flux, P-9 interlock, to be OPERABLE in MODE 1 with one of two circulating water pump breakers closed and condenser vacuum greater than or equal to 22 "Hg.

In MODE 1, a turbine trip could cause a load rejection beyond the capacity of the Steam Dump System, so the Power Range Neutron Flux interlock must be OPERABLE. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the reactor is not at a power level sufficient to have a load rejection beyond the capacity of the Steam Dump System.

e. Power Range Neutron Flux, P-10

The Power Range Neutron Flux, P-10 interlock is actuated ~~at approximately 10% power~~ when power is greater than the P-10 setpoint as determined by two-out-of-four NIS power range detectors. If power level falls below 10% RTP on 3 of 4 channels, the nuclear instrument trips will be automatically unblocked. The LCO requirement for the P-10 interlock ensures that the following Functions are performed:

- on increasing power, the P-10 interlock allows the operator to manually block the Intermediate Range Neutron Flux reactor trip;
- on increasing power, the P-10 interlock allows the operator to manually block the Power Range Neutron Flux-Low reactor trip;
- on increasing power, the P-10 interlock automatically provides a backup signal to block the Source Range Neutron Flux reactor trip, and also to de-energize the NIS source range detectors;
- on decreasing power, the P-10 interlock automatically enables the Power Range Neutron Flux-Low reactor trip and the Intermediate Range Neutron Flux reactor trip.

BASES

APPLICABLE SAFETY ANALYSES, LCO AND APPLICABILITY (continued)

to be OPERABLE when the bypass breaker is open or racked out.

These trip Functions must be OPERABLE in MODE 1 or 2 when a Reactor Trip Bypass Breaker is racked in and closed. In MODE 3, 4, or 5, this RPS trip Function must be OPERABLE when a Reactor Trip Bypass Breaker is racked in and closed and the Rod Control System is capable of rod withdrawal.

21. Automatic Trip Logic

The LCO requirement for the RTBs (Functions 18 and 19) and Automatic Trip Logic (Function 21) ensures that means are provided to interrupt the power to allow the rods to fall into the reactor core. Each RTB is equipped with an undervoltage coil and a shunt trip coil to trip the breaker open when needed. Each RTB is equipped with a bypass breaker to allow testing of the trip breaker while the unit is at power. The reactor trip signals generated by the RPS Automatic Trip Logic cause the RTBs and associated bypass breakers to open and shut down the reactor.

The LCO requires two trains of RPS Automatic Trip Logic to be OPERABLE. Having two OPERABLE channels ensures that random failure of a single logic channel will not prevent reactor trip. These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RPS trip Functions must be OPERABLE when the RTBs are closed and the Rod Control System is capable of rod withdrawal.

The RPS instrumentation satisfies Criterion 3 of the NRC Policy Statement.

ACTIONS

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.1-1.

LSSS value

In the event a channel's Trip Setpoint is found nonconservative with respect to the ~~Allowable Value,~~ or the transmitter, instrument loop, signal processing electronics, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected.

When the number of inoperable channels in a trip Function exceed those specified in one or other related Conditions associated with a trip Function, then the unit is outside the safety analysis. Therefore,

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.6

SR 3.3.1.6 is a calibration of the excore channels to the incore channels. If the measurements do not agree, the excore channels are not declared inoperable but must be calibrated to agree with the incore detector measurements. If the excore channels cannot be adjusted, the channels are declared inoperable. This Surveillance is performed to verify the f(ΔI) input to the overtemperature ΔT Function.

A Note modifies SR 3.3.1.6. The Note states that this Surveillance is required only if reactor power is > 50% RTP and that 24 hours is allowed for performing the first surveillance after reaching 50% RTP.

The Frequency of 92 EFPD is adequate. It is based on industry operating experience, considering instrument reliability and operating history data for instrument drift.

SR 3.3.1.7

SR 3.3.1.7 is the performance of a COT every 92 days.

A COT is performed on each required channel to ensure the entire channel will perform the intended Function.

Setpoints must be within the ~~Allowable Values~~ LSSS Values specified in Table 3.3.1-1.

The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint ~~methodology.~~ analysis.

The "as found" and "as left" values must also be recorded and verified to be within the required limits.

SR 3.3.1.7 is modified by a Note that provides a 4 hour delay in the requirement to perform this Surveillance for source range instrumentation when entering MODE 3 from MODE 2. This Note allows a normal shutdown to proceed without a delay for testing in MODE 2 and for a short time in MODE 3 until the RTBs are open and SR 3.3.1.7 is no longer required to be performed. If the unit is to be in MODE 3 with the RTBs closed for > 4 hours this Surveillance must be performed prior to 4 hours after entry into MODE 3.

BASES

SURVEILLANCE REQUIREMENTS (continued)

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint ~~methodology.~~ analysis The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint ~~methodology.~~ analysis

The Frequency of 18 months is based on the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint ~~methodology.~~ analysis

SR 3.3.1.10 is modified by a Note stating that this test shall include verification that the time delays are adjusted to the prescribed values where applicable.

SR 3.3.1.11

SR 3.3.1.11 is the performance of a CHANNEL CALIBRATION, as described in SR 3.3.1.10, every 18 months. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The CHANNEL CALIBRATION for the power range neutron detectors consists of a normalization of the detectors based on a power calorimetric and flux map performed above 15% RTP. The CHANNEL CALIBRATION for the source range and intermediate range neutron detectors consists of obtaining the detector plateau or preamp discriminator curves, evaluating those curves, and comparing the curves to the manufacturer's data. This Surveillance is not required for the NIS power range detectors for entry into MODE 2 or 1, and is not required for the NIS intermediate range detectors for entry into MODE 2, because the unit must be in at least MODE 2 to perform the test for the intermediate range detectors and MODE 1 for the power range detectors. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed on the 18 month Frequency.

SR 3.3.1.12

SR 3.3.1.12 is the performance of a COT of RPS interlocks every 18 months.

The Frequency is based on the known reliability of the interlocks and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.13

SR 3.3.1.13 is the performance of a TADOT of the Manual Reactor Trip, RCP Breaker Position, SI Input from ESFAS, and the Condenser Pressure-High and Circulating Water Pump Breaker Position inputs to the P-9 Interlock. This TADOT is performed every 18 months. The test shall independently verify the OPERABILITY of the undervoltage and shunt trip circuits for the Manual Reactor Trip Function for the Reactor Trip Breakers and the undervoltage trip circuits for the Reactor Trip Bypass Breakers.

The Frequency is based on the known reliability of the Functions and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

SR 3.3.1.14

SR 3.3.1.14 is the performance of a TADOT of Turbine Trip Functions. This TADOT is as described in SR 3.3.1.4, except that this test is performed prior to exceeding the P-9 interlock whenever the unit has been in MODE 3. This Surveillance is not required if it has been performed within the previous 31 days. Performance of this test will ensure that the turbine trip Function is OPERABLE prior to exceeding the P-9 interlock.

SR 3.3.1.15

SR 3.3.1.15 is the performance of an ACTUATION LOGIC TEST on the RCP Breaker Position (Two Loop), Reactor Coolant Flow-Low (Two Loop) and Underfrequency Bus A01 and A02 Trip Functions, and P-6, P-7, P-8, P-9 and P-10 Interlocks every 18 months.

The 18 month frequency is based on the need to perform this surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the surveillance were performed with the reactor at power.

REFERENCES

1. FSAR, Chapter 7.
2. FSAR, Chapter 14.
3. IEEE-279-1968.
4. ~~10 CFR 50.49.~~
5. ~~DG-I01, Instrument Setpoint Methodology.~~

B 3.3 INSTRUMENTATION

B 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

BASES

BACKGROUND

The ESFAS initiates necessary safety systems, based on the values of selected unit parameters, to protect against violating core design limits and the Reactor Coolant System (RCS) pressure boundary, and to mitigate accidents.

Add Insert ESFAS-1

The ESFAS instrumentation is segmented into three distinct but interconnected modules as identified below:

- Field transmitters or process sensors and instrumentation: provide a measurable electronic signal based on the physical characteristics of the parameter being measured;
- Signal processing equipment including analog protection system, field contacts, and protection channel sets: provide signal conditioning, compatible electrical signal output to protection system devices, and control board/control room/miscellaneous indications; and
- Relay Logic Racks including input, logic and output devices: initiates proper Engineered Safety Feature (ESF) actuation in accordance with the defined logic and based on the bistable outputs from the signal process control and protection system.

Field Transmitters or Sensors

To meet the design demands for redundancy and reliability, more than one, and often as many as four, field transmitters or sensors are used to measure unit parameters. In many cases, field transmitters or sensors that input to the ESFAS are shared with the Reactor Protection System (RPS). In some cases, the same channels also provide control system inputs. To account for calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the ~~Allowable Values.~~ The OPERABILITY of each transmitter or sensor can be evaluated when its "as found" calibration data are compared against its documented acceptance criteria.

LSSS values

INSERT ESFAS-1

Limiting Safety System Settings

A Limiting Safety System Setting is specified in Table 3.3.2-1 for each ESFAS Function that has an adjustable setpoint, to ensure that the Engineered Safety Feature acutations credited in the safety analyses occur within the limits assumed in the analyses.

To account for instrumentation channel uncertainties, including sensor and rack errors, normal instrument drift, and environmental and process errors, the LSSS values in Table 3.3.2-1 are conservative with respect to an Analytical Limit established for the Function in the safety analyses, or a Process Limit if the Function is not specifically credited in the safety analyses. The LSSS value is based on a calculated Limiting Trip Setpoint (LTSP), which is offset from the Analytical or Process Limit by all known uncertainties applicable to the channel. The field sensors and signal processing equipment for these channels are assumed to operate within uncertainties determined at a 95/95 confidence level.

In some cases, an Analytical or Process Limit may not exist for an ESFAS Function, such as an operating bypass (the SI Block on Pressurizer Pressure) that is based on a nominal Field Trip Setpoint (FTSP) not specifically credited in the safety analyses. For these cases, the LSSS value is based on an as-found tolerance limit of the nominal FTSP, rather than on a calculated LTSP.

The actual Field Trip Setpoint (FTSP) entered into the channel bistable during calibration is normally more conservative than the LSSS value, which provides design margin beyond the LTSP. This design margin provides further assurance that the ESFAS Function will operate prior to the process reaching the Analytical Limit or Process Limit for the Function.

Notes 1 and 2

Notes 1 and 2 in Table 3.3.2-1 apply to the LSSS column and address required actions during a Channel Operational Test (COT) surveillance related to as-left and as-found conditions of the RPS Functions that have LSSS values. Note 1 provides two conditions that must be met for the channel to be considered OPERABLE at the completion of the surveillance. These conditions assure that the COT portion of the channel is operating within the uncertainty values applied in the associated setpoint calculation.

Note 2 requires that a channel found outside the COT as-found acceptance criteria be evaluated prior to returning the channel to service. The out-of-tolerance condition will be evaluated under the Corrective Action Process, and may involve review of calibration/surveillance history, component replacement if it is determined a component has failed, cannot be calibrated within its as-left tolerance, the calibration is not repeatable, or there is an adverse performance history.

BASES

BACKGROUND (continued)

Signal Processing Equipment

Generally, three or four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. The process control equipment provides signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with setpoints established by safety analyses. If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable is forwarded to the logic relays.

Replace with Insert ESFAS-2

Generally, if a parameter is used only for input to the protection circuits, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function is still OPERABLE with a two-out-of-two logic. If one channel fails such that a partial Function trip occurs, a trip will not occur and the Function is still OPERABLE with a one-out-of-two logic.

Generally, if a parameter is used for input to the Relay Logic Racks and a control function, four channels with a two-out-of-four logic are sufficient to provide the required reliability and redundancy. The circuit must be able to withstand both an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Again, a single failure will neither cause nor prevent the protection function actuation.

These requirements are described in IEEE-279-1968 (Ref. 2).

Allowable Values

To allow for calibration tolerances, instrumentation uncertainties and instrument drift, the Allowable Values specified in Table 3.3.2-1 in the accompanying LCO are conservatively adjusted with respect to the analytical limits. A detailed description of the methodology used to calculate the Allowable Values, including their explicit uncertainties, is provided in DGI-01, Instrument Setpoint Methodology (Ref. 4). The actual nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT. If the measured setpoint does not exceed the Allowable Value, the bistable is considered OPERABLE.

Setpoints in accordance with the Allowable Value ensure that the consequences of Design Basis Accidents (DBAs) will be acceptable,

INSERT ESFAS-2

Generally, if a parameter is used only for input to the protection circuits, three channels with a two-out-of-three coincidence logic are sufficient to provide the required reliability and redundancy. If one of the three channels fails in a direction that would result in a non-trip of the affected channel, the Function is still OPERABLE with a two-out-of-two coincidence logic on the remaining two channels. If one of the three channels fails in a direction that trips the channel, the failure alone does not cause an ESFAS actuation and the Function is still OPERABLE with a one-out-of-two coincidence logic on the remaining two channels.

Generally, if a parameter is used for input to both protection circuits and a control function, four channels with a two-out-of-four coincidence logic are needed to provide the required reliability and redundancy. Under IEEE 279-1968 (Ref. 3), the control/protection interaction criterion requires that if a control malfunction can prevent protective action of a channel and the control malfunction also requires protective action by the same channel providing the control signal, then the failure of the channel providing the control signal and an additional failure of the remaining protection channels must be considered. With four channels in a two-out-of-four coincidence, the combined control/protection failures will neither cause nor prevent the protective action.

BASES

BACKGROUND (continued)

~~providing the~~ unit is operated from within the LCOs at the onset of the DBA and the equipment ~~functions as designed~~.

Each channel can be tested on line to verify that the signal processing equipment and setpoint accuracy is within the specified allowance requirements. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SR section.

~~The~~ Allowable Values listed in Table 3.3.2-1 are based on the methodology ~~described~~ in Reference 4, which incorporates ~~all~~ of the known uncertainties ~~applicable~~ for each ~~channel.~~ The magnitudes of these uncertainties are factored ~~into the~~ determination of each Allowable Value. All ~~field~~ sensors and signal processing equipment for these ~~channels~~ are assumed to operate within the allowances ~~of these~~ uncertainty magnitudes.

<u>Relay Logic Racks</u>

The Relay Logic Rack equipment is used for the decision logic processing of outputs from the signal processing equipment bistables. To meet the redundancy requirements, two trains of Relay Logic Racks, each performing the same functions, are provided.

The Relay Logic Racks perform the decision logic for most ESF equipment actuation; generates the electrical output signals that initiate the required actuation; and provides the status, permissive, and annunciator output signals to the main control room of the unit.

The bistable outputs from the signal processing equipment are sensed by the Relay Logic Rack equipment and combined into logic matrices that represent combinations indicative of various transients. If a required logic matrix combination is completed, the system will send actuation signals via master and slave relays to those components whose aggregate Function best serves to alleviate the condition and restore the unit to a safe condition. Examples are given in the Applicable Safety Analyses, LCO, and Applicability sections of this Bases.

The actuation of ESF components is accomplished through master and slave relays. The Relay Logic Racks energize the master relays appropriate for the condition of the unit. Each master relay then energizes one or more slave relays, which then cause actuation of the end devices.

BASES

APPLICABLE SAFETY ANALYSES, LCO AND APPLICABILITY (continued)

Thus, the high pressure Function will not experience any adverse environmental conditions and the ~~Allowable Value~~ LSSS value reflects only steady state instrument uncertainties.

Containment Pressure-High must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the primary and secondary systems to pressurize the containment following a pipe break. In MODES 4, 5, and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment.

d. <u>Safety Injection-Pressurizer Pressure-Low</u>

This signal provides protection against the following accidents:

- Inadvertent opening of a steam generator (SG) relief or safety valve;
- SLB;
- A spectrum of rod cluster control assembly ejection accidents (rod ejection);
- Inadvertent opening of a pressurizer relief or safety valve;
- LOCAs; and
- SG Tube Rupture.

Pressurizer pressure provides both control and protection functions: input to the Pressurizer Pressure Control System, reactor trip, and SI. However, two independent PORV open signals must be present before a PORV can open. Therefore, a single pressure channel failing high will not fail a PORV open and trigger a depressurization/SI event. Additionally, in the event of a failed open spray valve, RCS depressurization would be slow enough to be recognized by the operator and mitigated through manual actions to close the spray valve and energize the pressurizer heaters prior to reaching saturated conditions in the RCS. Therefore, there would be no uncontrolled loss of RCS inventory and no need for boron injection. Therefore, only three protection channels are necessary to satisfy the protective requirements.

BASES

APPLICABLE SAFETY ANALYSES, LCO AND APPLICABILITY (continued)

This Function must be OPERABLE in MODES 1, 2, and 3 (above the Pressurizer Pressure interlock) to mitigate the consequences of an HELB inside containment. This signal may be manually blocked by the operator below the Pressurizer Pressure interlock. Automatic SI actuation below this pressure setpoint is then performed by the Containment Pressure-High signal.

This Function is not required to be OPERABLE in MODE 3 below the Pressurizer Pressure interlock. Other ESF functions are used to detect accident conditions and actuate the ESF systems in this MODE. In MODES 4, 5, and 6, this Function is not needed for accident detection and mitigation.

e. <u>Safety Injection-Steam Line Pressure-Low</u>

Steam Line Pressure-Low provides protection against the following accidents:

- SLB;
- Feed line break; and
- Inadvertent opening of an SG relief or an SG safety valve.

Steam Line Pressure-Low provides a signal for control of the main steam atmospheric steam dump valves. However, a failure in a steam line pressure channel will not create a control failure that would result in a low steamline pressure SI event. Thus, three OPERABLE channels on each steam line are sufficient to satisfy the protective requirements with a two-out-of-three logic on each steam line.

With the transmitters located in the fan rooms and in the fuel pool area, it is possible for them to experience adverse environmental conditions during a secondary side break. Therefore, the ~~Allowable Value~~ LSSS value reflects both steady state and adverse environmental instrument uncertainties.

This Function is anticipatory in nature and has a lead/lag ~~ratio~~ time constants of ~~12/2.~~ 18/2

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY (continued)

and energy release to containment. The transmitters are located outside containment with the sensing lines passing through containment penetrations to sense the containment atmosphere in three different locations. Containment Pressure-High High provides no input to any control functions. Thus, three OPERABLE channels are sufficient to satisfy protective requirements with two-out-of-three logic. The transmitters and electronics are located outside of containment. Thus, they will not experience any adverse environmental conditions, and the ~~Allowable Value~~ reflects only steady state instrument uncertainties.

LSSS value

Containment Pressure-High High must be OPERABLE in MODES 1, 2, and 3, when there is sufficient energy in the primary and secondary side to pressurize the containment following a pipe break. This would cause a significant increase in the containment pressure, thus allowing detection and closure of the MSIVs. The Steam Line Isolation Function remains OPERABLE in MODES 2 and 3 unless all MSIVs are closed and de-activated. In MODES 4, 5, and 6, there is not enough energy in the primary and secondary sides to pressurize the containment to the Containment Pressure-High High setpoint.

d. <u>Steam Line Isolation-High Steam Flow Coincident With Safety Injection and Coincident With T_{avg}-Low</u>

This Function provides closure of the MSIVs during an SLB or inadvertent opening of an SG relief or safety valve to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment.

Two steam line flow channels per steam line are required OPERABLE for this Function. These are combined in a one-out-of-two logic to indicate high steam flow in one steam line. The steam flow transmitters provide control inputs, but the control function cannot cause the events that the function must protect against. Therefore, two channels are sufficient to satisfy redundancy requirements. The one-out-of-two configuration allows online testing because trip of one high steam flow channel is not sufficient to cause initiation.

LSSS value

The High Steam Flow ~~Allowable Value~~ is a ΔP corresponding to 20% of full steam flow at no load steam pressure.

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY (continued)

With the transmitters (d/p cells) located inside containment, it is possible for them to experience adverse environmental conditions during an SLB event. Therefore, the ~~Allowable Values~~ reflect both steady state and adverse environmental instrument uncertainties.

LSSS values

The main steam line isolates only if the high steam flow signal occurs coincident with an SI and low RCS average temperature. The Main Steam Line Isolation Function requirements for the SI Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating functions and requirements.

The T_{avg}-Low Function consists of four channels (two in each loop), providing input to both trains in a two-out-of-four logic configuration. Three channels of T_{avg} are required to be OPERABLE. The accidents that this Function protects against cause reduction of T_{avg} in the entire primary system. Therefore, the provision of three OPERABLE channels ensures no single random failure disables the T_{avg}-Low Function. The T_{avg} channels provide control inputs, but the control function cannot initiate events that the Function acts to mitigate. Therefore, additional channels are not required to address control protection interaction issues.

With the T_{avg} resistance temperature detectors (RTDs) located inside the containment, it is possible for them to experience adverse environmental conditions during an SLB event. Therefore, the ~~Trip Setpoint~~ reflects both steady state and adverse environmental instrumental uncertainties.

LSSS value

This Function must be OPERABLE in MODES 1 and 2, and in MODE 3, when a secondary side break or stuck open valve could result in rapid depressurization of the steam lines. The Steam Line Isolation Function is required to be OPERABLE in MODES 2 and 3 unless all MSIVs are closed and de-activated. This Function is not required to be OPERABLE in MODES 4, 5, and 6 because there is insufficient energy in the secondary side of the unit to have an accident.

e. <u>Steam Line Isolation-High High Steam Flow Coincident With Safety Injection</u>

This Function provides closure of the MSIVs during a steam line break ~~(or inadvertent opening of a relief or safety valve)~~ to

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY (continued)

maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment.

high-high

Two steam line flow channels per steam line are required to be OPERABLE for this Function. These are combined in a one-out-of-two logic to indicate ~~high~~ steam flow in one steam line. The steam flow transmitters provide control inputs, but the control function cannot cause the events that the Function must protect against. Therefore, two channels are sufficient to satisfy redundancy requirements.

~~The Allowable Value for high steam flow is a ΔP, corresponding to 120% of full steam flow at full steam pressure.~~

With the transmitters located inside containment, it is possible for them to experience adverse environmental conditions during an SLB event. Therefore, the ~~Allowable Value~~ LSSS value reflects both steady state and adverse environmental instrument uncertainties.

high-high

The main steam lines isolate only if the ~~high~~ steam flow signal occurs coincident with an SI signal. The Main Steam Line Isolation Function requirements for the SI Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating functions and requirements.

This Function must be OPERABLE in MODES 1, 2, and 3 when a secondary side break or stuck open valve could result in rapid depressurization of the steam lines unless all MSIVs are closed and de-activated. This Function is not required to be OPERABLE in MODES 4, 5, and 6 because there is insufficient energy in the secondary side of the unit to have an accident.

5. Feedwater Isolation

The primary function of the Feedwater Isolation signal is to stop the excessive flow of feedwater into the SGs. This Function is necessary to mitigate the effects of a high water level in the SGs, which could result in carryover of water into the steam lines and excessive cooldown of the primary system. The SG high water level is due to excessive feedwater flows.

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY (continued)

The Function is actuated on an SI signal, or when the level in either SG exceeds the high setpoint.

MFIV Isolation

An SI signal results in the following actions:

- ~~MFW pumps trip (causes subsequent closure of the MFW pump discharge valves),~~ and
- MFRVs and the bypass regulating valves close.

A SG Water Level-High in either SG results in the closure of the MFRVs and the bypass regulating valves.

a. <u>Feedwater Isolation-Automatic Actuation Logic and Actuation Relays</u>

   Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

b. <u>Feedwater Isolation-Steam Generator Water Level-High</u>

   This signal provides protection against excessive feedwater flow. The ~~ESFAS~~ SG water level instruments provide input to the SG Water Level Control System. If this input to the SG Water Level Control System fails low, it would cause a control action to open the Feedwater Control Valves for the affected SG. The remaining channels, in a two-out-of-two configuration, would be required to detect a high SG Water Level condition and initiate a Feedwater Isolation to prevent an overfill condition. Therefore this configuration does not meet the single failure criteria of Reference 1. However, justification for a two-out-of-three Feedwater Isolation-SG Water Level-High Function is provided in NUREG-1218, Reference 5.

   ~~Table 3.3.2-1 identifies the Technical Specification Allowable Value for the Feedwater Isolation – SG Water Level – High function as not applicable (NA). No Analytical Value is assumed in the accident analysis for this function. The nominal setting required for the Feedwater Isolation – SG Water Level – High function is 78% of span. This nominal setting was developed outside of the setpoint methodology and has been provided by the NSSS supplier.~~

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY (continued)

c. Feedwater Isolation-Safety Injection

Feedwater Isolation is also initiated by all Functions that initiate SI. The Feedwater Isolation Function requirements for these Functions are the same as the requirements for their SI function.

Therefore, the requirements are not repeated in Table 3.3.2-1. Instead Function 1, SI, is referenced for all initiating functions and requirements.

Feedwater Isolation Functions must be OPERABLE in MODES 1 and 2 and 3 except when all MFRVs, and associated bypass valves are closed and de-activated. In MODES 4, 5, and 6, the MFW System is not in service and this Function is not required to be OPERABLE.

6. Auxiliary Feedwater

The AFW System is designed to provide a secondary side heat sink for the reactor in the a event that the MFW System is not available. The system has ~~two~~ motor driven pump~~s~~ and a turbine driven pump, making it available during normal unit operation, during a loss of AC power, a loss of MFW, and during a Feedwater System pipe break. The normal source of water for the AFW System is the condensate storage tank (CST) (not safety related). ~~Upon a low level in the CST, the operators can manually~~ Upon a low pressure in the AFW pump suction piping, the suction source will automatically realign the pump suctions to the Service Water System, which is the safety related water source. The AFW System is aligned so that upon a pump start, flow is initiated to the respective SGs immediately.

a. Auxiliary Feedwater-Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

b. Auxiliary Feedwater-Steam Generator Water Level-Low Low

SG Water Level-Low Low provides protection against a loss of heat sink. A loss of MFW would result in a loss of SG water level. SG Water Level-Low Low in either SG will cause both AFW ~~motor-driven~~ pumps to start. The system is aligned so that upon start of the pumps, water immediately begins to flow to the SGs. ~~SG Water Level-Low Low in both SGs will cause the turbine-driven AFW pump to start.~~

BASES

LSSS value

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY (continued)

With the transmitters (d/p cells) located inside containment and thus possibly experiencing adverse environmental conditions (feed line break), the ~~Allowable Value~~ reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

c. Auxiliary Feedwater-Safety Injection

both

An SI signal starts ~~the motor driven~~ AFW pumps. The AFW initiation functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating functions and requirements.

and turbine driven

Functions 6.a through 6.c must be OPERABLE in MODES 1, 2, and 3 to ensure that the SGs remain the heat sink for the ~~reactor.~~ SG Water Level-Low Low in any operating SG will cause the motor driven AFW pumps to start. The system is aligned so that upon a start of the pump, water immediately begins to flow to the SGs. ~~SG Water Level-Low Low in both SGs will cause the turbine driven pump to start.~~ These Functions do not have to be OPERABLE in MODES 5 and 6 because there is not enough heat being generated in the reactor to require the SGs as a heat sink. In MODE 4, AFW actuation does not need to be OPERABLE because either AFW or residual heat removal (RHR) will already be in operation to remove decay heat or sufficient time is available to manually place either system in operation.

d. Auxiliary Feedwater-Undervoltage Bus A01 and A02

The LCO requires two channels per bus to be OPERABLE. A channel consists of an undervoltage relay and one set of associated contacts.

both AFW pumps

the SGs

A loss of power on the A01 and A02 buses provides indication of a pending loss of both Main Feedwater pumps and the subsequent need for some method of decay heat removal. A loss of power to Buses A01 and A02 will start ~~the turbine driven AFW pump~~ to ensure that ~~at least one SG~~ contains enough water to serve as the heat sink for reactor decay heat and sensible heat removal following the reactor trip.

Function 6.d must be OPERABLE in MODES 1 and 2. This ensures that ~~at least one~~ SG is provided with water to serve as the heat sink to remove reactor decay heat and sensible heat in

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY (continued)

the event of an accident. In MODES 3, 4, and 5, the MFW pumps may be normally shut down, and thus a pump trip is not indicative of a condition requiring automatic AFW initiation.

Add Insert ESF-2

7. ~~Condensate Isolation~~ Not Used

~~The Condensate Isolation Function serves as a backup protection~~ function in the event of a Main Steam Line Break inside containment with a failure of the Main Feedwater lines to isolate. An evaluation of IE Bulletin 80-04 showed that a single failure of a MFRV to close on a SI signal could allow feedwater addition to the faulted SG, leading to containment overpressure.

a. Containment Pressure-Condensate Isolation (CPCI)

The Condensate Isolation Function is actuated when containment pressure exceeds the high setpoint, and performs the following functions:

- Trips the condensate pumps; and
- Trips the heater drain pumps.

The Condensate Isolation Function must be OPERABLE in MODES 1, 2 and 3, except when all MFRVs and associated bypass valves are closed and de-activated. This Function is not required to be OPERABLE in MODES 4, 5 and 6, because there is insufficient energy in the secondary side of the unit to have an accident.

b. Condensate Isolation - Automatic Actuation Logic and Actuation Relays

Automatic Actuation logic and actuation relays consist of the same features and operate in the same manner as described for ~~ESFAS Function 1.b.~~

8. Pressurizer Pressure Safety Injection Block

To allow some flexibility in unit operations, the Pressurizer Pressure SI Block is included as part of the ESFAS.

The block permits a normal unit cooldown and depressurization without actuation of SI. With two-out-of-three pressurizer pressure channels (discussed previously) less than the setpoint, the operator can manually block the Pressurizer Pressure-Low and Steam Line

INSERT ESFAS-3
B 3.3.2

e. <u>AFW Pump Suction Transfer on Suction Pressure – Low</u>

A low pressure signal in the AFW pump suction line protects the AFW pumps against a loss of the normal supply of water for the pumps, the CST. Three pressure switches are located on the AFW pump suction line from the CST. A low pressure signal sensed by any two of the three switches will cause the emergency supply of water for both pumps to be automatically aligned to service water. The service water ensures that an adequate supply of water is available for the AFW System to maintain at least one of the SGs as the heat sink for reactor decay heat and sensible heat removal.

This Function must be OPERABLE in MODES 1, 2, and 3 to ensure a safety grade supply of water for the AFW System to maintain the SGs as the heat sink for the reactor. This Function does not have to be OPERABLE in MODES 5 and 6 because there is not enough heat being generated in the reactor to require the SGs as a heat sink. In MODE 4, AFW automatic suction transfer does not need to be OPERABLE because RHR will already be in operation, or sufficient time is available to place RHR in operation, to remove decay heat.

Table 3.3.2-1 Notes 1 and 2 are applicable.

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY (continued)

Pressure-Low SI signals. With two-out-of-three pressurizer pressure channels above the setpoint, the Pressurizer Pressure-Low and Steam Line Pressure-Low SI signals are automatically enabled. The operator can also enable these trips by use of the respective manual reset buttons. The ~~Allowable Value~~ LSSS value reflects only steady state instrument uncertainties.

This Function must be OPERABLE in MODES 1, 2, and 3 to allow automatic initiation of SI actuation on Pressurizer Pressure-Low or Steam Line Pressure-Low signals. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because system pressure must already be below the setpoint for the requirements of the heatup and cooldown curves to be met.

The ESFAS instrumentation satisfies Criterion 3 of ~~the NRC Policy Statement~~ 10 CFR 50.36(c)2(ii).

ACTIONS

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.2-1.

In the event a channel's Trip Setpoint is found nonconservative with respect to the ~~Allowable Value~~ LSSS value, or the transmitter, instrument Loop, signal processing electronics, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected. When the Required Channels in Table 3.3.2-1 are specified (e.g., on a per steam line, per loop, per SG, etc., basis), then the Condition may be entered separately for each steam line, loop, SG, etc., as appropriate.

When the number of inoperable channels in a trip function exceed those specified in one or other related Conditions associated with a trip function, then the unit is outside the safety analysis. Therefore, LCO 3.0.3 should be immediately entered if applicable in the current MODE of operation.

A.1

Condition A applies to all ESFAS protection functions.

Condition A addresses the situation where one or more channels or trains for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.2-1 and to take the Required

BASES

ACTIONS (continued)

unit in at least MODE 3 within an additional 6 hours (7 hours total time) and in MODE 5 within an additional 30 hours (37 hours total time). The allowable Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

F.1, F.2.1, and F.2.2

Condition F applies to Manual Initiation of Steam Line Isolation.

If a channel is inoperable, 1 hour is allowed to return it to an OPERABLE status. The Completion Time of one hour is reasonable considering the low probability of an event occurring during this interval. If the Function cannot be returned to OPERABLE status, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power in an orderly manner and without challenging unit systems. In MODE 4, the unit does not have any analyzed transients or conditions that require the explicit use of the protection functions noted above.

G.1, G.2.1 and G.2.2

Condition G applies to the automatic actuation logic and actuation relays for the Steam Line Isolation, Feedwater Isolation, ~~Condensate Isolation~~ and AFW actuation Functions.

If one train is inoperable, 6 hours are allowed to restore the train to OPERABLE status. The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be returned to OPERABLE status, the unit must be brought to MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. Placing the unit in MODE 4 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.3

SR 3.3.2.3 is the performance of a COT.

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. Setpoints must be found within the ~~Allowable Values~~ LSSS values specified in Table 3.3.2-1.

The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint ~~methodology~~ analysis. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint ~~methodology~~ analysis.

The "as found" and "as left" values must also be recorded and reviewed for consistency with the assumptions of the surveillance interval extension analysis (Ref. 4) when applicable.

The Frequency of 92 days is justified in Reference 4.

SR 3.3.2.4

SR 3.3.2.4 is the performance of a MASTER RELAY TEST. The MASTER RELAY TEST is the energizing of the master relay and verifying contact operation. This test is performed every 18 months.

SR 3.3.2.5

SR 3.3.2.5 is the performance of a SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified in one of two ways. Actuation equipment that may be operated in the design mitigation MODE is either allowed to function, or is placed in a condition where the relay contact operation can be verified without operation of the equipment. This test is performed every 18 months.

SR 3.3.2.6

SR 3.3.2.6 is the performance of a TADOT every 31 days. This test is a check of the Undervoltage Bus A01 and A02 Function.

The Frequency is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.2.7

SR 3.3.2.7 is the performance of a TADOT. This test is a check of the Manual Actuation Functions. It is performed every 18 months. The

BASES

SURVEILLANCE REQUIREMENTS (continued)

Frequency is adequate, based on industry operating experience and is consistent with the typical refueling cycle.

SR 3.3.2.8

SR 3.3.2.8 is the performance of a CHANNEL CALIBRATION.

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to measured parameter within the necessary range and accuracy.

analysis

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the setpoint ~~methodology~~. The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint ~~methodology~~.

The Frequency of 18 months is based on the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint ~~methodology~~.

This SR is modified by a Note stating that this test should include verification that the time constants are adjusted to the prescribed values where applicable.

REFERENCES

1. FSAR, Chapter 14.
2. IEEE-279-1968.
3. ~~10 CFR 50.49.~~ FSAR, Chapter 7
4. ~~DGI-01, Instrument Setpoint Methodology.~~ Not Used
5. NUREG-1218, April 1988.

B 3.3 INSTRUMENTATION

B 3.3.4 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

BASES

BACKGROUND

The DGs provide a source of emergency power when offsite power is either unavailable or is insufficiently stable to allow safe unit operation. Loss of voltage on either of the 4.16 kV safeguards buses will generate an LOP start signal for each associated DG.

Three channels of loss of voltage relays are provided on each 4.16 kV safeguards buses for detecting a loss of bus voltage. The three channels are combined in a two-of-three coincidence logic to initiate a loss of voltage signal that disconnects the safeguards bus from offsite power and starts the associated DG. The channels are designed to detect loss of voltage at approximately 77% of nominal bus voltage. The LOP start actuation is described in FSAR, Section 8.8 (Ref. 1).

Degraded voltage protection is also provided on each 4.16 kV safeguards bus. However, degraded voltage protection does not directly start the DGs. Degraded voltage protection will disconnect the affected bus from offsite power by opening the main supply breaker, causing a loss of voltage signal on the bus. Loss of 4.16 kV bus voltage protection will then start each associated DG.

Degraded voltage protection instrumentation consists of three channels of degraded voltage relays and bus time delay relays combined in separate two-out-of-three coincidence logics for each bus. One coincidence logic initiates degraded voltage protection after a time delay when an SI signal is present. The other coincidence logic initiates degraded voltage protection after a longer time delay when no SI signal is present. In both cases, degraded voltage protection is designed to disconnect the affected bus from offsite power to prevent damage or tripping of operating loads on a sustained low voltage condition below approximately 95% of nominal bus voltage.

Loss of voltage protection is also provided on the 480 V buses. This loss of voltage protection does not initiate DG start. During a loss of voltage to the safety-related 480 V buses, protective relays initiate load shedding and block automatic SI load sequencing until sufficient voltage recovers on the buses. This function is necessary to prevent overloading the DGs.

ADD INSERT LOP-1

INSERT LOP-1

Each DG has a breaker close timer relay. The purpose of the relays is to increase total time delay of the 4160 kV loss of voltage function to allow the 480 V loss of voltage function to operate and initiate load shedding prior to energizing the safeguards buses from the DG.

BASES

BACKGROUND (continued)

Three undervoltage relays are provided on each safety-related 480 V bus for detecting a loss of voltage. The relays are arranged in a two-of-three coincidence logic to generate load shedding signals for the associated 480 V bus.

Allowable Values

and DG breaker close timer

The loss of voltage, ~~and~~ degraded voltage relay settings are based on analytical limits established in electrical system analyses. The settings are such that adequate protection is provided when all instrument channel uncertainties and processing time delay uncertainties are taken into account.

Allowable Values are specified for voltage and time delay settings for the protection functions in SR 3.3.4.3. The actual voltage settings and time delay settings entered into the relays during calibration (the as-left settings) are more conservative than the Allowable Values. The Allowable Value provides a limit for the as-found relay setting measured during channel calibration prior to any adjustments. If the measured as-found relay setting does not exceed the Allowable Value, the relay is performing within the limits of the electrical analyses and is considered OPERABLE.

APPLICABLE SAFETY ANALYSES

The LOP DG start instrumentation is required for the Engineered Safety Features (ESF) Systems to function in any accident with a loss of offsite power. The LOP DG start instrumentation design is based on GDC 39, Emergency Power, in FSAR Section 8.0.

Accident analyses credit the loading of the DG based on the loss of offsite power during a loss of coolant accident (LOCA). The actual DG start has historically been associated with the ESFAS actuation (i.e., a safety injection signal). The analyses assume a non-mechanistic DG loading, which does not explicitly account for each individual component of loss of power detection and subsequent actions.

The required channels of LOP DG start instrumentation, in conjunction with the ESF systems powered from the DGs, provide unit protection in the event of any of the analyzed accidents discussed in Reference 2, in which a loss of offsite power is assumed. The delay times assumed in the safety analysis for the ESF equipment include the DG start delay, and the appropriate sequencing delay, if applicable.

The LOP DG start instrumentation channels satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The LCO for LOP DG start and load sequence instrumentation requires that three channels per bus of the 480 V loss of voltage Function and three channels per bus of the 4.16 kV loss of voltage and degraded voltage Functions shall be OPERABLE in MODES 1, 2, 3, and 4 when the LOP DG start and load sequence instrumentation supports safety systems associated with the ESFAS. In MODES 5 and 6, the three channels must be OPERABLE whenever the associated DG is required to be OPERABLE to ensure that the automatic start of the DG is available when needed. Loss of the LOP DG Start and Load Sequence Instrumentation Function could result in the delay of safety systems initiation when required. This could lead to unacceptable consequences during accidents. During the loss of offsite power the DG powers the motor driven auxiliary feedwater pumps. Failure of this pump ~~these pumps~~ to start would leave only one turbine driven pump, as well as an increased potential for a loss of decay heat removal through the secondary system.

APPLICABILITY

The LOP DG Start and Load Sequence Instrumentation Functions are required in MODES 1, 2, 3, and 4 because ESF Functions are designed to provide protection in these MODES. Actuation in MODE 5 or 6 is required whenever the required DG must be OPERABLE so that it can perform its function on an LOP or degraded power to the vital bus.

ACTIONS

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the channel is found inoperable, then the function that channel provides must be declared inoperable and the LCO Condition entered for the particular protection function affected.

Because the required channels are specified on a per bus basis, the Condition may be entered separately for each bus as appropriate.

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in the LCO. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

<u>A.1</u>

Condition A applies to the LOP DG start and load sequence Function with one loss of voltage or degraded voltage channel per bus inoperable.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

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

BASES

BACKGROUND

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

Add INSERT RCS-1

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

The RCS average temperature limits are established for unit operation from 5% to 100% RTP. The maximum RCS average temperature for operation at 100% RTP is used to establish the maximum RCS average temperature for unit operation between 5% and 100% RTP. Utilizing a Minimum Temperature for Criticality at 5% RTP, a linear progression is established for minimum RCS average temperature up to 100% RTP.

The RCS coolant average temperature limits are consistent with operation within the nominal operational envelope. Indications of temperature are averaged to determine a value for comparison to the limit. A higher average temperature will cause the core to approach DNB limits.

The RCS flow rate normally remains constant during an operational fuel cycle with all pumps running. The minimum RCS flow limit corresponds to that assumed for DNB analyses. RCS flow rate is determined by a precision calorimetric for comparison to the limit. A lower RCS flow will cause the core to approach DNB limits.

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

APPLICABLE SAFETY ANALYSES

The requirements of this LCO represent the initial conditions for DNB limited transients analyzed in the plant safety analyses (Ref. 1). The safety analyses have shown that transients initiated from the limits of this LCO will result in meeting the applicable DNBR ~~criterion of ≥ 1.3. This is the~~ criteria.

Insert RCS-1

The design method utilized to meet the DNB design criterion is the Revised Thermal Design Procedure (RTDP) with the WRB-1 DNB correlation. Uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, computer codes, and DNB correlation predictions are considered statistically to obtain DNB uncertainty factors in the RTDP methodology. RTDP design limit DNBR values are determined in order to meet the DNB design criterion based on the DNB uncertainty factors.

Additional DNBR margin is maintained by performing the safety analyses to DNBR limits that are higher than the design limit DNBR values. This margin between the design and safety analysis limit DNBR values is used to offset known DNBR penalties (e.g., rod bow, instrumentation biases, etc.), and to provide DNBR margin for design and operating flexibility.

The Standard Thermal Design Procedure (STDP) is used for those analyses where RTDP is not applicable. The parameters used in these analyses are treated in a conservative way from a DNBR standpoint in the STDP methodology. The parameter uncertainties are applied directly to the safety analyses input values to give the lowest minimum DNBR. The design DNBR limit for STDP is the 95/95 limit for the appropriate DNB correlation. Additional DNBR margin is maintained in the safety analyses to offset the applicable DNBR penalties.

The 95/95 DNBR correlation limit is 1.17 for the WRB-1 DNB correlation. The W-3 DNB correlation is used where the WRB-1 correlation is not applicable. The WRB-1 DNB correlation was developed based on mixing vane data, and therefore are only applicable in the heated rod spans above the first mixing vane grid. The W-3 DNB correlation, which does not take credit for mixing vane grids, is used to calculate the DNBR values in the heated region below the first mixing vane grid. The W-3 DNB correlation is applied in the analysis of accident conditions where the system pressure is below the range of the primary correlation. The W-3 DNBR correlation limit is 1.45 for system pressures in the range of 500 to 1,000 psia. The W-3 DNBR correlation limit is 1.30 for system pressures greater than 1,000 psia.

The WRB-1 DNB correlation is associated with transients that could impact the reactor core safety limits. The WRB-1-DNB correlation, along with the W-3 DNB correlation, is used in support of the licensing basis transient analyses.

BASES

The applicable DNBR criteria provide the

APPLICABLE SAFETY ANALYSES (continued)

acceptance limit for the RCS DNB parameters. Changes to the unit that could impact these parameters must be assessed for their impact on the DNBR criteria. The transients analyzed for include loss of coolant flow events and dropped or stuck rod events. A key assumption for the analysis of these events is that the core power distribution is within the limits of LCO 3.1.6, "Control Bank Insertion Limits"; LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)"; and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR) ."

The pressurizer pressure limit and the RCS average temperature limit specified in the COLR correspond to the analytical limits used in the safety analyses, with allowance for measurement uncertainty.

The RCS DNB parameters satisfy Criterion 2 of ~~the NRC Policy Statement.~~ 10 CFR 50.36(c)2(ii).

LCO

This LCO specifies limits on the monitored process variables - pressurizer pressure, RCS average temperature, and RCS total flow rate - to ensure the core operates within the limits assumed in the safety analyses. These variables are contained in the COLR to provide operating and analysis flexibility from cycle to cycle. However, the minimum RCS flow, usually based on maximum analyzed steam generator tube plugging, is retained in the TS LCO. Operating within these limits will result in meeting the DNBR criterion in the event of a DNB limited transient.

RCS total flow rate contains a measurement error based on performing a precision heat balance and using the result to calibrate the RCS flow rate indicators.

The numerical values for pressure, temperature, and flow rate specified in the COLR are given for the measurement location and have been adjusted for instrument error.

APPLICABILITY

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

A Note has been added to indicate the limit on pressurizer pressure is not applicable during short term operational transients such as a THERMAL POWER ramp increase > 5% RTP per minute or a

BASES

APPLICABLE SAFETY ANALYSES

In MODES 1, 2, and 3, the LCO requirement for a steam bubble is reflected implicitly in the accident analyses. Safety analyses performed for lower MODES are not limiting. All analyses performed from a critical reactor condition assume the existence of a steam bubble and saturated conditions in the pressurizer. In making this assumption, the analyses neglect the small fraction of noncondensible gases normally present.

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

The maximum pressurizer water level limit satisfies Criterion 2 of the NRC Policy Statement. Although the heaters are not specifically used in accident analysis, the need to maintain subcooling in the long term during loss of offsite power, as indicated in NUREG-0737 (Ref. 2), is the reason for providing an LCO.

LCO

The LCO requirement for the pressurizer to be OPERABLE with a water level of ~~≤ 50.8%~~ ≤ 52% in MODE 1, and ~~≤ 95%~~ ≤ 88% in MODE 2 and MODE 3, which includes instrument uncertainty ensures that a steam bubble exists. The pressurizer water level of ~~≤ 50.8%~~ ≤ 52% in MODE 1 is consistent with the assumptions used in the accident analyses. The water level of ~~≤ 95%~~ ≤ 88% in MODE 2 and MODE 3 is adequate protection for the pressurizer when a loss of normal feedwater is not a concern. ~~The pressurizer level limits in MODE 1 (50.8%) and in MODE 2 and MODE 3 (95%) do not include instrument uncertainty. The LCO is met when indicated pressurizer level is either ≤ 46 % in MODE 1 and ≤ 88 % in MODE 2 and MODE 3 based upon control room indication or ≤ 46.9% in MODE 1 and ≤ 88.4% in MODE 2 and MODE 3 based upon PPCS indication.~~ A higher water level is necessary in the pressurizer during cooldown to maintain pressurizer cooldown limits. Limiting the LCO maximum operating water level preserves the steam space for pressure control. The LCO has been established to ensure the capability to establish and maintain pressure control for steady state operation and to minimize the consequences of potential overpressure transients. Requiring the presence of a steam bubble is also consistent with analytical assumptions.

The LCO requires a capacity of ≥ 100 kW of OPERABLE pressurizer heaters. The required pressurizer heaters are heaters that are powered from a safeguards bus. The minimum heater capacity required is sufficient to maintain the RCS near normal operating pressure when accounting for heat losses through the pressurizer insulation. By maintaining the pressure near the operating conditions, a wide margin to subcooling can be obtained in the loops. The amount needed to maintain pressure is dependent on the heat losses.

ACTIONS (continued)

C.1 and C.2

If the pressurizer cannot be restored to OPERABLE status within the associated Completion Time of Required Action A.1 or B.1, or the pressurizer water level is not within the limit of MODE 2 and MODE 3, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

, which includes instrument uncertainty

This SR requires that during steady state operation, pressurizer level is maintained below the nominal upper limit to provide a minimum space for a steam bubble. The Surveillance is performed by observing the indicated level. ~~The pressurizer level limits in MODE 1 (50.8%) and in MODE 2 and MODE 3 (95%) do not include instrument uncertainty.~~ The Surveillance Requirement is met when indicated pressurizer level is ≤ 52% ~~46%~~ in MODE 1 and ≤ 88% in MODE 2 and MODE 3 ~~based upon control room indication or ≤ 46.9% in MODE 1 and ≤ 88.4% in MODE 2 and MODE 3 based upon PPCS indication.~~ The Frequency of 12 hours corresponds to verifying the parameter each shift. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess level for any deviation and verify that operation is within safety analyses assumptions. Alarms are also available for early detection of abnormal level indications.

SR 3.4.9.2

The required pressurizer heaters are heaters that are powered from a safeguards bus. The SR is satisfied when the power supplies are demonstrated to be capable of producing the minimum power and the associated pressurizer heaters are verified to have a combined capacity of ≥ 100kW. This may be done by testing the power supply output and by performing an electrical check on heater element continuity and resistance. The Frequency of 92 days is considered adequate to detect heater degradation and has been shown by operating experience to be acceptable.

REFERENCES

1. FSAR, Section 14.
2. NUREG-0737, November 1980.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Pressurizer Safety Valves

BASES

BACKGROUND

The pressurizer safety valves provide, in conjunction with the Reactor Protection System, overpressure protection for the RCS. The pressurizer safety valves are totally enclosed pop type, spring loaded, self actuated valves with backpressure compensation. The safety valves are designed to prevent the system pressure from exceeding the system Safety Limit (SL), 2735 psig, which is 110% of the design pressure.

Because the safety valves are totally enclosed and self actuating, they are considered independent components. The relief capacity for each valve, 288,000 lb/hr, is based on postulated overpressure transient conditions resulting from a complete loss of steam flow to the turbine. This event results in the maximum surge rate into the pressurizer, which specifies the minimum relief capacity for the safety valves. The discharge flow from the pressurizer safety valves is directed to the pressurizer relief tank. This discharge flow is indicated by an increase in temperature downstream of the pressurizer safety valves or increase in the pressurizer relief tank temperature or level.

Overpressure protection is required in MODES 1, 2, 3, 4, and 5; however, in MODE 4, with one or more RCS cold leg temperatures ≤ the LTOP enabling temperature specified in the PTLR, and MODE 5 and MODE 6 with the reactor vessel head on, overpressure protection is provided by operating procedures and by meeting the requirements of LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System."

2485 psig +2.5%\-3%

The pressurizer safety valve setpoint is ~~± 3%~~ for OPERABILITY; however, the valves are reset to ~~+2.67%/-1.78%~~ during surveillance to allow for drift and account for the ambient conditions associated with MODES 1, 2 and 3.

± 1%

The pressurizer safety valves are part of the primary success path and mitigate the effects of postulated accidents. OPERABILITY of the safety valves ensures that the RCS pressure will be limited to 110% of design pressure.

The consequences of exceeding the American Society of Mechanical Engineers (ASME) pressure limit (Ref. 1) could include damage to RCS components, increased leakage, or a requirement to perform additional stress analyses prior to resumption of reactor operation.

BASES

APPLICABLE SAFETY ANALYSES

All accident and safety analyses in the FSAR (Ref. 2) that require safety valve actuation assume operation of two pressurizer safety valves to limit increases in RCS pressure. The overpressure protection analysis (Ref. 3) is also based on operation of two safety valves. Accidents that could result in overpressurization if not properly terminated include:

a. Uncontrolled rod withdrawal from full power;

b. Loss of reactor coolant flow;

c. Loss of external electrical load;

d. Loss of normal feedwater;

e. Loss of all AC power to station auxiliaries; and

f. Locked rotor.

may be required for any of the above events

Detailed analyses of the above transients are contained in Reference 2. Safety valve actuation ~~is required in events c, d, and e (above)~~ to limit the pressure increase. Compliance with this LCO is consistent with the design bases and accident analyses assumptions.

Pressurizer safety valves satisfy Criterion 3 of ~~the NRC Policy Statement.~~ 10 CFR 50.36(c)2(ii).

LCO

The two pressurizer safety valves are set to open at the RCS design pressure (2500 psia), and within the ASME specified tolerance, to avoid exceeding the maximum design pressure SL, to maintain accident analyses assumptions, and to comply with ASME requirements. The pressurizer safety valve setpoint is ± ~~3%~~ +2.5%/ -3% for OPERABILITY; however, the valves are reset to ~~+2.67%/-1.78%~~ ± 1% during surveillance to allow for drift. The limit protected by this Specification is the reactor coolant pressure boundary (RCPB) SL of 110% of design pressure. Inoperability of one or more valves could result in exceeding the SL if a transient were to occur. The consequences of exceeding the ASME pressure limit could include damage to one or more RCS components, increased leakage, or additional stress analysis being required prior to resumption of reactor operation.

BASES

ACTIONS (continued)

below the LTOP enabling temperature specified in the PTLR, overpressure protection is provided by the LTOP System. The change from MODE 1, 2, or 3 to MODE 4 reduces the RCS energy (core power and pressure), lowers the potential for large pressurizer insurges, and thereby removes the need for overpressure protection by two pressurizer safety valves.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

SRs are specified in the Inservice Testing Program. Pressurizer safety valves are to be tested in accordance with the requirements of the ASME Code (Ref. 4), which provides the activities and Frequencies necessary to satisfy the SRs. No additional requirements are specified.

The pressurizer safety valve setpoint is ~~± 3%~~ 2485 psig +2.5%/ -3% for OPERABILITY; however, the valves are reset to ~~+2.67%/-1.78%~~ ±1% during the Surveillance to allow for drift.

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III.
2. FSAR, Chapter 14.
3. WCAP-7769, Rev. 1, June 1972.
4. ASME OM Code, Code for Operation and Maintenance of Nuclear Power Plants.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 Pressurizer Power Operated Relief Valves (PORVs)

BASES

BACKGROUND

The pressurizer is equipped with two types of devices for pressure relief: pressurizer safety valves and PORVs. The PORVs are air operated valves that are controlled to open at a specific set pressure when the pressurizer pressure increases and close when the pressurizer pressure decreases. The PORVs may also be manually operated from the control room.

Block valves, which are normally open, are located between the pressurizer and the PORVs. The block valves are used to isolate the PORVs in case of excessive leakage or a stuck open PORV. Block valve closure is accomplished manually using controls in the control room. A stuck open PORV is, in effect, a small break loss of coolant accident (LOCA). As such, block valve closure terminates the RCS depressurization and coolant inventory loss.

The PORVs and their associated block valves may be used by plant operators to depressurize the RCS to recover from certain transients if normal pressurizer spray is not available. Additionally, the series arrangement of the PORVs and their block valves permit performance of surveillances on the valves during power operation.

The PORVs may also be used for feed and bleed core cooling in the case of multiple equipment failure events that are not within the design basis, such as a total loss of feedwater.

The PORVs, their block valves, and their controls are powered from the vital buses that receive power from emergency power sources. Two PORVs and their associated block valves are powered from two separate safety trains (Ref. 1).

The plant has two PORVs, each having a relief capacity of 179,000 lb/hr at 2335 psig. ~~For plant operation at 2250 psia, the~~ The functional design of each PORV is based on maintaining pressure below the Pressurizer Pressure-High reactor trip setpoint following a step reduction of 50% of full load with steam dump. ~~However, for plant operation at 2000 psia, a 50% load rejection results in a maximum peak pressure of 2113 psia (Ref. 2). This peak pressure is below the Pressurizer Pressure-High reactor trip setpoint of 2210 psig and below the PORV actuation setpoint of 2335 psig, and will therefore not result in a reactor trip nor automatic actuation of the PORVs.~~ In addition, the PORVs may be used for low temperature overpressure protection

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BASES

APPLICABLE SAFETY ANALYSES (continued)

clad temperature is terminated solely by the accumulators, with pumped flow then providing continued cooling. As break size decreases, the accumulators aid in terminating the rise in clad temperature. As break size continues to decrease, the role of the accumulators continues to decrease until they are not required and the safety injection pumps become solely responsible for terminating the temperature increase.

This LCO helps to ensure that the following acceptance criteria established for the ECCS by 10 CFR 50.46 (Ref. 2) will be met following a LOCA:

a. *Maximum fuel element cladding temperature is* ≤ 2200°F;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. *Maximum hydrogen generation from a zirconium water reaction is* ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react; and

d. Core is *maintained in a coolable geometry.*

Since the accumulators discharge during the blowdown phase of a LOCA, they do not contribute to the long term cooling requirements of 10 CFR 50.46.

For the small break LOCA a nominal contained accumulator water volume of 1118 ft^3 is used, while a minimum water volume of 1100 ft^3 is used for the large break LOCA. The accumulator contained water volume for LOCA events is the same as the deliverable volume, since the accumulators are emptied, once discharged. A minimum accumulator liquid volume of 1100 ft^3 is modeled in the MSLB analysis, but this value does not present a limiting condition since the full *contents of the accumulators are not discharged into the RCS. For* large breaks, an increase in water volume can be either a peak clad temperature penalty or benefit, depending on downcomer filling and subsequent spill through the break during the core reflooding portion of the transient. The analysis makes a conservative assumption with respect to ignoring or taking credit for line water volume from the accumulator to the check valve. The maximum accumulator volume of 1136 ft^3 is assumed for equilibrium sump pH calculations.

For the post-LOCA subcriticality calculation, the minimum water volume of 1100 ft^3, and a boron concentration of ~~2600~~ ppm are assumed. The calculation is performed to assure reactor subcriticality in a post LOCA

2700

BASES

APPLICABLE SAFETY ANALYSES (continued)

environment. Of particular interest is the large break LOCA, since no credit is taken for control rod assembly insertion. A reduction in the accumulator minimum boron concentration would produce a subsequent reduction in the available containment sump concentration for post LOCA shutdown and an increase in the maximum sump pH. The maximum boron concentration is used in determining the minimum sump pH.

The large and small break LOCA analyses are performed at the minimum nitrogen cover pressure ~~of 714.7 psia~~, since sensitivity analyses have demonstrated that higher nitrogen cover pressure results in a peak clad temperature benefit. The maximum nitrogen cover pressure limit prevents accumulator relief valve actuation, and ultimately preserves accumulator integrity.

The effects on containment mass and energy releases from the accumulators are accounted for in the appropriate analyses (Ref. 3).

The accumulators satisfy Criterion 3 of ~~the NRC Policy Statement.~~ 10 CFR 50.36 (c) 2 (ii).

LCO

The LCO establishes the minimum conditions required to ensure that the accumulators are available to accomplish their core cooling safety function following a LOCA. Two accumulators are required to ensure that 100% of the contents of one of the accumulator will reach the core during a LOCA. This is consistent with the assumption that the contents of one accumulator spill through the break. If less than one accumulator injects during the blowdown phase of a LOCA, the ECCS acceptance criteria of 10 CFR 50.46 (Ref. 2) could be violated.

For an accumulator to be considered OPERABLE, the isolation valve must be fully open, power removed above 1000 psig, and the limits established in the SRs for contained volume, boron concentration, and nitrogen cover pressure must be met.

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS pressure > 1000 psig, the accumulator OPERABILITY requirements are based on full power operation. Although cooling requirements decrease as power decreases, the accumulators are still required to provide core cooling as long as elevated RCS pressures and temperatures exist.

This LCO is only applicable at pressures > 1000 psig. At pressures ≤ 1000 psig, the rate of RCS blowdown is such that the ECCS pumps can provide adequate injection to ensure that peak clad temperature remains below the 10 CFR 50.46 (Ref. 2) limit of 2200°F.

BASES

BACKGROUND (continued)

boric acid precipitation in the core following the LOCA, as well as excessive caustic stress corrosion of mechanical components and systems inside the containment.

APPLICABLE SAFETY ANALYSES

During accident conditions, the RWST provides a source of borated water to the ECCS and Containment Spray System pumps. As such, it provides containment cooling and depressurization, core cooling, and replacement inventory and is a source of negative reactivity for reactor shutdown (Ref. 1). The design basis transients and applicable safety analyses concerning each of these systems are discussed in the Applicable Safety Analyses section of B 3.5.2, "ECCS-Operating"; B 3.5.3, "ECCS-Shutdown"; and B 3.6.6, "Containment Spray and Cooling Systems." These analyses are used to assess changes to the RWST in order to evaluate their effects in relation to the acceptance limits in the analyses.

The RWST must also meet volume, boron concentration, and temperature requirements for non-LOCA events. The volume is not an explicit assumption in non-LOCA events since the required volume is a small fraction of the available volume. The deliverable volume limit is set by the LOCA and containment analyses. For the RWST, the deliverable volume is different from the total volume contained since, due to the design of the tank, more water can be contained than can be delivered. The minimum boron concentration is an explicit assumption in the main steam line break (MSLB) analysis to ensure the required shutdown capability. The maximum temperature ensures that the amount of cooling provided from the RWST during the heatup phase of a LOCA is consistent with safety analysis assumptions; the minimum temperature is an assumption in both the MSLB and large break LOCA, although the large break LOCA assumption is not the limiting value.

For a large break LOCA analysis, the minimum water volume limit of 275,000 gallons and the lower boron concentration limit of ~~2700~~ ppm are used to compute the post LOCA sump boron concentration necessary to assure subcriticality. The large break LOCA is the limiting case since the safety analysis assumes that all control rods are out of the core. 2800

The upper limit on boron concentration is used in determining the maximum allowable time to switch simultaneous injection following a LOCA. The purpose of switching simultaneous injection is to avoid boron precipitation in the core following the accident.

In the large break LOCA analysis, the containment spray temperature is assumed to be ~~33~~°F, maximizing containment cooling capability,
32

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4 Containment Pressure

BASES

BACKGROUND

The containment pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB). These limits also prevent the containment pressure from exceeding the containment design negative pressure differential with respect to the outside atmosphere.

Containment pressure is a process variable that is monitored and controlled. The containment pressure limits are derived from the input conditions used in the containment functional analyses and the containment structure external pressure analysis. Should operation occur outside the upper containment pressure limit coincident with a Design Basis Accident (DBA), post accident containment pressures could exceed calculated values.

APPLICABLE SAFETY ANALYSES

Containment internal pressure is an initial condition used in the DBA analyses to establish the maximum peak containment internal pressure. The limiting DBAs considered, relative to containment pressure, are the LOCA and SLB. The LOCA and SLB containment integrity evaluations are accomplished ~~by use of the digital computer code, COCO.~~ with the GOTHIC computer code

The initial pressure condition used in the containment LOCA analysis was ~~14.7 psia (0.0 psig).~~ 16.7 psia (2.0 psig). This resulted in a maximum peak pressure from a LOCA of ~~between 52 and 53~~ 55.35 psig. The initial pressure condition used in the SLB containment analysis was 16.7 psia (2.0 psig). This resulted in a maximum peak pressure from the limiting SLB inside containment of ~~59.8~~ 58.7 psig. The limiting SLB case assumed the failure of ~~a feedwater regulating valve at 100%~~ a feedwater isolation valve at 30% rated thermal power ~~plus measurement uncertainty.~~ *The SLB containment analysis shows that* the maximum peak calculated containment pressure results from this limiting SLB case. The limiting SLB case does not exceed the containment design pressure, of 60 psig.

The containment was also designed for an external pressure load equivalent to -2.0 psig. This limit is sufficient to accommodate increases in atmospheric pressure and decreases in containment temperature after the establishment of containment integrity without the use of the containment purge valves.

BASES

APPLICABLE SAFETY ANALYSES (continued)

and Containment Cooling System being rendered inoperable. The postulated DBA SLB was similarly analyzed, except that both trains of the Containment Spray System and the Containment Cooling System are assumed operable. This is acceptable since the DBA SLB analysis assumed a single failure of the feedwater ~~regulating~~ isolation valve as the worst case single failure for the containment integrity analysis.

The limiting DBA for the maximum peak containment air temperature is ~~a LOCA.~~ a SLB. The initial containment average air temperature assumed in the design basis analyses (Ref. 1) is 120°F. This resulted in a maximum containment air temperature of ~~291~~ 284.4°F. The design temperature of the containment structure is 286°F.

The ~~temperature~~ limit is used to establish the environmental qualification operating envelope for containment. ~~The maximum peak containment air temperature was calculated to exceed the containment design temperature for only a few seconds during the transient.~~ The basis of the containment design temperature~~, however,~~ is to ensure the performance of safety related equipment inside containment (Ref. 2). ~~Thermal analyses showed that the time interval during which the containment air temperature exceeded the containment design temperature was short enough that the equipment surface temperatures remained below the design temperature. Therefore, it~~ It is concluded that the calculated transient containment air temperature is acceptable for the DBA LOCA.

~~The containment pressure transient is sensitive to the initial air mass in containment and, therefore, to the initial containment air temperature.~~ The initial containment air temperature also has an impact on the containment pressure transient. This is primarily due to the DBA assumption that all the containment structures are initially at the same temperature as the containment air. The limiting DBA for establishing the maximum peak containment internal pressure is a SLB. The temperature limit is used in this analysis to ensure that in the event of an accident the maximum containment internal pressure will not be exceeded.

Containment average air temperature satisfies Criterion 2 of ~~the NRG Policy Statement.~~ 10 CFR 50.36(c)2(ii).

LCO

During a DBA, with an initial containment average air temperature less than or equal to the LCO temperature limit, the resultant peak accident temperature is maintained below the containment design temperature. As a result, the ability of containment to perform its design function is ensured.

The containment air temperature limit (120°F) does not include instrument uncertainty. The LCO is met when indicated containment temperature is ≤ 112.5°F.

BASES

BACKGROUND (continued)

LOCA:

The containment peak pressure analyses for a LOCA assumes the operation of one containment spray pump and two containment accident fan cooler units (single train failure) to ensure that containment design limits are not exceeded.

SLB:

Main Feedwater Isolation Valve (MFIV)

The containment peak pressure analysis for a SLB assumes that the single failure is a ~~Feed Regulating Valve (FRV)~~ remaining open. This was determined to be a more severe challenge to the containment peak pressure for this event than the loss of a single train of both spray and containment fan coolers. Therefore, both trains of containment spray and all four containment fan coolers are assumed to operate in the analysis of the containment response to a SLB.

An NaOH solution is drawn into the Containment Spray System via an eductor in a recirculation bypass line around each spray pump. The NaOH added in the spray ensures an alkaline pH for the solution recirculated in the containment sump. The alkaline pH of the containment sump water minimizes the evolution of iodine and minimizes the occurrence of chloride and caustic stress corrosion on mechanical systems and components exposed to the fluid.

The Containment Spray System is actuated either automatically by a containment Hi-Hi pressure signal or manually. An automatic actuation opens the containment spray pump discharge valves, starts the two containment spray pumps, and begins the injection phase. A manual actuation of the Containment Spray System requires the operator to actuate two separate switches on the main control board to begin the same sequence. Each containment spray train has two motor operated discharge isolation valves. One discharge valve is powered from the same safeguards power supply as the pump, while the other valve is powered from the opposite train's safeguards power. Only the valve associated with the same safeguards power supply as the pump is assumed to open due to single failure considerations. The "A" train contains discharge valves, SI 860A and SI 860B, with the SI 860A being the only valve required to be capable of opening automatically. The "B" train contains discharge valves SI 860C and SI 860D, with the SI 860D being the only valve required to be capable of opening automatically. Valves SI 860B and SI 860C are not required for system operability. The injection phase continues until an RWST level Low-Low alarm is received at which time the containment spray system is secured from operation.

BASES

BACKGROUND (continued)

LOCA

The containment pressure analysis for a LOCA assumes the operation of one containment spray pump and two containment accident fan cooler units (single train failure).

SLB:

Main Feedwater Isolation Valve (MFIV)

The containment peak pressure analysis for a SLB assumes that the single failure is ~~a Feed Regulating Valve (FRV)~~ remaining open. This was determined to be a more severe challenge to the containment peak pressure for this event than the loss of a single train of both spray and containment fan coolers. Therefore, both trains of containment spray and all four containment fan coolers are assumed to operate in the analysis of the containment response to a SLB.

APPLICABLE SAFETY ANALYSES

The Containment Spray System and Containment Cooling System limit the temperature and pressure that could be experienced following a LOCA or a SLB.. See the Bases for section 3.6.4 for further details of limiting pressure transients.

The analyses and evaluations assume a unit specific power level of 100% RTP plus power measurement uncertainty.

2.0

Initial (pre-accident) containment conditions of 120°F and ~~0.0~~ psig are assumed in the LOCA analysis. Initial (pre-accident) containment conditions of 120°F and 2.0 psig are assumed in the MSLB analysis. The analyses also assume a response time delayed initiation to provide conservative peak calculated containment pressure and temperature responses.

The Containment Spray System and the Containment Cooling System satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

APPLICABLE SAFETY ANALYSES (continued)

The postulated accidents are analyzed with the single worst-case active failure.

LOCA

The single failure is the loss of one ESF bus which results in one train of the Containment Spray System and two containment accident fan cooler units being rendered inoperable.

SLB

Main Feedwater Isolation Valve (MFIV)

The single failure is the failure of a ~~Feed Regulating Valve (FRV)~~ to close on demand. This results in a more severe transient than the loss of a train of spray and fan coolers because the continued addition of feed water creates a greater mass release to the containment, and transfers energy from both the RCS and the intact steam generator to the containment that would otherwise be confined in those two systems.

The analyses and evaluations show that under the worst case SLB scenario, the peak containment pressure reaches ~~59.8~~ 58.7 psig and the temperature reaches ~~285~~ 284.4°F. Both results meet the intent of the design basis. (See the Bases for LCO 3.6.4, "Containment Pressure," and LCO 3.6.5 for a detailed discussion).

BASES

LCO

LOCA

During a LOCA, a minimum of two containment accident fan cooler units with their accident fans running and one containment spray train are required to maintain the containment peak pressure and temperature below the design limits (Ref. 3). Additionally, one containment spray train is also required for containment temperature and pressure control, to remove iodine from the containment atmosphere, and to provide the motive force and flowpath to the containment sump for NaOH from the Spray Additive System.

SLB

Main Feedwater Isolation Valve (MFIV)

During a SLB event, the most limiting single failure is a ~~Feed Regulating Valve (FRV)~~ failing to close on demand, and continuing to feed the faulted steam generator. Therefore, both trains of containment spray and all four containment accident fan coolers and their associated accident fans are assumed to operate as designed (Ref. 3). The resulting transient bounds the failure of a single train of safeguards.

The single failure assumptions for a SLB involve containment sprays, containment coolers, and main feedwater isolation. Therefore, a safety function evaluation per TS 3.0.6 and TS 5.5.14 must be performed for the supported function of containment Operability if a loss of containment spray or containment fan cooler function occurs. The review must consider Main Feedwater Isolation OPERABILITY per the requirements of TS 3.7.3.

Each Containment Spray System consists of a spray pump, spray header, nozzles, valves, piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST upon an ESF actuation signal.

Each Containment Accident Fan Cooler Unit consists of cooling coils, accident backdraft damper, accident fan, service water outlet valves, and controls necessary to ensure an OPERABLE service water flow path.

A third case is analyzed to demonstrate that the MSSVs

BASES

APPLICABLE SAFETY ANALYSES (continued)

valves. This analysis demonstrates that RCS integrity is maintained by showing that the maximum RCS pressure does not exceed 110% of the design pressure. ~~All cases analyzed demonstrate that the MSSVs~~ maintain Main Steam System integrity by limiting the maximum steam pressure to less than 110% of the steam generator design pressure.

This case also assumes primary system pressure control via operation of the pressurizer power-operated relief valves and spray, but models primary side initial conditions at off-normal conditions to obtain a more limiting steam pressure transient.

In addition to the decreased heat removal events, reactivity insertion events may also challenge the relieving capacity of the MSSVs. The uncontrolled rod cluster control assembly (RCCA) bank withdrawal at power event is characterized by an increase in core power and steam generation rate until reactor trip occurs when either the Overtemperature ΔT or Power Range Neutron Flux-High setpoint is reached. Steam flow to the turbine will not increase from its initial value for this event. The increased heat transfer to the secondary side causes an increase in steam pressure and may result in opening of the MSSVs prior to reactor trip, assuming no credit for operation of the atmospheric or condenser steam dump valves. The FSAR Section 14.1.2 safety analysis of the RCCA bank withdrawal at power event for a range of initial core power levels demonstrates that the MSSVs are capable of preventing secondary side overpressurization for this AOO.

The FSAR safety analyses discussed above assume that all of the MSSVs for each steam generator are OPERABLE. If there are inoperable MSSV(s), it is necessary to limit the primary system power during steady-state operation and AOOs to a value that does not result in exceeding the combined steam flow capacity of the remaining OPERABLE MSSVs. The required limitation on primary system power necessary to prevent secondary system overpressurization have been determined by conservative heat balance calculations. In some circumstances it is necessary to limit the primary side heat generation that can be achieved during an AOO by reducing the setpoint of the Power Range Neutron Flux-High reactor trip function. For example, if more than one MSSV on a single steam generator is inoperable, an uncontrolled RCCA bank withdrawal at power event occurring from a partial power level may result in an increase in reactor power that exceeds the combined steam flow capacity of ~~the remaining~~ OPERABLE MSSVs. Thus, for multiple inoperable MSSVs on the same steam generator it is necessary to prevent this power increase by lowering the Power Range Neutron Flux-High setpoint to an appropriate value. When the Moderator Temperature Coefficient (MTC) is positive, the reactor power may increase above the initial value during an RCS heatup event (e.g., turbine trip). Thus, for any number of inoperable MSSVs it is necessary to reduce the trip setpoint if a positive MTC may exist at partial power conditions.

or turbine trip

B 3.7 PLANT SYSTEMS

B 3.7.2 Main Steam Isolation Valves (MSIVs) and Non-Return Check Valves

BASES

BACKGROUND

The MSIVs and non-return check valves isolate steam flow from the secondary side of the steam generators following a steam line break. In addition, the MSIVs are used to isolate the affected steam generator in the event of a steam generator tube rupture.

One MSIV is located in each main steam line outside, but close to containment. The MSIVs are downstream from the main steam safety valves (MSSVs) and auxiliary feedwater (AFW) pump turbine steam supply, to prevent MSSV and AFW isolation from the steam generators by MSIV closure. The MSIVs isolate the turbine, Condenser Steam Dump System, and other auxiliary steam supplies (with the exception of the turbine driven auxiliary feedwater pump) from the steam generators. The MSIVs in conjunction with the non-return check valves, isolate the steam generators from each other.

The MSIVs close on a main steam isolation signal generated by Containment Pressure High-High, Steam Flow High-High coincident with a Safety Injection, or Steam Flow High coincident with Low T_{avg} and a Safety Injection. The MSIVs may also be manually actuated.

Each MSIV has a normally closed bypass valve.

A description of the MSIVs is found in the FSAR, Section 10.1 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the MSIVs and non-return check valves is established by the analysis for the steam line break (SLB), discussed in the FSAR, Section 14.2.5 (Ref. 2). The design precludes the blowdown of more than one steam generator, assuming a single active component failure (e.g., the failure of one MSIV or non-return check valves to close on demand).

The SLB containment pressure calculation is a plant specific analysis described in section 14.2.5.C of the FSAR. The analysis concluded that in the worst case, a containment pressure of ~~59.8~~ 58.7 psig could be reached.

B 3.7 PLANT SYSTEMS

B 3.7.3 Main Feedwater Isolation

BASES

BACKGROUND

~~Main Feedwater Isolation functions to isolate main feedwater flow to the~~ secondary side of the steam generators following a Steam Line Break (SLB). The safety related function of the Main Feedwater Regulating Valves (MFRVs) and MFRV bypass valves is to provide isolation of main feedwater (MFW) flow to the secondary side of the steam generators following an SLB. Termination of feedwater addition to the affected steam generator limits the mass and energy release for SLBs and reduces the cooldown effects for SLBs.

Add INSERT MFIV-1

The Containment Pressure Condensate Isolation (CPCI) trip and main feedwater pump trip circuits also terminate main feedwater flow to the secondary side of the steam generators following an SLB inside containment. The CPCI circuit trips the two condensate pumps and the three heater drain tank pumps upon sensing a high pressure in containment.

One MFRV and associated bypass valve are located on each MFW line. The MFRVs and associated bypass valves are located upstream of the AFW injection point so that AFW may be supplied to the steam generators following MFRV and bypass valve closure.

The MFRVs and associated bypass valves close on receipt of a SI signal or steam generator water level high signal or a low T_{avg} with reactor trip signal. The CPCI actuates on a high containment pressure (2/3 logic, setpoint is 10% of containment design pressure). The MFW pumps trip on a Safety Injection (SI) signal.

A description of the MFRVs, associated bypass valve, CPCI circuit, and ~~MFW trip circuit can be found in the FSAR, Section 10.1 (Ref. 1).~~

APPLICABLE SAFETY ANALYSES

The design basis for MFW isolation is established by the SLB event as described in section 14.2.5.C of the FSAR. The SLB containment pressure calculation is a plant specific analysis. It concludes that in the worst case, containment pressure may reach a peak of ~~59.8~~ 58.7 psig.

A SFDP review per TS 3.0.6 and TS 5.5.14 must be performed for the supported function of containment Operability if a loss of Main Feedwater Isolation occurs. The review must consider the Operability of Containment Spray and Containment Fan Coolers per the requirements of TS 3.6.6.

The peak pressure is less than the containment design pressure of 60psig.

Insert MFIV-1
BACKGROUND

The MFIVs isolate main feedwater (MFW) flow to the secondary side of the steam generators following a high energy line break (HELB). The safety related function of the MFRVs is to provide the second isolation of MFW flow to the secondary side of the steam generators following an HELB. Closure of the MFIVs, MFRVs, and MFRV bypass valves terminates flow to the steam generators, terminating the event for feedwater line breaks (FWLBs) occurring upstream of the MFIVs or MFRVs. The consequences of events occurring in the main steam lines or in the MFW lines downstream from the MFIVs will be mitigated by their closure. Closure of the MFIVs, MFRVs, and MFRV bypass valves, effectively terminates the addition of feedwater to an affected steam generator, limiting the mass and energy release for steam line breaks (SLBs) or FWLBs inside containment, and reducing the cooldown effects for SLBs.

The MFIVs, MFRVs, and MFRV bypass valves, isolate the nonsafety related portions from the safety related portions of the system. In the event of a secondary side pipe rupture inside containment, the valves limit the quantity of high energy fluid that enters containment through the break, and provide a pressure boundary for the controlled addition of auxiliary feedwater (AFW) to the intact loops.

One MFIV, MFRV, and MFRV bypass valve are located on each MFW line, outside but close to containment. The MFIVs and MFRVs are located upstream of the AFW injection point, so that AFW may be supplied to the steam generators following MFIV or MFRV closure. The piping volume from these valves to the steam generators must be accounted for in calculating mass and energy releases, and refilled prior to AFW reaching the steam generator following either an SLB or FWLB.

The ~~MFIVs,~~ MFRVs, and MFRV bypass valves, close on receipt of a steam generator water level - high signal or a safety injection. The MFIVs close on emergency power initiation or safety injection. They may also be actuated manually. In addition to the MFIVs, MFRVs, and MFRV bypass valves, a check valve inside containment is available. The check valve isolates the feedwater line, penetrating containment, and ensures that the consequences of events do not exceed the capacity of the containment heat removal systems.

A description of the MFIVs, MFRVs, and MFRV Bypass Valves is found in the FSAR, Section 10.1 (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES (continued)

~~This peak pressure is less than the containment design pressure of 60 psig.~~

MFRVs

Sustained high feedwater flow could result in additional energy input into the containment and could also cause additional RCS cooldown; therefore, diverse isolation of MFW flow is provided to accommodate a single failure. In addition to the normal low T_{avg} with reactor trip signal isolation of the main feedwater ~~valves~~, any safety injection signal will close ~~all feedwater control valves, trip the main feedwater pumps, and close the feedwater pump discharge valves. Further isolation is provided for reduced SG pressures by tripping the condensate and heater drain tank pumps on a CPCI signal.~~

MFIVs, MFRVs, and MFRV Bypass Valves.

MFW Isolation satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO ensures that MFW flow to the steam generators is terminated following a steam line break (SLB).

MFIVs, and

This LCO requires Main Feedwater isolation ~~to~~ be OPERABLE. Main Feedwater isolation consists of the MFRVs, MFRV bypass valves and their associated isolation circuits~~, in addition to the MFW pump trip, and the CPCI circuits~~. This LCO ensures that in the event of an SLB inside containment, a single failure cannot result in continued MFW flow into the containment.

Failure to meet the LCO requirements can result in additional RCS cooldown or additional mass and energy being released to containment following an SLB inside containment.

~~Main Feedwater isolation supports containment OPERABILITY. Therefore, a safety function evaluation per TS 3.0.6 and TS 5.5.14 must be performed for the supported function if Main Feedwater isolation is not OPERABLE. The review must consider the Containment Spray and Containment Fan Cooler OPERABILITY requirements of TS 3.6.6.~~

APPLICABILITY

In MODES 1, 2, 3, MFW isolation is required to be OPERABLE to limit the amount of fluid added to containment in the event of a MSL break

Unit 1 - Amendment No,
Unit 2 - Amendment No.

BASES

APPLICABILITY (continued)

inside containment. MFW isolation must be OPERABLE whenever there is significant mass and energy in the steam generators.

In MODES 4, 5, and 6, steam generator energy is low. Therefore, MFW isolation is not required.

ACTIONS

A.1 and A.2

Condition A is modified by a Note indicating that separate Condition entry is allowed for each valve.

With one MFIV ~~MFRV or MFRV bypass valve~~ inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE ~~MFW isolation systems~~ MFRV and MFRV Bypass Valve and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths.

Inoperable MFIVs ~~MFRVs~~, that are closed or isolated, must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls to ensure that the valves are closed or isolated.

B.1 and B.2

Condition B is modified by a Note indicating that separate Condition entry is allowed for each inoperable ~~pump trip circuit.~~ valve.

With ~~CPCI or MFW pump trip circuit associated with~~ one or more MFRV ~~pumps~~ inoperable, action must be taken to restore the ~~affected pump trip circuits~~ valve to OPERABLE status, or ~~to secure the affected pumps from operation~~ close or isolate affected valve within 72 hours. ~~With the pumps secured from operation, they are in their required position.~~ When these valves are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE MFIVs, MFRVs and MFRV bypass valves and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths.

BASES

Inoperable MFRVs that are closed or isolated

ACTIONS (continued)

~~Pumps with inoperable trip circuits~~ must be verified ~~not to be in operation~~ on a periodic basis. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of other status indications available in the control room ~~(e.g., pump run lights, ammeters, etc.), and other administrative controls to ensure that the pump remains off.~~ that they are closed or isolated.

Add INSERT MFIV-2

D.1

~~C.1 and C.2~~

~~With one or more unisolated MFRVs or unisolated bypass valves inoperable and one or more condensate, heater drain or MFW pumps with inoperable trip circuits in operation, action must be taken to either; restore the affected valves or pump trip circuits to OPERABLE status, isolate the affected flow path, or secure the affected pumps within 8 hours. This action establishes a condition where at least one of the affected isolation systems is performing or capable of performing its required safety function. The 8 hour Completion Time is reasonable, based on operating experience, and the time necessary to complete the actions required to close the MFRV, associated bypass valve, or to secure the affected condensate, heater drain or MFW pump.~~

Add INSERT MFIV-3

E.1 and E.2

~~D.1 and D.2~~

If the MFW isolation systems cannot be restored to OPERABLE status, isolated, or secured within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1

MFIV,

This SR verifies that each MFRV and MFRV bypass valve will actuate to its isolation position on a actuation isolation signal (i.e., Safety Injection). The 18 month Frequency is based on a refueling cycle interval and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass this Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

or simulation actuation signal.

INSERT MFIV-2

C.1 and C.2

Condition C is modified by a Note indicating that separate Condition entry is allowed for each valve.

With MFRV Bypass Valve inoperable, action must be taken to restore the affected valve to OPERABLE status, or to close or isolate the inoperable valve within 72 hours. When these valves are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the *remaining* OPERABLE MFIV *and the low probability of an event occurring during the* time period that would require isolation of the MFW flow paths.

Inoperable MFRV Bypass Valves, that are closed or isolated, must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls to ensure that the valves are closed or isolated.

INSERT MFIV-3

With two inoperable valves in the same flowpath, there may be no redundant system to operate automatically and perform the required safety function. Although the containment can be isolated with the failure of two valves in parallel in the same flowpath, the double failure can be an indication of a common mode failure in the valves of this flowpath, and as such, is treated the same as a loss of isolation capability of this flowpath. Under these conditions, affected valves in each flowpath must be restored to OPERABLE status, or the affected flowpath isolated within 8 hours. This action returns the system to the condition where at least one valve in each flowpath is performing the required safety function. The 8 hour Completion Time is reasonable, based on operating experience, to complete the actions required to close the MFIV, MFRV, or MFRV Bypass Valve, or otherwise isolate the affected flowpath.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Add Insert MFIV-2

SR 3.7.3.2

~~This SR verifies that each MFW pump will trip on a actuation signal (i.e., Safety Injection). The 18 month Frequency is based on a refueling cycle interval and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass this Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.~~

~~SR 3.7.3.3~~

~~This SR verifies that each condensate and heater drain pump will trip on a CPCI actuation signal (i.e., High Containment Pressure). The 18 month Frequency is based on a refueling cycle interval and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass this Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.~~

REFERENCES

1. FSAR. Section 10.1.
2. TRM 4.7, Inservice Testing Program
3. ASME Boiler and Pressure Vessel Code, Section XI, OM code, Code for Operation and Maintenance of Nuclear Power Plants.

INSERT MFIV-2

This SR verifies the closure time of each MFIV, MFRV, and MFRV Bypass Valve is within the limits given in Reference 2 and is within that assumed in the accident and containment analyses. This SR also verifies the valve closure time in accordance with the Inservice Testing Program. This SR is normally performed upon returning the unit to operation following a refueling outage. These valves should not be tested at power, since even a part stroke exercise increases the risk of a valve closure with the unit generating power. This is consistent with the ASME Code Section XI (Ref. 3), quarterly stroke requirements during operation in MODES 1 and 2.

The Frequency for this SR is in accordance with the Inservice Testing Program.

B 3.7 PLANT SYSTEMS

B 3.7.5 Auxiliary Feedwater (AFW) System

BASES

BACKGROUND

The AFW System automatically supplies feedwater to the steam generators to remove decay heat from the Reactor Coolant System upon the loss of normal feedwater supply. The AFW pumps provide cooling water to the steam generator secondary side via connections to the main feedwater (MFW) piping inside containment. The steam generators function as a heat sink for core decay heat. The heat load is dissipated by releasing steam to the atmosphere from the steam generators via the main steam safety valves (MSSVs) (LCO 3.7.1) or atmospheric dump valves (LCO 3.7.4). If the main condenser is available, steam may be released via the steam bypass valves and recirculated to the CST.

two

one

The AFW System consists of ~~three~~ independent pump systems; ~~two~~ motor driven AFW pumps ~~which are shared between the two units~~, and one dedicated steam turbine driven pump per unit. ~~Each~~ motor driven ~~pump is~~ capable of providing 100% of the design AFW flow rate, ~~while the turbine driven pump is capable of providing 200% of the design flowrate.~~ Each pump is provided with a recirculation line to maintain pump discharge flow above the minimum required flow rate for pump cooling. ~~Each AFW pump system can be manually aligned to take suction from the service water system.~~ The normal source of water for the AFW pumps is the Condensate Storage Tank (CST) and the safety related supply is the Service Water (SW) System. Motor operated valves are provided to allow the suction supply for the AFW pumps to be manually transferred to the SW system. For an AFW pump system to be considered OPERABLE, its associated service water suction supply valve must be operable. ~~CST low level alarms and AFW pump low suction pressure alarms and trips are provided to alert personnel that the AFW pump suction supply must be manually swapped.~~

The

and turbine driven pumps are

assumed in the accident analysis.

Add INSERT AFW-1

~~Each motor driven AFW pump is powered from an independent safeguards power supply and feeds one steam generator in each unit. AFW pump P-38A supplies AFW flow to the Unit 1 and Unit 2 A steam generators, while AFW pump P-38B supplies the Unit 1 and Unit 2 B steam generators. Each motor driven AFW pump's discharge header contains two normally closed automatic motor operated valves. Upon receipt of an AFW actuation signal, the discharge valve associated with the affected unit receives an automatic open signal and the discharge valve associated with the unaffected unit receives an automatic close signal. This feature will ensure that 100% of the motor driven AFW pump flow will be delivered to the affected unit, thereby, assuring that~~

INSERT AFW-1

The pump suctions are automatically transferred to the service water system, if the AFW low suction pressure setpoint is reached. CST low level alarms alert personnel that the AFW pump suction supply must be monitored and transferred to the service water system before the low suction pressure setpoint is reached.

BASES

ADD INSERT AFW-2

BACKGROUND (continued)

~~the accident analysis flowrates are met. Each motor driven AFW pump is also equipped with a backpressure control valve, which is designed to preclude the motor driven AFW pump from tripping on an overcurrent condition at low steam generator pressures.~~

The motor driven AFW pump system~~s~~ ~~actuate~~ actuates automatically on steam generator water level (low-low) in one steam generator and upon receipt of a safety injection (SI) signal. If offsite power is available, the motor driven AFW pump systems actuate immediately. If offsite power is not available, the safeguards buses shed their normal operating loads and are connected to the emergency diesel generators (EDGs). The motor driven AFW pump system~~s~~ ~~are~~ is then actuated per their programmed time sequence. While not credited in any DBA analysis, the motor driven AFW pump system~~s~~ also ~~actuate~~ actuates on; a trip of all MFW pumps, and by the Anticipated Transient Without Scram Mitigating System Actuation Circuit.

Each unit's turbine driven AFW pump receives steam from both steam generator main steam lines upstream of the main steam isolation valves. Each of the two steam ~~feed~~ supply lines can ~~supply~~ pass 100% of the required steam flow to the turbine driven AFW pump. Both steam supply lines must be OPERABLE to consider the turbine driven AFW pump OPERABLE. All power-operated valves associated with the turbine driven AFW pump system are DC-powered, ~~with the exception of the service water suction supply valve (Unit 1 and Unit 2 AF-4006) which is powered from a 480 Volt AC safeguards bus.~~

The turbine driven AFW pump system actuates automatically on a ~~steam generator~~ water level - low-low ~~in both steam generators~~ In either steam generator. While not credited in any DBA analysis, the turbine driven AFW pump system also actuates on; a trip of all MFW pumps, undervoltage on both main feedwater pump buses, and by the Anticipated Transient Without Scram Mitigating System Actuation Circuit.

~~The AFW System is capable of supplying feedwater to the steam generators during normal unit startup, shutdown, and hot standby conditions.~~

~~One pump~~ Either of the pumps at full flow is sufficient to remove decay heat and cool the unit to residual heat removal (RHR) entry conditions. Thus, the requirement for diversity in motive power sources for the AFW System is met.

The AFW System is designed to supply sufficient water to the steam generator(s) to remove decay heat with steam generator pressure at the setpoint of the MSSVs. Subsequently, the AFW System supplies

INSERT AFW-2

Although the AFW system is capable of supplying feedwater to the steam generators during non-emergency conditions, its primary function is to allow safe shutdown following an accident or plant trip. The AFW motor driven AFW pump system is powered from safeguards power. The pump's discharge header splits into two branch lines to the unit's two steam generators. The flow control valves on the branch lines are set so each steam generator is provided with approximately one-half of the unit's total required flow. This feature precludes the motor driven AFW pump from tripping on an overcurrent condition at low steam generator pressure.

BASES

BACKGROUND (continued)

sufficient water to cool the unit to RHR entry conditions, with steam released through the ADVs.

The AFW System is discussed in the FSAR, Section 10.2 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The AFW System mitigates the consequences of any event with loss of normal feedwater.

The design basis of the AFW System is to supply water to the steam generator to remove decay heat and other residual heat by delivering at least the minimum required flow rate to the steam generators at pressures in excess of the steam generator safety valve set pressure.

In addition, the AFW System must supply enough makeup water to replace steam generator secondary inventory lost as the unit cools to MODE 4 conditions.

that

The AFW system is assumed to function in the mitigation of Design Basis Accidents (DBAs) and transients ~~to~~ include; Steam Generator Tube Rupture (SGTR), main steam line break, loss of normal feedwater, and loss of all AC power to the station auxiliaries. The AFW system must be capable of isolating AFW to the ruptured steam generator following a SGTR in addition to isolating the steam supply to turbine driven AFW pump associated with the ruptured steam generator. Although the AFW System will be initiated during the Small Break LOCA, the event has been analyzed with no credit for AFW. The Small Break LOCA was analyzed without AFW to be conservative and to limit the modeling required to address all possible combinations and time delays for various AFW system configurations.

pumps

The ESFAS automatically actuates the AFW ~~turbine driven pump~~ and associated power operated valves and controls when required to ensure an adequate feedwater supply to the steam generators. ~~during loss of power. DC power operated valves are provided for each AFW line to control the AFW flow to each steam generator.~~

Add INSERT AFW-2a

The AFW System satisfies the requirements of Criterion 3 of ~~the NRC Policy Statement.~~

10CFR 50.36(c)2(ii).

INSERT AFW-2a

A SFDP review per TS 3.0.6 and TS 5.5.14 must be performed for the supported function of Containment Operability if a MDAFW pump discharge valve is inoperable. The review must consider the Operability of Containment Spray and Containment Fan Coolers per the requirements of TS 3.6.6.

BASES

Two

one

LCO

This LCO provides assurance that the AFW System will perform its design safety function to mitigate the consequences of Design Basis Accidents and transients. ~~Three~~ AFW pump systems, consisting of ~~two shared~~ motor driven pump systems and one ~~dedicated~~ turbine driven pump system are required to be OPERABLE to ensure the availability of RHR capability for all events accompanied by a loss of offsite power and a single failure. ~~This is accomplished by powering two of the pumps from independent emergency buses. The third AFW pump is powered by a different means, a steam driven turbine supplied with steam from a source that is not isolated by closure of the MSIVs.~~

Add Insert AFW-3

two

automatically

The AFW System is configured into ~~three~~ pump systems. The AFW System is considered OPERABLE when the components and flow paths required to provide redundant AFW flow to the steam generators are OPERABLE, and the components required to ~~manually~~ transfer AFW pump suction supply to the service water system are OPERABLE. This requires that the ~~two~~ motor driven AFW pumps be OPERABLE, ~~each~~ capable of supplying AFW to ~~a separate steam generator~~. The turbine driven AFW pump is required to be OPERABLE with redundant steam supplies from each main steam line upstream of the MSIVs, and shall be capable of supplying AFW to both ~~of the~~ steam generators. The piping, valves, instrumentation, and controls in the required flow paths also are required to be OPERABLE. For an AFW pump system to be considered OPERABLE, a minimum recirculation flow path must be available, and the backup pneumatic supply for the minimum recirculation air-operated valve must be OPERABLE.

and

both steam generators

The LCO is modified by a Note indicating that only the motor driven AFW pump~~s which are associated with steam generators required to be operable for heat removal (per LCO 3.4.6) are~~ required to be OPERABLE in MODE 4. This is because of the reduced heat removal requirements and short period of time in MODE 4 during which the AFW is required and the insufficient steam available in MODE 4 to power the turbine driven AFW pump.

is

APPLICABILITY

In MODES 1, 2, and 3, the AFW System is required to be OPERABLE in the event that it is called upon to function when the MFW is lost. In addition, the AFW System is required to supply enough makeup water to replace the steam generator secondary inventory, lost as the unit cools to MODE 4 conditions.

In MODE 4 the AFW System may be used for heat removal via the steam generators.

In MODE 5 or 6, the steam generators are not normally used for heat removal, and the AFW System is not required.

INSERT AFW-3

This is accomplished by powering the motor driven pump from an emergency AC bus. The other AFW pump system does not rely on AC power. It relies on a steam turbine driven pump with a steam source that is not isolated by closure of the MSIVs and valves powered from DC sources.

when entering MODE 1.

BASES

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable AFW pump system ~~. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an AFW pump system inoperable and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.~~

A.1

Add Insert AFW-4

~~If one of the two steam supplies to the turbine driven AFW pump system is inoperable, action must be taken to restore the inoperable steam supply to OPERABLE status within 7 days. The 7 day Completion Time is reasonable, based on the following reasons:~~

~~a. The redundant OPERABLE steam supply to the turbine driven AFW pump;~~

~~b. The availability of redundant OPERABLE motor driven AFW pumps; and~~

~~c. The low probability of an event occurring that requires the inoperable steam supply to the turbine driven AFW pump.~~

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of Conditions to be inoperable during any continuous failure to meet this LCO.

The 10 day Completion Time provides a limitation time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which multiple Conditions are entered concurrently. The AND connector between 7 days and 10 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

B.1

one

for reasons other than Condition A,

With ~~the turbine driven~~ AFW pump system ~~(e.g., pump, flow path, or turbine)~~ inoperable in MODE 1, 2, or 3, action must be taken to restore the pump system to OPERABLE status within 72 hours. The 72 hour Completion Time is reasonable, based on redundant capabilities afforded by the remaining OPERABLE ~~motor driven~~ AFW pump system~~s~~, time needed for repairs, and the low probability of a DBA occurring during this time period.

This Condition includes loss of two steam supply lines to the turbine driven AFW pump.

INSERT AFW-4

If one of the two steam supplies to the turbine driven AFW train is inoperable, or if the turbine driven pump is inoperable while in MODE 3 immediately following refueling, action must be taken to restore the inoperable equipment to an OPERABLE status within 7 days. The 7 day Completion Time is reasonable, based on the following reasons:

a. For the inoperability of a steam supply to the turbine driven AFW pump, the 7 day Completion Time is reasonable, since there is a redundant steam supply to the turbine driven AFW pump.

b. For inoperability of a turbine driven pump while in MODE 3 immediately subsequent to a refueling, the 7 day Completion Time is reasonable due to the minimal decay heat in this situation.

c. For both the inoperability of a steam supply line to the turbine driven pump and an inoperable turbine driven AFW pump while in MODE 3 immediately following a refueling outage, the 7 day Completion Time is reasonable due to the availability of a redundant OPERABLE motor driven AFW pump, and due to the low probability of an event requiring the use of the turbine driven AFW pump.

BASES

ACTIONS (continued)

The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of Conditions to be inoperable during any continuous failure to meet this LCO.

The 10 day Completion Time provides a limitation on the time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which multiple Conditions are entered simultaneously. The AND connector between the 72 hour and 10 day Completion Times dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

~~C.1~~

With one of the motor driven AFW pump systems (e.g., pump or flow path) inoperable in MODE 1, 2, or 3, action must be taken to restore the pump system to OPERABLE status within 7 day. The 7 day Completion Time is reasonable, based on redundant capabilities afforded by the remaining OPERABLE motor driven and turbine driven AFW pump systems, time needed for repairs, and the low probability of a DBA occurring during this time period.

The second Completion Time for Required Action C.1 establishes a limit on the maximum time allowed for any combination of Conditions to be inoperable during any continuous failure to meet this LCO.

The 10 day Completion Time provides a limitation on the time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which multiple Conditions are entered simultaneously. The AND connector between the 7 day and 10 day Completion Times dictates that both Completion ~~Times apply simultaneously, and the more restrictive must be met.~~

~~D.1 and D.2~~ C.1 and C.2

When Required Action A.1 ~~, B.1,~~ or ~~C~~ B.1 cannot be completed within the required Completion Time, or if two AFW pump systems are inoperable in MODE 1, 2, or 3, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 18 hours.

~~Required Action D.1 is modified by a Note indicating that each unit may~~ be sequentially placed in MODE 3 within 12 hours when both units are in Condition D concurrently. Proper application of this Note requires that no more than 12 hours elapse between the time Condition D.1 is ~~entered for the first unit and entry into MODE 3 for both units. This~~

ACTIONS (continued)

The allowed Completion Times are ~~Completion Time extension is~~ reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

Required Action ~~D.2~~ C.2 is modified by a Note indicating that entry into MODE 4 is not required unless ~~one~~ motor driven AFW pump system is OPERABLE. This Completion Time extension precludes entry into an operational condition where ~~a~~ the motor driven AFW pump system may be needed ~~when no motor driven AFW pump systems are~~ and is not available.

The allowed Completion Times, as modified by the Notes, are reasonable based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

~~E.1~~ D.1

If ~~all three~~ both AFW pump systems are inoperable in MODE 1, 2, or 3, the unit is in a seriously degraded condition with no automatically initiated safety related ~~means for conducting a cooldown,~~ AFW pump systems and only limited means for conducting a cooldown with non-safety related equipment. In such a condition, the unit should not be perturbed by any action, including a power change, that might result in a trip. The seriousness of this condition requires that action be started immediately to restore one AFW ~~train~~ pump system to OPERABLE status.

Required Action ~~E.1~~ D.1 is modified by a Note indicating that all required MODE changes or power reductions are suspended until one AFW pump system is restored to OPERABLE status. In this case, LCO 3.0.3 is not applicable because it could force the unit into a less safe condition. This Note does not prohibit voluntary MODE changes that may be prudent for safe operation.

~~F.1~~ E.1

In MODE 4, either the reactor coolant pumps or the RHR loops can be used to provide forced circulation. This is addressed in LCO 3.4.6, "RCS Loops-MODE 4." With ~~one or more~~ the required motor driven pump systems inoperable, action must be taken to immediately restore the inoperable pump system(~~s~~) to OPERABLE status. The immediate Completion Time is consistent with LCO 3.4.6.

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

Verifying the correct alignment for manual, power operated, and

BASES

SURVEILLANCE REQUIREMENTS (continued)

the steam generators during pump testing. This Note allows suitable test conditions to be established while allowing a reasonable time period to complete the SR during unit startups and low power operation.

SR 3.7.5.3

the two

This SR verifies that AFW can be delivered to the appropriate steam generator in the event of any accident or transient that generates an ESFAS, by demonstrating that ~~each~~ motor driven AFW pump discharge ~~motor operated valve (AF-4020, 4021, 4022, and 4023)~~ actuate to their correct positions on an actual or simulated actuation signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. The 18 month Frequency is acceptable based on operating experience and the design reliability of the equipment.

flow control valves

pump systems

The SR is modified by a Note that states one or more AFW ~~trains~~ may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i.e., remotely or locally, as appropriate) realigned to the AFW mode of operation, provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable. Since AFW may be used during startup, shutdown, hot standby operations, and hot shutdown operations for steam generator level control, and these manual operations are an accepted function of the AFW system, OPERABILITY (i.e., the intended safety function) continues to be maintained.

SR 3.7.5.4

This SR verifies that the AFW pumps will start in the event of any accident or transient that generates an ESFAS by demonstrating that each AFW pump starts automatically on an actual or simulated actuation signal. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

The ability of the Main Steam supply valves for the turbine driven pump to actuate to the correct position on an actual or simulated actuation signal is verified by this SR. The ability of the motor driven AFW pump

BASES

flow control

SURVEILLANCE REQUIREMENTS (continued)

~~discharge~~ valves to actuate to the correct position on an actual or simulated actuation signal is also tested by this SR. ~~The AFW discharge pressure control valves do not receive an automatic actuation signal and are not included within this SR.~~

pump systems

This SR is modified by two Notes. Note 1 indicates that the SR may be deferred until suitable test conditions are established. This deferral is required because there is insufficient steam pressure to perform the test. Note 2 states one or more AFW ~~trains~~ may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i.e., remotely or locally, as appropriate) realigned to the AFW mode of operation, provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable. Since AFW may be used during startup, shutdown, hot standby operations, and hot shutdown operations for steam generator level control, and these manual operations are an accepted function of the AFW system, OPERABILITY (i.e., the intended safety function) continues to be maintained.

SR 3.7.5.5

This SR verifies that the AFW is properly aligned by verifying the flow paths from the CST to each steam generator supplied by the respective AFW pump system prior to exceeding 2% of RTP after more than 30 days in any combination of MODE 5 or 6 or defueled. OPERABILITY of AFW flow paths must be verified before sufficient core heat is generated that would require the operation of the AFW System during a subsequent shutdown. The Frequency is reasonable, based on engineering judgement and other administrative controls that ensure that flow paths remain OPERABLE. To further ensure AFW System alignment, flow path OPERABILITY is verified following extended outages to determine no misalignment of valves has occurred. This SR ensures that the flow path from the CST to the steam generators is properly aligned.

REFERENCES

1. FSAR, Section 10.2.
2. ASME OM Code, Code for Operation and Maintenance of Nuclear Power Plants.

B 3.7 PLANT SYSTEMS

B 3.7.6 Condensate Storage Tank (CST)

BASES

BACKGROUND

The CST is the preferred source of water to the steam generators for removing decay and sensible heat from the Reactor Coolant System (RCS). The CST provides a passive flow of water, by gravity, to the Auxiliary Feedwater (AFW) System (LCO 3.7.5). The steam produced is released to the atmosphere by the main steam safety valves or the atmospheric dump valves. The AFW pumps operate with a continuous recirculation to the CST at low flows.

** The CST value will be provided in a supplement to this LAR by July 30, 2009.

**

The CST is non-safety related, because the tanks are not located in a Safety Related Seismic Category I structure. Each of the two CSTs has a capacity of 45,000 gallons, and is shared by both units. As such, a single CST has sufficient capacity to supply the required ~~13,000~~ gallon per unit ~~volume~~. The safety related source of water to the AFW System is the Service Water System (LCO 3.7.8). An AFW pump system can be considered OPERABLE with an inoperable CST based on the OPERABILITY of its associated service water suction supply valve with service water available from either leg of the plant service water system. ~~CST low level alarms and AFW pump low suction pressure alarms and trips are provided to prevent pump damage and to alert personnel that the AFW pump suction supply must be manually swapped.~~

S

Add Insert CST-1

The Applicable Safety Analyses section of Bases 3.7.5 also applies to this Bases section.

A description of the CST is found in the FSAR, Section 10.2 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The CST provides the preferred source of water to the AFW pump systems to remove decay heat and to cool down a unit following various accidents as discussed in the FSAR, Chapter 14 (Ref. 2). The safety related source of water to the AFW pump systems is the Service Water System. Motor operated valves ~~are provided~~ to allow the suction supply for the AFW pumps to be ~~manually~~ transferred to the SW system. The Applicable Safety Analyses section of Bases 3.7.5 also applies to this Bases section.

The limiting event for CST volume is the Station Blackout event (Ref. 3). The minimum amount of water in the CST assures the capability to maintain the unit in MODE 3 for at least one hour concurrent with a loss of all AC power, while then allowing sufficient

INSERT CST-1

CST low level alarms alert personnel that the AFW pump suction supply must be monitored and transferred to the service water system before the low suction pressure setpoint is reached. The pump suctions are automatically transferred to the service water system if the AFW low suction pressure setpoint is reached.

BASES

APPLICABLE SAFETY ANALYSES (continued)

operator action time to transfer AFW suction to the service water system. The minimum CST level is consistent with NRC recommendations made in the Station Blackout Safety Evaluation (Ref. 4), which was calculated in accordance with the recommendations contained in NUMARC 87-00, Section 7.2 (Ref. 5). Once the suction source is transferred to the service water system, an unlimited supply of water is available from the lake via either leg of the plant service water system.

** The CST value will be provided in a supplement to this LAR by July 30, 2009.

10 CFR 50.36(c)2(ii)

The ~~CST~~ satisfies Criteria 2 and 3 of ~~the NRC Policy Statement.~~

LCO

level of ≥ ** gallons

The CST level requirement is for a ~~useable volume of ≥ 13,000 gallons~~, which assures the capability to maintain the unit in MODE 3 for at least one hour concurrent with a loss of all AC power~~, while then allowing sufficient operator action time to transfer AFW suction to the service water system~~. The basis for this limit is established in Reference 4. Since the CSTs are common to both units, this LCO may be satisfied by a single, or multiple, CST(s) containing the required combined volume. The safety related source of water to the AFW system is the service water system.

The OPERABILITY of the CST is determined by maintaining the tank level at or above the minimum required level. In addition, system piping and valves required to function during accident conditions that are directly associated with the CST must be OPERABLE.

APPLICABILITY

In MODES 1, 2, and 3, and in MODE 4, when steam generator is being relied upon for heat removal, the CST is required to be OPERABLE.

In MODE 5 or 6, the CST is not required because the AFW System is not required.

ACTIONS

A.1

If the CST is not OPERABLE, the CST must be restored to OPERABLE status within 7 days, to re-establish the preferred source of water to the AFW pump systems. The 7 day Completion Time is reasonable, based on the OPERABILITY of the service water system as a readily available safety related source of water to the AFW pump systems, and the low probability of an event occurring during this time period.

BASES

ACTIONS (continued)

B.1 and B.2

If the CST cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4, without reliance on the steam generator for heat removal, within 18 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

This SR verifies that the CST contains the required volume of cooling water. ~~The minimum CST volume limit (13,000 gallons) does not include instrument uncertainty. The Surveillance Requirement is met when indicated CST level is ≥ 9.75 feet with both CSTs cross tied supplying both units, ≥ 15.25 feet for a single tank supplying both units, or ≥ 7.0 feet with both CSTs cross tied supplying one unit.~~ The 12 hour Frequency is based on operating experience and the need for operator awareness of unit evolutions that may affect the CST inventory between checks. Also, the 12 hour Frequency is considered adequate in view of other indications in the control room, including alarms, to alert the operator to abnormal deviations in the CST level.

REFERENCES

1. FSAR. Section 10.2.
2. FSAR. Chapter 14.
3. 10 CFR 50.63.
4. NRC Safety Evaluation of the Point Beach response to the Station Blackout Rule, dated October 3, 1990.
5. Guidelines and Technical Bases for NUMARC Incentives Addressing Station Blackout at Light Water Reactors, Section 7.2, dated November, 1987.

ATTACHMENT 4

FPL ENERGY POINT BEACH, LLC
POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE

SUMMARY OF REGULATORY COMMITMENTS

4 Pages Follow

Attachment 4

Summary of Regulatory Commitments

Introduction

Point Beach Nuclear Plant (PBNP) plans on implementing an Extended Power Uprate (EPU) of approximately 17% rated thermal power. Uprate implementation is planned following the refueling outages of Spring 2010 for Unit 1 and Spring 2011 for Unit 2. The following Regulatory Commitments are arranged in four categories: Scheduled during the review process, modifications prior to operation at EPU conditions, program changes required prior to operation at EPU conditions, and procedure revisions required prior to operation at EPU conditions.

Schedule

1. The AFW Pump Suction Transfer on Suction Pressure Low value and the condensate storage tank surveillance value will be provided by July 30, 2009.

2. The following American Transmission Company (ATC) report is being submitted to NRC for information under a separate letter:

    1. Interconnection System Impact Study Report 106 MW Nuclear Generation Increase (53MW each at Point Beach Generators 1 and 2) Manitowoc County, Wisconsin, dated December 17, 2008

    An additional report, G833/G834 Interim Operation and Impacts Report 106 MW Nuclear Generation Increase (53MW each at Point Beach Generators 1 and 2) Manitowoc County, Wisconsin, dated December 30, 2008 is currently under review by FPL Energy Point Beach, LLC.

    These reports are being revised based on updated design input for the main generator ratings and outputs from the generator excitation model planned to support the EPU. When either of these reports are revised, they will be provided to the NRC within 45 days of receipt from ATC.

3. Final TS 5.6.4, Core Operating Limits Report, markups will be submitted within 45 days of Commission approval of LAR 258, Incorporate Best Estimate Large Break Loss-of-Coolant Analyses (LBLOCA).

Modifications

4. Main steam pipe support modifications will be completed to mitigate the larger flow induced fluid transient loads prior to operation of each unit at EPU conditions. See LR Section 2.2.2.2, Balance of Plant Piping, Components and Supports.

5. The steam generator moisture separator packages will be modified to maintain the steam moisture content below 0.25% prior to operation of each unit at EPU conditions. This will be verified as part of the startup testing program at EPU conditions. See LR Section 2.2.2.5, Steam Generators and Supports .

6. New main generator output breakers and associated protection scheme will be provided to isolate the generator from the distribution system when generator trips are required prior to operation of each unit at EPU conditions. See LR Section 2.3.3, AC Onsite Power System

7. The charging pump variable frequency drive installation for 1P-2C will be completed prior to operation of either unit at EPU conditions. See LR Section 2.3.3., AC Onsite Power System.

8. The loss of voltage relay time delay settings for the safety related 4160V and 480V and non-safety related 4160V will be implemented as part of the plant modification process prior to operation of each unit at EPU conditions. See LR Section 2.3.3., AC Onsite Power System.

9. The AFW system will be upgraded to install new unitized motor-driven pumps, and add AFW pump suction automatic switchover to service water upon loss of the condensate storage tank water source. This will be completed prior to operation of either unit at EPU conditions. See LR Section 2.5.4.5, Auxiliary Feedwater.

10. New Main Feedwater Isolation Valves (MFIVs) will be installed and main feedwater piping supports will be modified, to withstand the stress of an MFIV closure transient, prior to operation of the affected unit at EPU conditions. See LR Section 2.5.5.4, Condensate and Feedwater.

11. The Main Steam Isolation Valves (MSIVs) internals will be upgraded to address flow-induced vibration and closure loads prior to operation of the affected unit at EPU conditions. See LR Section 2.5.5.1, Main Steam.

12. The pressurizer backup heater actuation on pressurizer high level deviation signal will be removed prior to operation of each unit at EPU conditions. See LR Section 2.8.5.2.3, Loss of Normal Feedwater Flow.

13 A backup compressed gas supply for the Pressurizer Auxiliary Spray Valve inside containment on each unit will be installed prior to operation of that unit at EPU conditions. See LR Section 2.13, Risk Evaluation.

14. Eliminate the reliance on local manual action to gag the Motor-Driven and Turbine-Driven AFW pump mini-recirculation valves open prior to operation of either unit at EPU conditions. See LR Section 2.13, Risk Evaluation.

15. A self-cooled (i.e., air-cooled) air compressor will be installed to supply Instrument Air. The compressor will be independent of Service Water cooling and aligned for automatic operation. It will be installed prior to operation of either unit at EPU conditions. See LR Section 2.13, Risk Evaluation.

16. A combination of interim or final requirements including breaker protection improvements, installation of a switching station, line segment upgrades, and operating restrictions will be implemented to address the thermal and stability limits of the transmission grid that will be associated with the implementation of the PBNP EPU. These requirements will be addressed by PBNP and American Transmission Company (owner/operator of the transmission grid) to allow PBNP to operate either unit at EPU conditions. See LR Section 2.3.2, Offsite Power System.

Programs

17. A formal monitoring program for the steam generator steam drum components will be implemented prior to operation of each unit at EPU conditions. The monitoring will be conducted over two operating cycles to confirm components are performing adequately at EPU operating conditions. See LR Section 2.2.2.5, Steam Generators and Supports.

18. Additional detailed environmental qualification analyses will be performed to qualify four Honeywell microswitches in the containment façade and a Nutherm Panel in the Primary Auxiliary Building that did not have the recommended 10% percent margin as described in IEEE 323 Std.-1974 for EPU conditions, or they will be replaced with qualified components prior to the implementation of EPU on the associated unit. The Environmental Qualification (EQ) documentation for EQ equipment will be revised to reflect the EPU harsh environment parameters prior to operation of each unit at EPU conditions. See LR Section 2.3.1.1, Environmental Qualification of Electrical Equipment.

19. PBNP will implement WCAP-14696-A Revision 1, Westinghouse Owners Group Core Damage Assessment Guidance, which was approved by the NRC staff on September 2, 1999, for use by Westinghouse plants. This commitment will be implemented prior to operation of either unit at EPU conditions. See LR Section 2.10.2, Additional Review Areas (Health Physics).

Procedures

20. The reload and safety analysis check list for Unit 2 will be revised to include a line item limiting the steam generator tube plugging level to 3% until additional analysis is completed for operation with a tube plugging level greater than 3%. The reload and safety analysis check list for Unit 2 will be revised prior to operation of Unit 2 at EPU conditions. See LR Section 1.1, NSSS Parameters. See LR Section 2.2.2.5, Steam Generators and Supports.

21. The high pressurizer pressure reactor trip delay time of less than or equal to 1.0 second will be verified by a time delay test prior to operation of that unit at EPU conditions. See LR Section 2.8.5.2.1, Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum.

22. An EPU Power Ascension and Testing Program will be developed prior to operation of each unit at EPU conditions and will consist of initial startup testing, pre-modification baseline testing, post-modification testing, and power ascension testing. See LR Section 2.12, Power Ascension and Testing Plan.

Westinghouse

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Nuclear Services
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USA

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Proj letter ref: WEP-09-22
Our ref: CAW-09-2530

February 11, 2009

APPLICATION FOR WITHHOLDING PROPRIETARY
INFORMATION FROM PUBLIC DISCLOSURE

Subject: WCAP-14787, Revision 3, "Westinghouse Revised Thermal Design Procedure Instrument Uncertainty Methodology for Point Beach 1 & 2 Power Uprate (1775 MWt – Core Power with Feedwater Venturis, or 1800 MWt – Core Power with LEFM on Feedwater Header)" (Proprietary)

The proprietary information for which withholding is being requested in the above-referenced report is further identified in Affidavit CAW-09-2530 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 FPL Energy.

Correspondence with respect to the proprietary aspects of the application for withholding or the Westinghouse affidavit should reference this letter, CAW-09-2530, and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P.O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

Very truly yours,

J. A. Gresham

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

Enclosures

cc: George Bacuta (NRC OWFN 12E-1)

bcc: J. A. Gresham (ECE 4-7A) 1L
R. Bastien, 1L (Nivelles, Belgium)
C. Brinkman, 1L (Westinghouse Electric Co., 12300 Twinbrook Parkway, Suite 330, Rockville, MD 20852)
RCPL Administrative Aide (ECE 4-7A) 1L, 1A (letter and affidavit only)
R. Morrison (ECE 4-16A) 1L, 1A
P. Vaughan (ECE 3-19J) 1L, 1A

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 & Plant Licensing

Sworn to and subscribed before me
this 11th day of February, 2009

Notary Public

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Sharon L. Markle, Notary Public
Monroeville Boro, Allegheny County
My Commission Expires Jan. 29, 2011
Member, Pennsylvania Association of Notaries

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

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

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

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

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

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

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

(a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(v) The proprietary information sought to be withheld in this submittal is that which is appropriately marked in "WCAP-14787, Revision 3, "Westinghouse Revised Thermal Design Procedure Instrument Uncertainty Methodology for Point Beach 1 & 2 Power Uprate (1775 MWt – Core Power with Feedwater Venturis, or 1800 MWt – Core Power with LEFM on Feedwater Header)" being transmitted by FPL Energy 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 Point Beach Units 1 and 2 is expected to be applicable for other licensee submittals in response to certain NRC requirements for justification of the use of Westinghouse setpoint methodology.

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

(a) Demonstrate Westinghouse specific setpoint methodology.

(b) Provide customer specific calculations.

(c) Provide licensing 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 demonstrating compliance with certain setpoints and setpoint methodology.

(b) Westinghouse can sell support and defense of the technology to its customer 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 information 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).

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