UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

NOV 16 1989

MEMORANDUM FOR: Frank P. Gillespie, Director
Program Management, Policy Development and Analysis Staff
Office of Nuclear Reactor Regulation

FROM: Eric S. Beckjord, Director
Office of Nuclear Regulatory Research

SUBJECT: RESOLUTIONS OF GENERIC ISSUE 70, "POWER OPERATED RELIEF VALVE AND BLOCK VALVE RELIABILITY," AND GENERIC ISSUE 94, "ADDITIONAL LOW-TEMPERATURE OVERPRESSURE PROTECTION FOR LIGHT WATER REACTORS"

The enclosed generic letter (including the attachments NUREG-1316 for GI-70 and NUREG-1326 for GI-94) was reviewed by the Committee to Review Generi[illegible] Requirements at CRGR Meetings 167 on August 9, 1989 and 168 on August 2[illegible] 1989. The Committee is in agreement with the proposed resolutions for Generic Issues 70 and 94 and recommends implementation of the generic letter. A number of minor modifications to the generic letter were proposed by the CRGR. All the modifications recommended by the CRGR have been implemented in the enclosed generic letter and supporting documentation.

Accordingly, this generic letter, NUREG-1316 and NUREG-1326 are hereby forwarded to NRR for transmittal to all PWR licensees and CP holders.

Also enclosed are SRPs 3.2.2, 5.2.2, and 5.4.7. They have been revised to reflect the guidance provided in the generic letter. It is anticipated that these minor revisions to the SRPs will be made by NRR in the next scheduled revision of NUREG-0800. This action completes the RES effort on Generic Issues 70 and 94.

Eric S. Beckjord, Director
Office of Nuclear Regulatory Research

Enclosures: See following page

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Enclosures:
1. Proposed Generic Letter 89-XX
2. NUREG-1316, "Technical Findings and Regulatory Analysis Related to Generic Issue 70 - Evaluation of Power-Operated Relief Valve and Block Valve Reliability in PWR Nuclear Power Plants," dated September 1989.
3. NUREG-1326, "Regulatory Analysis for the Resolution of Generic Issue 94: Additional Low-Temperature Overpressure Protection for Light Water Reactors," dated September 1989.
4. Proposed revision to NUREG-0800, Section 3.2.2, "System Quality Group Classification."
5. Proposed revision to NUREG-0800, Section 5.2.2, "Overpressure Protection."
6. Proposed revision to NUREG-0800, Section 5.4.7, "Residual Heat Removal (RHR) System."

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Enclosure 1

To All Pressurized Water Reactor Licensees and Construction Permit Holders

SUBJECT: Resolution of Generic Issue 70, "Power-Operated Relief Valve and Block Valve Reliability," and Generic Issue 94, "Additional Low-Temperature Overpressure Protection for Light-Water Reactors" (Generic Letter 89-xx)

The purpose of this generic letter is to advise pressurized water reactor (PWR) licensees and construction permit (CP) holders of the staff positions delineated in Enclosures A and B to this letter. Enclosure A presents the staff position resulting from the resolution of Generic Issue 70 (GI-70) and is applicable to all Westinghouse and Babcock and Wilcox (B&W) designed plants and Combustion Engineering (CE) designed plants with power-operated relief valves (PORVs). Enclosure B presents the staff position resulting from the resolution of Generic Issue 94 (GI-94) and is applicable to all Westinghouse and CE designed plants whether or not they have PORVs and block valves. Enclosure B does not apply to B&W designed plants. The technical findings and regulatory analysis related to GI-70 are discussed in NUREG-1316, "Technical Findings and Regulatory Analysis Related to Generic Issue 70--Evaluation of Power-Operated Relief Valve and Block Valve Reliability in PWR Nuclear Power Plants" (Enclosure C). In Enclosure D, the staff prepared a regulatory analysis for GI-94 based on the work performed by PNL and reported in NUREG-1326, "Regulatory Analysis for the Resolution of Generic Issue 94, Additional Low-Temperature Overpressure Protection for Light-Water Reactors."

On the basis of technical studies for GI-70, the staff requests that, to enhance safety, actions identified in Section 3 of Enclosure A be taken by all PWR licensees and CP holders that use or could use PORVs to perform any of the safety-related functions identified in Section 2 of Enclosure A. These actions result from the staff interpretation of safety-related equipment (see 10 CFR § 50.49 and 10 CFR Part 100, Appendix A).

On the basis of technical studies for GI-94, the staff also requests that, to enhance safety, actions identified in Section 3 of Enclosure B be taken by all Combustion Engineering and Westinghouse PWR licensees and CP holders. These actions result from the staff interpretation of General Design Criteria 15 and 31 in 10 CFR Part 50, Appendix A. The information requested by this letter is directed at addressing these concerns.

Note that the staff's requests are based on the performance of PORV and PORV block valve designs used to date on U.S. power reactors. Currently certain valve manufacturers are developing modified designs with the goal of improving reliability. The use of more reliable valves should result in less frequent corrective maintenance and can result in longer inservice testing intervals as delineated in Section XI of the ASME Boiler and Pressure Vessel Code.

Accordingly, pursuant to Section 182 of the Atomic Energy Act and 10 CFR § 50.54 (f), you, as a PWR licensee or CP holder, are required to advise the NRC staff under oath or affirmation, within 180 days of the date of this letter, of your current plans relating to PORVs and block valves and to low-temperature over-pressure protection, in particular whether you intend to follow the staff positions included in Enclosures A and B as applicable, attached to this letter, or propose alternative measures, and your proposed schedule for implementation.

For PWR plants with an operating license, staff positions 1 and 2 in Section 3.1 of Enclosure A should be implemented by the end of the first refueling outage that starts 6 months or later from the date of this letter. The technical specification modifications in staff position 3 in Section 3.1 of Enclosure A and in Section 3 of Enclosure B should be submitted by the end of the first refueling outage that starts 6 months or later from the date of this letter.

For PWR CP holders, staff positions 1 and 2 in Section 3.1 of Enclosure A should be implemented prior to initial criticality or within 6 months of the date of this letter, whichever is later. The technical specification modifications in staff position 3 in Section 3.1 of Enclosure A and in Section 3 of Enclosure B should be submitted by the end of the first refueling outage that starts 6 months or later from the date of this letter.

If the applicable schedule cannot be met, the licensee or CP holder shall advise the staff of a proposed revised schedule, justification for any delay, and any planned compensating measures to be taken during the interim. Alternatives to schedules and the guidance provided herein will be evaluated on their merits on an individual case basis. Based on its review and the acceptability of these responses, the staff will close out GI-70 and GI-94 for each plant.

Your response shall include the following specific items.

1. A statement by licensees and CP holders as to whether they will commit to incorporate improvements 1, 2, and 3 in Section 3.1 of Enclosure A. With respect to improvement 3 in Section 3.1 of Enclosure A, licensees and CP holders shall state whether they will commit to use those modified limiting conditions of operation of PORVs and block valves in the technical specifications for Modes 1, 2, and 3 in Attachment A-1 of Enclosure A for Westinghouse and CE designed plants with two PORVs, or in Attachment A-2 of Enclosure A for Westinghouse designed plants with three PORVs, or in Attachment A-4 of Enclosure A for B&W designed plants.[1] In addition to this 10 CFR § 50.54(f) request, if the licensees and CP holders commit to implement these recommended technical specifications, it is requested that they submit modifications to their current technical specifications in a license amendment in accordance with the schedule noted above.

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[1] Plants that already have staff-issued technical specifications consistent with these requirements need merely state this in their response. No further action will be required for this aspect of the Commission's position.

2. A statement by licensees and CP holders as to whether they will submit a license amendment request to modify the technical specifications and commit to use the modified technical specifications for the low-temperature overpressure protection system concerning the limiting conditions of operation in Modes 5 and 6 as identified in Attachment B-1 of Enclosure B to this generic letter for Westinghouse or CE designed plants, as appropriate. In addition to this 10 CFR § 50.54(f) request, if the licensees and CP holders commit to implement these recommended technical specifications, it is requested that they submit modifications to their current technical specifications in a license amendment in accordance with the schedule noted above.

The actions to incorporate technical specification (TS) requirements for the resolution of GI-70 and GI-94 are considered to be consistent with the Commission's Policy Statement on Technical Specification Improvements. That policy statement captures existing requirements under Criterion 3 (Mitigation of Design Basis Accidents or Transients) or under the provisions to retain requirements that operating experience and probabilistic risk assessment show to be important to public health and safety. While it is recognized that PORVs for older plants may not have been classified as safety-related components that are used to mitigate a design basis accident and, therefore, they may not have been included in TS as part of the plant's licensing basis, this is not an acceptable basis for not implementing the proposed actions to incorporate TS requirements for PORVs consistent with the guidance provided. Likewise, such requirements would be retained in TS when implementing improvements in TS consistent with the Commission policy statement on the basis of Criterion 3 or risk considerations noted above.

Backfit Discussion

For GI-70, the actions proposed by the NRC staff to improve the reliability of PORVs and block valves, as identified in Section 3 of Enclosure A, represent new staff positions for some licensees and CP holders, and this request is considered a backfit in accordance with NRC procedures. This backfit is a cost-justified safety enhancement. Therefore, an analysis of the type described in 10 CFR 50.109(a)(3) and 50.109(c) was performed, and a determination was made that there will be a substantial increase in overall protection of the public health and safety and that the costs are justified in view of this increased protection. The analysis and determination will be made available in the Public Document Room with the minutes of the 167th and 168th meetings of the Committee to Review Generic Requirements.

It is noted that most of the recommended actions for GI-70 may already be implemented by those plants that have received operating licenses in recent years and would, therefore, represent less of a backfit than for older PWR plants that currently do not include PORVs and block valves in the ASME Section XI Inservice Testing Program and do not have technical specifications for PORVs and block valves or that operate with the block valves closed because of leaking PORVs.

For GI-94, the actions proposed by the NRC staff to improve the availability of the low-temperature overpressure protection (LTOP) system, as identified in Section 3 of Enclosure B, represent a new interpretation of existing requirements for some licensees and CP holders, and this request is considered a backfit in accordance with NRC procedures. This backfit is a cost-justified safety enhancement. Therefore, an analysis of the type described in 10 CFR 50.109(a)(3) and 50.109(c), was performed, and a determination was made that there will be a substantial increase in overall protection of the public health and safety and that the costs are justified in view of this increased protection. The analysis and determination will be made available in the Public Document Room with the minutes of the 167th and 168th meetings of the Committee to Review Generic Requirements.

This request is covered by Office of Management and Budget Clearance Number 3150-001, which expires December 31, 1989. The estimated average burden hours is 320 person-hours per licensee response, including assessment of the new recommendations, searching data sources, gathering and analyzing the data, and preparing the required reports. Comments on the accuracy of this estimate and suggestions to reduce the burden may be directed to the Office of Management and Budget, Room 3208, New Executive Office Building, Washington, D.C. 20503, and the U.S. Nuclear Regulatory Commission, Records and Reports Management Branch, Office of Administration and Resources Management, Washington, D.C. 20555.

Sincerely,

James G. Partlow
Associate Director for Projects
Office of Nuclear Reactor Regulation

Technical Contact: To be determined

Enclosures: See following page

*SEE PREVIOUS CONCURRENCE

EIB:DSIR	EIB:DSIR	EIB:DSIR	RPSIB:DSIR	RPSIB:DSIR	RPSIB:DSIR
RKirkwood/mb	FCherny	RBaer	EThrom	GMazetis	KKniel
11/06/89*	11/06/89*	11/06/89*	11/06/89*	11/06/89*	11/06/89*
D:DSIR	DD:RES	D:RES	NRR	NRR	
WMinners	TSpeis	EBeckjord	TMurley	JPartlow	
11/07/89*	11/8/89	11/8/89	11/ /89	11/ /89	

For GI-94, the actions proposed by the NRC staff to improve the availability of the low-temperature overpressure protection (LTOP) system, as identified in Section 3 of Enclosure B, represent a new interpretation of existing requirements for some licensees and CP holders, and this request is considered a backfit in accordance with NRC procedures. This backfit is a cost-justified safety enhancement. Therefore, an analysis of the type described in 10 CFR 50.109(a)(3) and 50.109(c), was performed, and a determination was made that there will be a substantial increase in overall protection of the public health and safety and that the costs are justified in view of this increased protection. The analysis and determination will be made available in the Public Document Room with the minutes of the 167th and 168th meetings of the Committee to Review Generic Requirements.

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Sincerely,

James G. Partlow
Associate Director for Projects
Office of Nuclear Reactor Regulation

Technical Contact: To be determined

Enclosures:

Enclosure A-Staff Positions Resulting from Resolution of Generic Issue 70.
Enclosure B-Staff Positions Resulting from Resolution of Generic Issue 94.
Enclosure C-NUREG-1316, "Technical Findings and Regulatory Analysis Related to Generic Issue 70--Evaluation of Power-Operated Relief Valve and Block Valve Reliability in PWR Nuclear Power Plants."
Enclosure D-NUREG-1326, "Regulatory Analysis for the Resolution of Generic Issue 94, Additional Low-Temperature Overpressure Protection for Light-Water Reactors."

EIB:DSIR	EIB:DSIR	EIB:DSIR	RPSIB:DSIR	RPSIB:DSIR	RPSIB:DSIR
RKirkwood/mb	FCherny	RBaer	EThrom	GMazetis	KKniel
11/2/89	11/6/89	11/6/89	11/6/89	11/6/89	11/6/89
D:DSIR	DD:RES	D:RES	NRR	NRR	
WMinners	TSpeis	EBeckjord	TMurley	JPartlow	
11/ /89	11/ /89	11/ /89	11/ /89	11/ /89	

Enclosures:
Enclosure A-Staff Positions Resulting from Resolution of Generic Issue 70.
Enclosure B-Staff Positions Resulting from Resolution of Generic Issue 94.
Enclosure C-NUREG-1316, "Technical Findings and Regulatory Analysis Related to Generic Issue 70--Evaluation of Power-Operated Relief Valve and Block Valve Reliability in PWR Nuclear Power Plants."
Enclosure D-NUREG-1326, "Regulatory Analysis for the Resolution of Generic Issue 94, Additional Low-Temperature Overpressure Protection for Light-Water Reactors."

Enclosure A to Generic Letter 89-XX

Staff Positions Resulting from
Resolution of Generic Issue 70 -
PORV and Block Valve Reliability

1. BACKGROUND

Generic Issue 70 (GI-70), "Power-Operated Relief Valve and Block Valve Reliability," involves the evaluation of the reliability of power-operated relief valves (PORVs) and block valves and their safety significance in PWR plants. The technical findings and regulatory analysis related to GI-70 are discussed in NUREG-1316, "Technical Findings and Regulatory Analysis Related to Generic Issue 70--Evaluation of Power-Operated Relief Valve and Block Valve Reliability in PWR Nuclear Power Plants" (Enclosure C). This report identifies those safety-related functions that may be performed by PORVs and also identifies potential improvements to PORVs and block valves. In support of the resolution of GI-70, the Oak Ridge National Laboratory (ORNL) performed a study of PORV and block valve operating experience. A report, prepared by ORNL, was issued as NUREG/CR-4692, "Operating Experience Review of Failures of Power Operated Relief Valves and Block Valves in Nuclear Power Plants," dated October 1987.

Traditionally, the PORV and its block valve are provided for plant operational flexibility and for limiting the number of challenges to the safety-related pressurizer safety valves. The operation of the PORVs has not been classified as a safety-related function, i.e., one on which the results and conclusions of the safety analysis are based and that invokes the highest level of quality and construction. For overpressure protection of the reactor coolant pressure boundary (RCPB) at normal operating temperature and pressure, the operation of PORVs has not been explicitly considered as a safety-related function. Also, an inadvertent opening of a PORV or safety valve has been analyzed in the Final Safety Analysis Reports as an anticipated operational occurrence with acceptable consequences. For these reasons, most PWRs, particularly those licensed prior to 1979, do not classify PORVs as safety-related components.

The Three Mile Island Unit 2 (TMI-2) accident focused attention on the reliability of PORVs and block valves since the malfunction of the PORV at TMI-2 contributed to the severity of the accident. On other occasions, PORVs have stuck open when called upon to function. Also, there are PORVs in many operating plants that have leakage problems so that the plants must be operated with the upstream block valves in the closed position. The technical specifications governing PORVs on most operating PWRs, which deal with closing the block valve and removing power, were developed to allow continued plant operation with degraded PORVs, but did not consider the need for the PORVs to perform the safety functions discussed below.

Following the TMI-2 accident, the staff began to examine transient and accident events in more detail, particularly with respect to required operator actions and equipment availability and performance. As a result, the staff initiated an evaluation of the role of PORVs to perform certain safety-related functions.

2. SAFETY FUNCTIONS OF PORVs AND BLOCK VALVES

The staff, in its evaluation, determined that over a period of time the role of PORVs has changed such that PORVs are now relied upon by many Westinghouse, B&W, and CE designed plants with PORVs to perform one, or more, of the following safety-related functions:

1. Mitigation of a design-basis steam generator tube rupture accident,
2. Low-temperature overpressure protection of the reactor vessel during startup and shutdown, or
3. Plant cooldown in compliance with Branch Technical Position RSB 5-1 to SRP 5.4.7, "Residual Heat Removal (RHR) System."

Where PORVs are used or could be used to perform one, or more, of the safety-related functions identified above or to perform any other safety-related function that may be identified in the future, it is appropriate to reconsider the safety classification of PORVs and the associated block valves. For certain PWR plants receiving an operating license in recent years, the staff has required these valves to be classified as safety-related components if they perform one, or more, safety-related functions.

For operating PWR plants, the staff has concluded that it is not cost effective to replace (backfit) existing non-safety-grade PORVs and block valves (and associated control systems) with PORVs and block valves that are safety grade even when they have been determined to perform any of the safety-related functions discussed above. Subsequent to the TMI-2 accident, a number of improvements were required of PORVs and block valves, such as requirements to be powered from Class IE buses and to have valve position indication in the control room. For operating plants, the greatest immediate benefits can be derived from implementing items 1 through 3 identified below, which can increase the reliability of these components and provide assurance they will function as required.

3. IMPROVEMENTS TO ALL PORVs AND BLOCK VALVES

3.1 Operating PWR Plants and Construction Permit Holders

Based on the analysis and findings for GI-70, the staff concludes that the following actions should be taken to improve the reliability of PORVs and block valves:

1. Include PORVs and block valves within the scope of an operational quality assurance program that is in compliance with 10 CFR Part 50, Appendix B. This program should include the following elements:

   a. The addition of PORVs and block valves to the plant operational Quality Assurance List.

   b. Implementation of a maintenance/refurbishment program for PORVs and block valves that is based on the manufacturer's recommendations or guidelines and is implemented by trained plant maintenance personnel.

c. When replacement parts and spares, as well as complete components, are required for existing non-safety-grade PORVs and block valves (and associated control systems), it is the intent of this generic letter that these items may be procured in accordance with the original construction codes and standards.

2. Include PORVs, valves in PORV control systems, and block valves within the scope of a program covered by Subsection IWV, "Inservice Testing of Valves in Nuclear Power Plants," of Section XI of the ASME Boiler and Pressure Vessel Code. As permitted by the Code, stroke testing of PORVs should only be performed during Mode 3 (HOT STANDBY) or Mode 4 (HOT SHUTDOWN) and in all cases prior to establishing conditions where the PORVs are used for low-temperature overpressure protection. Stroke testing of the PORVs should not be performed during power operation. Additionally, the PORV block valves should be included in the licensees' response to the expanded MOV test program discussed in NRC Generic Letter 89-10, "Safety-Related Motor Operated Valve Testing and Surveillance," dated June 28, 1989.

3. For operating PWR plants, modify the limiting conditions of operation of PORVs and block valves in the technical specifications for Modes 1, 2, and 3 to incorporate the position adopted by the staff in recent licensing actions. Attachments A-1 through A-3 are provided for guidance. The staff recognizes that some recently licensed PWR plants already have technical specifications in accordance with the staff position. Such plants are already in compliance with this position and need merely state that in their response. These recent technical specifications require that plants that run with the block valves closed (e.g., due to leaking PORVs) maintain electrical power to the block valves so they can be readily opened from the control room upon demand. Additionally, plant operation in Modes 1, 2, and 3 with PORVs and block valves inoperable for reasons other than seat leakage is not permitted for periods of more than 72 hours.

Enclosure A to Generic Letter 89-XX

Attachment A-1

Modified Standard Technical Specifications
for Combustion Engineering and Westinghouse Plants

REACTOR COOLANT SYSTEM

3/4.4.4 RELIEF VALVES

LIMITING CONDITION FOR OPERATION

The following is to be used when two PORVs are provided:

3.4.4 Both power-operated relief valves (PORVs) and their associated block valves shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With one or both PORVs inoperable because of excessive seat leakage, within 1 hour either restore the PORV(s) to OPERABLE status or close the associated block valve(s) with power maintained to the block valve(s); otherwise, be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With one PORV inoperable due to causes other than excessive seat leakage, within 1 hour either restore the PORV to OPERABLE status or close its associated block valve and remove power from the block valve; restore the PORV to OPERABLE status within the following 72 hours or be in HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

c. With both PORVs inoperable due to causes other than excessive seat leakage, within 1 hour either restore at least one PORV to OPERABLE status or close its associated block valve and remove power from the block valve and be in HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

d. With one or both block valves inoperable, within 1 hour restore the block valve(s) to OPERABLE status or place its associated PORV(s) in manual control. Restore at least one block valve to OPERABLE status within the next hour if both block valves are inoperable; restore any remaining inoperable block valve to operable status within 72 hours; otherwise, be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

e. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.4.4.1 In addition to the requirements of Specification 4.ι 5, each PORV shall be demonstrated OPERABLE at least once per 18 months by.

a. Operating the PORV through one complete cycle of full travel during MODES 3 or 4, and

b. Where applicable, operating solenoid air control valves and check valves on associated air accumulators in PORV control systems through one complete cycle of full travel for plants with air-operated PORVs, and

c. Performing a CHANNEL CALIBRATION of the actuation instrumentation.

4.4.4.2 Each block valve shall be demonstrated OPERABLE at least once per 92 days by operating the valve through one complete cycle of full travel, unless the block valve is closed in order to meet the requirements of ACTION a, b, or c in Specification 3.4.4.

4.4.4.3 The emergency power supply for the PORVs and block valves shall be demonstrated OPERABLE at least once per 18 months by:

a. Manually transferring motive and control power from the normal to the emergency power bus, and

b. Operating the valves through a complete cycle of full travel.

COMBUSTION ENGINEERING AND WESTINGHOUSE PLANTS

Enclosure A To Generic Letter 89-XX

Attachment A-2

Modified Standard Technical Specifications
for Westinghouse Plants with Three PORVs

REACTOR COOLANT SYSTEM

3/4.4.4 RELIEF VALVES

LIMITING CONDITION FOR OPERATION

The following is to be used when three PORVs are provided:

3.4.4 All power-operated relief valves (PORVs) and their associated block valves shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With one or more PORVs inoperable because of excessive seat leakage, within 1 hour either restore the PORV(s) to OPERABLE status or close the associated block valve(s) with power maintained to the block valve(s); otherwise, be in at least HOT STANDBY within the next 6 hours and HOT SHUTDOWN within the following 6 hours.

b. With one or two PORVs inoperable due to causes other than excessive seat leakage, within 1 hour either restore the PORV(s) to OPERABLE status or close the associated block valve(s) and remove power from the block valve(s); restore the PORV(s) to OPERABLE status within the following 72 hours or be in HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

c. With three PORVs inoperable due to causes other than excessive seat leakage, within 1 hour either restore at least one PORV to OPERABLE status or close the block valves and remove power from the block valve(s) and be in HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

d. With one or more block valves inoperable, within 1 hour restore the block valve(s) to OPERABLE status or place its associated PORV in manual control. Restore at least one block valve to OPERABLE status within the next hour if three block valves are inoperable; restore any remaining inoperable block valve(s) to operable status within 72 hours; otherwise, be in HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

e. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.4.4.1 In addition to the requirements of Specification 4.0.5, each PORV shall be demonstrated OPERABLE at least once per 18 months by:

a. Operating the PORV through one complete cycle of full travel during MODES 3 or 4, and

b. Where applicable, operating solenoid air control valves and check valves on associated air accumulators in PORV control systems through one complete cycle of full travel for plants with air-operated PORVs, and

c. Performing a CHANNEL CALIBRATION of the actuation instrumentation.

4.4.4.2 Each block valve shall be demonstrated OPERABLE at least once per 92 days by operating the valve through one complete cycle of full travel unless the block valve is closed in order to meet the requirements of ACTION a, b, or c in Specification 3.4.4.

4.4.4.3 The emergency power supply for the PORVs and block valves shall be demonstrated OPERABLE at least once per 18 months by:

a. Manually transferring motive and control power from the normal to the emergency power bus, and

b. Operating the valves through a complete cycle of full travel.

Enclosure A to Generic Letter 89-XX

Attachment A-3

Applicable to Combustion Engineering and Westinghouse Plants

3/4.4.4 RELIEF VALVES

Bases of the Limiting Condition for Operation (LCO) and Surveillance Requirements:

The OPERABILITY of the PORVs and block valves is determined on the basis of their being capable of performing the following functions:

A. Manual control of PORVs to control reactor coolant system pressure. This is a function that is used for the steam generator tube rupture accident and for plant shutdown. This function has been classified as safety related for more recent plant designs.

B. Maintaining the integrity of the reactor coolant pressure boundary. This is a function that is related to controlling identified leakage and ensuring the ability to detect unidentified reactor coolant pressure boundary leakage.

C. Manual control of the block valve to: (1) unblock an isolated PORV to allow it to be used for manual control of reactor coolant system pressure (Item A), and (2) isolate a PORV with excessive seat leakage (Item B).

D. Automatic control of PORVs to control reactor coolant system pressure. This is a function that reduces challenges to the code safety valves for overpressurization events.

E. Manual control of a block valve to isolate a stuck-open PORV.

Surveillance Requirements provide the assurance that the PORVs and block valves can perform their functions. Specification 4.4.4.1 addresses PORVs, 4.4.4.2 the block valves, and 4.4.4.3 the emergency (backup) power sources. The latter are provided for either PORVs or block valves, generally as a consequence of the TMI ACTION requirements to upgrade the operability of PORVs and block valves, where they are installed with non-safety-grade power sources, including instrument air, and are provided with a backup (emergency) power source. The block valves are exempt from the surveillance requirements to cycle the valves when they have been closed to comply with the ACTION requirements. This precludes the need to cycle the valves with full system differential pressure or when maintenance is being performed to restore an inoperable PORV to operable status.

Surveillance requirement 4.4.4.1.b has been added to include testing of the mechanical and electrical aspects of control systems for air-operated PORVs.

Testing of PORVs in HOT STANDBY or HOT SHUTDOWN is required in order to simulate the temperature and pressure environmental effects on PORVs. In many PORV designs, testing at COLD SHUTDOWN is not considered to be a representative test for assessing PORV performance under normal plant operating conditions.

The Modified Standard Technical Specification (STS) requirements include the following changes from prior STS guidance:

1. Clarify the statement of LCO by replacing "All" with "Both" where the design includes two PORVs.

2. ACTION statement a. includes the requirement to maintain power to closed block valve(s) because removal of power would render the block valve(s) inoperable and the requirements of ACTION statement c. would apply. Power is maintained to the block valve(s) so that it is operable and may be subsequently opened to allow the PORV to be used to control reactor pressure. Closure of the block valve(s) establishes reactor coolant pressure boundary integrity for a PORV that has excessive seat leakage. (Reactor coolant pressure boundary integrity takes priority over the capability of the PORV to mitigate an overpressure event.)

3. ACTION statements b. and c. include the removal of power from a closed block valve as additional assurance to preclude any inadvertent opening of the block valve at a time in which the PORV may not be closed due to maintenance to restore it to OPERABLE status. (In contrast, ACTION statement a. permits continued plant operation with the block valves closed, i.e., continued operation is not dependent on maintenance to eliminate excessive PORV leakage, and, therefore, ACTION statement a. does not require removal of power from the block valve.)

4. ACTION statements a., b., and c. have been changed to terminate the forced shutdown requirements with the plant being in HOT SHUTDOWN rather than COLD SHUTDOWN because the APPLICABILITY requirements of the LCO do not extend past the HOT STANDBY mode.

5. ACTION statement d. has been modified to establish remedial measures that are consistent with the function of the block valves. The prime importance for the capability to close the block valve is to isolate a stuck-open PORV. Therefore, if the block valve(s) cannot be restored to operable status within 1 hour, the remedial action is to place the PORV in manual control to preclude its automatic opening for an overpressure event and to avoid the potential for a stuck-open PORV at a time that the block valve is inoperable. The time allowed to restore the block valve(s) to operable status is based upon the remedial action time limits for inoperable PORVs per ACTION statements b. and c. since the PORVs are not capable of mitigating an overpressure event when placed in manual control. These actions are also consistent with the use of the PORVs to control reactor coolant system pressure if the block valves are inoperable at a time when they have been closed to isolate PORVs that have excessive seat leakage. The modified ACTION statement does not specify closure of the block valves because such action would not likely be possible when the block valve is

inoperable. Likewise, it does not specify either the closure of the PORV, because it would not likely be open, or the removal of power from the PORV. When the block valve is inoperable, placing the PORV in manual control is sufficient to preclude the potential for having a stuck-open PORV that could not be isolated because of an inoperable block valve. For the same reasons, reference is not made to ACTION statements b. and c. for the required remedial actions.

6. Surveillance requirement 4.4.4.2 has been modified to remove the exception for testing the block valves when they are closed to isolate an inoperable PORV. If the block valve is closed to isolate a PORV with excessive seat leakage, the operability of the block valve is of importance, because opening the block valve is necessary to permit the PORV to be used for manual control of reactor pressure. If the block valve is closed to isolate an otherwise inoperable PORV, the maximum allowable outage time is 72 hours, which is well within the allowable limits (25 percent) to extend the block valve surveillance interval (92 days). Furthermore, these test requirements would be completed by the reopening of a recently closed block valve upon restoration of the PORV to operable status, i.e., completion of the ACTION statement fulfills the required surveillance requirement.

Enclosure A to Generic Letter 89-XX

Attachment A-4

Modified Technical Specifications
for Babcock and Wilcox Plant

REACTOR COOLANT SYSTEM

3/4.4.4 RELIEF VALVE

LIMITING CONDITION FOR OPERATION

3.4.4 The power-operated relief valve (PORV) and its associated block valve shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With the PORV inoperable because of excessive seat leakage, within 1 hour either restore the PORV to OPERABLE status or close the associated block valve with power maintained to the block valve; otherwise, be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With the PORV inoperable due to causes other than excessive seat leakage, within 1 hour either restore the PORV to OPERABLE status or close the associated block valve and remove power from the block valve, and be in HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

c. With the block valve inoperable, within 1 hour restore the block valves to OPERABLE status or place the associated PORV in manual control and restore the block valve to operable status within the next hour; otherwise, be in HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

d. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.4.4.1 In addition to the requirements of Specification 4.0.5, the PORV shall be demonstrated OPERABLE at least once per 18 months by:

a. Operating the PORV through one complete cycle of full travel during MODES 3 or 4, and

b. Performing a CHANNEL CALIBRATION of the actuation instrumentation.

4.4.4.2 The block valve shall be demonstrated OPERABLE at least once per 92 days by operating the valve through one complete cycle of full travel unless the block valve is closed in order to meet the requirements of ACTION a or b in Specification 3.4.4.

4.4.4.3 The emergency power supply for the PORV and block valve shall be demonstrated OPERABLE at least once per 18 months by:

a. Manually transferring motive and control power from the normal to the emergency power supply, and

b. Operating the valve through a complete cycle of full travel.

BABCOCK & WILCOX PLANTS

Enclosure A to Generic Letter 89-XX

Attachment A-5

Applicable to Babcock and Wilcox Plants

3/4.4.4 RELIEF VALVE

Bases of the Limiting Condition for Operation (LCO) and Surveillance Requirements:

The OPERABILITY of the PORV and block valve is determined on the basis of their being capable of performing the following functions:

A. Manual control of the PORV to control reactor coolant system pressure. This is a function that is used for the steam generator tube rupture accident and for plant shutdown. This function has been classified as safety related for more recent plant designs.

B. Maintaining the integrity of the reactor coolant pressure boundary. This is a function that is related to controlling identified leakage and ensuring the ability to detect unidentified reactor coolant pressure boundary leakage.

C. Manual control of the block valve to: (1) unblock an isolated PORV to allow it to be used for manual control of reactor coolant system pressure (Item A), and (2) isolate the PORV with excessive seat leakage (Item B).

D. Automatic control of the PORV to control reactor coolant system pressure. This is a function that reduces challenges to the code safety valves for overpressurization events.

E. Manual control of a block valve to isolate a stuck-open PORV.

Surveillance Requirements provide the assurance that the PORV and block valve can perform their functions. Specification 4.4.4.1 addresses the PORV, 4.4.4.2 the block valve, and 4.4.4.3 the emergency (backup) power source. The latter is provided for either the PORV or block valve, generally as a consequence of the TMI ACTION requirements to upgrade the operability of PORVs and block valves, where they are installed with non-safety-grade power sources, including instrument air, and are provided with backup (emergency) power sources. The block valve is exempt from the surveillance requirements to cycle the valve when it has been closed to comply with the ACTION requirements. This precludes the need to cycle the valve with full system differential pressure or when maintenance is being performed to restore an inoperable PORV to operable status.

Testing the PORV in HOT STANDBY or HOT SHUTDOWN is required in order to simulate the temperature and pressure environmental effects on the PORV. In many PORV designs, testing at COLD SHUTDOWN is not considered to be a representative test for assessing PORV performance under normal plant operating conditions.

The Modified Standard Technical Specification (STS) requirements include the following changes from prior STS guidance:

1. ACTION statement a. includes the requirement to maintain power to the closed block valve, because removal of power would render the block valve inoperable and the requirements of ACTION statement c. would apply. Power is maintained to the block valve so that it is operable and may be subsequently opened to allow the PORV to be used to control reactor pressure. Closure of the block valve establishes reactor coolant pressure boundary integrity for a PORV that has excessive seat leakage. (Reactor coolant pressure boundary integrity takes priority over the capability of the PORV to mitigate an overpressure event.)

2. ACTION statement b. includes the removal of power from the closed block valve as additional assurance to preclude any inadvertent opening of the block valve at a time in which the PORV may not be closed due to maintenance to restore it to OPERABLE status. (In contrast, ACTION statement a. permits continued plant operation with the block valve closed, i.e., continued operation is not dependent on maintenance to eliminate excessive PORV leakage, and, therefore, ACTION statement a. does not require removal of power from the block valve.)

3. ACTION statements a. and b. have been changed to terminate the forced shutdown requirements with the plant being in HOT SHUTDOWN rather than COLD SHUTDOWN because the APPLICABILITY requirements of the LCO do not extend past the HOT STANDBY mode.

4. ACTION statement c. has been modified to establish remedial measures that are consistent with the function of the block valves. The prime importance for the capability to close the block valve is to isolate a stuck-open PORV. Therefore, if the block valve cannot be restored to operable status within 1 hour, the remedial action is to place the PORV in manual control to preclude its opening for an overpressure event and to avoid the potential for a stuck-open PORV at a time that the block valve is inoperable. The time allowed to restore the block valve to operable status is based upon the remedial action time limits for an inoperable PORV per ACTION statement b. since the PORV is not capable of mitigating an overpressure event when placed in manual control. This action is also consistent with the use of the PORV to control reactor coolant system pressure if the block valve is inoperable at a time when it was closed to isolate a PORV that has excessive seat leakage. The modified ACTION statement does not specify closure of the block valve because such action would not likely be possible when the block valve is inoperable. Likewise, it does not specify either the closure of the PORV, because it would not likely be open, or the removal of power from the PORV. When the block valve is inoperable, placing the PORV in manual control is sufficient to preclude the

potential for having a stuck-open PORV that could not be isolated because of an inoperable block valve. For the same reasons, reference is not made to ACTION statement b. for the required remedial action.

5. Surveillance requirement 4.4.4.2 has been modified to remove the exception for testing the block valve when it is closed to isolate an inoperable PORV. If the block valve is closed to isolate a PORV with excessive seat leakage, the operability of the block valve is of importance, because opening the block valve is necessary to permit the PORV to be used for manual control of reactor pressure. If the block valve is closed to isolate an otherwise inoperable PORV, the maximum allowable outage time is 72 hours, which is well within the allowable limits (25 percent) to extend the block valve surveillance interval (92 days). Furthermore, these test requirements would be completed by the reopening of a recently closed block valve upon restoration of the PORV tc operable status, i.e., completion of the ACTION statement fulfills the required surveillance requirement.

Enclosure B to Generic Letter 89-XX

Staff Positions Resulting from
Resolution of Generic Issue 94 -
Additional Low-Temperature Overpressure Protection
For Light-Water Reactors

1. BACKGROUND

Generic Issue 94 (GI-94), "Additional Low-Temperature Overpressure Protection for Light-Water Reactors," addresses concerns with the implementation of the requirements set forth in the resolution of Unresolved Safety Issue (USI) A-26, "Reactor Vessel Pressure Transient Protection (Overpressure Protection)." In support of GI-94, the Battelle Pacific Northwest Laboratories (PNL) performed a study based on actual operating reactor experiences to determine the risks associated with current low-temperature overpressure protection (LTOP) systems. A report, prepared by PNL, has been issued as NUREG/CR-5186, "Value/Impact Analysis of Generic Issue 94, Additional Low Temperature Overpressure Protection for Light-Water Reactors," dated November 1988. The staff has prepared a regulatory analysis for GI-94 based on the work performed by PNL and reported in NUREG-1326, "Regulatory Analysis for the Resolution of Generic Issue 94, Additional Low-Temperature Overpressure Protection for Light-Water Reactors" (Enclosure D).

Low-temperature overpressure protection (LTOP) was designated as Unresolved Safety Issue A-26 in 1978 (NUREG-0371). PWR licensees implemented procedures to reduce the potential for overpressure events and installed equipment modifications to mitigate such events based on the staff recommendations from the USI A-26 evaluations, under Multi-Plant Action Item B-04 (NUREG-0748). Current staff guidelines for LTOP are in Standard Review Plan Section 5.2.2, "Overpressure Protection," and in its attached Branch Technical Position (BTP) RSB 5-2, "Overpressure Protection of Pressurized Water Reactors While Operating at Low Temperatures" (NUREG-0800).

The administrative controls and procedures that were identified as part of Multi-Plant Action Item B-04 include the following items:

1. Minimize the time the reactor coolant system (RCS) is maintained in a water-solid condition.

2. Restrict the number of high-pressure safety injection pumps operable to no more than one when the RCS is in the LTOP condition.

3. Ensure that the steam generator to RCS temperature difference is less than 50 Deg F when a reactor coolant pump (RCP) is being started in a water-solid RCS.

4. Set the PORV setpoint (if the particular plant relies on this component for LTOP) to a plant-specific analysis supported value, and have surveillance that checks the PORV actuation electronics and setpoint.

Twelve PWR overpressure transients were reported during the period from 1981 to 1983 after completion of USI A-26. Two of these events, at Turkey Point Unit 4, exceeded the pressure/temperature limits of the technical specifications. During this same timeframe, there were 37 reported instances when at least one LTOP channel was out of service. In 12 of these cases, both LTOP channels were inoperable.

The continuation of overpressure transient events, and the unavailability of LTOP protection channels, suggested the need to reevaluate the current overpressure protection requirements, or their implementation, to determine whether additional measures are warranted.

Major overpressurization of the reactor coolant system while at low temperature, if combined with a critical crack in the reactor pressure vessel welds or plate material, could result in a brittle fracture of the pressure vessel. Failure of the pressure vessel could make it impossible to provide adequate coolant to the reactor core and result in major core damage or a core melt accident.

The safety significance of these continuing low-temperature overpressure transients was designated as Generic Issue 94, "Additional Low Temperature Overpressure Protection." The concerns of GI-94 are applicable to all PWR plants regardless of the features used to mitigate a low-temperature overpressure event or of any measures to preclude events that would challenge these features or exceed the design basis for LTOP.

The implementation of the requirement for an LTOP system (the resolution of USI A-26) has been found to be essentially uniform for the Combustion Engineering (CE) and Westinghouse (W) PWRs. With the exception of a few plants,* the LTOP protection systems consist of either redundant PORVs or redundant safety relief valves (SRVs) in the residual heat removal (RHR) system and in general meet the guidance set forth in Branch Technical Position RSB 5-2, "Overpressurization Protection of Pressurized Water Reactors While Operating at Low Temperatures."

Variability in meeting IEEE-279 requirements, equipment environmental qualification, and in meeting the guidance of Regulatory Guide 1.26, "Quality Group Classification and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants," exists. As part of the NRC staff acceptance of LTOP protection system designs for the implementation of the resolution of USI A-26, it was concluded that the costs associated with upgrading existing systems to meet the guidance of Regulatory Guide 1.26 were not

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* CE - San Onofre Units 2 and 3 rely on a single RHR (SDCS) SRV for LTOP. With the SRV inoperable, depressurize and vent within 8 hours.
- Maine Yankee relies on two PORVs when pressure is above 400 psig and two RHR SRVs when pressure is below 400 psig.

W - DC Cook Units 1 and 2 rely on either two PORVs or one PORV and one RHR SRV.
- Yankee Rowe relies on one PORV and two RHR SRVs.
- Newer Westinghouse plants allow either two PORVs or two RHR SRVs.

justifiable. Further evaluations performed for GI-94 have also concluded that it is not cost beneficial to upgrade these systems to fully safety-grade standards.

2. CURRENT STANDARD TECHNICAL SPECIFICATION REQUIREMENTS

The section of the Standard Technical Specifications (STS) covering the LTOP protection system is entitled Overpressure Protection System, Section 3.4.10.3 for CE plants and Section 3.4.9.3 for W plants. The LTOP system setpoints are established based on additional restrictions for the restart of an idle reactor coolant pump and on the number of high-pressure safety injection pumps and/or coolant charging pumps allowed to be operable when LTOP is required. These additional restrictions define the initial conditions for the plant-specific transient analyses performed to establish the LTOP system setpoints. The additional restrictions are provided regarding the restart of inactive reactor coolant pumps in Sections 3.4.1.3 (Hot Shutdown) and 3.4.1.4 (Cold Shutdown). High-pressure safety injection pump operability restrictions are provided in Section 3/4.5.3 (ECCS Subsystems). In addition to these administrative restrictions, the transient analyses are based on a dual-channel system being operable to satisfy the single failure criterion of 10 CFR Part 50, Appendix A, for a system that performs a safety function. Therefore, the Overpressure Protection System TS is consistent with Criterion 2 of the Commission's Policy Statement on Technical Specification Improvements for Nuclear Power Plants. The TS also satisfied Criterion 3 of the policy statement in that the LTOP system is the primary success path for the mitigation of low-temperature overpressure transients that present a challenge to a fission product barrier, in this case, the reactor pressure vessel.

PORVs are relied on, by most Westinghouse designed plants and about one-half of the Combustion Engineering plants, to provide LTOP protection. In addition to PORVs, the RHR SRVs are also relied on to provide LTOP protection for some W plants and for the CE plants that do not have PORVs. Newer W plants have TS that require either two PORVs or two RHR SRVs for LTOP protection.

The current STS ACTION requirements for the LTOP system include a 7-day allowable outage time (AOT) to restore an inoperable LTOP channel to operable status before other remedial measures would have to be taken. In addition, ACTION d. states that the provisions of Specification 3.0.4 are not applicable. Therefore, the plant may enter the modes for which the Limiting Conditions for Operation (LCO) apply, during a plant shutdown or placement of the head on the vessel following refueling, when an LTOP channel is inoperable. In this situation, the 7-day AOT applies for restoring the channel to operable status before other remedial measures would have to be taken. This is the same manner in which the ACTION requirements apply when an LTOP channel is determined to be inoperable while the plant is in a mode for which the LTOP system is required to be operable.

Based on the NRC evaluation of the LTOP system unavailability, it is concluded that additional restrictions on operation with an inoperable LTOP channel are warranted when the potential for a low-temperature overpressure event is the highest, and especially when the plant is in a water-solid condition. Furthermore, it is concluded that the additional restrictions regarding the restart of inactive reactor coolant pumps and regarding the operability of high-pressure safety injection pumps should be implemented in the TS, as indicated in the STS, and licensees should verify that these administrative restrictions have been implemented. Finally, it is concluded that these additional measures will help to emphasize the importance of the LTOP system, especially while operating in a water-solid condition, as the primary success path for the mitigation of overpressure transients during low-temperature operation.

3. IMPROVEMENTS IN PROTECTION SYSTEM AVAILABILITY

The staff has determined that LTOP protection system unavailability is the dominant contributor to risk from low-temperature overpressure transients. The staff has further concluded that a substantial improvement in availability when the potential for an overpressure event is the highest, and especially during water-solid operations, can be achieved through improved administrative restrictions on the LTOP system.

In developing the staff position on the resolution of the low-temperature overpressure protection generic issue, a number of factors have been taken into consideration.

The staff has considered the conditions under which a low-temperature overpressure transient is most likely to occur. While LTOP protection is required for all shutdown modes, the most vulnerable period of time was found to be MODE 5 (Cold Shutdown) with the reactor coolant temperature less than or equal to 200 Deg F, especially when water-solid, based on the detailed evaluation of operating reactor experiences performed in support of GI-94. LTOP transients that have challenged the overpressure protection system have occurred with reactor coolant temperatures in the range of 80 Deg F to 190 Deg F. In addition, a review of the STS for containment integrity indicates that there are no specific requirements imposed during MODE 5, when the reactor coolant temperature is below 200 Deg F. Industry responses to Generic Letter 87-12, "Loss of RHR While RCS Partially Filled," dated July 9, 1987, also indicate that containment integrity during MODE 5 is often relaxed to allow for testing, maintenance, and the repair of equipment.

In addition, the staff takes note of the fact that, in all instances when pressure/temperatures limits in the TS have been exceeded, one LTOP protection channel was removed from service for maintenance-related activities. During these events the redundant LTOP protection channel failed to mitigate the overpressure transient as a result of a system/component failure that had not been detected.

The reported LTOP transients have occurred in MODE 5 with RCS temperatures ranging from 80 Deg F to 190 Deg F. Since this temperature range includes MODE 6, RCS temperature less than 140 Deg F but with k-eff less than 0.95 as compared to k-eff less than 0.99 for MODE 5, the staff concludes that the additional administrative restriction for the single channel AOT is applicable to MODE 5 and MODE 6 (with the reactor pressure vessel head on).

The staff concludes that the LTOP system performs a safety-related function and inoperable LTOP equipment should be restored to an operable status in a shorter period of time. The current 7-day AOT for a single channel is considered to be too long under certain conditions. The staff has concluded that the AOT for a single channel should be reduced to 8 hours when operating in MODE 5 or 6 when the potential for an overpressure transient is highest. The operating reactor experiences indicate that these events occur during planned heatup (restart of an idle reactor coolant pump) or as a result of maintenance and testing errors while in MODE 5. The reduced AOT for a single channel in MODES 5 and 6 will help to emphasize the importance of the LTOP system in mitigating overpressure transients and provide additional assurance that plant operation is consistent with the design basis transient analyses.

Based on the foregoing concerns, added assurance of LTOP availability is to be provided by revising the current Technical Specification for Overpressure Protection to reduce the AOT for a single channel from 7 days to 8 hours when the plant is operating in MODES 5 or 6. Attachment B-1 is provided for guidance for Westinghouse and CE plants. The guidance provided is also applicable to plants that rely on both PORVs and RHR SRVs or that rely on RHR SRVs only. Attachment B-2 provides the staff bases for the Overpressure Protection Technical Specification.

In performing the studies for GI-94, the staff has assumed that the administrative controls and procedures identified in Section 1 have been implemented to ensure that the plant is being operated within the design base. If it is determined that the design base was developed based on restricted safety injection pump operability and/or differential temperature restrictions for RCP restart and that these restrictions have not been implemented as part of USI A-26, then these restrictions should be implemented now. This is not a new requirement. Attachment B-3 is provided for guidance.

Enclosure B to Generic Letter 89-XX

Attachment B-1

Modified Technical Specifications
for Combustion Engineering and Westinghouse Plants

REACTOR COOLANT SYSTEM

OVERPRESSURE PROTECTION SYSTEM

LIMITING CONDITION FOR OPERATION

3.4.9.3 Two power-operated relief valves (PORVs) shall be OPERABLE with a lift setting of less than or equal to [450] psig.

APPLICABILITY: MODE 4 when the temperature of any RCS cold leg is less than or equal to [275]°F, MODE 5, and MODE 6 when the head is on the reactor vessel and the RCS is not vented through a ___ square inch or larger vent.

ACTION:

a. With one PORV inoperable in MODE 4, restore the inoperable PORV to OPERABLE status within 7 days or depressurize and vent the RCS through at least a ____ square inch vent within the next 8 hours.

b. With one PORV inoperable in MODES 5 or 6, either (1) restore the inoperable PORV to OPERABLE status within 8 hours, or (2) complete depressurization and venting of the RCS through at least a ____ square inch vent within 16 hours.

c. With both PORVs inoperable, complete depressurization and venting of the RCS through at least a ____ square inch vent within 8 hours.

d. With the RCS vented per ACTIONS a, b, or c, verify the vent pathway at least once per 31 days when the pathway is provided by a valve(s) that is locked, sealed, or otherwise secured in the open position; otherwise, verify the vent pathway every 12 hours.

e. In the event either the PORVs or the RCS vent(s) are used to mitigate an RCS pressure transient, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 30 days. The report shall describe the circumstances initiating the transient, the effect of the PORVs or RCS vent(s) on the transient, and any corrective action necessary to prevent recurrence.

f. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.4.9.3 Each PORV shall be demonstrated OPERABLE by:

a. Performance of an ANALOG CHANNEL OPERATIONAL TEST, but excluding valve operation, at least once per 31 days; and

b. Performance of a CHANNEL CALIBRATION at least once per 18 months; and

c. Verifying the PORV isolation valve is open at least once per 72 hours.

Enclosure B to Generic Letter 89-XX

Attachment B-2

3/4.4.9.3 OVERPRESSURE PROTECTION SYSTEM

Bases of the Limiting Condition for Operation and Surveillance Requirements:

The OPERABILITY of the PORVs is determined on the basis of their being capable of performing the function to mitigate an overpressure event during low-temperature operation.

The Modified Standard Technical Specification (STS) requirements include the following changes from prior STS guidance:

1. The depressurizing and venting of the RCS is not classified as an overpressure protection system. However, the APPLICABILITY of the LCO excludes MODE 6 when the RCS is adequately vented. This avoids any possible question on Specification 3.0.4 being applied to preclude placement of the head on the vessel if any part of the LCO is not met when the RCS is vented.

2. The APPLICABILITY for MODE 6 is clarified as "when the head is on the reactor vessel" rather than as "MODE 6 with the reactor vessel head on."

3. ACTION a. is revised to clarify that it is only applicable in MODE 4.

4. ACTION b. was added to reduce the allowed outage time for an inoperable PORV to 8 hours in MODES 5 or 6. Because this LCO does not apply under certain conditions specified under the APPLICABILITY for this specification, the ACTION statements likewise do not apply under those conditions. ACTIONS a. and b. do not repeat those qualifying conditions that apply for these modes since the actions only apply when the unit is under those conditions.

5. ACTION d. includes the requirements to verify that ACTIONS a., b., or c. continue to be met on an ongoing basis when the unit would be in MODES 4, 5, or 6.

6. The Surveillance Requirements were simplified by removing requirements that exist because of the general requirements applicable to all surveillance requirements as specified in Section 4.0 of the TS.

7. Surveillance Requirement 4.4.9.3.2 was removed since it is addressed by ACTION d.

For plants with existing TS for PORVs used for LTOP, the only required change is that indicated to restrict the applicability of ACTION a. to MODE 4 and for incorporating ACTION b. Any other changes that are proposed consistent with the above guidance are voluntary. For a plant without existing TS for PORVs that are used for LTOP, a TS should be proposed that conforms to the above guidance.

Because some plants use residual heat removal (RHR) safety relief valves for LTOP, either in addition to or in lieu of PORVs, similar requirements are included in TS as noted above for PORVs. The same changes in ACTION requirements a. and b. are required, as noted above, for these plants. Likewise, any plant without existing TS for RHR suction relief valves that are used for LTOP should propose TS that are consistent with the above guidance. When only RHR safety relief valves are used for LTOP, the Surveillance Requirements would state: "No additional requirements other than those required by Specification 4.0.5."

Enclosure B to Generic Letter 89-XX

Attachment B-3

Technical Specifications Guidance
for Combustion Engineering and Westinghouse Plants

Operational Limitations Consistent With the Design Basis Assumptions for the Low-temperature Overpressure Protection (LTOP) System

The TS requirements for LTOP typically apply in MODE 4 when the temperature of any cold leg is below 275°F, MODE 5, and MODE 6 when the head is on the reactor vessel. During these conditions, one train (or channel) of the LTOP system is capable of mitigating an LTOP event that is bounded by the largest mass addition to the RCS or by the largest increase in RCS temperature that can occur. The largest mass addition to the RCS is limited based upon the assumption that no more than a fixed number of pumps are capable of providing makeup or injection into the RCS. Hence, this is a matter important to safety that pumps in excess of this design basis assumption for LTOP not be capable of providing makeup or injection to the RCS.

The capability for makeup and injection to the RCS is also a safety concern for normal makeup to the reactor coolant system for reactivity control as well as for events that could result in a loss of coolant from the RCS. The former are covered by Technical Specifications (TS) under Reactivity Control Systems, Charging Pump - Shutdown (MODES 5 and 6); Charging Pumps - Operating (MODES 1 through 4); and Flow Paths - Operating (MODES 1 through 4). The latter is covered by TS under Emergency Core Cooling Systems, ECCS Subsystems - T_{cold} Less Than 350°F (MODE 4).

The manner in which restrictions, consistent with the design basis assumptions of the LTOP system, have been incorporated in TS that require the operability of makeup or injection pumps has varied depending upon plant-specific considerations for the LTOP design and plant-specific designs for the use of pumps for makeup and ECCS functions. A common method has been the use of footnotes to the pump operability requirements to note that:

> A maximum of one Safety Injection [and/or] one charging pump shall be OPERABLE when the temperature of one or more of the RCS cold legs is less than 275°F.

This footnote is used for each specification that requires the operability of a safety injection and/or charging pump in MODES 4 or 5.

The Surveillance Requirements typically include the following:

> All Safety Injection [and/or] charging pumps, except the above required OPERABLE pump[s], shall be demonstrated to be inoperable by verifying that the motor circuit breakers are secured in the open position at least

once per 12 hours whenever the temperature of one or more of the RCS cold legs is less than or equal to 275°F.

Generally, it is preferable to include requirements for implementing the intent of an LCO as part of an LCO rather than to only define requirements, such as securing motor circuit breakers in the open position, in a Surveillance Requirement. Furthermore, the requirements for operable pumps could be stated in terms of requiring one pump to be operable rather in terms of "at least one pump shall be operable" and then including a footnote requiring that, in fact, no more than one pump shall be operable. The preferred alternative would be an LCO which stated:

> One Safety Injection [and/or] charging pump shall be operable and all other Safety Injection [and/or] charging pumps shall be secured with their motor circuit breakers in the open position.

The form of the above requirements for any given specification would be dependent upon which pumps are addressed by that specification, e.g., charging or injection pumps or both.

The surveillance requirements would be similar to that noted above with the following substitution:

> . . .except the above required OPERABLE pump(s), shall be demonstrated to be secured by verifying that the motor circuit breakers are in the open position. . . .

Changes to plant TS should be proposed to incorporate one of the above methods, to ensure that pumps are not capable of initiating a mass addition to the RCS that exceeds the design basis assumptions for the LTOP system, for plants that do not currently include such requirements.

The largest temperature increase in the RCS that could result in a challenge to the LTOP system is dependent upon the differential temperature between the RCS and the secondary system when starting a reactor coolant pump. Hence, this is also a matter important to safety when reactor coolant pumps are started and the resulting increase in RCS temperature is in excess of the design basis assumption for the LTOP system to mitigate the resulting increase in RCS pressure. The manner in which this design basis assumption of the LTOP system is reflected in TS has been the use of a footnote to the reactor coolant pump operability requirements to note that:

> A reactor coolant pump shall not be started with one or more of the RCS cold leg temperatures less than or equal to 275°F unless the secondary water temperature of each steam generator is less than ____°F above each of the RCS cold leg temperatures.

The above footnote has been included in the TS for residual heat removal under title of the Reactor Coolant System, Hot Shutdown.

Changes to plant TS should be proposed to incorporate the above method, to ensure that the starting of RCS pumps are not capable of initiating a pressure transient that exceeds the design basis assumptions for the LTOP system, for plants that do not currently have this requirement.

Enclosure 2

NUREG-1316

Technical Findings and Regulatory Analysis Related to Generic Issue 70

Evaluation of Power-Operated Relief Valve and Block Valve Reliability in PWR Nuclear Power Plants

U.S. Nuclear Regulatory Commission

Office of Nuclear Regulatory Research

R. Kirkwood

NUREG-1316

Technical Findings and Regulatory Analysis Related to Generic Issue 70

Evaluation of Power-Operated Relief Valve and Block Valve Reliability in PWR Nuclear Power Plants

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ABSTRACT

This report summarizes work performed by the Nuclear Regulatory Commission staff to resolve Generic Issue 70, "Power-Operated Relief Valve and Block Valve Reliability." The report evaluates the reliability of PORVs and block valves and their safety significance in PWR nuclear power plants. The report identifies those safety-related functions that may be performed by PORVs and describes ways in which PORVs and block valves may be improved. This report also presents the regulatory analysis for Generic Issue 70.

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ACRONYMS AND INITIALISMS

APS	Auxiliary pressurizer spray
ASME	American Society of Mechanical Engineers
ATWS	Anticipated transient without scram
BNL	Brookhaven National Laboratory
BTP	Branch Technical Position
B&W	Babcock and Wilcox
CE	Combustion Engineering
CESSAR	Combustion Engineering Standard Safety Analysis Report
CL	Capacity loss
CP	Construction permit
ECCS	Emergency core cooling system
EPRI	Electric Power Research Institute
FSAR	Final safety analysis report
GI-70	Generic Issue 70
LER	Licensee event report
LTOP	Low-temperature overpressure protection
OBE	Operating basis earthquake
ORNL	Oak Ridge National Laboratory
PORV	Power-operated relief valve
PRA	Probabilistic risk assessment
PWR	Pressurized water reactor
RCPB	Reactor coolant pressure boundary
RCS	Reactor coolant system
RPC	Replacement power cost
RSB	Reactor Systems Branch
SGTR	Steam generator tube rupture
SSE	Safe shutdown earthquake
TMI-2	Three Mile Island Unit 2
USI	Unresolved safety issue
WNP-1	Washington Nuclear Project Unit 1
10 CFR § 50.2	Title 10 Code of Federal Regulations Part 50, § 50.2—Definitions
10 CFR § 50.55a	Title 10 Code of Federal Regulations Part 50, § 50.55a—Codes and Standards
10 CFR Part 50, Appendix B	Title 10 Code of Federal Regulations Part 50, Appendix B-Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants
10 CFR Part 100, Appendix A	Title 10 Code of Federal Regulations Part 100, Appendix A—Seismic and Geologic Siting Criteria for Nuclear Power Plants

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EXECUTIVE SUMMARY

Examining Generic Issue 70 (GI-70), "Power-Operated Relief Valve and Block Valve Reliability," involves the evaluation of the reliability of power-operated relief valves (PORVs) and block valves and their safety significance in pressurized water reactor (PWR) nuclear power plants. Traditionally, the PORV and its block valve are provided for plant operational flexibility and for limiting the number of challenges to the pressurizer safety valves. The block valve is installed upstream of the PORV because of the potential for the PORV to leak or stick open. For overpressure protection of the reactor coolant pressure boundary (RCPB) at normal operating temperature and pressure, the operation of PORVs has not been explicitly considered as a safety-related function. Also, an inadvertent opening of a PORV or safety valve has been analyzed in the final safety analysis reports as an anticipated operational occurrence with acceptable consequences. For these reasons, most PWRs, particularly those licensed prior to 1979, do not have safety-related PORVs. The valve operators and their electrical control systems are normally designed to non-safety-related standards. However, the pressure-retaining elements of PORVs and block valves are within the RCPB and are constructed to the same codes and standards as those required for similar safety-related RCPB components.

The Three Mile Island Unit 2 (TMI-2) accident focused attention on the reliability of PORVs and block valves since the malfunction of the PORV at TMI-2 contributed to the severity of the accident. On other occasions PORVs have stuck open when called upon to function. Also, there are PORVs in many operating plants that have leakage problems so that the plants must be operated with the upstream block valves in the closed position. The technical specifications governing PORVs on most operating PWRs that deal with closing the block valve and removing power were developed to prevent excessive leakage through the valves and were not developed to ensure the operability of the PORVs. Following the TMI-2 accident, the staff began to examine transient and accident events in more detail, particularly with respect to required operator actions and equipment availability and performance. As a result, the staff initiated an evaluation of the role of PORVs in accident management and mitigation.

Over a period of time, the role of PORVs has changed such that PORVs are now relied upon by many Westinghouse, Babcock and Wilcox (B&W), and Combustion Engineering (CE) designed power plants with PORVs to perform one or more of the following design basis safety-related functions:

1. Mitigation of a steam generator tube rupture accident,

2. Low-temperature overpressure protection of the reactor vessel during startup and shutdown, or

3. Plant cooldown in compliance with Branch Technical Position RSB 5-1.

PORVs also provide safety-related functions for events beyond the design basis such as for reactor coolant system venting, feed and bleed cooling, and anticipated transient without scram (ATWS) mitigation. All events beyond the design basis, including the above three events, are not strictly speaking within the scope of GI-70. However, improvements in the reliability and availability of the PORVs would improve the ability of some plants to provide venting of noncondensable gases from the reactor coolant system and to mitigate an ATWS event, and would provide additional assurance of feed and bleed capability for those plants that include this technique in their emergency procedures. In addition, further risk implications from low-temperature overpressure protection were studied, as reported in NUREG-1326 (Ref. 1), as a separate action, Generic Issue 94, "Additional Low-Temperature Overpressure Protection for Light-Water Reactors." Generic Issue 84, "CE PORVs," is separately evaluating the need to upgrade or install PORVs to improve the reliability of the decay heat removal function.

In support of the resolution of GI-70, the Oak Ridge National Laboratory (ORNL) performed a study of PORV and block valve operating experience. A report, prepared by the ORNL Nuclear Operations Analysis Center, was issued as NUREG/CR-4692 (Ref. 2). This work was sponsored by the NRC Office of Nuclear Regulatory Research as a part of the Nuclear Plant Aging Research Program.

Brookhaven National Laboratory (BNL) also performed a study that estimated the risk reduction from improved PORV and block valve reliability. BNL prepared a report that was issued as NUREG/CR-4999 (Ref. 3). This study showed only a small potential decrease in core melt probability due to increased PORV and block valve reliability. This was in part because by staff direction the study did not include consideration of feed and bleed capability.

The classification of PORVs and block valves should be consistent with the system used for classifying other components of the RCPB and those other systems that perform a safety-related function as defined in Regulatory Guide 1.26 (Ref. 4). While PORVs were originally provided on PWRs for plant operational flexibility and for limiting the number of challenges to the pressurizer safety valves, the operation of PORVs for overpressure protection of the RCPB was not considered to be a safety-related function.

However, since PORVs are relied upon in many PWR plants to mitigate the design basis accidents identified above or to perform any other safety-related function that may be identified, the staff finds that it is appropriate to reconsider the safety classification of PORVs and the associated block valves.

For future PWR plants when PORVs and the associated block valves are used for any of the safety-related functions discussed above, these components should be classified as safety related and a minimum of two PORVs and block valves installed. Certain recently licensed plants and plants currently under active construction that have solenoid pilot-operated PORVs* such as Vogtle 1 and 2, Millstone 3, Callaway, and Wolf Creek meet these requirements.

For operating PWR plants and construction permit (CP) holders, there are a number of potential improvements to PORVs and block valves (short of upgrading to fully safety-grade hardware) that can increase the reliability of these components and provide assurance that they will function as required when called upon to perform a safety-related function. It is anticipated that the reliability of PORVs and block valves can be increased by implementing the following improvements:

1. Include PORVs and block valves within the scope of an operational quality assurance program that is in compliance with 10 CFR Part 50, Appendix B. This program should include the following elements:

    a. The addition of PORVs and block valves to the plant operational Quality Assurance List.

    b. Implementation of a maintenance/refurbishment program for PORVs and block valves that is based on the manufacturer's recommendations or guidelines and is implemented by trained plant maintenance personnel.

2. Include PORVs, valves in PORV control systems, and block valves within the scope of a program covered by Subsection IWV, "Inservice Testing of Valves in Nuclear Power Plants," of Section XI of the ASME Boiler and Pressure Vessel Code. As permitted by the Code, stroke testing of PORVs should only be performed during Mode 3 (HOT STANDBY) or Mode 4 (HOT SHUTDOWN) and in all cases prior to establishing conditions where the PORVs are used for low-temperature overpressure protection. Stroke testing of the PORVs should not be performed during power operation. The staff has concluded that stroke testing during power operation, in the words of the ASME Code, "is not practical" (reference ASME Section XI, Paragraph IWV-3412) because of the potential for a PORV to stick open during the stroke test. In addition, PORV block valves should be specifically included in the scope of safety-related motor-operated valves (MOVs) addressed in the resolution of Generic Issue II.E.6.1, "In Situ Testing of Valves," in NRC Generic Letter 89-10 (Ref. 5).

3. For operating PWR plants, modify the limiting conditions of operation of PORVs and block valves in the technical specifications for Modes 1, 2, and 3 to incorporate the staff position adopted in recent licensing actions. That is, ensure that plants that run with the block valves closed (e.g., due to leaking PORVs) maintain electrical power to the block valves so they can be readily opened from the control room upon demand. Additionally, plant operation in Modes 1, 2, and 3 with PORVs and block valves inoperable for reasons other than seat leakage is not permitted for periods of more than 72 hours.

4. Use, to the extent possible, more reliable PORV and PORV block valve designs that are resistant to failure. The NRC recognizes that licensees may choose to replace existing PORV and PORV block valves with more reliable designs as they are made available by valve manufacturers in the future. The use of more reliable valves should result in less frequent corrective maintenance and can result in longer inservice testing intervals as delineated in Section XI of the ASME Boiler and Pressure Vessel Code.

For new construction, the staff concludes that a minimum of two PORVs and block valves and associated controls for these components should be provided. These components should be identified as safety related if required to perform any of the safety-related functions discussed above or to perform any other safety-related function that may be identified in the future and should therefore be constructed to safety-grade standards.

This would include redundant and diverse control systems, designed to Seismic Category I requirements and environmentally qualified; increased technical specification surveillance requirements; increased inservice testing requirements; and inclusion within the scope of a quality assurance program that is in compliance with 10 CFR Part 50, Appendix B. The safety-related designation would include those improvements that were imposed subsequent to the TMI-2 accident, such as requirements

*As of the date of this report, Bellefonte 1 and 2 and WNP-1 are not considered to be plants under active construction.

—to be powered from Class 1E buses and to provide valve position indication in the control room.

The staff also concludes that item 4, identified above, should be implemented where possible in new construction and strongly encourages operating reactor owners to evaluate the benefits of replacing existing PORVs and block valves with more reliable designs.

For operating plants and CP holders, the staff concludes it is not cost effective to upgrade (backfit) existing non-safety-grade PORVs and block valves (and associated control systems) to full safety-grade qualification status when they have been determined to perform any of the safety-related functions discussed above or to perform any other safety-related function that may be identified in the future. Subsequent to the TMI-2 accident, a number of improvements were required of PORVs, such as requirements to be powered from Class 1E buses and to have valve position indication in the control room. Therefore, additional improvements that would result from upgrading PORVs to fully safety-grade status are considered to be of marginal benefit. For operating plants and CP holders, the greatest benefits can be derived from implementing items 1, 2, and 3 identified above. The staff is proposing that these requirements be imposed to increase the reliability of PORVs and block valves to provide assurance that they will function as required. Items 1, 2, and 3, which do not require hardware changes, can be implemented within the scope of current licensing criteria and coordinated with the Technical Specifications Improvement Program.

As noted above, the BNL study performed specifically in support of GI-70 did not include consideration of feed and bleed capability. In the course of the resolution of Unresolved Safety Issue (USI) A-45 as reported in NUREG/CR-5230 (Ref. 6), the use of feed and bleed cooling on the primary system as an alternative measure to remove decay heat from the reactor core was explored in some detail. These studies in general support the concept of feed and bleed. The effect of feed and bleed upon the probability of core melt was examined, and the report indicates that this capability reduces the estimated core melt probability for internal events by a significant amount on the order of 25 to 90 percent. Even if feed and bleed only reduces the core melt frequency by a fraction of the improvements indicated, it is a substantial reduction in public risk.

The proposed improvements to PORVs and block valves identified above enhances (but does not ensure) feed and bleed because:

1. Inclusion within an operational quality assurance program that is in compliance with 10 CFR Part 50, Appendix B, of an improved PORV maintenance/refurbishment program and additional surveillance testing provide better assurance that PORVs will open or close when called upon.

2. Currently, certain plants operate with the block valves closed. The technical specifications for these plants require that power be racked out at a valve motor control center, making it unlikely that feed and bleed could be initiated in a timely manner. The proposed revised technical specifications require those plants that run with the block valves closed (e.g., due to leaking PORVs) to maintain electric power to the block valves so they can be readily opened from the control room.

3. Placing the block valves within the scope of Generic Issue II.E.6.1, as reported in Generic Letter 89-10, would provide increased assurance that the block valves would open against system differential pressure to permit initiation of feed and bleed.

Based on the above, the staff concludes that the proposed actions to PORVs and block valves provide a substantial increase in the overall protection of the public health and safety.

The staff estimates that the outage avoidance costs, based on industry data reported by EPRI, would far exceed the cost of implementing items 1, 2, and 3. Specifically, the present value associated with the improvements to PORVs and block valves for items 1, 2, and 3 identified above are estimated to be $127,200 for a plant with two PORVs and two block valves. The present value of the outage avoidance cost is estimated to be $2,541,000. The overall cost benefit is estimated to result in a savings of $2,413,800 per reactor.

1 INTRODUCTION

Examining Generic Issue 70, "Power-Operated Relief Valve and Block Valve Reliability," involves the evaluation of the reliability of power-operated relief valves (PORVs) and block valves and their safety significance in PWR plants. Traditionally, the PORV and its block valve are provided for plant operational flexibility and for limiting the number of challenges to the pressurizer safety valves. The block valve is installed upstream of the PORV because of the potential for the PORV to leak or stick open. Figures 1.1 and 1.2 show two typical styles of PORVs currently in general use in PWR plants. Figure 1.1 is representative of a pilot-operated relief valve, and Figure 1.2 is representative of an air-operated (spring-loaded) relief valve. These two general types of PORVs are discussed in greater detail in Reference 2. Figure 1.3 shows the installation of PORVs and block valves on a typical PWR plant. For overpressure protection of the reactor coolant pressure boundary (RCPB) at normal operating temperature and pressure, the operation of PORVs has not been explicitly considered as a safety-related function. Also, an inadvertent opening of a PORV or safety valve has been analyzed in final safety analysis reports (FSARs) as an anticipated operational occurrence with acceptable consequences. For these reasons, most PWRs, particularly those licensed prior to 1979, do not have safety-related PORVs. The valve operators and their electrical control systems are normally designed to non-safety-related standards. However, the pressure-retaining elements of PORVs and block valves are within the RCPB and are constructed to the same codes and standards as those required for similar safety-related RCPB components. Some plants licensed prior to 1979 do maintain PORVs and block valves in an operational state to protect against challenges to the pressurizer safety valves, although other plants do not.

There have been no specific safety requirements addressed in existing regulatory guides or standard review plans (Ref. 7) for the PORVs and block valves except for compliance with Branch Technical Position (BTP) RSB 5-1 in Standard Review Plan 5.4.7. However, as discussed in Sections 2.1 and 2.2 of this report, the staff has learned that, with the exception of recently designed Combustion Engineering (CE) nuclear power plants without PORVs, PORVs are relied upon in Westinghouse and Babcock & Wilcox (B&W) designed plants to mitigate a design basis steam generator tube rupture (SGTR) accident and, as such, the staff has considered PORVs to perform a safety-related function. Owners of some recently licensed PWR plants, in responding to staff questions regarding this reliance on PORVs, have made the PORVs on their plants safety related and designed them to safety-grade standards. For older plants, the acceptability of relying on non-safety-grade PORVs to mitigate an SGTR design basis accident was raised in Reference 8.

As discussed in Section 2.2 of this report, PORVs are also relied upon to serve other functions such as low-temperature overpressure protection (LTOP) during plant cooldown in compliance with BTP RSB 5-2 in Standard Review Plan 5.2.2. In addition, PORVs provide safety benefits in events beyond the design basis such as reactor coolant system (RCS) venting, feed and bleed cooling, and ATWS mitigation.

Considering the potential safety-related functions associated with the PORVs and block valves, in addition to the original PORV loss-of-coolant-accident concern, it is obvious that there is a need to reassess the PORV and block valve with respect to the safety-related requirements in order to determine if improvements are necessary to plants with non-safety-related PORVs and block valves to ensure reliable PORV and block valve operation.

2 BACKGROUND

The Three Mile Island Unit 2 (TMI-2) accident focused attention on the reliability of PORVs and block valves since the malfunction of the PORV at TMI-2 contributed to the severity of the accident. On numerous occasions, as reported in Reference 2, PORVs have stuck open when these valves were called upon to function in operating plants. Also, there are PORVs in many operating plants with leakage problems so that the plants must be operated with the upstream block valves in the closed position.

The technical specifications governing PORVs on most operating PWRs that deal with closing the block valve and removing power were developed to prevent excessive leakage through the valves and were not developed to ensure the operability of the PORVs.

Prior to the Ginna SGTR event in January 1982, the thermal-hydraulic performance of SGTR events was not explicitly evaluated in licensing reviews. Instead, the review of the SGTR event emphasized the radiological consequences, and very general, unverified assumptions were made regarding the system performance. Following the TMI-2 accident, the staff began to examine transient and accident events in more detail, particularly with respect to required operator actions and equipment availability and performance. In addition, a reactor coolant pump seal leak occurred at H.B. Robinson Unit 2 on November 30, 1981, in which recovery was aggravated by malfunctioning pressurizer relief and block valves. As a result, the staff initiated an evaluation of the role of PORVs in accident management and mitigation. Finally, the staff specifically reviewed the role of PORVs in SGTR management and mitigation following the Ginna SGTR event.

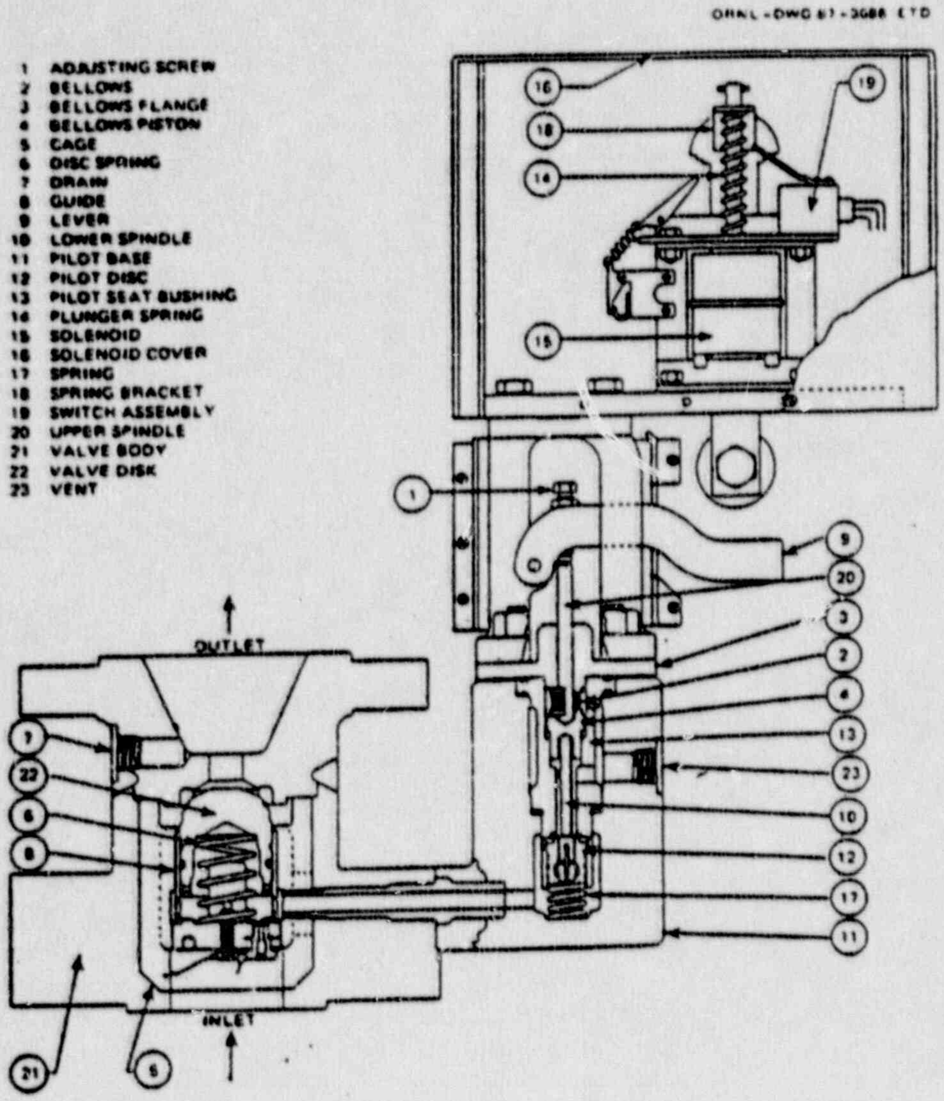

Figure 1.1 Pilot-operated relief valve (Courtesy of Dresser Industries).

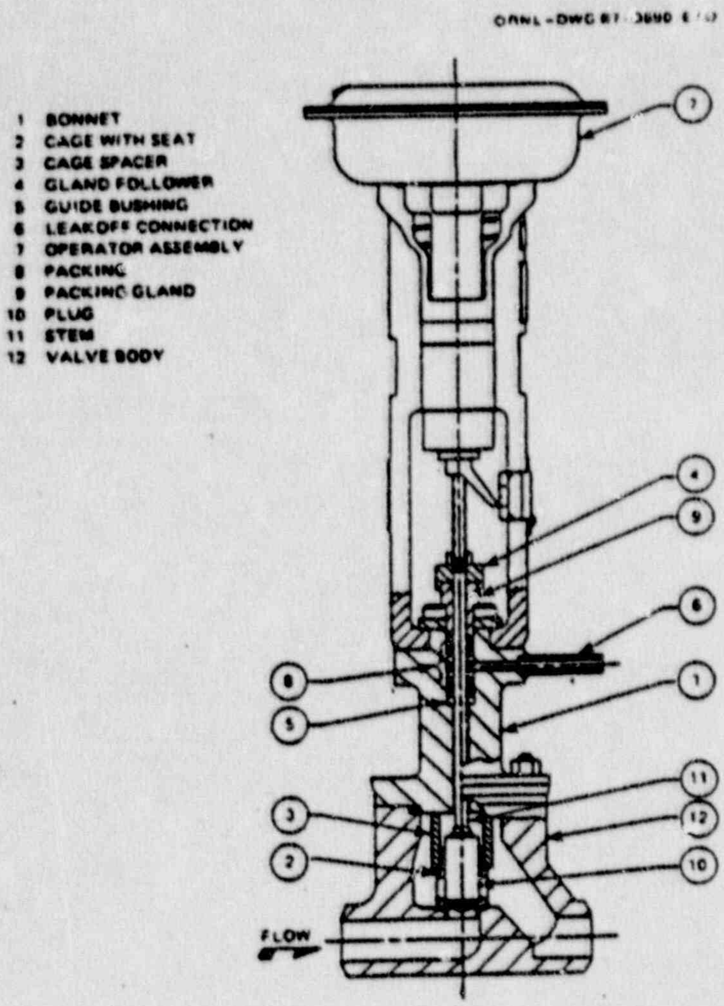

Figure 1.2 Air-operated (spring-loaded) relief valve (Courtesy of Copes-Vulcan).

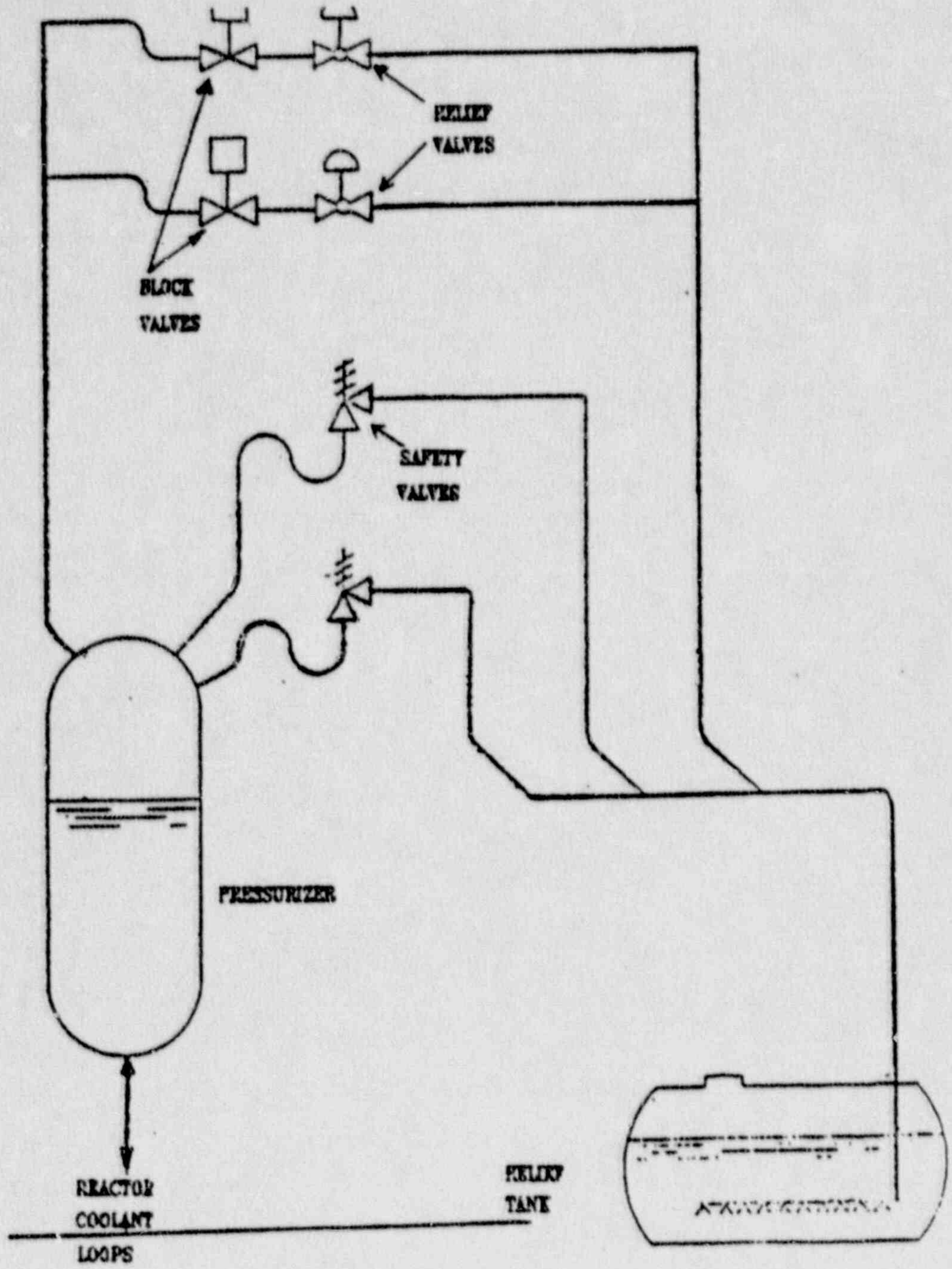

Figure 1.3 Pressurizer safety and relief valves.

Based on the above efforts, the staff concluded that PWR plants rely on a rapid primary system depressurization capability in order to limit the primary-to-secondary leakage (and thus limit the radiological release to the secondary systems) assumed in the SGTR licensing analyses. In SGTR scenarios where the reactor coolant pump flow is lost (i.e., loss of offsite power for compliance with General Design Criterion 17), Westinghouse and B&W plants rely on the pressurizer PORVs, which are, in most plants, designed to non-safety-related requirements.

In certain new plants without PORVs, designed by CE, such as San Onofre Units 2 and 3 and Waterford Unit 3, this depressurization function is accomplished by a safety-related auxiliary pressurizer spray (APS) system. However, in the CE-designed CESSAR System 80 plants, such as Palo Verde Units 1-3, the APS system (including its water supply) is not fully designed to safety-related requirements and is identified by the NRC staff in Supplement 3 of the CESSAR safety evaluation report as an unresolved item subject to resolution. It is not clear to the staff whether CE plants with PORVs rely on their PORVs or APS system for mitigation of an SGTR event, nor is it known whether these systems are designed to safety-related standards. However, this matter will be resolved as part of Generic Issue 84, "CE PORVs," which is separately evaluating the need to upgrade or install PORVs to improve the reliability of the decay heat removal function.

Although Westinghouse and some B&W plants have an auxiliary pressurizer spray system, it is not designed to safety-related requirements and is not designed for use when engineered safety features are actuated. The staff has notified all licensing boards associated with PWRs designed by Westinghouse and B&W of the staff findings regarding reliance on PORVs for SGTR mitigation.

In most plants, the LTOP system is designed to use the PORVs. For this mode of operation, the valves are typically set to open at approximately 500 psig rather than the high-pressure (approximately 2300 psig) setpoint used at power. Westinghouse and some CE-designed plants use redundant PORVs for LTOP concerns.

These plants are brought to a water-solid condition during shutdown. In contrast, B&W owners use a single PORV, and the gas (steam or nitrogen) space in the pressurizer functions as the primary LTOP system. The PORV and associated actuation circuitry function as a backup should the operator fail to terminate a low-temperature overpressure challenge prior to compression of the gas space. In the new CE plants without PORVs, low-temperature overpressure protection is provided by relief valves on the shutdown cooling system. LTOP systems, as specified in BTP RSB 5-2 in Standard Review Plan 5.2.2, are to be single failure proof, testable, designed to Section III of the ASME Boiler and Pressure Vessel Code and powered from essential buses. BTP RSB 5-2 also notes that IEEE-279* should be used as guidance in the design of LTOP systems and further specifies that LTOP systems should be designed to function during an operating basis earthquake and not during a safe shutdown earthquake. The LTOP system requirements were implemented as Multi-Plant Action Item B-04. As noted in Section 2.3 of this report, when PORVs are used for high point vents in some plants, in accordance with Item II.B.1 of NUREG-0737 (Ref. 9), both PORVs and block valves are required to be seismically and environmentally qualified.

For PWRs licensed before 1982, there are no technical specification requirements that these components be operational when the plant is at power. Continued operation at power with inoperable PORVs is permitted by the technical specifications if the block valve is closed and power to the block valve(s) is removed. Many plants now operate with the PORVs blocked.

Westinghouse PWRs licensed since 1982 have upgraded technical specifications that permit plant operation only for periods up to 72 hours with PORVs or block valves considered inoperable for any reason other than excessive seat leakage.

BTP RSB 5-1 in Standard Review Plan 5.4.7 requires that plants licensed after January 1978 be capable of cooldown to cold shutdown conditions using only safety-related equipment (BTP RSB 5-1 allows some relief from this position for plants whose construction permit was docketed before January 1978). It may be necessary to use safety-grade PORVs for plants without safety-related auxiliary pressurizer spray systems in order to comply with this staff position.

Item II.D.1 of Reference 9 requires all plants to demonstrate the ability ofthe PORVs and block valves to function under all flow conditions expected during transient and accident conditions. It also requires that the block valves be capable of closing to ensure isolation of a stuck-open PORV. In response to this requirement, PORVs were tested extensively by the Electric Power Research Institute (EPRI) and the results reported in Reference 10. Limited block valve testing was also performed as a part of the EPRI test program.

Item II.D.3 of Reference 9 requires direct indication of PORV position. Item II.G.1 of Reference 9 requires emergency power for PORVs and block valves.

*IEEE Standard 279 has been replaced by IEEE Standard 603, which is endorsed by Regulatory Guide 1.153, "Criteria for Power, Instrumentation, and Control Portions of Safety Systems."

2.1 Safety Functions of PORVs and Block Valves

In PWR plants, PORVs and associated block valves were originally provided for plant operational flexibility and for limiting the number of challenges to the pressurizer safety valves. For overpressure protection of the RCPB at normal operating temperature and pressure, the operation of PORVs had not explicitly been considered as a safety-related function because of the availability of the safety-related pressurizer safety valves. Therefore, these components were designated as non-safety-related because they were required neither to safely shut down the plant nor to mitigate the consequences of accidents.

However, over a period of time the role of PORVs has changed such that PORVs are now relied upon by many Westinghouse, B&W, and CE plants with PORVs to perform one or more of the following design basis safety-related functions:

1. Mitigation of a steam generator tube rupture accident,

2. Low-temperature overpressure protection of the reactor vessel during startup and shutdown, or

3. Plant cooldown in compliance with BTP RSB 5-1.

In addition to these design basis safety-related functions, PORVs also provide safety-related functions for events beyond the design basis such as for reactor coolant system venting, feed and bleed cooling, and ATWS mitigation. All events beyond the design basis, including the above three events, are not strictly speaking within the scope of Generic Issue (GI) 70. However, improvements in the reliability and availability of the PORVs would improve the ability of some plants to provide venting of noncondensable gases from the RCS, as discussed in Section 2.3 of this report, to mitigate an ATWS event, and would, as discussed in Section 5.3 of this report, provide additional assurance of feed and bleed capability for those plants that include this technique in their emergency procedures.

2.2 Description of PORV Safety Functions

This section provides a description of the safety-related functions that may be performed by PORVs on PWR plants.

2.2.1 Steam Generator Tube Rupture

In the event of an SGTR, leakage of reactor coolant from the primary system to the secondary system will eventually pressurize the secondary system. The secondary safety valves will then lift, allowing the leaked reactor coolant to escape directly to the environment. To prevent this situation from occurring, the primary pressure must be rapidly decreased to stop the primary-to-secondary leakage. This depressurization can be accomplished in a variety of ways, including (1) the use of the normal pressurizer spray that is available only when the reactor coolant pumps are running; (2) the use of the auxiliary pressurizer spray, which does not require the reactor coolant pumps but rather derives its flow from the charging pumps; or (3) opening the PORV and discharging steam from the pressurizer steam space. The Westinghouse, B&W, and CE plants with PORVs rely on the pressurizer PORV to accomplish this depressurization whenever the reactor coolant pumps are not operating. However, current CE plants without PORVs apparently rely on the auxiliary pressurizer spray system to keep the offsite radiological consequences within regulatory limits. The ability of these CE-designed plants without PORVs to meet regulatory requirements is discussed in NUREG-1044 (Ref. 11). In addition, Generic Issue 84, "CE PORVs," is separately evaluating the need to install PORVs to improve the reliability of the decay heat removal function.

2.2.2 Low-Temperature Overpressure Protection

When the PWR reactor coolant system is in a cold shutdown condition, the maximum allowable pressure in the reactor vessel is low because of vessel irradiation and embrittlement. The inadvertent starting of a high-pressure safety injection pump can result in an overpressure transient. To ensure that in these situations the maximum pressure remains below the limits specified in the license technical specifications, a low-temperature overpressure protection system (LTOPS) must be available. BTP RSB 5-2 in Standard Review Plan 5.2.2 states the functional requirements for this system, but does not specify a particular mitigation technique. In addition, Generic Issue 94, "Additional Low-Temperature Overpressure Protection for Light-Water Reactors," as a separate action evaluated further risk implications from LTOP due to the continuing occurrence of overpressure transient events after the completion of Generic Issue A-26, "Low Temperature Over-Pressure Protection," that was resolved by Multi-Plant Action B-04. As a part of the resolution of Generic Issue 94, the staff prepared a regulatory analysis based on work performed by Battelle Pacific Northwest Laboratories; this analysis is reported in NUREG-1326 (Ref. 1).

Most PWR designs use PORVs as a means of mitigating low-temperature overpressure transients. In these plants, the PORV setpoint is manually lowered to around 500 psig at low RCS temperatures, and, should the RCS pressure reach this value, the PORV opens to limit system pressure. Westinghouse and some of the CE plants with

—PORVs use redundant PORVs for low-temperature overpressure transients, whereas B&W plants use the pressurizer gas space as a primary means of controlling overpressure and the single PORV as a backup. In the current CE-designed plants without PORVs, low-temperature overpressure protection is provided by relief valves on the shutdown cooling system.

2.2.3 Plant Cooldown in Compliance with Branch Technical Position RSB 5-1

Branch Technical Position (BTP) RSB 5-1 in Standard Review Plan 5.4.7 states that current PWRs should have safety-grade systems capable of maintaining the RCS in the hot standby condition for 4 hours, followed by a cooldown to the cold shutdown condition. In Westinghouse, B&W, and CE plants with PORVs, depressurization of the RCS is accomplished by using a combination of either RCS fluid contraction caused by the cooldown and heat losses from the pressurizer to ambient or by a safety-related PORV. However, the new CE plants without PORVs apparently rely on the auxiliary pressurizer spray system as if it were a safety-related system.

2.3 Reactor Coolant System Venting

Following the TMI-2 accident, a number of additional requirements were imposed on reactor plant applicants and licensees. One of these requirements, Item II.B.1 of Reference 9, requires that high point vents be installed in PWRs for the purpose of venting from the reactor coolant system noncondensable gases that may inhibit natural circulation and adversely affect core cooling during loss of offsite power events. When PORVs are used for high point vents, both the PORVs and block valves are required to be seismically and environmentally qualified and included within the scope of an inservice testing program that is in conformance with Section XI of the ASME Boiler and Pressure Vessel Code.

2.4 Three Mile Island Unit 2 PORV

The failure of the PORV to reclose during the initial TMI-2 transient initiated the accident and contributed to its severity. The open or partially open PORV therefore provided a pathway in the RCPB for the release of accident-generated hydrogen, steam, and fission products directly from the primary system to the containment building.

Consideration was given to removal of the PORV and a section of the downstream piping with subsequent efforts to examine these components. The intent of the examination was to determine, if possible, the actual failure mechanism of the PORV and also to determine the survivability of various electrical components and cables associated with the PORV. There was considerable uncertainty as to whether the PORV in its post-accident condition, that is, severely corroded from exposure of years in a high humidity and a high radiation environment, would provide any conclusive evidence as to the cause of its failure to close.

Because of funding and scheduling difficulties, it was decided that the effort to identify the failure mode of the TMI-2 PORV was not justified on a cost/benefit basis as a part of the work performed under GI-70 and the effort was therefore not undertaken.

2.5 NRC Information Notice 89-32, Surveillance Testing of Low-Temperature Overpressure Protection Systems

The staff in Information Notice 89-32 (Ref. 12) expressed concern with respect to potential plant operability problems due to lack of inservice testing of PORVs in their LTOP mode. The staff noted that in three cases (identified in the information notice) valve opening times that were in analyses of the licensee's LTOP systems were not being transferred into inservice testing requirements and eventually into plant surveillance test procedures. A significant increase in valve opening time could result in 10 CFR Appendix G limits being exceeded during a design basis transient.

Paragraph IWV-3400 of Section XI of the ASME Boiler and Pressure Vessel Code requires valves to be exercised to the position required to fulfill their safety function. Therefore, not testing the PORVs in the open direction is not in accordance with the Code.

As noted in Section 5.2 of this report, it is anticipated that the reliability of PORVs and block valves can be increased by implementing the improvements presented in Table 5.1. Specifically, item 2 of Table 5.1 in part recommends that stroke time testing of PORVs should be performed in accordance with Subsection IWV of ASME Section XI of the ASME Boiler and Pressure Vessel Code. When establishing stroke time acceptance criteria for PORVs used in LTOP systems, licensees should take into account the PORV opening stroke time used in the setpoint analysis for the LTOP system.

3 CONTRACTOR REPORTS

In support of the resolution of GI-70, the Oak Ridge National Laboratory (ORNL) performed a study of PORV and block valve operating experience. A report, prepared by the ORNL Nuclear Operations Analysis Center, was issued as NUREG/CR-4692 (Ref. 2). This work was sponsored by the NRC Office of Nuclear Regulatory

—Research as a part of the Nuclear Plant Aging Research Program.

Brookhaven National Laboratory (BNL) also performed a study that estimated the risk reduction from improved PORV/block valve reliability. BNL prepared a report that was issued as NUREG/CR-4999 (Ref. 3).

3.1 NUREG/CR-4692

NUREG/CR-4692 (ORNL/NOAC-233) contains a review of nuclear power plant operating events involving failure of PORVs and associated block valves. The report reviewed events reported from 1971 to mid-1986. Each PORV and block valve event was judged as to the severity of the failure, and the terms chosen to identify the degree of failure were as follows:

1. "Degraded" (but operable), the component operated at less than its specified performance level, and

2. "Failed," the component was completely unable to perform its function.

A compilation of PORV and block valve events with respect to failure severity is shown in Table 3.1.

Table 3.1 Failure severity.

	Degraded	Failed	Total
PORV mechanical	77	24	101
PORV control	30	61	91
PORV design	6	0	6
Block valve events	17	15	32
Total	130	100	230

Thus 23 percent of the PORV mechanical events and 67 percent of the PORV control events were failures. Forty-seven percent of the block valve events were also failures.

A review of the PORV mechanical failure modes indicates the most common mechanical degradation or failure mechanism for PORVs appears to be deterioration of the seat/disc interface or other internal parts by high-pressure steam and/or water. This results in internal leakage through the valve seat into the valve outlet tailpipe and was the most common failure mode apparent from the study (61%) while failure of the PORV to open was 12 percent and failure to close was 7 percent.

A summary of identified PORV mechanical failure and degradation modes by reactor vendor is shown in Table 3.2.

Table 3.2 Failure and degradation modes—PORV mechanical.

	B&W	W	CE	Total
Leakage—internal	19	33	10	62
Leakage—external	-	3	-	3
Failure to open	3	8	1	12
Failure to close	4	3	-	7
Other	6	6	5	17
Total	32	53	16	101

A review of the PORV control failure modes indicates the most common control failure or degradation mechanism for PORVs (57%) involved problems with the air or electrical actuation controls that would have prevented operation of the PORV if it had been required. Twelve percent of events where the PORV unintentionally opened resulted mostly from inadvertent or accidental actuation by human error.

A summary of identified failure and degradation modes for PORV controls by reactor vendor is shown in Table 3.3.

Table 3.3 Failure and degradation modes—PORV controls.

	B&W	W	CE	Total
Failure to open	3	2	1	6
Failure to close	1	1	-	2
Spurious opening	1	4	6	11
Control degraded	1	49*	2	52
Other	4	12	4	20
Total	10	68	13	91

* Twenty-five events involved recurring problems with nitrogen control systems at North Anna 1 and 2.

For block valves, 37 percent of the events involved external leakage, and 37 percent involved failure of the block valve to close on demand. Such a failure can pose a threat to safety if it occurs in coincidence with a stuck-open PORV. For this reason, the ability to close is the most important function for PORV block valves. As noted above, there are a number of PORV internal leakage events (62%), and many plants operate with the block valve closed when the unit is at power. Therefore, under these circumstances it is also important that the block valve be able to open reliably as well as close.

A summary of identified failure and degradation modes for block valves is shown in Table 3.4.

Table 3.4 Failure and degradation modes—block valves.

Leakage—external	12
Failure to open	2
Failure to close	12
Spurious opening	3
Other	3
Total	32

A review of events collected for NUREG/CR-4692 indicates that Dresser and Crosby pilot-valve designs accounted for 40 percent of the PORV mechanical failures. These designs were involved in failures that occurred at all nine B&W plants. (Most CE units have blocked off their PORVs or do not employ them in the design.)

Table 3.5 presents a compilation of PORV mechanical failures and degradation listed by PORV manufacturer. It should be noted that the Dresser and Copes-Vulcan designs have been in use for a number of years, hence the relatively high total number of events.

Table 3.5 PORV mechanical failures and degradation.

	Failure Severity		
PORV Manufacturer	Failed	Degraded	Total
Crosby (p)*	2	5	7
Dresser (p)	8	25	33
Garrett (p)		5	5
Copes-Vulcan (a)**	3	25	28
Masoneilan (a)	3	7	10
Control components (a)		2	2
Unknown	8	8	16
Total	24	77	101

*(p) Pilot-operated.
**(a) Air-operated (spring close).

As noted in Appendix D to NUREG/CR-4692, PORV control systems for PWRs are not provided by the valve manufacturer. These control systems are usually provided by the nuclear steam supply system supplier, architect-engineer, or utility. There is, therefore, no comparable table to Table 3.5 for PORV control failures and degradation by PORV manufacturer.

An assessment of the need to upgrade PORVs and block valves to safety-related status concludes that such action would improve PORV and block valve reliability. ORNL believes the greatest improvement would result from using a more reliable PORV design. The reliability of existing PORVs and block valves would be enhanced by improved surveillance testing, advanced diagnostic techniques where applicable, and maintenance applied to PORVs and block valves, particularly the block valve motor operator.

ORNL also interviewed four PORV manufacturers in order to obtain their views related to manufacturing, installation, testing, maintenance, and operation of these valves and any feedback from utilities or problems encountered during operation of PORVs.

3.2 NUREG/CR-4999

In NUREG/CR-4999 (BNL-NUREG-52101), an analysis was performed to explore the risk reduction potential of improving the PORV and block valve reliability for two representative PWR plants, Indian Point 3 and Oconee 3. Existing probabilistic risk assessments (PRAs), pertinent event trees, fault trees, and the equipment reliability data presented in the Indian Point probabilistic safety study and in the Oconee PRA were used to quantify the benefits of improved PORV and block valve reliability in terms of potential reduction in core melt frequencies. Because of their importance, attention was focused upon those safety-related functions identified in Section 2.1, namely, an SGTR accident, the use of PORVs in reactor vessel LTOP events, plant cooldown in compliance with BTP RSB 5-1, and the feasibility of using PORVs as high point vents to supplement the functions of the reactor vessel head vent system. In addition to the above, a stuck-open PORV was also studied.

The core melt frequencies attributable to PORV or block valve failures were found by BNL to be relatively insignificant and to represent only a very small fraction of the total core melt frequency attributable to internal plant events. Specifically, BNL results show a potential reduction in core melt frequency of about 1 to 3E-7 for the SGTR and stuck-open PORV events. For LTOP events, the BNL study showed a potential reduction of core melt frequency of about 2E-6. It should be noted that BNL used information for the plant system reliabilities provided in the utilities' PRA documents.

The staff believes that the BNL results, which were largely based on the Indian Point 3 (Ref. 13) and Oconee (Ref. 14) PRAs, underestimate the safety benefit that would be achieved by improving PORV and block valve reliability for the following reasons:

1. The Indian Point 3 and Oconee PRAs that were the basis of the BNL study used PORV failure rates that were as much as two orders of magnitude lower than the failure rates determined by ORNL in NUREG/CR-4692.

2. The BNL study did not consider that older PWRs are permitted to operate at power indefinitely with the block valves closed and power removed. In this operating configuration, the PORVs are not available to perform the safety functions listed in Section 2.1.

3. By staff direction, the BNL study did not include consideration of feed and bleed capability. (See Section 5.3.)

Although the staff believes that items 1 and 2 above result in a somewhat low estimate of the potential reduction in core melt frequency by BNL, the BNL fault trees are dominated by operator error considerations, particularly for the SGTR event. Therefore, it does not appear that the results would have changed a great deal even if BNL had used higher PORV failures and considered that plants often operate with the block valves closed and power removed. However, as discussed in Section 5.3, the consideration of feed and bleed indicates a much greater safety importance of PORVs and block valves.

4 CONSTRUCTION OF PORVs AND BLOCK VALVES

Although most PWRs licensed prior to 1979 did not have safety-related PORVs and block valves, it was recognized that the pressure-retaining portions of these components were a part of the reactor coolant pressure boundary (RCPB) as defined in 10 CFR § 50.2. At the time they were not considered to perform a safety-related function (other than retaining reactor coolant system pressure) because they were not required to shut down the reactor and maintain it in a safe shutdown condition or to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the guideline exposures of 10 CFR Part 100, Appendix A. For these reasons PORVs and block valves were not considered to be safety related.

4.1 Codes and Standards

Since the pressure-retaining portions of PORVs and block valves perform the same safety-related function as other safety-related pressure-retaining components of the RCPB, they are constructed to the same codes and standards in conformance with 10 CFR § 50.55a. As noted in Appendix D to NUREG/CR-4692 (Ref. 2), PORVs are currently constructed to Section III, Class 1, of the ASME Boiler and Pressure Vessel Code. Prior to introduction of the 1971 Edition of Section III of the Code, PORVs were constructed to earlier codes and standards, such as the Draft ASME Code for pumps and valves, manufacturer standards, USAS B31.1.0—1967, and related standards, such as B16.5. Block valves are of the same construction as other motor-operated gate valves in PWRs and are constructed to the same codes and standards as those identified above for PORVs.

4.2 Seismic Design

The seismic qualification of PORVs and block valves is an area in which there appears to be no uniform application of seismic design requirements. Since 1972, Regulatory Guide 1.29 (formerly Safety Guide 29) (Ref. 15) has specified that the RCPB should be seismically designed to withstand the effects of a safe shutdown earthquake (SSE), that is, Seismic Category I. However, unless specifically requested by the customer, PORVs were not normally qualified to Seismic Category I requirements.

4.3 Quality Assurance

As noted in Appendix D to NUREG/CR-4692, PORVs are generally constructed to a manufacturer's quality assurance program that is in compliance with 10 CFR Part 50, Appendix B. The manufacturers' quality assurance programs have been in effect at least since the introduction of valves into the 1971 Edition of Section III of the ASME Boiler and Pressure Vessel Code. Prior to 1971, PORVs were constructed to each manufacturer's quality assurance program.

4.4 Control Systems

The control systems for PORVs and block valves are not supplied by the valve manufacturer but are designed and supplied by the PWR nuclear steam supply system supplier or the architect-engineer. For PORVs the control systems consist of an external power supply that is pneumatic or electrical for valve operation. Valve operation is typically controlled by an electrical signal resulting from high system pressure or by manual actuation from the control room. The block valve is actuated by the motor operator and is manually controlled by an electrical signal from the control room. Prior to the TMI-2 accident, PORV and block valve control systems were not qualified to standards, such as IEEE-382. Post-TMI-2 PORV and block valve control systems are now generally qualified to IEEE-382, IEEE-323, and IEEE-344.

4.5 Motor Operators

With the exception of San Onofre Unit 1, in all U.S. reactor designs to date, the PORV block valve is a gate valve actuated by a motor operator. The basic design of the block valve actuator is the same as for other actuators using an electric motor when used on gate valves in similar applications of PWRs. The major manufacturers of electric motor valve operators in the United States are Limitorque and Rotork.

4.6 Safety-Related and Non-Safety-Related PORVs and Block Valves

There are several differences between PORVs and block valves that are classified as safety related and those PORVs and block valves that are classified as non-safety-related.

During construction, PORVs, valves in PORV control systems, and block valves that are safety related are currently constructed to a manufacturer's quality assurance program that is in compliance with 10 CFR Part 50, Appendix B. These components are designed to Seismic Category I requirements and are environmentally qualified. The control systems of safety-related PORVs and block valves are also constructed in accordance with the quality assurance, seismic, and environmental requirements identified above. Components that are non-safety-related need not be constructed to any of the above quality assurance, seismic, or environmental requirements. However, as noted in Section 4.1 of this report, the pressure-retaining portions of PORVs and block valves are constructed to the same codes and standards as other RCPB components.

4.7 Operating Plant Maintenance

For operating plants, prior to the TMI-2 accident, maintenance practices on PORVs and block valves and associated control systems, including the block valve motor operators, varied widely from plant to plant. This was because of the perception that these components did not perform a safety-related function and were therefore not safety related.

PORVs that were degraded by excessive leaking were frequently blocked by closure of the associated block valve. Plant operation in this manner for plants licensed prior to 1982 is permitted by the plant technical specifications. The operational readiness of these degraded PORVs is questionable and cannot be ensured when they are called upon to open and close on demand, as happened in the case of TMI-2. In the post-TMI-2 era, there appears to be a greater awareness of the impact of malfunctioning PORVs and of the need for prompt operator action. However, as discussed in NUREG/CR-4692, it appears there is still a need for improvement in maintenance practices of PORVs and block valves.

5 REGULATORY ANALYSIS

5.1 Alternatives

The alternatives that were considered in the resolution of GI-70 are as follows:

1. Take no further action.

2. Require operating plants, all future PWRs, and those currently under construction (except for CE plants without PORVs) to install safety-related PORVs and block valves and associated controls for these components.

3. Require (1) operating plants and those currently under construction to include those improvements presented in Table 5.1 of this report to existing non-safety-grade PORVs and block valves, and (2) all future PWRs (except for CE plants without PORVs) to install safety-related PORVs and block valves and associated controls for these components.

Alternative 1 to take no further action was rejected based on an assessment of PORV failures as reported in NUREG/CR-4692 (Ref. 2). If no action is taken, accidents that challenge PORVs and block valves may compromise plant safety. For example, on many PWRs the PORVs and block valves are not tested to verify their operational status and on other PWRs are operated with the PORVs in a degraded condition. Continued power operation with inoperable PORVs is permitted by the technical specifications, and many plants now operate in this condition. The operational status of these PORVs is uncertain and they cannot be relied upon to perform a safety function.

The part of Alternative 2 that requires operating plants and those currently under construction to install safety-related PORVs and block valves or upgrade existing valves to safety-grade status was rejected because the staff concluded that it is not the most cost-effective method of achieving an acceptable level of safety. In the staff's judgment, an acceptable level of safety for existing PORVs and block valves can be achieved at less cost by other means. The installation of safety-grade PORVs and block valves on operating plants could require redundant and diverse control systems, components designed to Seismic Category I requirements and environmentally qualified; increased technical specification surveillance requirements; increased inservice testing requirements; and inclusion within the scope of a quality assurance program that is in compliance with 10 CFR Part 50, Appendix B. In addition, there may be rerouting of piping and subsequent piping reanalysis. Implementation of this alternative would probably require additional plant outage time beyond that normally required during refueling. The part of Alternative 2 that would require future PWRs to install safety-related PORVs and block valves and associated controls for these components is discussed as Part (1) of Alternative 3.

Part (1) of Alternative 3 that requires operating plants and those currently under construction to include those improvements presented in Table 5.1 of this report to existing non-safety-grade PORVs and block valves was adopted because it was the most cost-effective means of achieving an acceptable level of safety for these components provided they perform one or more of the safety-related functions discussed in Section 2.1 of this report. The estimated annual utility costs required to implement those improvements identified in Table 5.1 are presented in Table 5.2. The overall cost benefit per reactor is presented in Section 5.4 of this report. Part (2) of Alternative 3 that requires all future PWRs to install safety-related PORVs and block valves and associated control systems for these components was adopted provided the licensee performs one or more of the safety-related functions discussed in Section 2.1 of this report. CE plants without PORVs are not considered to be within the scope of these requirements. PORVs and block valves would therefore be classified in a manner that is consistent with other safety-related components in PWR plants.

Table 5.1 Potential improvements to PORVs and block valves.

1. Include PORVs and block valves within the scope of an operational quality assurance program that is in compliance with 10 CFR Part 50, Appendix B. This program should include the following elements:

   a. The addition of PORVs and block valves to the plant operational Quality Assurance List.

   b. Implementation of a maintenance/refurbishment program for PORVs and block valves that is based on the manufacturer's recommendations or guidelines and is implemented by trained plant maintenance personnel.

2. Include PORVs, valves in PORV control systems, and block valves within the scope of a program covered by Subsection IWV,* "Inservice Testing of Valves in Nuclear Power Plants," of Section XI of the ASME Boiler and Pressure Vessel Code. As permitted by the Code, stroke testing of PORVs should only be performed during Mode 3 (HOT STANDBY) or Mode 4 (HOT SHUTDOWN) and in all cases prior to establishing conditions where the PORVs are used for low-temperature overpressure protection. Stroke testing of the PORVs should only be performed during Mode 3 (HOT STANDBY) or Mode 4 (HOT SHUTDOWN) and in all cases prior to establishing conditions where the PORVs are used for low-temperature overpressure protection. Stroke testing of the PORVs should not be performed during power operation. The staff has concluded that stroke testing during power operation, in the words of the ASME Code, "is not practical" (reference ASME Section XI, Paragraph IWV-3412) because of the potential for a PORV to stick open during the stroke test. Additionally, the PORV block valves should be included in the licensees' response to the expanded MOV test program discussed in Generic Letter 89-10 (Ref. 5).

3. For operating PWR plants, modify the limiting conditions of operation of PORVs and block valves in the technical specifications for Modes 1, 2, and 3 to incorporate the position adopted by the staff in recent licensing actions. The staff recognizes that some recently licensed PWR plants already have technical specifications in accordance with the staff position. Such plants are already in compliance with this position and need merely state that in their response. These recent technical specifications require that plants that run with the block valves closed (e.g., due to leaking PORVs) maintain electrical power to the block valves so they can be readily opened from the control room upon demand. Additionally, plant operation in Modes 1, 2, and 3 with PORVs and block valves inoperable for reasons other than seat leakage is not permitted for periods of more than 72 hours.

4. Use, to the extent possible, more reliable PORV and PORV block valve designs that are resistant to failure. The NRC recognizes that licensees may choose to replace existing PORV and PORV block valves with more reliable designs as they are made available by valve manufacturers in the future. The use of more reliable valves should result in less frequent corrective maintenance and can result in longer inservice testing intervals as delineated in Section XI of the ASME Boiler and Pressure Vessel Code.

*In the 1988 Addendum to ASME Section XI, the content of Subsection IWV is replaced with a reference to Part 10 of ASME/ANSI OM-1987, "Inservice Testing of Valves in Light-Water Reactor Power Plants."

In addition, it is anticipated that the following proposed standard applicable to currently used PORVs will be included in OM-1987 and may ultimately be referenced in Subsection IWV of ASME Section XI:

OM-13, Requirements for Periodic Performance Testing and Monitoring of Power-Operated Relief Valve Assemblies

5.2 Potential Improvements to PORVs and Block Valves

The classification of PORVs and block valves should be consistent with the system used for classifying other components of the RCPB and systems that perform a safety-related function as defined in Regulatory Guide 1.26 (Ref. 4). While PORVs were originally provided in PWRs for plant operational flexibility and for limiting the number of challenges to the pressurizer safety valves, the operation of PORVs for overpressure protection of the RCPB was not considered to be a safety-related function. However, since PORVs are relied upon in many PWR plants to mitigate certain design basis accidents or to perform any other safety-related function that may be identified, the staff finds that it is appropriate to reconsider the classification of PORVs and the associated block valves.

For future PWR plants when PORVs and the associated block valves are used for any of the safety functions discussed in Section 2.1 of this report, these components should be classified as safety related and a minimum of two PORVs and block valves installed. Certain recently licensed plants and plants currently under active construction that have solenoid pilot-operated PORVs,* such as Vogtle 1 and 2, Millstone 3, Callaway, and Wolf Creek, meet these requirements.

For operating PWR plants and construction permit holders, there are a number of potential improvements to PORVs and block valves (short of upgrading to fully safety-grade hardware) that can increase the reliability of these components and provide assurance that they will function as required when called upon to perform a safety-related function. It is anticipated that the reliability of PORVs and block valves can be increased by implementing the improvements presented in Table 5.1.

The estimated utility present value for implementation of the improvements to PORVs and block valves for items 1, 2, and 3 of Table 5.1 are presented in Table 5.2. These present value estimates are in constant dollars using a real discount rate of 5 percent for a period of 30 years and are for a plant with two PORVs and two block valves.

*As of the date of this report, Bellefonte 1 and 2 and WNP-1 are not considered to be plants under active construction.

Table 5.2 Present value of improvements to PORVs and block valves.

Item	Description	Utility Cost/ Reactor
1	Include PORVs and block valves in an operational quality assurance program that is in compliance with 10 CFR Part 50, Appendix B (onetime cost of $8,000 plus a recurring cost of $200 per year for 30 years).	$11,100
2	Implement a maintenance/refurbishment program for PORVs and block valves (recurring cost of $5,300 per year for 30 years).	$81,600
3	Testing in accordance with Subsection IWV of Section XI of the ASME Code for PORVS and block valves (recurring cost of $1,200 per year for 30 years).	$18,500
4	Revision of technical specifications for PORVs and block valves (onetime cost of $16,000).	$16,000
5	Test block valves in accordance with NRC Generic Letter 89-10.	*
Total utility present value for implementation of items 1, 2, 3, and 4		$127,200

* See Value-Impact Analysis as reported in NUREG/CR-5140 (Ref. 16) for resolution of Generic Issue II.E.6.1, "In Situ Testing of Valves," as reported in NRC Generic Letter 89-10 (Ref. 5).

5.3 Safety Benefits

As discussed in Section 3.2, the BNL study performed specifically in support of GI-70 showed only a small potential decrease in core melt probability. This was in part because by staff direction the study did not include consideration of feed and bleed capability.

In the course of the resolution of Unresolved Safety Issue (USI) A-45, as reported in NUREG/CR-5230 (Ref. 6), the use of feed and bleed cooling on the primary system as an alternative, essentially last resort, measure to remove decay heat from the reactor core was explored in some detail. Studies performed under USI A-45 in general support the concept of feed and bleed, but do point out that timing is a critical parameter in establishing whether or not primary feed and bleed can successfully remove decay heat. However, discussions with personnel at various PWR plants revealed that most PWR utilities claim that feed and bleed is a viable decay heat removal method and at some plants is incorporated into the plant procedures.

The effect of the feed and bleed process upon the probability of core melt p(cm) was examined in NUREG/CR-5230 (Ref. 6) as a sensitivity issue, and in constructing accident sequence event trees credit was given for this capability. The core melt probabilities for internal events only, with and without feed and bleed, were calculated, and the report indicates that feed and bleed capability reduces the estimated core melt probability for internal events by a significant amount—on the order of 25 to 90 percent. The results are plant specific and show that feed and bleed reduces core melt frequency by 4.8E-5 to 1.15E-3. These results are presented in Table 5.3. Even if feed and bleed only reduces the core melt frequency by a fraction of the improvements shown above, it is a substantial reduction in public risk.

Table 5.3 Core melt probability with and without feed and bleed from case studies in USI A-45 (internal events only) with recovery

Plant Year	p(cm) per Reactor Year Without Feed and Bleed	p(cm) per Reactor Year With Feed and Bleed	p(cm) per Reactor
A	1.87E-4	1.39E-4	4.8E-5
B	1.00E-4	7.1E-5	2.9E-5
C	4.8E-5	1.4E-5	3.4E-5
D	1.23E-3	8.8E-5	1.14E-3

The analysis performed in NUREG/CR-5230 clearly show that a feed and bleed capability can have a significant effect on the probability of core melt; however, it is noted that decisions to feed and bleed must be made early in an accident progression for it to be successful.

The proposed actions to PORVs and block valves that are presented in Table 5.1 of this report enhance (but do not ensure) feed and bleed because:

1. Inclusion within an operational quality assurance program that is in compliance with 10 CFR Part 50, Appendix B, of an improved PORV maintenance/refurbishment program and additional surveillance testing provide better assurance that PORVs will open or close when called upon.

2. Currently, certain plants operate with the block valves closed. The technical specifications for these plants require that power be racked out at a valve motor control center, making it unlikely that feed and bleed could be initiated in a timely manner. The proposed revised technical specifications require those plants that run with the block valves closed to maintain electric power to the block valves so they can be readily opened from the control room.

3. Placing the block valves within the scope of NRC Generic Letter 89-10 (Ref. 5) would provide increased assurance that the block valves would open against system differential pressure to permit initiation of feed and bleed.

Based on the above, the staff concludes that the proposed actions to PORVs and block valves provide a substantial increase in the overall protection of the public health and safety.

5.4 Outage Avoidance Cost

As noted on page 3-32 of Reference 17, PWR capacity losses, that is, outage time due to RCS relief valve problems, have remained relatively unchanged over the years. As examples: over the years 1968-1979 plant capacity losses from the RCS safety/relief valves were 0.15 percent, and for the years 1980-1982 the RCS safety/relief valve capacity losses were 0.18 percent (page 4-57 of Ref. 18). Approximately 75-85 percent of the RCS safety/relief valve capacity losses are attributed to PORVs and block valves (Refs. 17 and 18).

Based on the above EPRI historical data, PORVs and block valves have been responsible for, on an average, PWR capacity losses (CL) of approximately:

$$CL = (0.8)\,[(12)(0.15)-(3)(0.18)]/15 = 0.12\%$$

The EPRI observation that the capacity losses attributed to these valves have remained relatively constant over the years infers that little, if any, improvement has been made in the maintenance and quality assurance procedures for these valves. EPRI in their limiting factors study on valves (page 5-4 of Ref. 19) concluded that, during a plant lifetime, valve performances could be significantly improved by proper operation and maintenance. In this regard, EPRI stated: "Probably no other single recommendation

—will improve valve availability as much as proper care and respect during plant lifetime."

Considering the above and other EPRI recommendations (see Sections 5.6 and 5.7 of Ref. 19), it is estimated that placing PORVs and block valves on the quality assurance program list of critical valves, improvements in PORV and block valve maintenance programs and quality assurance procedures, inservice testing in accordance with Section XI of the ASME Code and additional testing for PORV block valves requested in NRC Generic Letter 89-10, and upgrading the technical specifications on these valves as discussed in Table 5.1 of this report could result in approximately a 75 percent reduction in plant capacity losses attributed to PORVs and block valves.

Considering an average replacement power cost (RPC) of $500,000 per day, the above improvements in PORVs and block valves could yield a yearly per plant outage avoidance cost (savings) of:

OAC = (0.75)(CL)(365)(RPC) = $165,000 per reactor year:

Present value with a real discount rate of 5 percent for a period of 30 years:

OAC (Present value) = $2,541,000 per reactor

5.5 Cost/Benefit Comparison

The calculated numerical values used in this cost/benefit comparison are used only as an aid to the decisionmaking process and are not intended to be used as the final decisionmaking criterion on this issue. The values are, therefore, considered a supplementary tool to provide additional insight in an overall evaluation of this issue (Ref. 20).

The present value associated with the improvements to PORVs and block valves for items 1, 2, 3, and 4 of Table 5.2 of this report are estimated to be $127,200 for a plant with two PORVs and two block valves.

The overall cost benefit (OC_b) present value per reactor is:

OC_b(Present Value) = Outage Avoidance Cost (OAC) - Implementation Cost (I_c) of items 1, 2, 3, and 4, Table 5.2

OC_b (Present Value) = OAC $2,541,000 - I_c $127,200 = $2,413,800 per reactor

The projected costs to the NRC upon implementation of items 1, 2, and 3 of Table 5.1 of this report are as follows. Implementation of items 1(b) and 2 are recurring costs that result from inspections and evaluations covered by existing NRC monitoring programs and are not chargeable to the operation cost of this issue. Implementation of items 1(a) and 3 are one time costs of $15,000 per plant.

6 FINDINGS

For future PWR plants, the staff concludes that a minimum of two PORVs and block valves and associated controls for these components should be provided. These components should be identified as safety related if required to perform any of the safety-related functions discussed in Section 2.1 of this report or to perform any other safety-related function that may be identified in the future and should therefore be constructed to safety-grade standards. This would include redundant and diverse control systems, designed to Seismic Category I requirements and environmentally qualified; increased technical specification surveillance requirements; increased inservice testing requirements; and inclusion within the scope of a quality assurance program that is in compliance with 10 CFR Part 50, Appendix B. The safety-grade designation would include those improvements that were imposed subsequent to the TMI-2 accident, such as requirements to be powered from Class 1E buses and to provide valve position indication in the control room. The staff also concludes that item 4 in Table 5.1 of this report should be implemented where possible in future PWR plants and strongly encourages operating reactor owners and construction permit holders to evaluate the benefits of replacing existing PORVs and block valves with more reliable designs.

For operating plants and construction permit holders, the staff concludes it is not cost effective to replace (backfit) existing non-safety-grade PORVs and block valves (and associated control systems) with PORVs and block valves that are safety grade for the sole purpose of making them safety grade when they have been determined to perform any of the safety-related functions discussed in Section 2.1 of this report or to perform any other safety-related function that may identified in the future. Subsequent to the TMI-2 accident, a number of improvements were required of PORVs, such as requirements to be powered from Class 1E buses and to have valve position indication in the control room. Therefore, additional improvements that would result from upgrading PORVs to fully safety-grade status are considered to be of marginal benefit. For operating PWR plants and construction permit holders, the greatest immediate benefits can be derived from implementing items 1 through 3 in Table 5.1 of this report. The staff is proposing that these requirements be imposed to increase the reliability of PORVs and block valves to provide assurance they will function as required. Items 1 through 3 in Table 5.1 of this report, which do not require hardware changes, can be implemented within the scope of current licensing criteria and coordinated with the Technical Specifications Improvement Program.

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Enclosure 3

NUREG-1326

Regulatory Analysis for the Resolution of Generic Issue 94, "Additional Low-Temperature Overpressure Protection for Light-Water Reactors"

U.S. Nuclear Regulatory Commission

Office of Nuclear Regulatory Research

E. D. Throm

NUREG-1326

REGULATORY ANALYSIS FOR THE RESOLUTION OF GENERIC ISSUE 94, "ADDITIONAL LOW-TEMPERATURE OVERPRESSURE PROTECTION FOR LIGHT-WATER REACTORS"

Manuscript Completed: September 1989
Date Published:

E. D. Throm

Division of Safety Issue Resolution
Office of Nuclear Regulatory Research
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

ABSTRACT

Low-temperature overpressure protection (LTOP) is required in pressurized water reactors (PWRs) to provide protection against brittle reactor pressure vessel failure following an anticipated event. Typically these events are a result of either mass imbalance (excess charging in comparison to available letdown flow or inadvertent safety injection) or energy input transients (restarting an idle reactor coolant pump causing an increase in the reactor coolant system pressure as a result of mixing cold water from the inactive loop with the remainder of the hot fluid and as a result of direct energy addition from a warmer secondary side heat sink). The significance of these events is heightened during water-solid operations.

Low-temperature overpressure protection is required in the shutdown modes of operation, Mode 4 - Hot Shutdown, Mode 5 - Cold Shutdown, and Mode 6 - Refueling with the reactor vessel head bolted down. While operating in Modes 5 and 6 and with the reactor coolant temperature below 200°F, there are no technical specifications for containment integrity. The consequences of an unmitigated low-temperature overpressure event can be significant as a result of either containment bypass or failure of containment to isolate following reactor pressure vessel failure.

This report presents the regulatory analysis for Generic Issue 94, "Additional Low-Temperature Overpressure Protection for Light-Water Reactors." It includes (1) a summary of the issue, (2) the proposed technical resolution, (3) alternative resolutions considered by the Nuclear Regulatory Commission (NRC), (4) an assessment of the benefits and cost of the alternatives considered with additional emphasis on the recommended resolution, (5) the decision rationale, and (6) the impacts and relationships between GI-94 and other NRC programs and requirements.

The majority of the technical evaluations, and the development of the cost analyses, for the various alternatives considered were performed by Battelle Pacific Northwest Laboratories (PNL) under Technical Assistance to the Division of Reactor and Plant Systems, RES, FIN Number B-2998 (NUREG/CR-5186).

Additional considerations that could impact on the recommendations and conclusions regarding GI-94 have been addressed by the NRC staff. Most notable are a reevaluation of the consequence analyses to ensure that the estimated risk, in person-rem, is not overly conservative, and an adjustment in the NRC and industry implementation cost estimates to account for plants not considered in the PNL risk evaluation. These are plants licensed after the end of 1986 or currently in the process of being licensed for operation.

NUREG-1326

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CONTENTS

TABLES

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ACRONYMS AND INITIALISMS

ACI	Autoclosure interlock (of RHR suction line isolation valves)
ALARA	As low as reasonably achievable
ANSI	American National Standards Institute
AOT	Allowable outage time
ASME	American Society of Mechanical Engineers
B&W	Babcock and Wilcox
BTP	Branch technical position
BV	Block valve
BWR	Boiling water reactor
CDF	Core damage frequency
CE	Combustion Engineering
CFR	Code of Federal Regulations
COMS	Cold overpressure mitigation system (see LTOP)
DHR	Decay heat removal system (used by B&W)
ECCS	Emergency core cooling system
EPRI	Electric Power Research Institute
GDC	General Design Criterion, Appendix A, 10 CFR Part 50
GI	Generic Issue (used by NRC)
gpm	gallons per minute
HPSI	High-pressure safety injection
LER	Licensee event report
LCO	Limiting conditions of operation
LTOP	Low-temperature overpressure protection system (generic NRC term)
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation, NRC
NSSS	Nuclear steam supply system
OMS	Overpressure mitigation system
PORV	Power-operated relief valve
PNL	Battelle Pacific Northwest Laboratories
psi	pounds per square inch
PTS	Pressurized thermal shock
PWR	Pressurized water reactor
RCS	Reactor coolant system
RCP	Reactor coolant pump
RES	Office of Nuclear Regulatory Research, NRC
RHR	Residual heat removal system (used by Westinghouse)
RSB	Reactor Systems Branch
RT(ndt)	reference temperature, nil-ductility transition
SI	Safety injection (refers to high-pressure pumps)
SDCS	Shutdown cooling system (used by CE)
SP	setpoint
SRP	Standard Review Plan
SRV	Safety relief valve
STS	Standard technical specifications
TS	Technical specification
TWC	Through wall crack
USI	Unresolved Safety Issue
VFP	Vessel fracture probability
W	Westinghouse

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EXECUTIVE SUMMARY

General Design Criterion 15 of Appendix A to 10 CFR Part 50 requires that "the reactor coolant system and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences."

Anticipated operational occurrences, as defined in Appendix A to 10 CFR Part 50, are "those conditions of normal operation which are expected to occur one or more times during the life of the nuclear power unit and include but are not limited to loss of power to all recirculation pumps, tripping of the turbine generator set, isolation of the main condenser, and loss of offsite power."

General Design Criterion 31 of Appendix A to 10 CFR Part 50 requires that "the reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions (1) the boundary behaves in a nonbrittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing, and postulated accident conditions and the uncertainties in determining (1) material properties, (2) the effects of irradiation on material properties, (3) residual, steady state and transient stresses, and (4) size of flaws."

Appendix G to 10 CFR Part 50 provides the fracture toughness requirements for the reactor pressure vessel under certain conditions. To ensure that the Appendix G limits of the reactor coolant pressure boundary are not exceeded during any anticipated operational occurrences, technical specification pressure/temperature limits are provided for operating the plant.

In the late 1970s, it was noted that there were a large number of events occurring at reactors while operating at low temperatures (shutdown modes) where the technical specification pressure/temperature limits were being exceeded. The frequency of these overpressure transients was determined to be within the anticipated operational occurrence definition.

Low-temperature overpressure protection (LTOP) was designated as Unresolved Safety Issue (USI) A-26 in 1977 (NUREG-0371 -- Ref. 1). PWR licensees implemented procedures to reduce the potential for overpressure events and installed equipment modifications to mitigate such events based on staff recommendations from the USI A-26 evaluations, under Multi-Plant Action Item B-04 (NUREG-0748 -- Ref. 2). The current staff guidelines for the LTOP system are found in Standard Review Plan 5.2.2, "Overpressure Protection," and in its attached Branch Technical Position BTP-RSB 5-2, "Overpressure Protection of Pressurized Water Reactors While Operating at Low Temperatures" (NUREG-0800 -- Ref. 3).

Twelve overpressure transients, in PWRs, were reported during the period from 1981 to 1983 (Ref. 4) after completion of USI A-26. Two of these events, at Turkey Point Unit 4, exceeded the technical specification pressure/temperature limits. In addition, during this same timeframe there were 37 reported instances when at least one LTOP channel was out of service. In 12 of these cases, both LTOP channels were inoperable.

The continuation of overpressure transient events, and the unavailability of LTOP protection channels, suggested the need to reevaluate the current overpressure protection criteria, or their implementation, to determine whether additional considerations are warranted.

Major overpressurization of the reactor coolant system while at low temperature, if combined with a critical crack in the reactor pressure vessel welds or plate material, could result in a brittle fracture of the pressure vessel. As long as the fracture resistance of the reactor pressure vessel material is relatively high, these events are not expected to cause vessel failure. However, the fracture resistance of the reactor pressure vessel materials decreases with exposure to fast neutrons during the life of a nuclear power plant. The rate of decrease is dependent on the metallurgical composition of the vessel walls and welds. If the fracture toughness of the vessel has been reduced sufficiently by neutron irradiation, low-temperature overpressure events could cause propagation of fairly small flaws that might exist near the inner surface. The assumed initial flaw might propagate into a crack through the vessel wall of sufficient extent to threaten vessel integrity and, therefore, core cooling capability.

The safety significance of these continuing low-temperature overpressure transients was designated as Generic Issue 94, "Additional Low-Temperature Overpressure Protection" (Ref. 5). GI-94 applies to the design and operation of all PWRs. BWRs have been excluded from consideration because they do not normally operate in a water-solid configuration.

The Babcock and Wilcox plants have also been excluded from this evaluation because these units have not experienced any low-temperature overpressure transients and, based on theoretical risk, do not contribute to the overall risk of low-temperature overpressure events. Babcock and Wilcox plants do not operate in a water-solid condition. A steam or nitrogen bubble is maintained in the pressurizer. The bubble provides a minimum of 10 minutes for the operator to respond to an anticipated low-temperature overpressure event. A single path is provided for pressure relief (PORV or RHR safety relief valve).

In reaching its proposed resolution for GI-94, the NRC staff considered six specific alternative courses of action. The requirements would be applicable to all Westinghouse and Combustion Engineering plants, both operating reactors and reactors in the construction stage of licensing. Fifty-two Westinghouse plants and 15 Combustion Engineering plants are considered in the determination of the industry and the NRC implementation costs.

The general objective of GI-94 is to evaluate the need for additional low-temperature overpressure protection and to examine alternatives to reduce the risk of core damage accidents associated with low-temperature overpressure events in PWRs by reducing the likelihood of these events. The basis for this is the need to ensure that there is a low likelihood of brittle reactor pressure vessel failure (through wall crack (TWC)). Such a failure, unlike most other accident scenarios that can lead to core damage, could result in the reactor pressure vessel's being unavailable for either subsequent recovery of the reactor core or as an additional barrier for fission product retention.

To achieve these objectives, the staff's proposed resolution for GI-94 recommends a revision to the plant technical specification for overpressure protection to ensure that both low-temperature overpressure protection channels are operable, especially in a water-solid condition; that is, to treat operationally the low-temperature overpressure protection system as a system that performs a safety-related function.

The specific action recommended is to reduce the allowable outage time (AOT) for a single LTOP channel when operating in Mode 5 (cold shutdown) or Mode 6 (with the reactor pressure vessel head bolted down) from the current AOT of 7 days to an AOT of 8 hours before remedial actions to depressurize and to vent the reactor coolant system would be required.

The overall best estimate value/impact, not including accident avoidance costs, is about $160 per person-rem averted. If cost savings to the industry from accident avoidance (cleanup and repair of onsite damage and replacement power) were included, the overall value/impact ratio would improve significantly as the avoided costs for cleanup and repair and for replacement power more than offset the combined implementation costs for the industry and the NRC staff.

Table ES.1 is provided as a summary of the best estimate dose reductions, occupational exposures, industry implementation costs, NRC implementation costs, and the value/impact ratio for each of the alternatives studied by the staff. The base case TWC frequency is 3.24×10^{-6} per reactor year.

Table ES.1 Summary of best estimate value/impact (V/I) ratios for alternatives evaluated by NRC.

Alternative	TWC Freq Reduction (1/R-yr)	Dose Reduction (person-rem)	Occupational Exposure (person-rem)	Industry Costs ($1,000s)	NRC Costs ($1,000s)	V/I Ratio(*) ($ per averted person-rem)
2	2.89×10^{-6}	14,500	n/a	1,370	950	160
3(a)	1.07×10^{-6}	7,000	n/a	3,630	1,840	780
3(b)	0.21×10^{-6}	1,400	n/a	1,290	950	1,600
3(a&b)	1.20×10^{-6}	8,400	n/a	4,920	2,790	920
4(a)	0.16×10^{-6}	700	n/a	770	650	1,900
4(b)	0.16×10^{-6}	700	n/a	4,770	650	7,750
5	1.82×10^{-6}	8,200	900	16,000	570	2,000
5(a)	3.00×10^{-6}	13,400	900	16,000	570	1,200
6(a)	3.24×10^{-6}	16,000	23,000	41,450	1,450	2,700
6(b)	1.74×10^{-6}	9,300	23,000	41,450	1,450	4,600

Notes:

*	Sum of industry plus NRC implementation costs ($s) divided by dose reduction (person-rem).
2	Technical specification change, 67 plants, proposed resolution.
3(a)	SI lockout, 67 plants.
3(b)	RCP restart, 67 plants.
3(a&b)	Both SI and RCP, 67 plants.
4(a)	ACI removal, w/o cost for disconnecting ACI, 40 PORV plants.
4(b)	ACI removal, w/cost for disconnecting ACI, 40 PORV plants.
5	Safety-grade OMS, 40 PORV plants.
5(a)	Sensitivity Study, safety-grade OMS, 40 PORV plants.
6(a)	Pressurizer bubble, peak pressure less than 600 psi, 67 plants.
6(b)	Pressurizer bubble, 10% chance of reaching 2500 psi, 67 plants.

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1. STATEMENT OF PROBLEM

General Design Criterion 15 of Appendix A to 10 CFR Part 50 requires that "the reactor coolant system and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences."

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Low-temperature overpressure protection (LTOP) was designated as Unresolved Safety Issue (USI) A-26 in 1978 (NUREG-0371 -- Ref.1). PWR licensees implemented procedures to reduce the potential for overpressure events and installed equipment modifications to mitigate such events based on staff recommendations from the USI A-26 evaluations, under Multi-Plant Action Item B-04 (NUREG -0748 -- Ref.2). The current staff guidelines for the LTOP system are found in Standard Review Plan 5.2.2, "Overpressure Protection," and in its attached Branch Technical Position BTP-RSB 5-2, "Overpressure Protection of Pressurized Water Reactors While Operating at Low Temperatures" (NUREG-0800 -- Ref. 3).

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The safety significance of these continuing low-temperature overpressure transients was designated as Generic Issue 94, "Additional Low-Temperature Overpressure Protection" (Ref. 5). GI-94 applies to the design and operation of all PWRs. BWRs have been excluded from consideration because they do not normally operate in a water-solid configuration.

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2. OBJECTIVES

The general objective of GI-94 is to evaluate the need for additional low-temperature overpressure protection and to examine alternatives to reduce the risk of core damage accidents associated with low-temperature overpressure events in PWRs by reducing the likelihood of these events. The basis for this is the need to ensure that there is a low likelihood of brittle reactor pressure vessel failure (through wall crack - (TWC)). Such a failure, unlike most other accident scenarios that can lead to core damage, could result in the reactor pressure vessel's being unavailable for either subsequent recovery of the reactor core or as an additional barrier for fission product retention.

In considering the risks associated with low-temperature overpressure events, the NRC staff has identified specific characteristics related to these events that differ from most core damage accidents. The concerns are related to the failure of the reactor pressure vessel itself, not the failure of emergency core cooling systems or decay heat removal systems. In addition, low-temperature overpressure events relate to shutdown modes of operation, Modes 4, 5, and 6, and the containment may be open during one of these events.

Low-temperature overpressure protection (LTOP) is a subset of the broader class of events related to reactor pressure vessel integrity, commonly referred to as pressurized thermal shock (PTS) events. However, the severe thermal stresses due to overcooling of the reactor pressure vessel are not present during LTOP events. When PTS was being evaluated by both the industry and the NRC staff in the early 1980s, the requirements of USI A-26 had just been imposed on the industry and consequently LTOP was not addressed in these studies. It was believed that the resolution of USI A-26 had adequately resolved LTOP concerns and these events were not considered in the probabilistic risk assessments performed (Ref. 6).

Reactor pressure vessel failure resulting from brittle fracture is generally defined as a through wall crack (TWC), resulting from the initiation and propagation of an assumed small flaw in the vessel. The probability of a TWC, or the vessel fracture probability (VFP), is calculated with the VISA computer program (Ref. 7) for an assumed transient. Crack, or flaw, initiation may not always result in a TWC. Depending on the vessel material characteristics and the assumed transient, some cracks that initiate may arrest in the tougher sections of the vessel (farther away from the inside of the vessel where the irradiation damage is attenuated). VISA accounts for this. For cracks that may propagate through the wall, some may not result in core damage. However, studies performed as part of the PTS effort indicate that a large fraction of TWCs could result in large openings in the reactor vessel for longitudinal welds, or complete opening of circumferential welds (Ref. 8).

For the purpose of evaluating the risk from low-temperature overpressure events, the NRC staff assumes that the probability of a through wall crack is equal to the probability of core damage.

In addition to minimizing the likelihood of brittle reactor pressure vessel fracture (a through wall crack), the general objective of the proposed requirements is to make the risk from LTOP transients during shutdown operations a small contributor to the overall risk associated with the operation of a PWR, based on the guidance and objectives of the Commission's Safety Goal Policy Statement (Ref. 9). On the core damage frequency (CDF) risk level, a target for the resolution of Generic Issue 94 is that the contribution from LTOP transients be a small part (a few percent) of an overall CDF target of $1x10^{-4}$ per reactor year.*

Since LTOP transients occur most frequently in Mode 5, when containment may be open, an LTOP transient CDF target of $1x10^{-6}$ per reactor year may also be considered to be compatible with the proposed general performance guidelines given in the Commission's Safety Goal Policy, i.e., that the probability of a large release from an operating nuclear power plant should be no greater than $1x10^{-6}$ per reactor year. A more direct comparison of this CDF target with the policy guidelines requires a definition of "large release" in the policy statement.

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* More recently, a core damage frequency goal of $5x10^{-5}$ per reactor year has been proposed under the safety goal implementation program. This is a factor of two lower than the $1x10^{-4}$ value used herein, but is within the uncertainty inherent in calculations and assumptions made assessing compliance with either goal, and its adoption in lieu of a $1x10^{-4}$ goal would not affect the recommendations made in this regulatory analysis.

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3. ALTERNATIVE RESOLUTIONS

In reaching its proposed resolution of GI-94, the staff considered six specific alternative courses of action. These are discussed below. The requirements would be applicable to all Westinghouse and Combustion Engineering plants, both operating reactors and reactors in the construction stage of licensing. Fifty-two Westinghouse plants and 15 Combustion Engineering plants are considered in the determination of the industry and the NRC implementation costs. Additional discussions of each of these alternatives is provided in Section 5.

3.1 Alternative 1 - No Action Alternative

This alternative assumes that no additional low-temperature overpressure protection need be provided. It also assumes that all applicable requirements and guidance to date have been implemented, but no implementation is assumed for related generic issues, or other staff requirements or guidance, that are still unresolved or still under review.

3.2 Alternative 2 - Change to Technical Specifications

To achieve the objectives stated in Section 2 above, this alternative calls for a modification to the plant technical specification for overpressure protection to ensure that both low-temperature overpressure protection channels are operable, especially in a water-solid condition; that is, to treat operationally the low-temperature overpressure protection system as a system that performs a safety-related function. A summary of specific aspects of this alternative is as follows:

- The role of PORVs has changed such that PORVs are now relied upon to perform one or more of the following safety-related functions:

  a. mitigate a design-basis steam generator tube rupture event,

  b. low-temperature overpressure protection of the reactor pressure vessel during startup and cooldown, or

  c. plant cooldown in accordance with Branch Technical Position BTP RSB 5-1 to Standard Review Plan Section 5.4.7, "Residual Heat Removal (RHR) System" (Ref. 3).

- For plants that rely on safety relief valves in the residual heat removal system for low-temperature overpressure protection, the technical specification for overpressure protection parallels that of the PORV group of plants.

- The current technical specification ACTION statement allows 7 days to restore an inoperable LTOP channel to operable status or depressurize and vent the reactor coolant system (RCS) within the next 8 hours. With both LTOP channels inoperable, the ACTION statement requires the RCS to be depressurized and vented within 8 hours.

- Under the current bases for Specification 3.0.4, operations need not be restricted when corrective action should be taken to obtain compliance with a specification under certain situations even if the corrective actions are required within a limited period of time. Exceptions from Specification 3.0.4 have been provided for a limited number of specifications when startup with inoperable equipment would not affect plant safety.

3.3 Alternative 3 - SI and RCP Restrictions

Alternative 3 would require removal of all power to safety injection pumps and prohibit reactor coolant pump restart while in a water-solid condition.

3.4 Alternative 4 - Removal of RHR Autoclosure Interlock

Alternative 4 would allow for crediting use of the RHR safety relief valves, in addition to the PORVs, for pressure relief in mitigating an LTOP transient. Removal of the autoclosure isolation (ACI) interlock on the RHR suction lines would be an additional requirement and has been evaluated as part of Generic Issue 99, "RHR/RCS Suction Line Interlocks on PWRs." For plants that rely on only the RHR safety relief valves for LTOP protection, no additional benefit would be obtained from this alternative.

3.5 Alternative 5 - Safety-Grade LTOP System

Alternative 5 would require that the low-temperature overpressure protection system be upgraded to a fully safety-grade system.

3.6 Alternative 6 - Pressurizer Bubble

Alternative 6 would require that water-solid operation be prohibited by providing for a steam or nitrogen bubble in the pressurizer at all times (other than during hydrostatic pressure tests).

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4. TECHNICAL FINDINGS

The PNL evaluation of low-temperature overpressure protection included a determination of the frequency of overpressure transients while at low temperatures, the failure of the overpressure protection system on a demand basis, and the theoretical peak pressure that could be obtained, given failure of the overpressure protection system. The probability of reactor pressure vessel fracture due to brittle fracture was estimated based on the neutron-induced embrittlement of the limiting vessel material over the remaining lifetime of each plant. The detailed evaluation is found in NUREG/CR-5186 (Ref. 10).

The frequency of overpressure transients was determined from actual operating reactor experiences, as reported in the licensee event report (LER) system. Special reports and industry reports were also reviewed to augment the LER data base. Technical specification reporting requirements provide for a 30-day report to the Commission whenever the low-temperature overpressure protection system is used to mitigate a pressure transient. Overpressure protection system unavailability was also determined from the same sources. The period from 1980 through the end of 1986 is considered in this evaluation. The LER and literature search was performed by the NRC staff and is summarized in Appendix A. More recent LTOP events that have occurred in 1987 and the early part of 1988 have been reviewed to determine if the base case evaluation would have been altered by a detailed accounting of these events. PNL concluded that the base case would not be altered by more than about 10%. None of these more recent events would have resulted in high reactor coolant system pressures if the LTOP systems had failed.

The reactor pressure vessel fracture probability was obtained by PNL from the VISA computer program (Ref. 7). To account for the effects of neutron irradiation damage, the mean surface RT(ndt), reference temperature nil-ductility transient, shift was calculated using Revision 2 to Regulatory Guide 1.99 (Ref. 11).

Reactor pressure vessel failure resulting from brittle fracture is generally defined as a through wall crack (TWC), resulting from the initiation and propagation of an assumed small flaw in the vessel. The probability of a TWC, or the vessel fracture probability (VFP), is calculated with the VISA computer program (Ref. 7) for an assumed transient. Crack, or flaw, initiation may not always result in a TWC. Depending on the vessel material characteristics and the assumed transient, some cracks that initiate may arrest in the tougher sections of the vessel (farther away from the inside of the vessel where the irradiation damage is attenuated). VISA accounts for this. For cracks that may propagate through the wall, some may not result in core damage. However, studies performed as part of the PTS effort indicate that a large fraction of TWCs could result in large openings in the reactor vessel for longitudinal welds, or complete opening of circumferential welds (Ref. 8).

In addition to evaluating the operating reactor experiences frequencies, the root causes for the overpressure transients and overpressure protection system unavailability were also determined. To the extent feasible, the operator reactions and responses to the actual events were also considered by PNL, thus establishing the best estimate, or base case, profile for the low-temperature overpressure transient event frequency, overpressure protection system unavailability, and theoretical peak pressure spectrum.

In reviewing the actual operating reactor events as reported in the LERs, it was noted that the licensees have always reported prompt operator action in response to low-temperature overpressure transients. In 1 to 2 minutes, the operators have diagnosed the situation and taken appropriate actions to terminate the effects of the transients, usually resulting in only one or two cycling of the PORVs before stabilizing the reactor coolant system pressure below the Appendix G limits. PNL therefore assumed a 3-minute operator response time to develop the best estimate peak pressure spectrum; somewhat conservative but not a worst case evaluation.

The operating reactors were classified by overpressure protection system design. Three groups were identified.

1. Two PORVs, water-solid operation allowed: 32 Westinghouse units and eight Combustion Engineering units (40 total units).

2. Two SRVs in the RHR, water-solid operation allowed: nine Westinghouse units and six Combustion Engineering units (15 total units).

3. Single PORV with pressurizer bubble at all times, all Babcock and Wilcox plants (8 units).

There are a small number of plants that have been licensed with low-temperature overpressure protection systems that do not fall into one of the above groups. However, they have been included in one of the three groups dependent on either the type of relief path (PORV or SRV) employed or by determining the appropriate group based on the technical specification requirements currently in existence at the plant.

Low-temperature overpressure protection is required during shutdown modes of operation, Modes 4, 5, and 6. A review of the actual events concluded that virtually all events are occurring in Mode 5 with reactor coolant system temperatures ranging from 80°F to 190°F. The characteristic transient used to determine the vessel fracture probability, conditional on event occurrence, was developed based on the actual operating events. A vessel wall temperature of 120°F and a heatup rate of 25°F per hour were used. The 120°F wall temperature is representative of the average temperature at which low-temperature overpressure events have occurred. This temperature is also lower than that at which the reactor pressure vessel head may be removed at many plants and represents a reasonable limiting temperature for this evaluation. A 25°F per hour heatup rate appears to be a reasonable estimate based on heatup with decay heat and residual heat removal system pump energy prior to reactor coolant pump restart.

A peak theoretical pressure was determined by PNL for each event, assuming the low-temperature overpressure protection system failed to mitigate the event. If an additional pressure relief path were available, for example, the residual heat removal system safety relief valves, the peak pressure was limited to the SRV setpoint, provided the rated relief capacity could accommodate the challenge.

For events that occurred without another pressure relief path, the peak theoretical pressure was limited to that which could be achieved 3 minutes after the initiation of the event. The 3-minute operator action response time was determined by PNL from the review of the actual events. In all cases the operators have recognized the overpressure transient and initiated actions to correct the situation within a 1- to 2-minute time period. The NRC staff attributes this rapid response characteristic to training and procedure development in response to the implementation of Unresolved Safety Issue A-26. In addition, a rapid response will limit the number of times the PORV is cycled while mitigating the event.

The Babcock and Wilcox plants have been excluded from this evaluation because these units have not experienced any low-temperature overpressure transients and do not contribute to the overall risk of low-temperature overpressure events. Babcock and Wilcox plants do not operate in a water-solid condition. A steam or nitrogen bubble is maintained in the pressurizer. The bubble provides a minimum of 10 minutes for the operator to respond to an anticipated low-temperature overpressure event. A single path is provided for pressure relief (PORV or RHR SRV).

For the period from 1980 through the end of 1986, there were 30 challenges to the LTOP systems at the 55 Westinghouse and Combustion Engineering plants operating during this timeframe. Twenty-three occurred in the PORV class plants and seven in the RHR SRV class plants. Two events in the PORV plants and one in the RHR SRV plants exceeded the Appendix G limits. The PORV plants accumulated 244 reactor years of experience and the RHR SRV plants accumulated 56 reactor years of experience.

Essentially all the LTOP challenge events have occurred when the reactor coolant system was water-solid (pressurizer filled). The events fall into two categories: those resulting from mass addition and those caused by energy addition. Both of these types of events cause rapid pressurization when the reactor coolant system is water-solid.

A representative pressurization rate for mass addition events was calculated by PNL. Using the compressibility of water of 0.0046% delta volume per unit volume per atmosphere of pressure increase, and based on a reactor coolant system volume of 11,000 cubic feet, the pressurization rate was calculated to be 3.8 psi per gallon injected into the reactor coolant system.

Water expands when heated, increasing the pressure of a water-solid system. PNL calculated the pressurization rate for energy addition events using the above value for compressibility and the specific volume of water in the 100 to 200°F temperature range. The pressurization rate was calculated to be 100 psi per °F increase in the reactor coolant system average temperature. Slow heating of the reactor coolant system by operation of a single reactor coolant pump generally does not exceed 25°F per hour, which would correspond to a pressure increase of about 42 psi per minute.

The mass addition events resulted in injection rates ranging from 20 gallons per minute (gpm) to 600 gpm. The higher rates are associated with inadvertent safety injection events, while the lower values are typical of excess charging without letdown. The energy addition events are identified by the differential temperature between the secondary side and primary side of the reactor coolant system. The warmer steam generator is the heat source for these events. The allowable temperature differential for reactor coolant pump restart is specified in the current technical specification. In the actual experiences data base, the differential temperature is usually small, although in one case it was reported to be 85°F.

The operating reactor experiences data base is summarized in Table 4.1 for the PORV plants and in Table 4.2 for the RHR SRV plants. Included in these tables are the mass flow rates, temperature differences, the LTOP pressure setpoints and the calculated peak (or hypothetical) pressures assuming failure of the LTOP system. The actual peak pressure is provided for reference. Also provided are the various pressure setpoints for the pressure relief systems as well as the specific feature that limited the peak pressure, either an alternative relief path or the assumed 3-minute operator response time.

Table 4.3 summarizes the current frequency of low-temperature overpressure events and overpressure protection system unavailability. The vessel fracture probability (or core damage frequency), as derived from the actual operating reactor experiences, is also provided for the mean plant in each group over the remaining plant lifetime of the group. The mean core damage frequency for low-temperature overpressure events, as determined under GI-94, is 3.24×10^{-6} per reactor year. The mean core damage frequency for the PORV plants is 3.04×10^{-6} per reactor year, and the mean core damage frequency for the RHR SRV plants is 3.76×10^{-6} per reactor year.

The likelihood of a low-temperature overpressure event and the likelihood that the overpressure protection system will fail on demand, as well as the resulting theoretical pressure spectrum, are considered to be equal for all plants within each group. That is to say, no credit or penalty was given to any plant as a result of that plant's specific operating history. However, the resultant estimate of vessel fracture varies from plant to plant and from year to year. The probability of reactor pressure vessel fracture increases with plant life. Vessels become more brittle with age as a result of neutron irradiation. From plant to plant, the chemical composition of the limiting reactor pressure vessel material also varies, and the plant-specific vessel fracture probability for each plant is unique to that composition. The estimated vessel fracture probability for each plant has been calculated and summed to obtain the group total and mean values.

A review of current standard technical specifications for containment integrity in shutdown modes (Modes 4, 5, and 6) indicates that no containment integrity requirements are imposed for reactor coolant temperatures less than 200°F, except during refueling operations when the reactor pressure vessel head is removed. Since the low-temperature overpressure events of concern to this evaluation occur in Mode 5 at reactor coolant temperatures between 80°F and 190°F, the assumption that containment is open, at least part of the time, is judged to be valid. Containment integrity will be treated parametrically in this analysis.

The consequence evaluation for a low-temperature overpressure event, which results in reactor pressure vessel fracture, was obtained for a late core melt sequence with containment bypass (Ref. 12). The studies were performed in conjunction with Generic Issue 70, "Power-Operated Relief Valve and Block Valve Reliability." The estimated consequence for this event was found to be 9 million person-rems over a 30-year period for a typical eastern site with 100 persons per square mile population density. A 50-mile radius is used for all consequence evaluations as required by current NRC guidelines (Ref. 13).

Because of the wide variation in the plant-specific vessel fracture probabilities and because of differences between sites, the NRC staff did not select either a "typical" plant or use the "average" plant for this analysis (for example, use the value and impact for the "typical" or "average" plant and multiply the results by the number of plants within a group). The variation in plant-specific vessel fracture probability, as well as the variation in site-specific consequences based on population density and environmental factors, are considered in this evaluation of risk and consequence.

The plant-specific vessel fracture probability, integrated over the remainder of life, was obtained for the mean surface RT(ndt) shift expected to occur for each plant (the VISA probability results are provided in terms of the mean surface RT(ndt) value).

To account for site-specific variables, population density, environmental conditions, and reactor size, the generic consequence in Reference 12 has been scaled, by the NRC staff, to the Siting Source Term data provided in Reference 14. Appendix B provides a discussion of the technique employed and compares the results to the generic source term evaluation. The objective of performing this scaling evaluation is to ensure that the estimate of the consequences from low-temperature overpressure transients properly accounts for the plant-specific variations in the source term (as a function of the power rating of a plant) and in the population density and environmental factors that affect the calculation of the consequences. The scaled source term evaluation results in a 30% reduction in estimated dose, in person-rem, as compared to the generic source term evaluation (based on Ref. 12).

The results of the scaling study are provided in Table 4.4 for each plant category and for different release categories, based on the through wall crack frequencies, or core damage frequencies, presented in Table 4.3. The generic value overestimates the consequences for the RHR SRV plants. These plants are the older, low-power units or the newer plants that tend to have better reactor pressure vessel materials. The dominant contribution based on vessel fracture probability comes from the older, low-power plants.

Table 4.1 Summary of PORV class operating reactor experiences.

Mass Addition Events

Plant	Yr	Mass Flow Rate (gpm)	PORV LTOP SP (psi)	RHR ACI SP (psi)	RHR SRV SP (psi)	RCS Initial Pres (psi)	Peak Pres Limited by Alt Path	Peak Pres Limited by 3 Min	Hypo Peak Pres (psi)	Actual Peak Pres (psi)
Calvert Cliffs	83	40	450	700	315	400		X	850	425
Ginna	83	40	435	450	600	310		X	760	435
North Anna 1	81	300	430	600	467	unk	X		467	430
North Anna 1	83	530	430	600	467	350	X		467	430
North Anna 1	84	40	430	600	467	350	X		467	410
North Anna 1	85	20	430	600	467	350	X		467	430
Palisades	81	40	400	none	300	300		X	850	400
Salem 2	83	300	375	600	375	unk	X		375	375
San Onofre 1	83	600	522	370	500	300		X	2500	522
Surry 1	81	200	410	none	600	350	X		600	410
Surry 1	84	100	410	none	600	325	X		600	412
Surry 1	85	200	410	none	600	350	X		600	410
Turkey Pt 4	81	90	415	465	600	310		X	1400	1100
Turkey Pt 4	81	90	415	465	600	340		X	1400	750
Zion 1	84	100	435	600	450	unk	X		450	450
Zion 2	85	190	435	600	450	unk		X	2500	435
Zion 2	86	150	435	600	450	unk	X		450	450

Energy Addition Events

Plant	Yr	Mass Flow Rate (gpm)	PORV LTOP SP (psi)	RHR ACI SP (psi)	RHR SRV SP (psi)	RCS Initial Pres (psi)	Peak Pres Limited by Alt Path	Peak Pres Limited by 3 Min	Hypo Peak Pres (psi)	Actual Peak Pres (psi)
North Anna 2	82	85	385	600	467	364	X		467	385
North Anna 2	82	35	385	600	467	350	X		467	365
Palisades	85	min	400	none	300	300		X	500	375
Salem 2	84	min	375	600	375	325	X		375	350
Salem 2	85	min	375	600	375	325	X		375	380
Salem 2	85	min	375	600	375	340	X		375	380

Table 4.2 Summary of RHR SRV class operating reactor experiences.

Mass Addition Events

Plant	Yr	Mass Flow Rate (gpm)	PORV LTOP SP (psi)	RHR ACI SP (psi)	RHR SRV SP (psi)	RCS Initial Pres (psi)	Peak Pres Limited by Alt Path	Peak Pres Limited by 3 Min	Hypo Peak Pres (psi)	Actual Peak Pres (psi)
Byron 1	85	600	450	700	450	unk	X		450	450
Callaway	86	20	450	680	450	400	X		450	463
Farley 1	86	40	none	700	450	400		X	850	450
Farley 2	86	180	none	700	450	400		X	2500	700

Energy Addition Events

Plant	Yr	Mass Flow Rate (gpm)	PORV LTOP SP (psi)	RHR ACI SP (psi)	RHR SRV SP (psi)	RCS Initial Pres (psi)	Peak Pres Limited by Alt Path	Peak Pres Limited by 3 Min	Hypo Peak Pres (psi)	Actual Peak Pres (psi)
Farley 1	86	min	none	700	450	400		X	550	450
Farley 2	83	min	none	700	450	400		X	600	480
Summer	86	min	none	700	450	400		X	550	450

Since assumptions regarding containment are important to the estimation of public risk, and because LTOP transients predominately occur in Mode 5 when containment integrity is relaxed to allow for testing, maintenance, and the repair of equipment, three estimates for public risk are used to study the effects of containment assumptions. The best estimate evaluation is based on a 50% probability weighting of a large release as a result of the containment's being open at the time of the core damage accident and a 50% probability weighting that the release is small, or similar to an SST2 release. The high estimate is based on the containment's being open at the time of the core damage accident. The low estimate is based on a 10% probability weighting of a large release as a result of the containment's being open and a 90% probability weighting of a small release. The base case consequences for the three containment assumptions are provided in Table 4.5.

The mean 50-mile radius population density around U.S. nuclear power plant sites is estimated to be 340 persons per square mile by the year 2000 (Ref. 15). The site-specific value ranges from about 40 to 3000 (Indian Point) with a median value of 185 persons per square mile. For the plants considered in this evaluation, the mean population density used to determine the consequences is estimated to be 280 persons per square mile (Refs. 14 and 16) based on 1982 population estimates. The projected mean population density for the plants considered is estimated to be 480 persons per square mile by the year 2000, or about 50% higher. Though not considered in this evaluation, if an adjustment to account for the projected population growth is desired, then the consequences (person-rem values) could be multiplied by 1.5 and the value/impact ratios ($ per averted person-rem) divided by 1.5 (or multiplied by 0.7). This assumes that the consequences would be directly related to the increased population.

As seen in Table 4.4, assumptions concerning containment integrity for fission product retention can result in an order of magnitude change in the estimated consequences of an unmitigated LTOP transient. This would suggest that additional or modified containment requirements for

Modes 4, 5, and 6 could achieve the risk reduction objective of GI-94. The NRC staff has not considered this as a proposed alternative for the resolution of GI-94. The LTOP protection concern is related to GDC 15 and GDC 31 to provide assurance that the probability of a rapidly propagating fracture of the reactor pressure vessel during anticipated operation occurrences is minimized.

Table 4.3 Base case mean core damage frequencies from LTOP events.

Plant Category	Challenge Frequency (per R-Y)	LTOP Unavailability	Overpressure Spectrum psi	Overpressure Spectrum Frac	Mean TWC Probability Over Life(1)	Mean Core Damage Freq (per R-Y)(2)
1. PORVs (40 plants)	0.094(3)	0.087(3)	2500	0.09	3.92×10^{-3}(4)	2.89×10^{-6}
			1400	0.09	1.96×10^{-4}	1.44×10^{-7}
			850	0.13	5.32×10^{-6}	5.[illegible]$\times 10^{-9}$
			600	0.69	2.06×10^{-7}	1.16×10^{-9}
					Total	3.04×10^{-6}
2. RHR SRVs (15 plants)	0.125(5)	0.143(5)	2500	0.14	1.50×10^{-3}	3.75×10^{-6}
			850	0.14	2.00×10^{-6}	5.01×10^{-9}
			600	0.72	2.21×10^{-7}	2.84×10^{-9}
					Total	3.76×10^{-6}
3. B&W (8 plants)	0.018(6)	0.087(6)	850	0.05	1.09×10^{-6}	negligible
			600	0.95	1.00×10^{-7}	negligible
					Total	negligible
					Industry Mean Core Damage Frequency(7)	3.24×10^{-6}

Notes:

(1) Mean through wall crack (TWC) probability for all plants in each category, averaged over remaining lifetime from 1986 through end-of-license. PORV plants: 969 total years, 24 years/plant. RHR SRV plants: 452 total years, 30 years/plant. B&W plants: 183 total years, 23 years/plant.

(2) Mean core damage frequency based on probability of reaching peak pressure and total for each category of plants. Based on assumption that through wall crack leads to core damage.

(3) Frequency: 23 events in 244 reactor years. Unavailability: Based on the two events at Turkey Point 4 in 1981, unavailability is two out of 23 demands.

(4) Read as 3.92 times 10 to the minus 3, or 0.00392.

(5) Frequency: 7 events in 56 reactor years. Unavailability: Based on the event at Farley 2 in 1983, unavailability is one out of seven demands.

(6) Frequency: Less than one event in 56 reactor years. Unavailability: Assume single PORV failure rate similar to PORV class of plants.

(7) $(40 \times 3.04 \times 10^{-6} + 15 \times 3.76 \times 10^{-6})/(40+15)$

Table 4.4 Consequences for various release categories.

	Generic Value (Person-Rem)	Scaled Value (Person-Rem)	SST1 Value (Person-Rem)	SST2 Value (Person-Rem)
40 PORV Plants	26,600	25,000	30,700	2,300
15 RHR SRV Plants	15,300	4,600	5,700	300
55 Total Plants	41,900	29,600	36,400	2,600

Notes:

Generic Value - based on Reference [illegible] LTOP transient.

Scaled Value - includes consideration of differences between units based on population density, environmental conditions, and operating power levels.

SST1 Value - based on SST1 release, similar to PWR-2 release fractions. Direct breach of containment.

SST2 Value - based on SST2 release, similar to PWR-5 release fractions. Containment fission product mitigation systems function, failure to isolate containment.

Table 4.5 Base case consequences for various containment assumptions.

	Best Estimate (50% Scaled Value plus 50% SST2 Value) (Person-Rem)	High Estimate (100% Scaled Value) (Person-Rem)	Low Estimate (10% Scaled Value plus 90% SST2 Value) (Person-Rem)
40 PORV Plants	13,600	25,000	4,570
15 RHR SRV Plants	2,400	4,600	730
55 Total Plants	16,000	29,600	5,300

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5. VALUE/IMPACT ANALYSIS

5.1 Costs and Benefits of Alternative Proposed Resolutions

5.1.1 Alternative 1 - No Action Alternative

This alternative assumes that no additional action is necessary, based on the evaluation of the current risk associated with low-temperature overpressure events and on the staff's review of the operating reactor experiences from 1980 through the end of 1986. It is also assumed that all applicable requirements and guidance approved to date have been implemented, but no implementation is assumed for related generic issues that are still currently unresolved.

In considering the risk associated with low-temperature overpressure events, the NRC staff has identified specific characteristics related to these events that differ from most core damage accidents. The concerns are related to the failure of the reactor pressure vessel itself, not the failure of emergency core cooling systems or decay heat removal systems. In addition, low-temperature overpressure events relate to shutdown modes of operation, Modes 4, 5, and 6, and the containment may be open during one of these events.

Low-temperature overpressure protection (LTOP) is a subset of the broader class of events related to reactor pressure vessel integrity, commonly referred to as pressurized thermal shock (PTS) events. However, the severe thermal stresses due to overcooling of the reactor pressure vessel are not present during LTOP events. When PTS was being evaluated by both the industry and the NRC staff in the early 1980s, the requirements of USI A-26 had just been imposed on the industry and consequently LTOP was not addressed in these studies. It was believed that the resolution of USI A-26 had adequately resolved LTOP concerns and these events were not considered in the probabilistic risk assessments performed (Ref. 6).

Reactor pressure vessel failure resulting from brittle fracture is generally defined as a through wall crack (TWC), resulting from the initiation and propagation of an assumed small flaw in the vessel. The probability of a TWC, or the vessel fracture probability (VFP), is calculated with the VISA computer program (Ref. 7) for an assumed transient. Crack, or flaw, initiation may not always result in a TWC. Depending on the vessel material characteristics and the assumed transient, some cracks that initiate may arrest in the tougher sections of the vessel (farther away from the inside of the vessel where the irradiation damage in attenuated). VISA accounts for this. For cracks that may propagate through the wall, some may not result in core damage. However, studies performed as part of the PTS effort indicate that a large fraction of TWCs could result in large openings in the reactor vessel for longitudinal welds, or complete opening of circumferential welds (Ref. 8).

The likelihood of a reactor pressure vessel through wall crack or the mean core damage frequency estimate, based on the operating reactor experiences, is 3.24×10^{-6} per reactor year over the remaining licensed life of the PWRs evaluated. As a plant approaches the PTS screening criteria, 10 CFR 50.61, the through wall crack probability will increase to 7.4×10^{-6} per reactor year, assuming the LTOP event frequencies, unavailability, and peak pressure spectrum profiles remain constant.

The PNL evaluation for the mean through wall crack frequency, or mean core damage frequency, is based on the operating reactor experiences and represents a best estimate evaluation of the risk from low-temperature overpressure transients. There are uncertainties in the estimated mean through wall crack frequency. These are addressed below.

Frequency of Events

The estimated frequency of low-temperature overpressure events was obtained from a review of actual operating plant events as reported to the Commission under requirements contained in the technical specifications. For this evaluation the events have been limited to actual transients that have challenged the low-temperature overpressure protection system and have occurred after the plant became operational, taken to be the date the unit first generated electrical power. Pre-commercial events and precursor events are not included. Pre-commercial events are excluded because they pose no risk (no fuel in the reactor or the vessel has not experienced any irradiation damage). Precursor events, events that could have challenged the low-temperature overpressure system but for other reasons did not, are also excluded because there is no assurance that the reported instances are representative of actual total experiences. Consideration of pre-commercial and precursor events would increase the estimated frequency of low-temperature events from 0.1 per reactor year (30 events in 300 reactor years) to 0.183 per reactor year (55 events in 300 reactor years) for the period from 1980 through the end of 1986. Though not considered in this evaluation, there were at least an additional six events in 1987, none of which would have changed the base case risk evaluation significantly (less than a 10% change).

Overpressure Protection System Unavailability

The overpressure protection system unavailability for the PORV group of plants (0.087 per demand) is based on the two events at Turkey Point in 1981. Of the 23 events in this group, overpressure protection was not available in these two instances. In both events one of the redundant low-temperature overpressure protection channels had been removed from service for maintenance. As a result of a single failure in the remaining channel, the system was not able to mitigate the pressure transient to the Appendix G pressure/temperature limits. Prompt operator action resulted in limiting the peak pressures to 1100 psi and 750 psi.

The overpressure protection system unavailability for the SRV group of plants (0.143 per demand) is based on the event at Farley 2 in 1983. Of the seven events in this group, overpressure protection was not available in this one instance. In this event one of the redundant low-temperature overpressure protection channels had been removed from service for maintenance. As a result of a single failure in the remaining channel, the system was not able to mitigate the pressure transient to the Appendix G pressure/temperature limits.

The actual failure was attributed to mechanical binding of the passive spring-loaded safety relief valve, which eventually opened at about 700 psi. While it may appear that the unavailability for this group of plants is high and based on an abnormal situation, it is noted that in 1973 a similar event occurred at Zion 1. The residual heat removal system safety relief valve failed to open during a charging/letdown imbalance transient and the pressure rose to 1300 psi after the autoisolation setpoint pressure of 600 psi was reached, resulting in isolation of the residual heat removal system (Ref. 17).

In addition, a potentially significant event occurred at Millstone 3 in January 1988. A combination of system interactions, plant personnel communication errors, and inadequate procedures results in both the PORVs and the residual heat removal system safety relief valves being unavailable to mitigate a maintenance-induced low-temperature event. Prompt operator action prevented the peak pressure from exceeding the Appendix G pressure/temperature limits. The licensee believed that LTOP protection was being provided by redundant PORVs. In reality, LTOP protection was being provided by redundant RHR SRVs up to the time when one was removed for maintenance. The remaining relief path was lost as a result of unrelated maintenance activities, which produced inadvertent closure of the RHR suction line isolation valves, resulting in a mass addition event--charging without letdown. Had the licensee recognized that LTOP protection was being provided by the RHR SRVs, the plant technical specification would have allowed removal of one valve for up to 7 days without further restrictions on plant operations and this event may not have changed. Although LTOP unavailability in RHR SRV plants could be approximately a factor of two higher than assumed in this evaluation (two out of eight versus one out of seven), the LTOP event frequency and peak pressure spectrum would not be changed significantly for the RHR SRV class of plants. The estimated base case mean through wall crack frequency for the RHR SRV class of plants would increase from 3.76×10^{-6} to 6.0×10^{-6} per reactor year. The mean frequency for all plants would increase from 3.24×10^{-6} to 3.85×10^{-6} per reactor year.

In all three cases, one of the two low-temperature overpressure protection channels had been removed from service for maintenance. Plant startup, allowed under the current technical specification, resulted in exceeding current Appendix G pressure/temperature limits as a result of a single failure in the overpressure protection system during anticipated low-temperature overpressure events.

Since the technical specification for all plants would allow for plant operations under similar circumstances, the low-temperature overpressure protection system unavailability based on the actual operating events is judged to be appropriate for evaluating the potential risk from low-temperature overpressure transients.

Vessel Failure Probabilities

The chemistry and fluence data used in this evaluation were obtained from plant-specific submittals in response to licensing activities related to USI A-49, "Pressurized Thermal Shock." The mean surface RT(ndt) shifts for the limiting vessel material were calculated over the plant lifetime using Reference 11, considered by both the staff and the industry to be representative of the state-of-the-art knowledge concerning irradiation-induced damage.

The characteristic transient used to determine the vessel failure probability, conditional on event occurrence, was developed based on the actual operating events. A vessel wall temperature of 120°F and a heatup rate of 25°F per hour were used. The 120°F wall temperature is representative of the average temperature at which low-temperature overpressure events have occurred. This temperature is also lower than that at which the reactor pressure vessel head may be removed at many plants and represents a reasonable limiting temperature for this evaluation. A 25°F per hour heatup rate appears to be a reasonable estimate based on heatup with decay heat and residual heat removal system pump energy prior to reactor coolant pump restart. A 50°F change in the assumed vessel wall temperature is estimated to result in a factor of two change in vessel failure probability (cooler--a factor of two larger, warmer--a factor of two less). The vessel failure probability is dominated by the pressure contribution. At a heatup rate of 50°F per hour, the failure probability is estimated to be about 10% higher, as a result of the increased thermal stress contribution.

The staff recognizes that there have been concerns with the flaw distribution (crack size and frequency) assumptions used in the VISA computer program, as identified during the rulemaking process for USI A-49, "Pressurized Thermal Shock." However, the use of VISA for this evaluation is appropriate for the quantification of risk due to brittle vessel failure in that the results are consistent and based on a previously developed methodology well known to both the NRC staff and the industry. Sensitivity studies point to uncertainties in the flaw size distributions as the major unknown factor in predicting the failure probability of reactor vessels (Ref. 7).

Sensitivity studies have been performed on the VISA models used to determine the reactor pressure vessel through wall crack (TWC) probability in conjunction with the pressurized thermal shock studies for USI A-49 (Refs. 18 and 19). The effects of material property uncertainties, such as the fracture toughness and crack arrest toughness, and uncertainties in the assumed distribution of the copper content in the vessel material tend to increase the TWC probability calculated from a factor of two to about an order of magnitude. On the other hand, the effects of the crack length-to-depth ratio assumption indicate a decrease in the TWC probability calculated. For the LTOP transient, in going from an infinite length crack (the base case) to a 6:1 length-to-depth crack, the TWC probability decreases by a factor of about three. The infinite crack length assumption is recommended for use because strong experimental data bases have not been established for justifying the use of a particular flaw length distribution (Ref. 19). The assumptions used are consistent with the recommendations of References 18 and 19.

The through wall crack probability obtained from VISA is used to obtain an estimate of the core damage frequency and to allow the NRC staff to estimate the relative importance of low-temperature overpressure transients. The impact attributes (cleanup and repair, replacement power costs, and offsite damage costs) are based on risk reduction estimates of the core damage frequency for proposed alternatives. In addition, the base case (or current) risk estimate can be used to estimate the potential costs of the no action alternative.

Containment Integrity

The consequence evaluation for low-temperature overpressure events is based on containment bypass or failure of containment to isolate following an event. Low-temperature overpressure protection is required for shutdown modes of operation. They occur most frequently in Mode 5, cold shutdown, with reactor coolant temperatures less than 200°F. A review of current standard technical specifications for containment integrity in shutdown modes (Modes 4, 5, and 6) indicates that no containment integrity requirements are imposed for reactor coolant temperatures less than 200°F, except during refueling when the pressure vessel head is removed.

It is therefore reasonable to assume that containment integrity and containment isolation are questionable. Containment has been treated parametrically in this evaluation and, for the assumptions used, the proposed resolution is shown to be cost beneficial and well within the value/impact ratio of $1,000 per person-rem averted.

The frequency of low-temperature overpressure events has remained relatively constant. Excluding precursor events and including pre-commercial events, the frequency of events prior to 1980 was about 0.15 per reactor year, and after 1980 (through the end of 1986), 0.12 per reactor year. In total, from 1969 through the end of 1986, there were 91 low-temperature-related events (precursor and pre- and post-commercial) occurring at 36 of the 55 plants evaluated in this study. It is therefore reasonable to assume that the event frequencies developed during this study are applicable to all Westinghouse and Combustion Engineering PWRs. Further, the actual events all fall within the design base for the low-temperature overpressure protection system--mass and energy input imbalances resulting from charging/letdown flow mismatches, inadvertent safety injection, and reactor coolant pump restarts.

From the above operating experience, the frequency of low-temperature overpressure events is expected to remain constant, at about 0.1 per reactor year. It is therefore appropriate for the NRC staff to consider that low-temperature overpressure events are anticipated transients and that the requirements of Appendix G in defining the acceptable pressure/temperature limits for operation are also appropriate.

The NRC staff does not recommend this alternative ("no action"). Low-temperature overpressure protection requirements have been imposed on PWR licensees to ensure that adequate protection against brittle reactor pressure vessel failure is provided, particularly for anticipated operational transients. To ensure that adequate margins are maintained, the Appendix G pressure/temperature limits are identified in the technical specifications to meet the requirements of General Design Criterion 31. While the overall probability of a through wall crack is estimated to be on the order of 3×10^{-6} per reactor year, the likelihood of exceeding the Appendix G pressure/temperature limits is once in each ten events as a result of LTOP system unavailability.

No costs are usually attributed to a "No Action" alternative because the future costs of accidents are conventionally counted as benefits or averted costs in the assessment of the alternative actions. However, a core damage accident resulting from a low-temperature overpressure transient is estimated to result in $1.2 billion in cleanup and repair costs. In addition, replacement power costs could occur during the cleanup and repair period. If the accident also results in a large release of radioactivity offsite, the costs of relocating people, restricting food and water, cleanup of contamination, and health consequences would add to these costs. Based on a 10-year period for the cleanup and repair of onsite damage, the present value of these averted costs for 67 plants is estimated to be about $5 million, based on a 5% continuous discount rate and a mean core damage frequency of 3.24×10^{-6} per reactor year. The present value of averted costs for offsite damage for 67 plants is estimated to be as high as $8 million for a large release, discounted at 5% over the remaining life of the plants included in this study. Thus, the convention of accounting for these averted costs in the assessment of other alternatives should not obscure the possible costs associated with the "No Action" alternative.

5.1.2 Alternative 2 - Change to Technical Specifications

The benefit from implementing a proposed change to the technical specification for overpressure protection would be a reduction in the frequency of core damage per reactor year due to a low-temperature overpressure event. The risk reduction is based on improvements in low-temperature overpressure protection system availability. In addition to implementation costs associated with this proposal, operational cost increases resulting from increased outage times are also considered.

The industry implementation costs would be primarily those incurred to revise the current overpressure protection technical specification and to modify the plant cooldown and heatup procedures to reflect the revised technical specification. The NRC costs would be primarily those associated with the review and approval of the revised technical specifications. These are discussed in the following paragraphs.

5.1.2.1 Risk Reduction Estimates

To estimate the change in the expected risk that the proposed resolution could effect, both the postulated radioactive exposure (in person-rem) that would result in the event of an accident and the reduction of the core damage frequency must be estimated.

Two groups of plants are used for this evaluation, as discussed previously. The grouping was based on the type of low-temperature overpressure protection system employed at the plant. Group 1 consists of those Westinghouse and Combustion Engineering plants that use PORVs for protection. Group 2 consists of those Westinghouse and Combustion Engineering plants that use safety relief values in the residual heat removal system for protection. Newer Westinghouse plants that allow either PORVs or RHR SRVs were placed in Group 2. The newer plants tend to have better reactor pressure vessel material properties and lower vessel failure probabilities due to the irradiation embrittlement. This grouping assumption will not have a significant impact on this evaluation.

The current technical specification for overpressure protection allows one of the two channels to be out of service for 7 days with no restrictions on plant operations. This allows the low-temperature overpressure protection system to be degraded to a single channel system. The technical specification excludes the low-temperature overpressure protection system from being considered as a system that performs a safety-related function. An operability check of a channel that reveals a failure before a mode change does not (need not) prohibit proceeding with less than the minimum number of channels in service (for LTOP, two channels are specified as the minimum).

The proposed alternative would ensure that both channels are operable, when providing protection against brittle reactor pressure vessel failure while operating in Mode 5. An inoperable channel needs to be returned to operable status as soon as possible, and the NRC staff believes that it is not appropriate to continue with actions to return to power operations with only one channel operable, as currently allowed by the overpressure protection technical specification.

The reduction in core damage frequency expected would be equivalent to the logical "and" of the estimated unavailability of the single channel system on which this evaluation is based. For the Group 1 (PORVs) plants the reduction is estimated to be from 0.087 to 0.087*0.087, or 0.0076. For the Group 2 (RHR SRVs) plants the reduction is estimated to be from 0.143 to 0.143*0.143, or 0.02. The mean through wall crack frequency, or core damage frequency, is reduced from 3.24×10^{-6} per reactor year to 3.47×10^{-7} per reactor year. The core damage frequency reduction is 2.89×10^{-6} per reactor year.

The actual benefit, in terms of LTOP protection availability, may be less than assumed if undetected common cause failures are considered. Common cause failures, such as leakage past PORVs or air/nitrogen system failures, which are detectable, require immediate action to depressurize and vent the reactor coolant system under the current technical specifications.

In the LER data base, there are 25 events that have been classified as both LTOP protection channels unavailable. Of these 25 events, 12 were related to PORV leakage or air/nitrogen problems. Of the remaining 13, four would be classified as common cause failures. In two cases, procedural error resulted in no LTOP protection for 14 and 36 hours. In one case, the PORV block valves were found to be closed for a period of about 5 hours. In the second case, a blank flange was installed in the vent line and found about 8 hours later. No low-temperature overpressure transients occurred during these periods of time.

There was one reported case where component failures were not detected by required surveillance--the Millstone 3 event in January 1988. Unrecognized system interaction between the solid state protection system and the overpressure mitigation system (OMS) was not detected, rendering both OMS channels inoperable for more than 2 months. The alternative relief paths via the RHR SRVs were available until January, when one path was removed for maintenance-related activities and the other relief path was lost as a result of unrelated activities, which inadvertently caused isolation of the RHR system. The loss of the letdown flow path with continued charging resulted in an LTOP transient that could not be mitigated by the LTOP protection system. Prompt operator action limited the peak pressure to a value below the Appendix G limits. For this evaluation it is assumed that the common cause failure existed for 1800 hours (more than 2 months), even though alternative relief paths were available during this period of time.

The average time plants spend in shutdown modes is about 30% per reactor year (110 days), including refueling outages (Ref. 20) with refueling outage times when the reactor is disassembled accounting for about 20 of the 110 days. It is assumed that LTOP protection is required 25% of a year per reactor year, about 2200 hours. In 340 reactor years (including accumulated experiences through 1987 to properly account for Millstone 3), undetected common cause failures resulted in LTOP protection unavailability for roughly 1800 hours during the 745,000 hours when LTOP protection is assumed to be needed. The probability of an undetected common cause failure resulting in LTOP protection unavailability is therefore estimated to be 0.0024 per demand, as compared to the 0.1 per demand (three failures in 30 total events) LTOP independent unavailability used for this evaluation.

The LTOP protection unavailability, including undetected common cause failures, is estimated to be about 20% higher than used in this evaluation. The assumed improvement in LTOP unavailability is from 0.1 to 0.01 per demand. If the common cause contribution is 0.0024 of the base case 0.1 per demand unavailability, then the resultant channel independent unavailability would be 0.0976 per demand (0.1 - 0.0024). The LTOP unavailability would then be 0.0024 for common cause failures plus 0.0976*0.0976 for independent failures, or 0.012 per demand.

The estimation of risk (in person-rem) is also dependent on assumptions concerning containment integrity at the time of an accident. Since low-temperature overpressure events occur most frequently in Mode 5 at reactor coolant system temperature less than 200°F, containment integrity is uncertain. No technical specifications for containment integrity exist below 200°F (except during refueling operations when the reactor pressure vessel head has been removed). Industry responses to NRC Generic Letter 87-12 (Ref. 21) indicate that containment integrity during Mode 5 is often relaxed to allow for testing and maintenance, and for repair of equipment (for example, containment penetrations, steam generators, and reactor coolant pumps). Three risk estimates are employed to address containment integrity.

The best estimate value assumes that there is a 50% probability of the containment's being open at the time of the accident. The open containment consequence is based on the scaled source term evaluation presented in Appendix B. For the other 50%, the containment consequence is based on the Siting Source Term evaluation for an SST2 release (Severe core damage. Containment fails to isolate. Fission product release mitigating systems, e.g., sprays and fan coolers, operate to reduce release--similar to WASH-1400 PWR-5 release).

The high estimate value assumes that the containment is open and the fission product release mitigating systems do not operate. The low estimate value assumes that there is a 10% probability of the containment's being open at the time of the accident. The source terms are the same as the best estimate case, but weighted 10/90 instead of 50/50.

In addition to public health consequences, there are also occupational health consequences associated with the accident. The short-term and long-term occupational exposures are taken from Section 3.3, "Occupational Health (Accidental)," of NUREG/CR-3568 (Ref. 22). The dose reduction estimate is based on an average reduction in core damage frequency of 2.89×10^{-6} per reactor year, based on the proposed resolution of GI-94 for 67 plants over an average remaining lifetime of 28 reactor years.

The dose reduction estimates for the three cases are provided in Table 5.1. The proposed resolution should not result in any additional operational exposure to plant personnel.

Table 5.1 Value/impact summary for the proposed resolution of GI-94 (for 67 plants).

	Dose Reduction (person-rem)			Costs ($1,000s)		
Parameter	Best Est.	High Est.	Low Est.	Best Est.	High Est.	Low Est.
Public Health	14,500	26,700	4,700			
Occupational Exposure (accidental)	180	240	60			
Occupational Exposure (routine)(1)	NA	NA	NA			
Industry Implementation(2)				1,290	2,570	640
Industry Operational(3)				80	400	80
NRC Implementation				950	1,840	500
Value/Impact Ratio(4) (Sum of industry and NRC implementation costs divided by the public dose reduction estimate - $/averted person-rem)				160	180	260

Notes:

(1) No significant routine exposure is anticipated as a result of the proposed resolution. Low-temperature overpressure protection channel surveillance involves electrical circuit check without containment entry.

(2) Costs associated with revisions to technical specifications and plant cooldown and heatup procedures.

(3) Present value of estimated replacement power costs resulting from delayed startup caused by proposed resolution. Applicable to PORV plants only (40 of 67 units), see text.

(4) This does not take into account the additional negative impacts associated with avoided plant damage costs or replacement power costs resulting from reduced frequency of core damage (see text, Section 5.1.2.5).

5.1.2.2 Industry Implementation Cost Estimates

The cost to the licensees to comply with the proposed requirements will vary depending on assumptions concerning the level of effort necessary to revise the technical specification for overpressure protection and to revise the plant cooldown and heatup procedures to reflect the change. In addition, there may be an extended outage resulting from the requirement to ensure both low-temperature overpressure protection channels operable prior to startup. The cost would be associated with additional replacement power. The replacement power costs would impact only plants using PORVs. The technical specification for PORV plants requires channel operability checks every 31 days. The proposed recommendation would require immediate action to replace a failed channel to operable status before proceeding with planned startup operations.

Since there are no additional surveillance requirements for the plants that rely on the residual heat removal system safety relief valves, because these are passive devices, no additional surveillance checks for operability are performed during shutdown. There will be no additional delay in startup time and therefore no replacement power costs for the RHR SRV plants.

Appendix C provides the bases for the industry costs associated with the proposed recommendation for the resolution of GI-94.

The industry implementation costs are provided in Table 5.1. The costs are based on the level of effort required to revise the technical specification and plant cooldown and heatup procedures. The best estimate costs are based on a level of effort associated with a simple change, $17,400 per plant for the technical specification changes and $1,900 per plant for revisions to the plant procedures. The high estimate is based on a level of effort associated with a complex change, $34,800 per plant for the technical specification changes and $4,800 per plant for revisions to the plant procedures. The low estimate assumes the level of effort is one-half of that associated with the simple change.

Industry operational costs are estimated based on the present value of additional replacement power resulting from delayed startup as a result of the proposed resolution for GI-94 (see Appendix C) and are applicable only to plants that use PORVs for low-temperature overpressure protection. Assuming a 4-hour delay in startup (estimated from Ref. 23) at $500,000 per day for replacement power, the estimated cost is $83,000. However, only a fraction of startups will be delayed.

It is assumed that there are four nonrefueling shutdowns per reactor year per plant (Ref. 24). In most cases the shutdown mode will be exited prior to the need for repeating the surveillance. It is assumed that 5% of the time (once every 5 years) surveillance is required prior to restart. Further assuming that the probability of fixing the channel actually delays the startup 5% (one out of twenty) of the time and that the channel unavailability is 0.087 per demand, the frequency of delayed startup is estimated as:

$$(4 \text{ shutdowns/year}) \times (0.05 \text{ delays}) \times (2 \text{ channels}) \times (0.087/\text{demand}) \times (0.05 \text{ repair delays}) = 1.74\times10^{-3} \text{ delays per reactor year.}$$

The average annual cost of a delayed startup, based on a 4-hour delay, is estimated to be (4 hr/24 hr) x $500,000/day x 1.74×10^{-3} per reactor year, or $145. At a discount rate of 5% the present value of the replacement power cost is $2,000 per PORV plant, over the average remaining lifetime of the PORV plants (24 years). At a 10% discount the present value is $1,400. If the need to return an inoperable channel to service occurs once per reactor year, then the cost of replacement power would be five times greater than assumed, or $10,000 per plant (at a 5% discount rate).

5.1.2.3 NRC Implementation Cost Estimates

The cost to the NRC to review and approve the revised technical specification will vary depending on assumptions concerning the level of effort necessary to perform the review.

Appendix D provides the bases for the NRC costs associated with the proposed recommendation for the resolution of GI-94.

The NRC implementation cost estimates are calculated using the same assumptions as applied to the industry implementation costs. For the simple technical specification change, the best estimate cost is estimated at $14,200 per plant, and for the complex change the high estimate cost is $27,400 per plant. The low estimate is based on halving the simple, or routine, cost estimate. The NRC implementation costs estimates are provided in Table 5.1.

5.1.2.4 Value/Impact Summary

The value/impact summary for the proposed resolution of Generic Issue 94, "Additional Low-temperature Overpressure Protection for Light-Water Reactors," is provided in Table 5.1. The proposed resolution would impact all Westinghouse and Combustion Engineering PWRs. Plants using either PORVs or the RHR SRVs can reduce the risk of brittle reactor pressure vessel failure and reduce the probability of exceeding Appendix G pressure/temperature limits by an order of magnitude by simply considering the safety-related role of these components, while operating at low-temperature, especially when water-solid. The likelihood of a low-temperature overpressure transient resulting in a peak pressure exceeding the Appendix G pressure/temperature limits would be reduced from one-in-ten to one-in-one hundred, the desired objective of GI-94. The likelihood of brittle reactor pressure vessel fracture (a through wall crack) is minimized.

The proposed resolution for Generic issue 94 reduces the mean core damage frequency to less than 1×10^{-6} per reactor year, from 3.24×10^{-6} to 3.5×10^{-7} per reactor year, meeting the target CDF objective stated in Section 2. For a plant that approaches the PTS screening criteria at the end-of-license (with a CDF of 7×10^{-6} per reactor year), the target CDF objective would also be met (with the CDF reduced to 7×10^{-7} per reactor year).

5.1.2.5 Averted Damage Costs

Including the costs of averted plant damage, replacement power, and offsite costs can significantly affect the overall cost-benefit evaluation. In addition, the present value associated with these factors can serve as a measure of the worth of a proposed alternative. If two or more proposed alternatives could achieve similar risk reduction, but with markedly different costs, then the present value estimates could be used to evaluate the relative worth of an alternative.

The estimated present value costs for avoided plant damage are summarized in Table 5.2. The cost for the cleanup and repair of a plant following reactor pressure vessel fracture and fission product release is estimated to be $1.2 billion (Refs. 22 and 25). The replacement power cost is based on the daily replacement cost typically used to estimate short-term power replacement costs. Should it become necessary for a utility to provide replacement power for a long period of time, for example, 10 years as assumed herein, it is probable that alternative methods would be considered that may lower the actual costs. The detailed evaluation is provided in Appendix E.

If cost saving to the industry from accident avoidance (cleanup and repair of onsite damage and replacement power) were to be considered, the overall value/impact ratios would be improved significantly. At a 5% discount rate, the present value of avoided damage would more than offset the $2.32 million best estimate implementation cost.

If the added savings to the industry from accident avoidance resulting in reduced offsite health and property costs were to be considered, a measure of the total worth of accident avoidance could be estimated. From Appendix E, the estimated present value costs for offsite effects are summarized in Table 5.3.

The total present value of avoided damage is dependent on the release category assumption (containment integrity at the time of the accident). Table 5.3 provides additional information that can be used to assist in evaluating the benefits associated with any proposed alternative for GI-94. To account for containment integrity assumptions, the SST1 and SST2 costs need to be properly weighted to develop the present value costs of avoided damage. It is noted that these cost estimates for offsite damage are probably conservative in that the fission product releases for a low-temperature overpressure event are lower than those associated with an SST1 release.

The total avoided damage costs (both onsite and offsite) for the 67 plants are estimated to be $8.3 million for the best estimate case, $11.6 million for the high estimate case, and $5.4 million for the low estimate case (assuming a 5% discount rate).

Table 5.2 Estimated present value costs for avoided onsite damage (for 67 plants).

	10% Discount Over 10 Years	5% Discount Over 10 Years
Cleanup and Repair	$1,200,000	$2,200,000
Replacement Power	$1,300,000	$2,400,000
Total	$2,500,000	$4,600,000

Table 5.3 Estimated present value costs for avoided offsite health and personal property damage (for 67 plants).

	Based on SST1 Costs Over Plant Life		Based on SST2 Costs Over Plant Life	
	10% Discount	5% Discount	10% Discount	5% Discount
Offsite Health	$ 640,000	$ 970,000	$ 23,000	$ 36,000
Offsite Property	$4,060,000	$6,180,000	$ 63,000	$ 86,000
Total	$4,700,000	$7,150,000	$ 86,000	$ 122,000

5.1.3 Alternative 3 - SI and RCP Restrictions

Like Alternative 2, Alternative 3 addresses risk reduction by evaluating changes to the technical specifications that are intended to lower the frequency of occurrence of low-temperature overpressure events. These revisions would apply to all 67 Westinghouse and Combustion Engineering plants. The technical specification changes here would provide for additional administrative controls on the systems and components involved in causing a pressure transient while operating at low temperatures, instead of increasing the availability of the mitigating system as proposed in Alternative 2.

The first change would be to require that all high-pressure safety injection (HPSI) pumps be locked out or have power removed when operating in a water-solid condition. However, this alternative would also remove the SI path as the normal means of supplying highly borated water for reactivity control. A review of the Westinghouse and Combustion Engineering standard technical specifications indicates that boration requirements can be met with power removed to the SI pumps. Two additional boration paths are identified for use in Modes 4 and 5. One contains the boric acid tank, boric acid transfer pumps, and a charging pump. The other contains the borated water storage tank and a charging pump.

In addition, this alternative would not allow the restart of a reactor coolant pump while in a water-solid condition to provide additional risk reduction. Although there are current restrictions in the standard technical specifications regarding restart of a reactor coolant pump, this alternative would be more stringent and a new technical specification would have to be developed for this requirement. Under the current technical specifications, reactor coolant pump restart is allowed in a water-solid condition provided the secondary side temperature is not hotter than the primary side by a specified value (as determined by analysis performed by each licensee).

5.1.3.1 Risk Reduction Estimates

The reduction in the mean core damage frequency associated with either an SI or an RCP technical specification change, as well as the estimated change if both were to be implemented, are provided in Table 5.4 as Alternatives 3(a), 3(b), and 3(a) & 3(b), respectively.

The risk reduction for the proposed recommendation to lock out all HPSI is estimated by evaluating the reduction in the frequency of LTOP events due to inadvertent safety injection and to determine the revised peak pressure spectrum without these events. This is a scoping assumption to maximize the risk reduction estimates. LTOP unavailability is assumed to be the same as for the base case. Three of the PORV class mass addition events would not have occurred, North Anna 1 in 1981 and in 1983, and San Onofre 1 in 1983 (see Table 4.1). The San Onofre 1 event would have eliminated one of the two 2500 psi cases in the PORV class of plants. SI lockout would have eliminated one of the RHR SRV mass addition events, the 450 psi event at Byron 1 in 1985 (see Table 4.2). The frequency of low-temperature overpressure events, based on the revised base case (the elimination of events), would be 0.082 (20 events in 244 reactor years) for PORV plants with the SI proposal and 0.107 (six events in 56 reactor years) for the RHR SRV plants.

The risk reduction for not allowing RCP restart is estimated in a similar manner. For the PORV class of plants, all six energy addition events would have been eliminated. In addition, the two Turkey Point 4 events in 1981 and one of the North Anna 1 (1984) mass addition events would have been eliminated (see Table 4.1). For the RHR SRV class, all three of the energy addition events would have been eliminated. The frequency of low-temperature overpressure events, based on the revised base case (the elimination of events), would be 0.057 (14 events in 244 reactor years) for PORV plants with the RCP proposal and 0.071 (four events in 56 reactor years) for the RHR SRV plants.

Overall, if both proposed actions were to be implemented, the frequency of low-temperature overpressure events is estimated to be reduced from 0.094 to 0.045 per reactor year for PORV plants and from 0.125 to 0.054 per reactor year for RHR SRV plants. The frequency of events would remain high enough to still consider LTOP events as anticipated operational transients, at least once in the plant lifetime.

The peak pressure spectrum would also change if these proposed actions were implemented, as shown in Table 5.5.

The LTOP unavailability will not change from the base case as a result of these proposed actions. The vessel fracture probability, at a given peak pressure, is a constant. The risk reduction estimate in through wall crack frequency for SI lockout is 1.07×10^{-6} per reactor year, from 3.24×10^{-6} to 2.17×10^{-6} per reactor year. The RCP restart proposal reduction is 2.12×10^{-7} per reactor year, from 3.24×10^{-6} to 3.03×10^{-6} per reactor year. The overall risk reduction in through wall crack frequency is estimated to be 1.20×10^{-6} per reactor year, from 3.24×10^{-6} to 2.04×10^{-6} per reactor year.

Table 5.4 Mean core damage frequency estimates for Alternative 3.

Alternative	Mean Core Damage Frequency (CDF) Before 1/RY	After 1/RY	CDF Reduction 1/RY	Ratio
3(a)	3.24×10^{-6}	2.17×10^{-6}	1.07×10^{-6}	1.49
3(b)	3.24×10^{-6}	3.03×10^{-6}	2.12×10^{-7}	1.07
3(a)&(b)	3.24×10^{-6}	2.04×10^{-6}	1.20×10^{-6}	1.59

Alternative Descriptions

3(a) - No SI when water-solid, technical specification change.

3(b) - No RCP restart when water-solid, technical specification change.

3(a)&(b) - Both SI and RCP requirements, technical specification changes.

Table 5.5 Peak pressure spectrum summary for Alternative 3.

Plant Group	Pressure (psi)	Base Case Fraction	SI Lock Out Fraction	RCP Restart Fraction	SI and RCP Fraction
PORV Plants	2500	0.09	0.05	0.14	0.09
	1400	0.09	0.10	0.	0.
	850	0.13	0.15	0.21	0.18
	600	0.69	0.70	0.65	0.73
RHR SRV Plants	2500	0.14	0.17	0.25	0.33
	850	0.14	0.17	0.25	0.33
	600	0.72	0.66	0.50	0.34

5.1.3.2 Industry Implementation Cost Estimates

The industry implementation cost estimates, with high and low values, are provided in Table 5.6. The best estimate costs for the SI technical specification change and plant procedure revisions are based on the complex change cost estimates, $34,800 and $7,500 per plant, respectively. In addition, training costs are expected for the new SI requirement to ensure that boration requirements will be met. The training cost is estimated to be $11,800 per plant, for a total cost of $54,100 per plant. The high estimate cost is based on doubling the cost to account for the additional costs associated with meeting boration requirements, $108,200 per plant. The low estimate cost is based on the simple, or routine, change cost estimates, without the need for additional training. The costs are $17,400 and $1,900, or $19,300 total per plant.

The best estimate costs for the RCP restart technical specification change and plant procedure revisions are based on the routine change cost estimates, $17,400 and $1,900 per plant, respectively, for a total cost of $19,300 per plant. The high estimate costs are based on the complex costs estimates of $34,800 and $4,800, for a total cost of $39,600 per plant. The low estimate costs are based on halving the simple, or routine, change cost estimates. The costs are $8,700 and $900, or $9,600 total per plant.

The industry implementation cost for both actions is a straight forward addition of the individual costs. The best estimate cost is therefore $73,400 per plant. The high estimate and low estimate costs are $148,000 and $28,900 per plant, respectively.

Table 5.6 Implementation cost estimates for Alternative 3.

Alternative Cost Item	Plants Affected	Unit Costs: Best Est. ($)	Unit Costs: High Est. ($)	Unit Costs: Low Est. ($)	Total Costs: Best Est. ($1,000s)	Total Costs: High Est. ($1,000s)	Total Costs: Low Est. ($1,000s)
3(a)							
Industry							
Tech Spec	All	34,800	69,800	17,400			
Procedures	All	7,500	15,000	1,900			
Training	All	11,800	23,600	0			
Total					3,630	7,250	1,290
NRC							
Tech Spec	All	27,400	54,800	14,200	1,840	3,670	950
Total					5,470	10,920	2,240
3(b)							
Industry							
Tech Spec	All	17,400	34,800	8,700			
Procedures	All	1,900	4,800	900			
Total					1,290	2,650	650
NRC							
Tech Spec	All	14,200	27,400	7,100	950	1,840	
Total					2,240	4,490	1,130
3(a)&(b)							
Industry Total	All	73,400	148,000	28,900	4,920	9,910	1,940
NRC Total	All	41,600	82,200	21,300	2,790	5,510	1,430
Total	All	115,000	230,200	50,200	7,710	15,420	3,370

Alternative descriptions - See footnote to Table 5.4.
Plants affected: All - Applicable to 67 units. PORVs - Applicable to 40 units. RHR SRVs - Applicable to 27 units.

5.1.3.3 NRC Implementation Cost Estimates

The NRC implementation costs are based on the same assumptions regarding whether the change to the technical specifications are judged to be complex or routine and are provided in Table 5.6. Assumptions used to estimate the high and low cost estimates are consistent with those used to estimate the industry implementation costs. For the SI change the NRC best estimate implementation is based on a complex change, $27,400 per plant. The high and low estimates are $54,800 (double the complex cost) and $14,200 (routine change) per plant, respectively.

The NRC best estimate implementation cost for the RCP restart technical specification change is $14,200 (routine) per plant. The high estimate is based on the complex cost estimate, $27,400 per plant. The low estimate is based on halving the routine cost, or $7,100 per plant.

The NRC implementation cost for both actions is a straightforward addition of the individual costs. The best estimate cost is therefore $41,600 per plant. The high estimate and low estimate costs are $82,200 and $21,300 per plant, respectively.

5.1.3.4 Value/Impact Summary

The value/impact summary for Alternative 3 is provided in Table 5.7, for each of the three containment assumptions, based on the overall risk reduction and costs for both actions.

Alternative 3 is not recommended because of the lower estimated risk reduction and the high costs associated with these changes when compared to the proposed resolution, Alternative 2. This alternative does not improve the LTOP system availability, nor does it appear to reduce the overall event frequency to a value that could be considered low enough to exclude these transients from consideration as anticipated operational transients.

Table 5.7 Value/impact summary for Alternative 3 (for 67 plants).

	TWC Reduction /R-year	Industry + NRC Cost	Person-Rem Averted	Value/Impact Ratio ($/Person-Rem)
Best Estimate	1.20×10^{-6}	$ 7.71 million	8,400	920
High Estimate	1.20×10^{-6}	$15.42 million	15,600	990
Low Estimate	1.20×10^{-6}	$ 3.37 million	2,800	1,200

5.1.4 Alternative 4 - Removal of RHR Autoclosure Interlock

This alternative explored risk reduction from low-temperature overpressure events if the autoclosure interlock (ACI) on the residual heat removal suction line isolation valves is removed. It is expected that the frequency of low-temperature overpressure events will be reduced if the ACI is removed because spurious closure of the suction line isolation valves resulting in a loss of letdown will not occur. The base case risk analysis credits limiting the peak pressure of a low-temperature overpressure event to the residual heat removal system safety relief valve setpoint if the residual heat removal system were functional and the ACI setpoint is above the safety relief valve setpoint.

An informal survey conducted by PNL of plants evaluated in this study found that 17 out of 26 plants surveyed would not be affected (the RHR SRV setpoint is actually below the ACI setpoint). About 14 plants (out of the 40 PORV plants) would actually benefit from this alternative. Plants that rely on the residual heat removal system safety relief valves do not benefit from this alternative because the ACI feature is not permitted in the design. To maintain a common basis for evaluating alternatives, the NRC staff assumes that this alternative will be beneficial to the PORV plant group, and the value/impact evaluation is based on these 40 PORV plants, both in overall risk reduction and in implementation costs.

While inadvertent isolation of the RHR can result in a low-temperature overpressure event, the operating reactor experiences from 1980 through 1986 do not indicate that spurious ACI is a significant contributor to LTOP risk. There were no LTOP transients (events during shutdown operations that challenged the LTOP systems) directly related to spurious ACI of the RHR suction line valves. Prior to the implementation of USI A-26 requirements, about half of the low-temperature overpressure transients occurred with the RHR isolated. A large fraction of these were attributed to ACI actuation. The NRC staff believes that the requirements of USI A-26 and the awareness of LTOP concerns, combined with the slow closing time of the RHR suction line isolation valves (on the order of 2 minutes), have provided sufficient guidance and time to plant operators to mitigate these events before they challenge the PORVs.

The risk reduction is therefore assumed to be related to the greater availability of the RHR SRVs in the PORV plant group to limit the peak pressure of a low-temperature overpressure event if the PORVs fail to mitigate the transient.

5.1.4.1 Risk Reduction Estimates

This alternative would not reduce either the LTOP event frequency or the unavailability of the PORV to mitigate low-temperature overpressure transients. Risk reduction would be obtained by reducing the frequency of achieving high pressure from the base case value to 600 psi, the typical RHR SRV setpoint pressure.

For the PORV class of plant, if the ACI feature had been removed, three of the 23 operating reactor events would have resulted in lower peak pressures. The Ginna SI event (1983) and the two Turkey Point 4 events (1981) would have been limited to 600 psi, the SRV setpoint. In the base case, 15 events were already assumed to be limited to the RHR SRV setpoint, three occurred when the RHR was already isolated, one involved inadequate capacity to relieve the mass flow rate, and one was a result of an electrical upset as opposed to an ACI actuation. The peak pressure spectrum that would result from this alternative is shown in Table 5.8.

The reduction in the through wall crack frequency for the PORV plants is estimated to be 1.60×10^{-7} per reactor year, from the base case value of 3.04×10^{-6} per reactor year to 2.88×10^{-6} per reactor year. This alternative does not result in a significant reduction because the probability of high pressure events, combined with RHR isolation not related to ACI, is unchanged.

In addition to the actual removal of the ACI, there are additional costs related to technical specification changes and revised plant procedures. The best estimate values are based on a routine change, $17,400 for the technical specification change and $1,900 for changes to plant operating and maintenance procedures, for a total of $19,300 per plant. The high cost estimate assumes that the technical specification change is complex, $34,800 per plant, and that the cost to revise procedures remains the same, for a total cost of $36,700 per plant. The low cost estimate is based on halving the routine cost estimate, $8,700 per plant.

In addition to the costs associated with implementation of this alternative, there may be additional costs to both the industry and the NRC that would reduce the overall benefit. Additional costs would include plant-specific studies to demonstrate that overall plant safety would not be adversely impacted, and any additional features to protect against the inadvertent overpressurization of the residual heat removal system (an interfacing loss-of-coolant accident, Event V).

5.1.4.2 Industry Implementation Cost Estimates

The industry implementation cost estimates, with high and low values, are provided in Table 5.9. Recently completed work on Generic Issue 99 indicates that the cost for removal of the autoclosure interlock feature, including the costs for a plant-specific analysis, cable disconnecting, interlock logic reprogramming, and radiation exposure, ranges from $100,000 to $150,000 per plant (Ref. 26). These values are used for this evaluation.

5.1.4.3 NRC Implementation Costs Estimates

The NRC implementation cost estimates are provided in Table 5.9. Based on recently completed work on Generic Issue 99, the NRC cost associated with the review of the ACI removal is $2,000 per plant. The technical specification change cost is based on a routine change, $14,200 per plant. The high estimate is based on a complex change cost, $27,400 per plant, and the low estimate is one-half of the routine cost, $7,100 per plant.

Table 5.8 Peak pressure spectrum summary for Alternative 4.

Plant Group	Pressure (psi)	Base Case Fraction	ACI Removal Fraction
PORV Plants	2500	0.09	0.09
	1400	0.09	0.0
	850	0.13	0.09
	600	0.69	0.82
RHR SRV Plants	Not affected by Alternative 4		

Table 5.9 Implementation cost estimates for Alternative 4 (for 40 PORV plants).

		Unit Costs			Total Costs		
Cost Item	Plants Affected	Best Est. ($)	High Est. ($)	Low Est. ($)	Best Est. ($1,000s)	High Est. ($1,000s)	Low Est. ($1,000s)
Industry							
ACI removal	PORVs	100,000	150,000	100,000			
Total					4,000	6,000	4,000
Tech Spec	PORVs	17,400	34,800	8,700			
Procedures	PORVs	950	950	450			
Main. Proc	PORVs	950	950	450			
Total					770	1,470	380
NRC							
ACI removal	PORVs	2,000	2,000	2,000			
Total	PORVs				80	80	80
Tech Spec	PORVs	14,200	27,400	7,100			
Total					570	1,100	280
Total Without ACI Removal Costs					1,340	2,570	660
Total With ACI Removal Costs					5,420	8,550	4,740

5.1.4.4 Value/Impact Summary

The value/impact summary for Alternative 4 is provided in Table 5.10, for each of the three containment assumptions, based on the overall risk reduction. Two cost studies are provided. In the first case, the costs are based on technical specification and plant procedure changes only. This would be equivalent to increasing the current ACI setpoint to a value higher than the RHR SRV setpoint for additional LTOP protection (provided of course *that* the SRV could be shown to be adequately sized to prevent overpressurization of the RHR). In the second case, the costs include the actual removal of the ACI, assuming no additional benefit for non-LTOP-related reduction in person-rem.

While a reduction in risk can be achieved for this alternative for low-temperature overpressure concerns, it is not known if the SRV setpoint can be modified to ensure that the requirements of Appendix G, the pressure/temperature limits, are met over plant life, while providing margins to ensure that the net pump suction head of the residual heat removal pumps is maintained following cycling of the SRVs. In addition, a plant-specific analysis would be required to ensure that the overall plant safety would not be adversely impacted.

The risk reduction estimate for this alternative is small, because the base case evaluation already credits the RHR SRVs in limiting the peak pressure if the PORVs fail to mitigate an LTOP transient. The resultant value/impact ratios are high, in excess of the $1,000 per averted person-rem guideline.

Alternative 4 is not recommended as a requirement to resolve GI-94, although in conjunction with GI-99, "RCS/RHR Suction Line Interlocks in PWRs," the removal of the autoclosure interlock appears to be beneficial. The low-temperature overpressure event frequency can be reduced (resulting from spurious closure of the RHR suction line isolation valve and loss of letdown). The NRC staff believes that, although ACI removal is beneficial to GI-94 concerns, a determination that overall plant safety is not adversely impacted by its removal would have to be further addressed.

Table 5.10 Value/impact summary for Alternative 4 (for 40 PORV plants).

	TWC Reduction /R-year	Industry + NRC Cost	Person-Rem Averted	Value/Impact Ratio ($/Person-Rem)
Without ACI Removal Costs				
Best Estimate	1.60×10^{-7}	$ 1.34 million	700	1,900
High Estimate	1.60×10^{-7}	$ 2.57 million	1,300	2,000
Low Estimate	1.60×10^{-7}	$ 0.66 million	250	2,600
With ACI Removal Costs				
Best Estimate	1.60×10^{-7}	$ 5.42 million	700	7,750
High Estimate	1.60×10^{-7}	$ 8.65 million	1,300	6,650
Low Estimate	1.60×10^{-7}	$ 4.74 million	250	19,000

5.1.5 Alternative 5 - Safety-Grade LTOP System

Alternative 5 evaluated risk reduction based on requiring the low-pressure overpressure protection systems to be upgraded to a fully safety-grade system. The following changes were identified:

1. Upgrade components to meet applicable environmental qualification design criteria required for safety-related equipment. (Regulatory Guide 1.26, "Quality Group Classification and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants.")

2. Upgrade actuation circuitry to meet redundancy and electrical separation criteria by NRC regulations and IEEE standards. This does not apply to the passive, spring-loaded RHR SRVs. (IEEE Standard 279, endorsed by Regulatory Guide 1.153, "Criteria for Power, Instrumentation, and Control Portions of Safety Systems.")

3. Upgrade maintenance and surveillance testing activities on valves and actuation circuitry such that documentation, schedules, and testing methods satisfy the requirements set forth for safety-grade equipment. (ASME Boiler and Pressure Vessel Code, Section XI, subsection IWV, "Inservice Testing of Valves in Nuclear Power Plants.")

To gain insight into the potential improvement in low-temperature overpressure protection system availability gained by this alternative, a comparative evaluation was performed by PNL using the Sequoyah system as a model for a fully safety-grade system (Sequoyah 1 and 2 are operating plants with a fully safety-grade system installed). In addition, informal interviews with vendor personnel and NRC inspectors were performed by PNL and used to gain additional insights for this alternative. Industry studies (Ref. 27) and NRC studies (Ref. 28) were also reviewed.

It was concluded by PNL that upgrading the low-temperature overpressure protection system to safety-grade status is not expected to result in significant changes to the PORV or RHR SRV hardware design or functioning. Environmentally qualified valves are expected to be identical to existing valves. Little additional credit can be given for upgrades in actuation circuitry that provide improved redundancy and electrical separation. The potential benefit associated with this alternative would be achieved through better surveillance requirements.

5.1.5.1 Risk Reduction Estimates

As previously stated, from a risk standpoint, the low-temperature overpressure protection system can be considered to be a one-channel system since the technical specification allows one channel out of service continuously for 7 days at a time. This time is long compared to that required to heat up the plant and exit the low-temperature overpressure protection operating mode. Surveillance and system startup activities during heatup make this the most likely time for an upset to challenge the low-temperature overpressure protection system. All three of the actual overpressurization events, where the peak pressure exceeded the Appendix G limit, in the data base resulted from a single channel failure when the other, redundant channel was removed from service for maintenance during startup.

The Millstone 3 event of January 19, 1988, peripherally supports the conclusion that safety-grade low-temperature overpressure protection circuitry may provide minimal reduction in unavailability. The NRC Special Inspection Report 50-423/88-03 addressing this event states: "The COPS (Cold Overpressure Protection System, the Millstone 3 OMS) is safety grade with redundant power supplies, actuation channels and equipment trains." Nevertheless, both channels were disabled more than 2 months before the event when the solid state protection system was tagged out, and this common mode failure was not detected until the event was analyzed. In this case, what was thought to be redundant and separate not only failed to prevent single channel failure but failed to prevent simultaneous failure of both channels caused by unrecognized system interactions.

A study performed by Oak Ridge National Laboratory (Ref. 28) stated that "an assessment of the need to upgrade PORVs and BVs (block valves) to safety-related status concludes that such action would slightly improve PORV and BV reliability." A study performed by EPRI (Ref. 27) provided the results of a reliability assessment, based on fault tree analysis and operating reactor failure rate data. No credit was taken for PORV reliability improvement that might result from qualification of the PORVs. This also indicated that little improvement in availability would be expected from an upgrade to safety grade.

Based on discussions with vendor and industry personnel and based on available literature concerning PORVs, the reduction in PORV unavailability due to hardware and circuitry upgrades is estimated by PNL to be less than 20%.

Upgrading the system to safety grade may lead to improved maintenance and surveillance attention for the PORV-based group of plants. The unavailability of the PORV as a function of the surveillance test interval, failure rate, test duration, and mean time to repair is given as:

$$Q = L \times T/2 + L \times T(r) + T(t)/T$$

where:
- Q is the PORV unavailability
- L is the failure rate, failures/hour
- T is the test interval, hours
- T(r) is the mean repair time, hours
- T(t) is the test interval, hours.

The present test interval is 31 days, or 774 hours. The mean repair time is estimated at 8 hours, and the test interval is assumed to be 2 hours. A review of LER data between 1980 and 1986 identified 25 instances (at 12 plants) in 187 reactor years when both PORVs were declared inoperable for low-temperature overpressure protection. If it is assumed that low-temperature overpressure protection is required 10% of the time (one-third of the 30% per reactor year spent in shutdown modes), then the estimated failure rate, L, would be:

$$L = 25 \text{ failures} / 187 \text{ reactor year} / 867 \text{ hours per year, or}$$

$$L = 1.52 \times 10^{-4} \text{ failures per hour.}$$

The expected unavailability is therefore 0.063, which appears to be in good agreement with the 0.087 value used in this evaluation, as derived from the LER LTOP data base.

In addition to the 25 times both channels were declared inoperable, there were an additional 18 reports when one channel was declared inoperable, excluding the SRV plants. For the accumulated 244 reactor years of PORV experience, the resultant failure rate would be 2.0×10^{-4} failures per hour, for an unavailability of 0.079.

The optimum test interval may be obtained from the unavailability equation for Q and is found to be 7 days. The corresponding unavailability would be reduced to 0.025, if the test interval was reduced from 31 to 7 days. However, other factors could affect this improvement, such as additional maintenance errors or errors introduced during testing.

PNL concluded that a reduction in the PORV LTOP unavailability may be obtained by more frequent surveillance. A more thorough analysis would be required to substantiate such an improvement, roughly a 60% reduction in unavailability (from 0.063 to 0.025) based on this study.

The hardware and surveillance improvements cannot simply be added. The hardware upgrades would reduce the failure rate. If it is assumed that the failure rate is reduced by 20%, from 1.52×10^{-4} failure per hour to 1.22×10^{-4} failure per hour, to account for improved hardware, then the resulting unavailability would be 0.023, as compared to 0.025.

This alternative would not reduce the frequency of LTOP events or result in any changes to the base case peak pressure spectrum. The peak pressure spectrum is calculated assuming failure of the LTOP system. The LTOP system unavailability would be reduced from the base case value of 0.087 to 0.035, a 60% reduction. The mean core damage frequency estimates are provided in Table 5.11. Since there are uncertainties associated with the estimated reduction in PORV unavailability resulting from a requirement to upgrade to a safety-grade system, a sensitivity evaluation is provided, as Case 5(a), where the reduction in unavailability is estimated to be from 0.087 (the single channel unavailability) to 0.035*0.035 to account for both channels being available. If the PNL estimate is considered to be a measure of improved PORV availability based on the single channel assumption, then Case 5(a) could also be considered as adding the requirements of Alternative 2 to this alternative. In either case, the risk reduction for Case 5(a) is nearly 100% of the base case PORV contribution.

Table 5.11 Mean core damage frequency estimates for Alternative 5 (PORV plants only).

Alternative	Mean Core Damage Frequency (CDF) Before 1/RY	After 1/RY	CDF Reduction 1/RY	Ratio
5	$3.04x10^{-6}$	$1.22x10^{-6}$	$1.82x10^{-6}$	2.5
5(a)	$3.04x10^{-6}$	$4.27x10^{-8}$	$3.00x10^{-6}$	71.2

5.1.5.2 Industry Implementation Cost Estimates

The cost for upgrading the low-temperature overpressure protection system to a fully safety-grade system includes one time costs for technical specification revisions, procedure revision, environmental qualification, PORV actuation design, hardware replacement, valve installation, PORV actuation circuitry installation (two per PORV), additional ASME testing (ANSI/ASME), recurring analog channel tests, and potential replacement power costs.

For this alternative it is assumed that there is no benefit to upgrading the RHR SRV plants to safety grade. The NRC staff believes that, since the RHR system is designed to ASME Section III, Class 2, Seismic Category I requirements, no improvements in LTOP unavailability would be achieved. However, if it was found that on a plant-specific basis this alternative would result in an improvement, or if it was found to be necessary to replace the RHR SRV, there would be costs associated with this alternative. These costs are identified but not applied to the this value/impact evaluation for PORV plants only.

Using the guidelines of NUREG/CR-4627 (Ref. 29), supplemented by PNL discussions with licensees and vendors, the industry implementation costs per unit are estimated in Table 5.12.

As a result of increased surveillance requirements, it is possible that delays in restart could occur for the PORV plants resulting in additional replacement power costs. In most cases restart will occur before repeating the surveillance test. Four forced shutdowns per reactor year are assumed. It is also assumed that delays would occur 20% of the time (four times over a 5-year period), and that 20% of the time the delays would actually result in a longer shutdown time; that is, returning a channel to operability is the only action that needs to be completed prior to restart. The failure rate of a channel is assumed to be 0.087, the same unavailability as the base case. Assuming the average delay is 4 hours, at a cost of $500,000 per day, then the annual average cost for replacement power is calculated as:

(4 shutdowns/yr) * (0.20 delays) *
(4 channels) * (0.087 failure/demand) *
(0.20 repair delays) * (4 hr/24 hr) *
($500,000/day)

= $4,600 per plant per reactor year.

The present value of the replacement power, over the average 24-year remaining lifetime of the PORV plants, is estimated to be $60,000 per plant at a 5% discount, or $42,000 per plant at a 10% discount. The best estimate cost to upgrade the PORVs to safety grade is $387,000 per plant, or $16 million for the 40 PORV plants. The high cost and low cost estimates are obtained by doubling and halving the best estimate cost, respectively, for values of $32 million and $8 million. With respect to the upper bound, as the necessary labor effort increases, consideration must be given to the impact of radiation exposure (stay time) on resultant labor costs. Stay time has been estimated to impact labor cost by a factor of three for the moderate radiation zones involved in this alternative. This is a result of delays associated with dressing out, ALARA factors, interfacing with health physics, etc. The best estimate cost did not involve stay time because the hours, and hence the exposure, were judged by PNL to be amenable to normal shift work practices. If the stay time becomes an important factor in completing the work, labor cost would increase by a factor of six instead of merely doubling.

In addition to the financial costs associated with the safety-grade upgrade, there are also additional occupational exposures that would arise as a result of installation and new test requirements. The dose estimates are based on NUREG/CR-4627 Abstract 4.1, "Typical System-Average Dose Rates." The per plant occupational dose is summarized in Table 5.13. The RHR SRV values are provided for reference only, the value/impact evaluation for this alternative addresses the PORV plants only.

The total occupational exposure for the 40 PORV plants is estimated to be 900 person-rems for the installation of the safety-grade equipment and additional testing that would be required for this alternative.

Table 5.12 Best estimate unit cost to upgrade OMS to be safety-grade.

	Per Plant Costs $/Plant, 1988	
Item	PORV	RHR SRV
Technical Specification Revision Routine, NUREG/CR-4627, 2.2.1, 6.4	17,400	17,400
Maintenance Procedure Revision Routine, NUREG/CR-4627, 2.2.2, 6.4	900	900
Equipment Environmental Qualification	140,000	90,000
PORV Analog Circuit Design	15,000	n/a
Valve Hardware Package	60,000	20,000
Valve Installation NUREG/CR-4627, 6.1,2.1.5,2.1.6,2.1.7,6.4,6.5	5,400	4,700
Analog Circuit Installation, PORV only cost of installing two circuits NUREG/CR-4627, 6.1,2.1.5,2.1.6,2.1.7,6.4,6.5	98,000	n/a
Additional ASME Valve Test, cost per test Tests commence 5 years after installation NUREG/CR-4627, 6.1,2.1.5,2.1.6,2.1.7,6.4,6.5	1,600	1,500
Additional Analog Circuit Tests, PORV only, cost per year NUREG/CR-4627, 6.3 and 6.4	3,200	n/a
Replacement power cost 5% discount, PORV only	60,000	n/a
Total per Unit Cost	401,500	133,000

Note: The RHR SRV costs are provided for reference only. The value/impact evaluation for this alternative is based on risk reduction and costs for the PORV plants only.

5.1.5.3 NRC Implementation Cost Estimates

The best estimate NRC implementation cost is based on the review and approval of a routine technical specification change, $14,200 per plant. The high estimate is based on a complex change, $27,400 per plant, and the low estimate is obtained by halving the routine cost, $7,100 per plant. The industry and NRC implementation costs are summarized in Table 5.14.

5.1.5.4 Value/Impact Summary

The value/impact summary for Alternative 5 is provided in Table 5.15, for each of the three containment assumptions, based on the overall risk reduction. Two cost benefit results are provided. In the first case, the risk reduction and the costs are based on LTOP upgrade to safety grade. In the second case, the risk reduction can be considered to include Alternative 2, the change to the overpressure protection system technical specification to ensure that both channels are operable when water-solid.

Because of the high costs associated with this alternative and because the decrease in risk is predominately a result of considerations under Alternative 2, the NRC staff does not recommend this alternative. Even if the risk reduction were 100%, the value/impact evaluation exceeds the $1,000 per averted person-rem guideline.

Table 5.13 Per plant occupational dose for safety-grade OMS upgrade.

	Per Plant Occupational Dose (person-rem per plant)	
Action Item	PORV	RHR SRV
Valve Installation, two valves	4.2	2.4
Analog Channel Installation, PORV only, two channels	13.3	n/a
ANSI/ASME Valve Tests, 3 tests over plant life, 2 valves per plant	4.8	3.3
Total per plant	22.3	5.7

Table 5.14 Implementation cost estimates for Alternative 5 (for 40 PORV plants).

		Unit Costs			Total Costs		
Cost Item	Plants Affected	Best Est. ($)	High Est. ($)	Low Est. ($)	Best Est. ($1,000s)	High Est. ($1,000s)	Low Est. ($1,000s)
Industry							
Total	PORVs	401,500	803,000	200,800			
Total	RHR SRVS	133,000	265,000	66,000(Note)			
Total	PORVs				16,000	32,000	8,000
NRC Tech Spec	PORVs	14,200	27,400	7,100	570	1,100	280
Total					16,570	33,100	8,280

Note:

Alternative 5 is assumed to be applicable to PORV plants only. In general, the RHR SRVs are ASME Section III, Class 2, Seismic Category I valves. Benefits from safety-grade considerations are expected to be minimal. However, should it be found that a plant-specific upgrade would be beneficial, then the unit cost summary provided for the RHR SRV plants can be used to estimate that cost of implementation to the industry. The NRC unit cost will be the same for any RHR SRV plant.

Table 5.15 Value/impact summary for Alternative 5 (for 40 PORV plants).

	TWC Reduction /R-year	Industry + NRC Cost	Person-Rem Averted	Value/Impact Ratio ($/Person-Rem)
OMS Upgrade to Safety Grade				
Best Estimate	1.82×10^{-6}	$16.57 million	8,200	2,000
High Estimate	1.82×10^{-6}	$33.10 million	15,000	2,200
Low Estimate	1.82×10^{-6}	$ 8.28 million	2,700	3,100
OMS Upgrade Sensitivity				
Best Estimate	3.00×10^{-6}	$16.57 million	13,400	1,200
High Estimate	3.00×10^{-6}	$33.10 million	24,600	1,350
Low Estimate	3.00×10^{-6}	$ 8.28 million	4,500	1,850

5.1.6 Alternative 6 - Pressurizer Bubble

This alternative explored risk reduction from low-temperature overpressure events by evaluating a steam or nitrogen bubble in the pressurizer (e.g., no water-solid operations in Westinghouse and Combustion Engineering plants). The risk reduction is achieved by providing more time for the operator to respond to a low-temperature overpressure event. Based on the historical operator performance discussed previously, the best estimate for operator action is assumed to be 3 minutes to recognize and mitigate an event. With a sufficiently sized bubble, the peak theoretical pressure would be limited to 600 psi. If 10 minutes is assumed, then the peak pressure could reach the primary system safety relief valve setpoint value of 2500 psi with the same frequency, about 10% of the time, as the base case analysis previously described. Even with a pressurizer bubble, the mass addition events that can occur at Westinghouse and Combustion Engineering plants (inadvertent SI and charging without letdown) are sufficient to result in 2500 psi assuming the LTOP system fails to mitigate the transient and the operator fails to respond in 3 minutes.

Under this alternative it is assumed that the current low-temperature overpressure protection system would not be modified. Redundant channels are still assumed. The frequency of events and consideration of the inadvertent high-pressure safety injection and charging transients indicate that operator actions cannot be relied on to mitigate the low-temperature overpressure events at Westinghouse and Combustion Engineering plants; that is, there may be less than 10 minutes available for the operator to diagnose and mitigate a low-temperature overpressure event before the pressure would exceed the Appendix G limit.

This alternative would require the ability to deliver large quantities of high-pressure nitrogen (800 cubic feet at up to 500 to 600 psi, or about 10,000 standard cubic feet) to the pressurizer prior to plant cooldown and subsequently vent the nitrogen and process it through the waste gas system on plant heatup. The high pressure is required to ensure adequate reactor coolant pump seal integrity prior to restart of an idle pump.

System requirements were developed by PNL based on a comparison to the Rancho Seco, plant which is representative of the B&W system for providing a nitrogen bubble. PNL reviewed final safety analysis report data from Sheron Harris, Byron, SNUPPS, Seabrook, and the CE CESSAR 80 plants and compared the system descriptions to the Rancho Seco information.

PNL assumed that the existing nitrogen delivery system (for safety injection tank overpressure fill) at affected plants has sufficient capacity to meet the stated needs. Modification to the plant nitrogen delivery system would be required to route the nitrogen to the pressurizer.

PNL also assumed that the current waste gas system has adequate capacity to handle the stated needs. It is also assumed that no other plant modifications are needed to allow venting of the nitrogen from the pressurizer to the waste gas system. In current designs, the venting of the pressurizer is to the pressurizer quench tank, which operates under a low-pressure nitrogen blanket and is already vented to the waste gas system.

PNL also assumed that operations can be conducted in such a manner that no additional modifications to the heat removal system for the quench tank are required. Two options appear reasonable for purging the nitrogen bubble at low temperatures that avoid overheating the quench tank. One would require taking the pressurizer water solid briefly, as the pressurizer heaters are energized to heat the pressurizer to saturation conditions and produce a steam bubble. The PORV would be opened to vent the pressurizer and charging flow would be increased so that nitrogen is pushed out as water fills the pressurizer. The second is the procedure used at B&W plants, whereby water in the pressurizer is heated with the nitrogen bubble in place, while primary pressure is maintained between 50 and 100 psi. Once saturation is achieved, the pressurizer is vented by cycling the PORV while maintaining pressure between 50 and 100 psi. Complete venting of the nitrogen bubble is indicated when the pressurizer pressure remains constant when the PORV is opened.

An alternative mode of operation would be to heat the pressurizer to saturation after the reactor coolant system pressure was raised to several hundred psi. The increased density of the vented steam would require modification to the quench tank heat removal system to accommodate the added heat load. Though not considered for this evaluation, the total estimated cost of the modified heat removal system would probably exceed one million dollars per unit.

5.1.6.1 Risk Reduction Estimates

This alternative would not change the frequency of LTOP initiating events or reduce the unavailability of the LTOP system, as compared to the base case. Risk reduction would be achieved by limiting the peak pressure to 600 psi or less if a 3-minute operator action time is assumed. There is a possibility that the peak pressure may still reach 2500 psi if it is assumed that the operator fails to respond in 3 minutes. It is possible to reach 2500 psi pressures in less than 10 minutes. The peak pressure spectrum for Alternative 6 is provided in Table 5.16, for each assumption regarding operator response time.

The estimated risk reduction for this alternative is provided in Table 5.17. Two cases are shown. Case 6(a) is based on limiting the peak pressure to 600 psi or less for all LTOP transients, and Case 6(b) assumes that there is a 10% chance that the peak pressure will reach 2500 psi if the operator fails to mitigate the transients within 3 minutes. The event frequency and LTOP unavailability are assumed to be the same as the base case evaluation.

Table 5.16 Peak pressure spectrum for Alternative 6.

Plant Group	Pressure (psi)	Base Case Fraction	3 Minutes Fraction	10 Minutes Fraction
PORV Plants	2500	0.09	0.0	0.1
	1400	0.09	0.0	0.0
	850	0.13	0.0	0.0
	600	0.69	1.0	0.9
RHR SRV Plants	2500	0.14	0.0	0.1
	850	0.14	0.0	0.0
	600	0.72	1.0	0.9

Table 5.17 Mean core damage frequency estimates for Alternative 6.

Alternative	Mean Core Damage Frequency (CDF) Before 1/RY	After 1/RY	CDF Reduction 1/RY	Ratio
6(a)	$3.24x10^{-6}$	$1.63x10^{-9}$	$3.24x10^{-6}$	1990.
6(b)	$3.24x10^{-6}$	$1.50x10^{-6}$	$1.74x10^{-6}$	2.2

5.1.6.2 Industry Implementation Cost Estimates

The best estimate industry unit costs associated with this alternative, without the need to modify the quench tank heat removal system, are provided in Table 5.18 based on NUREG/CR-4627 cost estimates. Additional details are provided in Section 11.2 of the PNL value/impact analysis for Generic Issue 94 (Ref. 10).

The industry implementation cost is doubled for the high cost estimate and halved for the low cost estimate. The best estimate industry implementation cost, for 67 plants, is $41.45 million, with the high and low costs being $83 million and $21 million, respectively. With respect to the upper bound, as the necessary labor effort increases, consideration must be given to the impact of radiation exposure (stay time) on resultant labor costs. Stay time has been estimated to impact labor cost by a factor of three for the moderate radiation zones involved in this alternative. This is a result of delays associated with dressing out, ALARA factors, interfacing with health physics, etc. The best estimate cost did not involve stay time because the hours, and hence the exposure, were judged by PNL to be amenable to normal shift work practices. If the stay time becomes an important factor in completing the work, labor cost would increase by a factor of six instead of merely doubling.

In addition to financial costs, there are occupational exposures associated with this alternative. Based on NUREG/CR-4627 Abstract 4.0, "Occupational Radiation Exposure," and labor adjustments, the per plant occupational exposure expected during installation of the nitrogen system is estimated to be 216 person-rems. Based on ASME Section XI, manual valve operation tests, periodic inspection and maintenance of this system, the additional occupational exposure, over the remaining plant life, is estimated to be about 125 person-rems per unit. Based on

67 units, the total occupational exposure is estimated to be 23,000 person-rems.

5.1.6.3 NRC Implementation Cost Estimates

The best estimate NRC implementation cost is based on a routine technical specification review, $14,200 per plant. In addition, the review, inspection and evaluation of the licensee implementation is estimated to require 180 staff hours per plant (20% of the industry engineering effort).

Based on Section 5.2 of NUREG/CR-4627, the cost is estimated as $7,500 per plant. The high cost estimate assumes the technical specification is complex and doubles the review effort, $27,400 and $15,000 per plant respectively, $42,400 total per plant. The low cost estimate is taken as one-half of the best estimate. The industry and NRC implementation cost estimates are summarized in Table 5.19.

5.1.6.4 Value/Impact Summary

The value/impact summary for Alternative 6 is provided in Table 5.20 for each of the three containment assumptions, based on the overall risk reduction. Two risk studies are provided. In the first case, the risk reduction is based on limiting the peak pressure to 600 psi or less. In the second case, the risk reduction includes a 10% probability of reaching 2500 psi as a result of a high mass addition transient that is not mitigated by the operator.

This alternative is not recommended because the best estimate value/impact ratio, assuming a 100% reduction in risk, is well above the $1,000 per averted person-rem guideline. In addition, the resultant occupational exposure associated with this alternative is high, 23,000 person-rems, as compared to the estimated public dose reduction estimates.

Table 5.18 Industry unit implementation cost for nitrogen bubble.

Action Item	Per Plant Cost ($/plant, 1988)
Technical Specification (Routine)	17,400
Waste Gas System Analysis	15,600
Nitrogen System Engineering	48,600
Nitrogen System Materials (valve, piping, instrumentation, etc.)	50,000
Installation (labor and engineering support)	270,000
Additional Nitrogen Procedures	22,200
System Startup and Installation Tests	18,700
Licensing	9,300
System Quality Assurance	104,900
Initial Training	4,200
Maintenance and Periodic Inspection Present value, 5% discount over life	57,000
Total Cost Per Unit	618,600

Table 5.19 Implementation cost estimates for Alternative 6 (for 67 plants).

		Unit Costs			Total Costs		
Cost Item	Plants Affected	Best Est. ($)	High Est. ($)	Low Est. ($)	Best Est. ($1,000s)	High Est. ($1,000s)	Low Est. ($1,000s)
Industry							
Total	All	618,600	1,237,200	309,300	41,450	83,000	21,000
NRC							
Tech Spec	All	14,200	27,400	7,100			
Q/A Review	All	7,500	15,000	3,750			
Total					1,450	2,840	730
Total					42,900	85,840	21,730

Table 5.20 Value/impact summary for Alternative 6 (for 67 plants).

	TWC Reduction /R-year	Industry + NRC Cost	Person-Rem Averted	Value/Impact Ratio ($/Person-Rem)
Peak Pressure 600 psi				
Best Estimate	3.24×10^{-6}	$42.90 million	16,000	2,700
High Estimate	3.24×10^{-6}	$85.84 million	29,600	2,900
Low Estimate	3.24×10^{-6}	$21.73 million	5,300	4,100
Peak Pressure 10% 2500 psi				
Best Estimate	1.74×10^{-6}	$42.90 million	9,300	4,600
High Estimate	1.74×10^{-6}	$85.84 million	17,200	5,000
Low Estimate	1.74×10^{-6}	$21.73 million	3,100	7,000

5.1.7 Summary of Best Estimate Value/Impact Ratios for All Alternatives

Table 5.21 is provided as a summary of the best estimate dose reductions, occupational exposures, industry implementation costs, NRC implementation costs and the value/impact ratio for each of the alternatives studied by the staff. The base case TWC frequency is estimated to be 3.24×10^{-6} per reactor year.

Table 5.21 Summary of best estimate value/impact (V/I) ratios for alternatives evaluated by NRC.

Alternative	TWC Freq Reduction (1/R-yr)	Dose Reduction (person-rem)	Occupational Exposure (person-rem)	Industry Costs ($1,000s)	NRC Costs ($1,000s)	V/I Ratio(*) ($ per averted person-rem)
2	2.89×10^{-6}	14,500	n/a	1,370	950	160
3(a)	1.07×10^{-6}	7,000	n/a	3,630	1,840	780
3(b)	0.21×10^{-6}	1,400	n/a	1,290	950	1,600
3(a&b)	1.20×10^{-6}	8,400	n/a	4,920	2,790	920
4(a)	0.16×10^{-6}	700	n/a	770	650	1,900
4(b)	0.16×10^{-6}	700	n/a	4,770	650	7,750
5	1.82×10^{-6}	8,200	900	16,000	570	2,000
5(a)	3.00×10^{-6}	13,400	900	16,000	570	1,200
6(a)	3.24×10^{-6}	16,000	23,000	41,450	1,450	2,700
6(b)	1.74×10^{-6}	9,300	23,000	41,450	1,450	4,600

Notes:

* Sum of industry plus NRC implementation costs ($s) divided by dose reduction (person-rem).

2 Technical specification change, 67 plants, proposed resolution.

3(a) SI lockout, 67 plants.
3(b) RCP restart, 67 plants.
3(a&b) Both SI and RCP, 67 plants.

4(a) ACI removal, w/o cost for disconnecting ACI, 40 PORV plants.
4(b) ACI removal, w/cost for disconnecting ACI, 40 PORV plants.

5 Safety-grade OMS, 40 PORV plants.
5(a) Sensitivity study, safety-grade OMS, 40 PORV plants.

6(a) Pressurizer bubble, peak pressure less than 600 psi, 67 plants.
6(b) Pressurizer bubble, 10% chance of reaching 2500 psi, 67 plants.

5.2 Relationships With Other Regulatory Issues

5.2.1 Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials"

Revision 2 of this regulatory guide (Ref. 11) was used to determine the mean surface RT(ndt) shift resulting from irradiation-induced embrittlement for each reactor vessel in the study. The plant-specific chemistry data and fluence projections to end-of-license were obtained from licensee submittals related to the "Pressurized Thermal Shock" program, USI A-49. Revision 2 is considered by both the staff and the industry to be representative of the state-of-the-art knowledge concerning irradiation damage.

Application of Revision 2 to the Appendix G pressure/temperature limit analysis results in an earlier narrowing of the operational window for most plants. The operational window is defined as the pressure envelope within which the operator must control pressure to ensure a high enough pressure to ensure reactor coolant pump seal integrity and cooling and low enough to avoid exceeding the Appendix G pressure/temperature limits following the actuation of the low-temperature overpressure protection system during an anticipated operational transient (for example, restart of an idle reactor coolant pump or an inadvertent safety injection transient).

The impact of Revision 2 on the low-temperature overpressure protection system is considered in this evaluation. The operational concerns (the closing or narrowing of the operational window) have been addressed as part of the regulatory guide in its supporting regulatory analysis. As part of the implementation recommendation for Revision 2, Branch Technical Position RSB 5-2 to Standard Review Plan 5.2 is being revised to include a definition of "low temperature." The intended purpose of defining "low temperature" is to provide more operational flexibility near the low-temperature overpressure protection system enable temperature for plants that rely on fixed setpoint PORVs for protection.

Industry awareness of the operational window concerns have prompted many licensees to review their plant instrumentation, procedures, and low-temperature overpressure event histories to determine what additional actions can be taken to reduce the occurrence of these events. Specific actions under consideration are:

1. Better pressure instrumentation for low-temperature operations to reduce the instrumentation uncertainties and widen the operational window.

2. Direct temperature indication of the secondary side temperature to ensure that the secondary is not warmer than assumed in the safety analyses studies for the low-temperature overpressure protection system setpoint analysis.

3. Provide an accumulator air or nitrogen bottle to the air-actuated normal letdown isolation valve to prevent loss of letdown due to problems with the air or nitrogen system.

These actions, if taken, may reduce the frequency of low-temperature overpressure events at some plants. However, the dominant risk is still associated with those events resulting from maintenance and testing errors, which result in charging without letdown or inadvertent safety injection events. These events have the potential to drive the system pressure to the primary safety relief valve setpoint pressure, 2500 psi, if the low-temperature overpressure protection system fails to mitigate the transient.

In addition, as part of the implementation for Regulatory Guide 1.99, Revision 2, the staff is also incorporating clarification into SRP 5.3.2, "Pressure-Temperature Limits," (Ref. 3) to ensure that whenever the Appendix G limits are revised the corresponding low-temperature overpressure protection system setpoints are also adjusted, as needed, to ensure that the Appendix G limits will not be exceeded as a result of an anticipated operational transient.

5.2.2 Generic Issue 99, "RCS/RHR Suction Line Interlocks in PWRs"

The findings related to removal of the autoclosure interlock (ACI) on the residual heat removal suction line isolation valves in this study for GI-94 are consistent with preliminary information under GI-99. While this action does not result in a significant reduction in risk from low-temperature overpressure events, the benefit to decay heat removal concerns may be sufficient justification to allow licensees to remove the interlock. In addition, each licensee would also have to perform a safety analysis to demonstrate that overall plant safety is not adversely impacted by removal of the autoisolation closure feature.

5.2.3 Generic Issue 70, "Power-Operated Relief Valve and Block Valve Reliability"

The proposed resolution for GI-94 is consistent with the preliminary findings of GI-70, although the risk reduction for low-temperature overpressure protection is significant when the PORVs (and the residual heat removal system safety relief valves) are administratively treated as components that are used to perform a safety-related function. The cost-benefit evaluation does not support an effort to upgrade the low-temperature overpressure protection system to a fully safety-grade system. Also for low-temperature overpressure protection, the marginal risk reduction that might be achieved by revising the testing schedule for the PORVs appears not to be justified as discussed in Section 5.1.5 and is not included as part of the proposed resolution to GI-94.

A substantial reduction in risk can be obtained by simply considering the safety significance of these valves in providing protection against brittle fracture failure of the reactor pressure vessel. GI-94 has determined that PORV unavailability resulting from not identifying these valves as being related to overall plant safety is the dominant contributor to their unavailability. This finding is equally valid for plants that rely on the RHR SRVs since these valves are also treated as not being related to overall plant safety when providing protection for low-temperature overpressure events in the overpressure protection technical specification.

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6. DECISION RATIONALE

Major overpressurization of the reactor coolant system while at low temperature, if combined with a critical crack in the reactor pressure vessel welds or plate material, could result in a brittle fracture of the pressure vessel. As long as the fracture resistance of the reactor pressure vessel material is relatively high, these events are not expected to cause vessel failure. However, the fracture resistance of the reactor pressure vessel materials decreases with exposure to fast neutrons during the life of a nuclear power plant. The rate of decrease is dependent on the metallurgical composition of the vessel walls and welds. If the fracture toughness of the vessel has been reduced sufficiently by neutron irradiation, low-temperature overpressure events could cause propagation of fairly small flaws that might exist near the inner surface. The assumed initial flaw might propagate into a crack through the vessel wall of sufficient extent to threaten vessel integrity and, therefore, core cooling capability. Failure of the pressure vessel could make it impossible to provide adequate coolant to the reactor core and could result in major core damage or a core damage accident.

The mean core damage frequency, or reactor pressure vessel through wall crack (TWC) probability, is estimated to be in the $3x10^{-6}$ to $4x10^{-6}$ per reactor year range over the remaining licensed life of the 55 Combustion Engineering and Westinghouse PWRs considered in this evaluation. For a plant that approaches the PTS screening criterion (10 CFR 50.61) at end-of-license, the TWC probability is estimated to be $7x10^{-6}$ per reactor year, assuming that the frequency of LTOP events and the unavailability of the LTOP system remain constant.

A review of current standard technical specifications for containment integrity in shutdown modes (Modes 4, 5, and 6) indicates that no containment integrity requirements are imposed for reactor coolant temperatures less than 200°F, except during refueling when the reactor pressure vessel head is removed. Industry responses to NRC Generic Letter 87-12 (Ref. 21) indicate that containment integrity during Mode 5 is often relaxed to allow for testing, maintenance, and repair of equipment (for example, containment penetrations, steam generators, and reactor coolant pumps). Three risk estimates were employed to address containment integrity. Since the low-temperature overpressure events of concern to this evaluation occur in Mode 5 at reactor coolant temperatures between 80° and 190°F, the assumption that containment is open, at least part of the time, is judged to be valid. Containment integrity has been treated parametrically in this analysis. The resulting public risk from LTOP events, integrated over the remaining licensed life of the 55 PWRs considered, ranges from 5,300 to 29,600 person-rems, with the best estimate value being 16,000 person-rems.

The present value, assuming a 5% discount rate, of core damage accidents resulting from LTOP events is estimated to be between $6.1 million and $13 million, with a best estimate value of $9.2 million, for onsite (replacement power and cleanup and repair) damage and offsite (health and property) damage.

The proposed recommendation, to improve the LTOP system availability, results in a change in the estimated core damage frequency of $2.89x10^{-6}$ per reactor year from $3.24x10^{-6}$ to $3.5x10^{-7}$ per reactor year, a factor of ten improvement. The combined industry and NRC implementation best estimate cost is $2.32 million. The best estimate averted person-rem is 14,500 for a best estimate value-impact ratio of $160 per averted person-rem. The present value best estimate for averted damage, onsite and offsite, is $8.3 million.

Although the mean core damage frequency (CDF) for LTOP events ($3x10^{-6}$ per reactor year) is not large in comparison to other typical CDFs associated with loss-of-coolant accidents or loss of decay heat removal accidents ($1x10^{-4}$ to $1x10^{-5}$ per reactor year range), with plant age the LTOP CDF increases because of reactor pressure vessel irradiation embrittlement. Also, though not quantified or explicitly considered in this evaluation, if life extension is considered, then the LTOP CDF could approach the $1x10^{-5}$ per reactor year range, assuming no additional actions are taken.

The LTOP core damage accident, resulting from the brittle fracture of the reactor pressure vessel, is a non-recoverable event. Even with emergency core cooling system functional, failure of the pressure vessel could make it impossible to provide adequate coolant to the reactor core and could result in major core damage or a core damage accident.

Further, since these events are most likely to occur in Mode 5, the containment could be open or non-isolatable following vessel fracture.

While a requirement for containment integrity, during Mode 5 (water-solid) with one LTOP channel inoperable, could reduce the public risk (in person-rem), the staff does not consider this mitigation action as an alternative for the resolution of GI-94. The likelihood of a core damage accident would not change. The costs associated with onsite damage would not be reduced. The present value best estimate onsite damage cost is $5.2 million, based on a 5% discount rate, of the total $9.2 million cost with offsite damage. Mitigation of public risk does not address the importance of preventing risk by ensuring that the likelihood of a rapidly propagating fracture of the reactor pressure vessel due to embrittlement is minimized, as required by Appendix A, "General Design Criteria," to 10 CFR Part 50.

The staff proposal is to modify the current technical specification for overpressure protection to emphasize the safety-related function of the PORVs, and the RHR SRVs, for LTOP protection, especially when water-solid. The reported LTOP transients have occurred in Mode 5 with RCS temperatures ranging from 80°F to 190°F. Since this temperature range includes Mode 6, RCS temperature less than 140°F but with k_{eff} less than 0.95 as compared to k_{eff} less than 0.99 for Mode 5, the staff concludes that the additional administrative restriction for the single channel AOT is applicable to Mode 5 and Mode 6 (with the reactor pressure vessel head on).

Technical specifications are required by the Atomic Energy Act of 1954 and are implemented in the Code of Federal Regulations, 10 CFR 50.36. Technical specifications are the rules for the normal operation of a nuclear power plant that ensure it is prepared to respond to accidents. They define the operating conditions and limiting conditions on which safety analyses are based. Since they are a part of the nuclear plant's operating license, the technical specifications also have a legal basis.

The proposed recommendation, that the low-temperature overpressure protection system be considered as a system that performs a safety-related function--in particular during Mode 5 or 6 operation, is consistent with the intended function attributed to concerns with brittle reactor pressure vessel failure as defined in 10 CFR 50 Appendix A and Appendix G. It is not appropriate to consider the function of this system as not being related to plant safety.

The staff therefore recommends that the technical specification for overpressure protection be modified to ensure both channels of the low-temperature overpressure protection system be operable, especially during Mode 5 or 6 operations. The allowable outage time (AOT) would be decreased from 7 days to 8 hours with one channel inoperable in Mode 5 or 6. This recommendation applies to all holders of an operating license or holders of a construction permit for Westinghouse and Combustion Engineering PWRs.

The proposed resolution for GI-94 is consistent with the preliminary findings of GI-70, although the risk reduction for low-temperature overpressure protection is significant when the PORVs (and the residual heat removal system safety relief valves) are administratively treated as safety-related components. The cost-benefit evaluation does not support an effort to upgrade the low-temperature overpressure protection system to a fully safety-grade system.

A substantial reduction in risk can be obtained by simply considering the safety significance of these valves in providing protection against brittle fracture failure of the reactor pressure vessel. GI-94 has determined that PORV unavailability resulting from not identifying these valves as being related to overall plant safety is the dominant contributor to their unavailability. This finding is equally valid for plants that rely on the RHR SRVs since these valves are also treated as not being related to overall plant safety when providing protection for low-temperature overpressure events in the overpressure protection technical specification.

6.1 Conclusions Concerning LTOP Implementation

Low-temperature overpressure protection (LTOP) was designated as Unresolved Safety Issue (USI) A-26 in 1977 (Ref. 1). PWR licensees implemented procedures to reduce the potential for overpressure events and installed equipment modifications to mitigate such events, under Multi-Plant Action B-04 (Ref. 2).

The administrative controls and procedures that were identified as part of B-04 include the following items:

1. Minimize the time the reactor coolant system (RCS) is maintained in a water-solid condition.

2. Restrict the number of high-pressure SI pumps operable to no more than one when the RCS is in the LTOP condition.

3. Ensure that the steam generator to RCS temperature difference is less than 50°F when a reactor coolant pump (RCP) is being started in a water-solid RCS.

4. Set the PORV setpoint (if the particular plant relies on this component for LTOP) to a plant-specific analysis supported value and have surveillance that checks the PORV actuation electronics and setpoint.

The current staff guidelines for the LTOP system are found in Standard Review Plan Section 5.2.2, "Overpressure Protection," and in its attached Branch

Technical Position (BTP) RSB 5-2, "Overpressure Protection of Pressurized Water Reactors While Operating at Low Temperatures" (Ref. 3).

The implementation of the requirements for low-temperature overpressure protection (LTOP), the resolution of USI A-26, has been found to be essentially uniform for the Combustion Engineering (CE) and Westinghouse (W) PWRs. With the exception of a few plants,* the LTOP protection systems consist of either redundant PORVs or redundant safety relief valves in the residual heat removal system (RHR SRVs) and in general meet the guidance set forth in Branch Technical Position RSB 5-2, "Overpressurization Protection of Pressurized Water Reactors While Operating at Low Temperatures."

Variability in meeting IEEE-279 requirements, equipment environmental qualification, and the guidance of Regulatory Guide 1.26 (Ref. 30) exists. As part of the NRC staff acceptance of LTOP protection system designs for the implementation of the resolution of USI A-26, it was concluded that the costs associated with upgrading existing systems to meet these requirements were not justifiable. Further evaluations performed for GI-94 have also concluded that it is not cost beneficial to upgrade these systems to fully safety grade.

The section of the standard technical specification covering the LTOP protection system is titled Overpressure Protection System, Section 3.4.10.3 for CE plants and Section 3.4.9.3 for W plants. The LTOP system setpoints are established based on additional restrictions for the restart of an idle reactor coolant pump and on the number of high-pressure safety injection pumps and/or coolant charging pumps allowed to be operable when LTOP is required. These additional restrictions define the initial conditions for the plant-specific transient analyses performed to establish the LTOP system setpoints. The additional restrictions are provided regarding the restart of inactive reactor coolant pumps in Sections 3.4.1.3 (Hot Shutdown) and 3.4.1.4 (Cold Shutdown). High-pressure safety injection pump operability restrictions are provided in Section 3/4 5.3 (ECCS Subsystems).

In addition to these administrative restrictions, the transient analyses are based on a dual-channel system's being operable to satisfy the single failure criterion of 10 CFR Part 50 Appendix A for a system that performs a safety function. Therefore, the overpressure protection system technical specification is consistent with Criterion 2 of the Commission's Policy Statement on Technical Specification Improvements for Nuclear Power Plants. The technical specification also satisfies Criterion 3 of the Policy Statement in that the LTOP system is the primary success path for the mitigation of low-temperature overpressure transients that present a challenge to a fission product barrier--in this case, the reactor pressure vessel.

The standard technical specification action requirement for the LTOP system includes a 7 day AOT to restore an inoperable LTOP channel to operable status before other remedial measures would have to be taken (depressurize and vent the reactor coolant system). In addition, Action d. states that the provisions of Specification 3.0.4 are not applicable. Therefore, the plant may enter the modes for which the limiting conditions for operation (LCOs) apply, during a plant shutdown or placement of the head on the vessel following refueling, when an LTOP channel is inoperable. In this situation, the 7-day AOT applies for restoring the channel to operable status before remedial measures would have to be taken. This is the same manner in which the action requirements apply when an LTOP channel is determined to be inoperable while the plant is in a mode for which the LTOP system is required to be operable.

Based on the NRC evaluation of the LTOP system unavailability, it is concluded that additional restrictions on operation with an inoperable LTOP channel are warranted when the potential for a low-temperature overpressure event is the highest, and especially when the plant is in a water-solid condition. The probabilistic risk assessment performed in support of the resolution of GI-94 is based on the administrative controls and procedures identified as part of the Multi-Plant Action Item B-04 recommendations. It is therefore concluded that these additional restrictions regarding, in particular, the restart of inactive reactor coolant pumps and the operability of high-pressure safety injection pumps should be implemented in the technical specifications, as indicated in the standard technical specifications. Licensees should verify that these administrative restrictions have been implemented. Finally, it is concluded that these additional measures will help to emphasize the importance of the LTOP system, especially while operating in a water-solid condition, as the primary

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* CE - San Onofre Units 2 and 3 rely on a single RHR (SDCS) SRV for LTOP. With the SRV inoperable, within 8 hours depressurize and vent.
- Maine Yankee relies on two PORVs when pressure is above 400 psig and two RHR SRVs when pressure is below 400 psig.

W - DC Cook Units 1 and 2 rely on either two PORVs or one PORV and one RHR SRV.
- Yankee Rowe relies on one PORV and two RHR SRVs.
- Newer Westinghouse plants allow either two PORVs or two RHR SRVs.

success path for the mitigation of overpressure transients during low-temperature operation.

6.2 Improvements in LTOP Protection System Availability

The staff has determined that LTOP protection system unavailability is the dominant contributor to risk from low-temperature overpressure transients. The staff has further concluded that a substantial improvement in availability, especially during water-solid operations, can be achieved through improved administrative restrictions on the LTOP protection system.

In developing the staff position on the resolution of the low-temperature overpressure protection generic issue, a number of factors have been taken into consideration.

PORVs are relied on, by most Westinghouse-designed plants and about one-half of the Combustion Engineering plants, to provide LTOP protection. The NRC has determined that over a period of time the role of the PORVs has changed such that PORVs are now relied upon to perform one, or more, of the following safety-related functions:

1. Mitigation of a design-basis steam generator tube rupture accident,

2. LTOP protection of the reactor pressure vessel during startup and shutdown, or

3. Plant cooldown in compliance with Branch Technical Position RSB 5-1 to SRP 5.4.7, "Residual Heat Removal (RHR) System."

In addition to PORVs, the residual heat removal system safety relief valves (RHR SRVs) are also relied on to provide LTOP protection for some Westinghouse plants and for the Combustion Engineering plants that do not have PORVs. Newer Westinghouse plants have technical specifications that require either two PORVs or two RHR SRVs for LTOP protection.

The NRC staff has considered the conditions under which a low-temperature overpressure transient is most likely to occur. While LTOP protection is required for all shutdown modes, the most vulnerable period of time was found to be Mode 5 (Cold Shutdown) with the reactor coolant temperature less than 200°F, especially when water-solid, based on the detailed evaluation of operating reactor experiences performed in support of GI-94. LTOP transients, which have challenged the overpressure protection system, have occurred with reactor coolant temperatures in the range of 80°F to 190°F. In addition, a review of the standard technical specifications for containment integrity indicates that there are no specific requirements imposed during Mode 5, when the reactor coolant temperature is below 200°F. Industry responses to Generic Letter 87-12 (Ref. 21) also indicate that containment integrity during Mode 5 is often relaxed to allow for testing, maintenance, and the repair of equipment.

The reported LTOP transients have occurred in Mode 5 with RCS temperatures ranging from 80°F to190 °F. Since this temperature range includes Mode 6, RCS temperature less than 140°F but with k_{eff} less than 0.95 as compared to k_{eff} less than 0.99 for Mode 5, the staff concludes that the additional administrative restriction for the single channel AOT is applicable to Mode 5 and Mode 6 (with the reactor pressure vessel head on). The staff proposal is to modify the current technical specification for overpressure protection to emphasize the safety-related function of the PORVs, and the RHR SRVs, for LTOP protection in Mode 5 or 6, especially when water-solid.

The staff concludes that the LTOP system performs a safety-related function and inoperable LTOP equipment should be restored to an operable status in a shorter period of time. The current 7-day AOT is considered to be too long under certain conditions. The staff has concluded that the AOT should be reduced to 8 hours when operating in Mode 5 or 6, when the potential for an overpressure transient is highest. The operating reactor experiences indicate that these events occur during planned heatup (restart of an idle reactor coolant pump) or as a result of maintenance and testing errors while in Mode 5. The reduced AOT in Mode 5 or 6 will help to emphasize the importance of the LTOP system in mitigating overpressure transients and provide additional assurance that plant operation is consistent with the design basis transient analyses.

The evaluation performed for the resolution of this generic issue is based on plants being in compliance with their LTOP design bases analyses. Licensees should verify that the administrative controls and procedures identified in Section 6.1 have been implemented to ensure that the plant is being operated within the design base. If it is determined that the design base was developed based on restricted SI pump operability and/or differential temperature restrictions for RCP restart and that these restriction have not been implemented as part of USI A-26 and Multi-Plant Action Item B-04, then these restrictions should be implemented. This is not a new requirement.

The proposed resolution for Generic Issue 94, "Additional Low-Temperature Overpressure Protection for Light-Water Reactors," is expected to reduce by an order of magnitude the risks associated with operating at low temperatures. The likelihood of an anticipated low-temperature overpressure transient's exceeding the pressure/temperature limits prescribed under Appendix G to 10 CFR Part 50 is also expected to be reduced from one-in-ten to one-in-one hundred, thereby minimizing the probability of a rapidly propagating fracture of the reactor pressure vessel in conformance with General Design Criterion 31 and General Design Criterion 15.

The likelihood of a low-temperature overpressure transient's resulting in a peak pressure exceeding the Appendix G pressure/temperature limits would be reduced from one-in-ten to one-in-one hundred, the desired objective of GI-94. The likelihood of brittle reactor pressure fracture (a through wall crack) is minimized.

The proposed resolution for Generic Issue 94 reduces the mean core damage frequency to less than $1x10^{-6}$ per reactor year, from $3.24x10^{-6}$ to $3.5x10^{-7}$ per reactor year, meeting the target CDF objective stated in Section 2 above. For a plant that approaches the PTS screening criteria at the end-of-license (with a CDF of $7x10^{-6}$ per reactor year), the target CDF objective would also be met (with the CDF reduced to $7x10^{-7}$ per reactor year).

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7. IMPLEMENTATION

The staff proposes to implement the recommendation for the resolution of Generic Issue 94 by issuing a generic letter to all licensees and holders of a construction permit for Westinghouse and Combustion Engineering designed nuclear steam supply systems. The content of the generic letter will address the staff concerns related to the current administrative treatment of the low-temperature overpressure protection system as not being a system that performs a safety-related function.

Plant operations in a degraded mode (one out of two channels removed from service), when the LTOP system is providing protection against brittle vessel failure, could result in unacceptable consequences to the health and safety of the public. During Mode 5 (and Mode 6) operations, where LTOP transients occur, the containment integrity requirements are often relaxed to permit maintenance, testing, and repair activities.

Each licensee will be requested to revise the overpressure protection technical specification to ensure that both channels of the system are operable when providing protection against brittle vessel failure. Sample standard technical specifications will be provided for guidance.

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APPENDIX A

SUMMARY OF OPERATING REACTOR EXPERIENCES

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The purpose of this appendix is to document the results of Task 1 of the Task Action Plan for Generic Issue 94, "Additional Low-Temperature Overpressure Protection for Light-Water Reactors." The Task 1 objective was to update the operational experiences data base to determine the root causes of low-temperature overpressure events, to determine the unavailability of the protection systems installed during and after 1980, and to determine the peak pressure and the initial temperature of actual low-temperature overpressure events. This work was performed by the NRC staff.

The experiences data base has been developed from five sources:

1. NUREG-0224, "Reactor Vessel Pressure Transient Protection for Pressurized Water Reactors" (Ref. A.1)

2. NUREG/CR-2789, "Pressure Vessel Thermal Shock at U.S. Pressurized Water Reactors: Events and Precursors, 1963-1981" (Ref. A.2).

3. AEOD Case Study C401, "Low Temperature Overpressure Events at Turkey Point Unit 4" (Ref. A.3)

4. LER Update Search (Ref. A.4).

5. Docket 50-275, "RHR System Autoclosure Interlock Removal Report for Diablo Canyon Nuclear Power Plant" (Ref. A.5)

The objective of Task 1 was to determine the post-1980 data base regarding events and low-temperature overpressure protection (LTOP) or overpressure mitigation system (OMS) performance data. Operating Modes 4 (hot shutdown), 5 (cold shutdown), and 6 (cold shutdown with reactor vessel head untensioned, or refueling) are considered for this data base. Five categories are used to describe the cause of overpressure events. These categories are described in Table A.1. In summary they are:

(1) Safety-injection-related events ....S
(2) Charging- and letdown-related events C
(3) Residual heat removal (RHR) isolation ....R
(4) Reactor coolant pump restart events ....P
(5) Other events, not related to above four categories .....Q

It is noted that some events have occurred prior to the actual date of commercial operation at a given facility. These data are included in the updated data base because they are informative with respect to the root cause of overpressure events. The date each unit began commercial operations is noted in the data tables and, for this study, is taken to be the date when a unit first generated electricity (NUREG-0020, "Licensed Operating Reactors").

NUREG-0224 (Ref. A.1) listed 30 events that resulted in significant overpressure transients while in shutdown modes of operation. One event has been excluded from this report because it occurred at a BWR (number 24 of Table 1, Peach Bottom Unit 2, 3/6/74). In addition to the remaining 29 events, three other unidentified events were listed (Appendix C, 1 in 1977 and 2 in 1978). Since these events pre-date the implementation of LTOP systems, further identification was not made. The 29 identified NUREG-0224 events are summarized in Table A.2.

NUREG/CR-2789 (Ref. A.2) identified 15 events in shutdown Modes 4, 5, and 6, which were not identified in the other data sources. Six events pre-date 1980 and nine occurred after 1980. None of these events resulted in significant overpressure transients, pressures over 500 psi. All of these events are classified as precursors, or potential overpressure events. Two other events located in NUREG/CR-2789 were redundant, one from NUREG-0224 and one from the AEOD Case Study C401. The 15 NUREG/CR-2789 events are summarized in Table A.3.

Ten events, excluding the two Turkey Point 4 events, are identified in AEOD C401 (Ref. A.3). Eight of these were also located in the LER Update Search. The two special report events were not located in the LERs because the ORNL data base does not include special reports. One event is classified as pre-commercial. All of these 10 events were successfully mitigated by the LTOP protection systems. In addition, one of the events (at Calvert Cliffs) also reported both LTOP channels unavailable. Following actuation of the PORV, the operator closed the block valve. The operator thought the PORV actuation was spurious. The second PORV was out of service for maintenance. The 10 AEOD C401 events are summarized in Table A.4. The Turkey Point 4 data are entered under the LER Update Search because these two events include cases where LTOP channels were also unavailable.

The Sequence Coding and Search System (SCSS) data base includes data from 1981 through May 1986, and about one-half of the 1980 LERs. Two searches were performed to locate relevant data:

1. Find LERs coded with 'RCS' or pressurizer systems and with the abstract[ing] containing 'POP', 'OVERPRES', or 'LTOP'.

2. Find LERs coded with the 'RCS' or pressurizer systems with an effect of high pressure and with a unit effect of hot or cold shutdown, hot standby, or refueling.

Ninety-three LERs were located. These were screened and 57 were found to be applicable. Some of the LERs report multiple events. Seven were redundant to the AEOD C401 data base.

Additional data were located and included in the LER Update Search data. A preliminary report by AEOD, "Air Systems Problems at U.S. Light Water Reactors," December 1986, identified additional LTOP data, not found elsewhere. Most notable is a special report for Farley Unit 2, where the peak pressures during two LTOP events were 700 psi and 480 psi. In addition, a report prepared by Westinghouse for Diablo Canyon listed LTOP events not previously found (Ref. A.5).

With the exception of the two Turkey Point Unit 4 events and the one event at Farley 2, no other events resulted in significant overpressure transients, exceeding the Appendix G limits. The LTOP (OMS) systems functioned when required to limit the overpressure to an acceptable value, in accordance with Appendix G (10 CFR Part 50) requirements.

The LER Update Search located 37 LTOP events, and 21 cases with one LTOP channel out of service and 25 cases with both LTOP channels declared out of service. Sixteen of the 37 LTOP events are classified as precursor events. The LER Update Search data are summarized in Table A.5.

The data have been compared to the date a plant was declared commercial. This date is taken to be the date the plant first generated electricity (from NUREG-0020). This date selection screens out the fewest events for precommercial data evaluation.

The data base (excluding B&W) consists of the following:

		Actual LTOP Events		Precursor LTOP Events	
Source	Total	Post Commercial	Pre-Commercial	Post Commercial	Pre-Commercial
Pre-1980 Data					
NUREG-0224	28	14	14	-	-
NUREG/CR-2789	5	-	-	5	-
AEOD C401	-	-	-	-	-
LERs	3	2	1	-	-
Total	36	16	15	5	-
Post-1980 Data					
NUREG-0224	-	-	-	-	-
NUREG/CR-2789	8	-	4	-	4
AEOD C401	10	9	1	-	-
LERs	37	21	-	15	1
Total	55	30	5	15	5

Source	Total	One LTOP Unavailable: Post Commercial	One LTOP Unavailable: Pre-Commercial	Both LTOPs Unavailable: Post Commercial	Both LTOPs Unavailable: Pre-Commercial
AEOD C401	1	-	-	1	-
LERs	45	16	5	24	-
Total	46	16	5	25	0

Vendor	Total	Actual LTOP Events: Post Commercial	Actual LTOP Events: Pre-Commercial	Precursor LTOP Events: Post Commercial	Precursor LTOP Events: Pre-Commercial
Combustion Engineering	12	5	2	4	1
Westinghouse	79	41	18	16	4
Total	91	46	20	20	5

Vendor	Total	One LTOP Unavailable: Post Commercial	One LTOP Unavailable: Pre-Commercial	Both LTOPs Unavailable: Post Commercial	Both LTOPs Unavailable: Pre-Commercial
Combustion Engineering	6	1	-	5	-
Westinghouse	40	15	5	20	-
Total	46	16	5	25	-

There were 30 overpressure transients during the period 1980 through 1986. The two Turkey Point 4 events in 1981, at 750 and 1100 psi, and one of the two events at Farley 2 in 1983, at 700 psi (the other reached 480 psi) exceeded the Appendix G pressure/temperature limits as specified in the technical specifications.

The LTOP events data base is summarized below:

Vendor	Safety Injection Post	Safety Injection Pre	Charging /Letdown Post	Charging /Letdown Pre	RHR Isolation Post	RHR Isolation Pre	RCP Restart Post	RCP Restart Pre	Others /Op. Errs. Post	Others /Op. Errs. Pre
Combustion Engineering	2	1	-	2	2	-	2	-	3	-
Westinghouse	19	6	13	11	6	1	12	2	7	2
	--	--	--	--	--	--	--	--	--	--
Total	21	7	13	13	8	1	14	2	10	2

The LTOP unavailability data base is summarized below:

Vendor	Maintenance One	Maintenance Both	Operator Errors One	Operator Errors Both	Component Failure One	Component Failure Both	PORV Leak Isolated One	PORV Leak Isolated Both	Air/N2 Problems. One	Air/N2 Problems. Both
Combustion Engineering	1	2	-	3	-	-	-	-	-	-
Westinghouse (Post Com)	4	4	-	2	3	2	3	4	5	8
Westinghouse (Pre-Com)	1	-	-	-	-	-	3	-	1	-
	--	--	--	--	--	--	--	--	--	--
Total	6	6	-	5	3	2	6	4	6	8

There are a few cases where plants have contributed numerous events to the data base, four or more overpressure events and/or four or more reported cases of LTOP unavailability. These plants are summarized below.

Indian Point 2 (Westinghouse)

Eight of the 31 NUREG-0224 overpressure transients occurred at Indian Point 2. Five of these are classified as pre-commercial.

McGuire 1 (Westinghouse)

McGuire 1 accounts for four pre-commercial safety injection events (Ref. A.2).

North Anna 1 and 2 (Westinghouse)

North Anna 1 and 2 account for three cases with one LTOP channel unavailable and five cases with both channels out. Seven of the eight events relate to problems with the nitrogen pressure system used to actuate the PORVs.

North Anna 1 and 2 also account for eight LTOP events. All were successfully mitigated by the LTOP system.

Salem 2 (Westinghouse)

Salem 2 accounts for four cases of one LTOP channel unavailable and six cases with both channels out. Eight of the 10 events resulted from isolation of leaky PORVs.

Salem 2 also accounts for five LTOP events. All were successfully mitigated by the LTOP system. One of the five is a pre-commercial event.

Surry 1 (Westinghouse)

Surry 1 accounts for seven LTOP events: one high-pressure event prior to 1980 and six after 1980. Three of these six are precursors, and the remaining three were successfully mitigated by the LTOP system.

Zion 2 (Westinghouse)

Zion 2 accounts for five LTOP events: one high-pressure event prior to 1980 and four after 1980. Two of these four are precursors, and the remaining two were successfully mitigated by the LTOP system.

Tables A.6 through A.16 provide the details from the literature searches.

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A.2 D.L. Phung, "Pressure Vessel Thermal Shock at U.S. Pressurized Water Reactors: Events and Precursors, 1963-1981," Oak Ridge National Laboratory, NUREG/CR-2789, ORNL/NSIC-210, May 1983.

A.3 Memorandum from C.J. Heltemes, Jr., to H.R. Denton, "Case Study Report--Low-Temperature Overpressure Events at Turkey Point 4," AEOD Case Study C401, dated March 16, 1984.

A.4 Letter from G.T. Mays, Director, Nuclear Safety Information Center, ORNL, to E.D. Throm, NRC, dated September 2, 1986.

A.5 Westinghouse Electric Corporation, Power Systems, "RHR System Autoclosure Interlock Removal Report for Diablo Canyon Nuclear Power Plant," Docket No. 50-275, WCAP-11117, Revision 2, Appendix D, dated August 4, 1987.

Table A.1 LTOP coding system.

Event Sequence Identifier:

S	-	Inadvertent safety injection as a result of operator error during SI testing, inadvertent SI actuation signal. Could be SI pump or accumulators.
C	-	Excess charging flow. Typically with letdown isolated but not caused by residual heat removal system isolation. Possible high CC flow.
R	-	Residual heat removal (RHR) system isolation resulting in charging without letdown.
P	-	Restart of a reactor coolant pump (RCP).
Q	-	Other events. Operator errors, procedure errors, or related to maintenance.

LTOP Unavailability Identifier:

1O	-	One low-temperature overpressure (LTOP) channel or relief path unavailable. Does not necessarily represent all planned maintenance that does not need to be reported.
2O	-	Both LTOP channels or relief paths unavailable. May include one out for maintenance when the second fails to mitigate an overpressure event.

Causes broken down into five categories:

(1)	-	Maintenance,
(2)	-	Operator error,
(3)	-	Component failure,
(4)	-	PORV leakage and isolation, and
(5)	-	Air or nitrogen system failures.

Pressure Column Identifier:

N/A	-	Data unavailable.
None	-	No actual pressure transient, a precursor event.
Temp	-	Overcooling event, no pressure data.
S.P.	-	Upper bound pressure limited to LTOP setpoint. Event mitigated.

Events used by PNL to define the operating reactor experience data base are marked with (*) in the summary data tables.

Table A.2 Summary of NUREG-0224 LTOP data.

Reactor (Commercial)	Type	Date	Pressure (psi) From	Pressure (psi) To	Temperature (Deg F)	Cause(1)
Beaver Valley 1 06/14/76	(W)	02/24/76	400	1000	130	C-Operator error, El. bus transfer, w/RHRS (pre-com)
		03/05/76	400	1150	150	S-Operator error, El. bus de-energized w/RHRS (pre com)
		03/13/76	425	495	190	S-Inadvertent safety injection (pre-com)
D.C. Cook 1 02/10/75	(W)	04/14/76	N/A	1040	110	C-Inadvertent letdown isolation, w/RHRS
R.E. Ginna 12/02/69	(W)	1969	95	2485	100	C-Inadvertent letdown isolation,w/RHRS(pre-com)
Indian Point 2 06/26/73	(W)	02/16/72	420	670	140	C-Unknown cause, w/o RHRS (pre-com)
		02/17/72	420	650	180	C-Operator isolated letdown, w/RHRS (pre-com)
		03/08/72	400	640	115	P-Reactor coolant pump restart (pre-com)
		04/06/72	422	680	170	C-Operator isolated letdown, w/RHRS (pre-com)
		05/18/73	440	575	130	C-Letdown isolated, w/RHRS (pre-com)
		01/23/74	425	525	190	P-Reactor coolant pump restart
		02/22/74	150	560	115	S-Inadvertent safety injection, accumulator
		09/12/76	400	515	110	C-Letdown isolated, air loss, w/RHRS
Indian Point 3 04/27/76	(W)	09/30/76	50	2250	185	R-RHR isolation, spurious
Oconee 2 12/05/73	(BW)	11/15/73	800	1860	300	Q-Procedure error, physics tests (pre-com)
Palisades 12/31/71	(CE)	09/01/74	N/A	960	150	Q-Operator error
Point Beach 2 08/02/72	(W)	12/10/74	345	1400	170	S-Inadvertent safety injection
		02/28/76	400	830	168	R-RHR isolated, reduced letdown
Prairie Island 1 12/04/73	(W)	10/31/73	430	1100	132	P-Reactor coolant pump restart (pre-com)
		01/16/74	395	840	90	S-Inadvertent safety injection, accumulator
Prairie Island 2 12/21/74	(W)	11/27/74	N/A	900	155	C-Inadvertent letdown isolation,w/RHRS(pre-com)
Surry 1 07/04/72	(W)	01/28/73	450	590	80	S-Inadvertent safety injection, accumulator
St. Lucie 1 05/07/76	(CE)	08/1[illegible]/75	210	600	105	C-Inadvertent letdown isolation,w/SDCS(pre-com)
		06/17/76	435	815	100	P-Reactor coolant pump restart
Trojan(2) 12/23/75	(W)	07/22/75	400	3326	100	R-RHR isolation, charging pumps (pre-com)
Turkey Point 3 11/02/72	(W)	12/03/74	50	800	105	R-RHR isolation
Zion 1 06/28/73	(W)	06/13/73	110	1290	105	C-Operator error (pre-com)
		06/03/75	100	1100	115	R-RHR isolation
Zion 2 12/26/73	(W)	09/18/75	95	1300	88	R-RHR isolation

(1) First one/two letters used to code data, see Table A.1.

(2) Apparently pressurizer PORVs and SRV were isolated at time of event.

Table A.3 Summary of NUREG/CR-2789 data.

Reactor (Commercial)	Type	Date	Pressure (psi) From	To	Temperature (Deg F)	Cause[1]
Davis-Besse 08/28/77	(BW)	04/19/80	N/A		140	S-Inadvertent SI, maintenance, 3500 gals, to 170F [LTOP set-pressure is 330 psi]
D.C. Cook 1 02/10/75	(W)	07/23/81	100	325		C-filling and venting
Farley 1 08/18/77	(W)	10/24/79	N/A			S-Inadvertent SI, maintenance, precursor event
McGuire 1 09/12/81	(W)	03/30/81[2]	N/A			S-Inadvertent SI, maintenance, precursor (pre-com)
		03/30/81[2]	N/A			S-Inadvertent SI, maintenance, precursor (pre-com)
		04/29/81	N/A			S-Inadvertent SI, maintenance, precursor (pre-com)
		05/07/81	None			S-Inadvertent SI, oper. error, precursor (pre-com)
Millstone 2 11/09/75	(CE)	03/14/79	N/A			R-RHR (SDC) LPSI pump stopped, precursor event
		03/14/79	Temp			R-RHR (SDC) isolation, precursor event
Oconee 3 09/18/74	(BW)	10/19/79	308	360	200	C-excess make-up, operator error
Surry 1 07/04/72	(W)	10/01/72	Temp			O-SG blowdown, valve failure, precursor event
		04/26/80	N/A			S-Inadvertent SI, maintenance, precursor event
		04/30/80	N/A			S-Inadvertent SI, maintenance, precursor event
Zion 2 12/26/73	(W)	05/25/76	N/A			S-Inadvertent safety injection, precursor event
		09/03/80	N/A			S-Inadvertent safety injection, 1 min, precursor

(1) First one/two letters used to code data, see Table A.1.

(2) Two events reported.

Table A.4 Summary of AEOD Case Study C401 data.

Reactor (Commercial)	Type	Date	Pressure (psi) From	Pressure (psi) To	Temperature (Deg F)	Cause (1)
Calvert Cliff 1 01/03/75	(CE)	04/26/83 04/26/83		425	198	(*)O-Operator error, closes one PORV 2O-Operator error, 17 minutes
R.E. Ginna 12/02/69	(W)	06/09/83 (2)		S.P.		(*)C-Excess charging [LTOP set-pressure 435 psi]
North Anna 1 04/17/78	(W)	03/29/81		S.P.		(*)S-Inadvertent safety injection [LTOP set-pressure 430 psi]
North Anna 2 08/25/80	(W)	05/18/82 05/24/82 05/23/83 (3)		S.P. S.P. 387	 115	(*)P-Reactor coolant pump restart [LTOP 405 psi] (*)P-Reactor coolant pump restart (*)S-Inadvertent safety injection,3 min at 528 gpm
Palisades 12/31/71	(CE)	12/04/81 (4)		S.P.		(*)S-Inadvertent safety injection, 4 min [LTOP set-pressure 400 psi]
Salem 2 06/03/81	(W)	06/17/83		S.P.		(*)S-Inadvertent safety injection [LTOP set-pressure 375 psi]
San Onofre 2 09/20/82	(CE)	05/07/82 (2)		S.P.		C-Letdown decreased w/ charging, /SDCS(pre-com) [LTOP set-pressure 400 psi]
Surry 1 07/04/72	(W)	07/02/81 (4)		S.P.	190	(*)C-Inadvertent charging, FCV failure [LTOP set-pressure 410 psi]

(1) First one/two letters used to code data, see Table A.1.

(2) All AEOD events, with the exception of these two special reports, were also located in the LER Update Search performed 9/4/86.

(3) Listed under Unit 1 in AEOD report.

(4) Event date listed as 1982 in AEOD report, corrected to 1981 based on LER Update Search of 09/4/86.

(*) Events considered in developing base case risk analysis.

Table A.5 Summary of LER Update Search data.

Reactor (Commercial)	Type	Date	Pressure (psi) From	Pressure (psi) To	Temperature (Deg F)	Cause[1]
Byron 1 03/01/85	(W)	03/18/85	N/A			(*)S-Oper. error, inadvertent SI, precursor
Callaway 1 12/19/84	(W)	07/16/84	350	425	140	C-Excess charging, loss of instr. air (pre-com)
		07/16/84	350	425	140	C-Excess charging, loss of instr. air (pre-com)
		04/05/86	380	463	104	(*)C-Excess charging, RCP seal injection valve failure
Catawba 2 5/18/86	(W)	04/09/86	260	399		C-Letdown isolated by operator (pre-com)
Calvert Cliffs 1 01/03/75	(CE)	10/20/85				2O-Calibration error, maintenance
D.C. Cook 2 03/22/78	(W)	01/08/83				2O-Low Air supply pressure, isolated during test
		07/03/83				2O-Loss of Air supply, 24 hours
		07/28/85	None			S-Inadvertent safety injection, precursor event
Farley 1 08/18/77	(W)	11/09/80	None			C-More than 1 CC pump available, precursor event
		11/07/86	400	450		(*)C-Operator error on pressure control
		11/15/86	400	450		(*)P-RCP restart, third pump
Farley 2 05/25/81	(W)	10/15/83[2]		700	170	(*)C-Excess charging, loss of instr. air
		10/15/83[2]				1O-Out for maintenance
		10/15/83[2]		480	170	(*)P-RCP restart
		10/15/83[2]				1O-Out for maintenance
R.E. Ginna 12/02/69	(W)	05/06/80				2O-Operator/procedure error, 14 hours
		05/22/84	None			S-Inadvertent SI, low SG pressure, precursor
Haddam Neck 08/07/77	(W)	11/30/83[2]				1O-Loss of Air supply
		11/30/83[2]				1O-Loss of Air supply
		08/03/84	315	380	325	Q-Unknown, PORVs open, oper. closed, no transient
		08/03/84				2O-Operator closed for 17 min.
		01/05/86				2O-Component failure, interlock
Maine Yankee 11/08/72	(CE)	07/17/81				1O-Out for maintenance, 7 hr 20 minutes
		12/01/83	None			Q-Operator error, outdated procedures, precursor
Mc Guire 1 09/12/81	(W)	03/10/82				1O-Calibration error, timing, maintenance
Mc Guire 2 05/23/83	(W)	04/13/83				1O-Instrument error, air in line, maintenance
		08/27/86	360	368	180	Q-Too close to set-point
		11/15/86	350	368	180	Q-Too close to set-point
Millstone 2 11/09/75	(CE)	06/15/85				2O-Procedure error, operator error
North Anna 1 04/17/78	(W)	03/ /78		575		Q-Electrical problem (pre-com)
		03/ /80		570		Q-Valve failure, RHR relief valve opens
		03/18/81				2O-Low N2 pressure, 1 out 8 hr then other fails
		11/10/82				2O-Block valve closed, 5 hours, maintenance
		10/09/83				1O-Loss of N2, 4 days
		09/14/84	350	410	88	(*)P-Reactor Coolant Pump restart
		12/16/85	None			S-10,000 gal accumulator, vented, precursor event
		12/19/85	350	395	135	(*)C-Charging and letdown control

(1) First one/two letters used to code data, see Table A.1.

(2) AEOD report, "Air Systems Problems in U.S. Light Water Reactors."

(3) Two events over a two week period.

(*) Events considered in developing base case risk analysis.

Table A.5 Summary of LER Update Search data (con't).

Reactor (Commercial)	Type	Date	Pressure (psi) From	Pressure (psi) To	Temperature (Deg F)	Cause [(1)]
North Anna 2	(W)	08/14/80				1O-Low N2 pressure, vented
08/25/80		11/02/80				1O-Low N2 pressure, 12 hours
		06/20/81				2O-Low N2 pressure, 7 hrs 45 min
		08/06/81 [(3)]				2O-Low N2 pressure, 8 hours
		08/17/81 [(3)]				2O-Low N2 pressure, 8 hours
Palisades	(CE)	08/13/83				2O-Procedure error, TS implementation,op. error
12/31/71		08/26/85	350	375		(*)P-Reactor coolant pump restart, third pump
		09/14/85				2O-Calibration error, cal. 8/27/85, maintenance
Palo Verde 1	(CE)	01/28/86	None			S-Inadvertent safety injection, precursor event
06/10/85		04/06/85				S-Inadvertent safety injection, precur.(precom)
Point Beach 2	(W)	10/25/82 [(2)]				1O-Loss of Air, operator error
08/02/72						
Prairie Island 1	(W)	10/ /74	N/A			S-Inadvertent safety injection
12/04/73						
H.B. Robinson 2	(W)	01/ /78	360	560	155	Q-Heatup when RHR pump stopped
09/26/70		11/04/83				1O-Component, limit switch
		12/15/84				2O-Air/N2 isolated, 1 hour
Salem 1	(W)	07/16/81				1O-PORV leak, isolated, 48 hours
12/25/76		01/06/82				1O-PORV leaked, isolated, 24 hours
		01/07/82				1O-Failed manual test,component,other open/vent
Salem 2	(W)	04/19/81 [(3)]				1O-PORV leak, isolated, 24 hours
06/03/81		04/23/81 [(3)]				1O-PORV leak, isolated, 3 days
		04/29/81 [(3)]				1O-PORV leak, isolated, 4 days
		05/15/81	330	360	175	Q-Operator error,maintenance, PZR bub(pre-com)
		06/12/81 [(4)]				2O-PORVs leak, isolated
		06/18/81 [(4)]				2O-PORVs leak, isolated
		07/09/81				1O-PORV leak, isolated
		01/22/83				2O-PORVs leak, isolated
		01/26/83				2O-PORV leak, other no Air
		04/25/83				2O-Blank in vent line, 6 hours, maintenance
		08/30/83				2O-Position indicator fails, 8 hours, component
		02/15/84	325	350		(*)P-Reactor coolant pump restart
		03/29/85	325	380		(*)P-Reactor coolant pump restart
		03/30/85	325	380		(*)P-Reactor coolant pump restart
San Onofre 1	(W)	11/10/83	300	522	120	(*)S-Inadvertent safety injection
07/16/67						
Surry 1	(W)	02/09/83				2O-Low backup Air pressure,normal air available
07/04/72		06/01/84	325	412	145	(*)C-Excess charging, operator error
		05/12/85	350	410	150	(*)C-Letdown decrease w/charging
Summer	(W)	05/06/85		450		(*)P-Reactor Coolant Pump restart [Note: RHR SRV failed to fully reseat]
11/16/82						
Trojan	(W)	05/21/85				S-SI signal 3 minutes, hear removed, precursor
12/23/75		10/21/86	none			Q-PORV open in 8 sec, should be 0.28 sec, maintenance (precursor event)

(1) First one/two letters used to code data, see Table A.1.

(2) AEOD report, "Air Systems Problems in U.S. Light Water Reactors."

(3) Three events over a one week period reported.

(4) Two events over a one week period reported.

(*) Events considered in developing base case risk analysis.

Table A.5 Summary of LER Update Search data (con't).

Reactor (Commercial)	Type	Date	Pressure (psi) From	To	Temperature (Deg F)	Cause [1]
Turkey Point 4 06/21/73	(W)	11/28/81	310	1100	110	(*)P-Reactor coolant pump restart
		11/29/81	340	750	110	(*)P-Reactor coolant pump restart
		11/28/81				20-1 maintenance, other fails
		11/29/81				20-1 maintenance, other fails
		10/09/84				10-Component failure PORV opens,operator closes
Yankee Rowe 11/10/60	(W)	07/17/81				10-Maintenance error
Zion 1 06/28/73	(W)	09/11/84		450		(*)C-Increased charging flow, op error
Zion 2 12/26/73	(W)	01/03/86 [2]	400	435		(*)R-RHR isolated letdown,w/charging 190 gpm
		01/03/86 [2]		435		(*)Q-possible electrical bus problem

(1) First one/two letters used to code data, see Table A.1.

(2) Two events reported.

(*) Events considered in developing base case risk analysis.

Table A.6 Summary of Babcock and Wilcox plants.[1]

Plant	MW(e)	Docket	Commercial Date	R-Yrs (12/86)	S	C	R	P	Q	Sum	Events /R-Yr	1O	1 Out /R-Yr	2O	2 Out /R-Yr	HP	HP /R-Yr
Arkansas One-1	836	50-313	8/ 1/74	12.4	-	-	-	-	-	-	---	-	---	-	---	-	---
Crystal River 3	825	50-302	1/30/77	9.9	-	-	-	-	-	-	---	-	---	-	---	-	---
Davis-Besse 1	880	50-346	8/28/77	9.3	1	-	-	-	-	1	.107	-	---	-	---	-	---
Oconee 1	860	50-269	5/ 6/73	13.7	-	-	-	-	-	-	---	-	---	-	---	-	---
Oconee 2	860	50-270	12/ 5/73	13.1	-	-	-	-	1	1	.077	-	---	-	---	1	.077
Oconee 3	860	50-287	9/ 1/74	12.3	-	1	-	-	-	1	.081	-	---	-	---	-	---
Rancho Seco 1	916	50-312	10/13/74	12.2	-	-	-	-	-	-	---	-	---	-	---	-	---
Three Mile 1	792	50-289	6/19/74	12.5	-	-	-	-	-	-	---	-	---	-	---	-	---

(1)
S-Safety injection
C-Charging/letdown
R-RHR isolation
P-RCP restart
Q-Other/oper. error
HP-High-pressure event, >500 psi
1O-One LTOP channel out
2O-Both LTOP channels out

Table A.7 Summary of Combustion Engineering plants.[1]

Plant	MW(e)	Docket	Commercial Date	R-Yrs (12/86)	S	C	R	P	Q	Sum	Events /R-Yr	1O	1 Out /R-Yr	2O	2 Out /R-Yr	HP	HP /R-Yr
Arkansas One-2*	858	50-368	12/26/78	8.0	-	-	-	-	-	-	---	-	---	-	---	-	---
Calvert Cliffs 1	845	50-317	1/ 3/75	12.0	-	-	-	-	1	1	.083	-	---	2	.167	-	---
Calvert Cliffs 2	845	50-318	12/ 7/76	10.1	-	-	-	-	-	-	---	-	---	-	---	-	---
Ft. Calhoun 1	478	50-285	8/25/73	13.4	-	-	-	-	-	-	---	-	---	-	---	-	---
Maine Yankee	790	50-309	11/ 8/72	14.1	-	-	-	-	1	1	.071	1	.071	-	---	-	---
Millstone 2	830	50-336	11/ 9/75	11.1	-	-	2	-	-	2	.180	-	---	1	.090	-	---
Palisades	798	50-255	12/31/71	15.0	1	-	-	1	1	3	.200	-	---	2	.133	1	.067
Palo Verde 1*	1270	50-528	6/10/85	1.6	2	-	-	-	-	2	1.250	-	---	-	---	-	---
Palo Verde 2*	1270	50-529	5/20/86	.6	-	-	-	-	-	-	---	-	---	-	---	-	---
San Onofre 2**	1070	50-361	9/20/82	4.3	-	1	-	-	-	1	.234	-	---	-	---	-	---
San Onofre 3**	1080	50-363	9/25/83	3.3	-	-	-	-	-	-	---	-	---	-	---	-	---
St. Lucie 1	810	50-335	5/ 7/76	10.7	-	1	-	1	-	2	.188	-	---	-	---	2	.188
St. Lucie 2	810	50-389	6/13/83	3.6	-	-	-	-	-	-	---	-	---	-	---	-	---
Waterford 3*	1165	50-382	3/18/85	1.8	-	-	-	-	-	-	---	-	---	-	---	-	---

(1)
S-Safety injection
C-Charging/letdown
R-RHR isolation
P-RCP restart
Q-Other/oper. error
HP-High-pressure event, >500 psi
1O-One LTOP channel out
2O-Both LTOP channels out

Notes:
*-LTOP with 2 SDCS SRVs
**-LTOP with 1 SDCS SRV

Table A.8 Summary of Westinghouse plants.(1)

Plant	MW(e)	Docket	Commercial Date	R-Yrs (12/86)	S	C	R	P	Q	Sum	Events /R-Yr	1O	1 Out /R-Yr	2O	2 Out /R-Yr	HP	HP /R-Yr
Beaver Valley 1	833	50-334	6/14/76	10.6	2	1	-	-	-	3	.284	-	---	-	---	3	.284
Byron 1#	1120	50-454	3/ 1/85	1.8	1	-	-	-	-	1	.556	-	---	-	---	-	---
Callaway 1#	1150	50-463	10/24/84	2.2	-	3	-	-	-	3	1.346	-	---	-	---	-	---
Catawba 1	1145	50-413	1/22/85	1.9	-	-	-	-	-	-	---	-	---	-	---	-	---
Catawba 2	1145	50-414	5/18/86	.6	-	1	-	-	-	1	1.613	-	---	-	---	-	---
Cook 1	1030	50-315	2/10/75	11.9	-	2	-	-	-	2	.168	-	---	-	---	1	.084
Cook 2	1090	50-316	3/22/78	8.8	1	-	-	-	-	1	.114	-	---	2	.228	-	---
Diablo Canyon 1	1084	50-275	11/11/84	2.1	-	-	-	-	-	-	---	-	---	-	---	-	---
Diablo Canyon 2	1106	50-323	10/20/85	1.2	-	-	-	-	-	-	---	-	---	-	---	-	---
Farley 1*	860	50-348	8/18/77	9.4	1	2	-	1	-	4	.426	-	---	-	---	-	---
Farley 2*	860	50-364	5/25/81	5.6	-	1	-	1	-	2	.357	2	.357	-	---	1	.179
Haddam Neck	582	50-213	8/ 7/67	19.4	-	-	-	-	1	1	.052	2	.103	2	.103	-	---
Indian Pt. 2	873	50-247	6/26/73	13.5	1	5	-	2	-	8	.592	-	---	-	---	8	.592
Indian Pt. 3	965	50-286	4/27/76	10.7	-	-	1	-	-	1	.094	-	---	-	---	1	.094
Kewaunee*	535	50-305	4/ 8/74	12.7	-	-	-	-	-	-	---	-	---	-	---	-	---
McGuire 1	1180	50-369	6/30/81	5.5	4	-	-	-	-	4	.727	1	.182	-	---	-	---
McGuire 2	1180	50-370	5/23/83	3.6	-	-	-	-	2	2	.554	1	.277	-	---	-	---
Millstone 3	1150	50-423	2/12/86	.9	-	-	-	-	-	-	---	-	---	-	---	-	---
North Anna 1	890	50-338	4/17/78	8.7	2	1	-	1	1	5	.505	1	.115	2	.230	-	---
North Anna 2	890	50-339	8/25/80	6.4	1	-	-	2	-	3	.472	2	.315	3	.472	-	---
Point Beach 1	497	50-266	11/ 6/70	16.2	-	-	-	-	-	-	---	-	---	-	---	-	---
Point Beach 2	497	50-301	8/ 2/72	14.4	1	-	1	-	-	2	.139	1	.069	-	---	2	.139
Prairie Island 1	507	50-282	12/ 4/73	13.1	2	-	-	1	-	3	.229	-	---	-	---	3	.229
Prairie Island 2	507	50-306	12/21/74	12.0	-	1	-	-	-	1	.083	-	---	-	---	1	.083
R.E. Ginna	470	50-244	12/ 2/69	17.1	1	2	-	-	-	3	.176	-	---	1	.059	1	.059
Robinson 2	655	50-261	9/26/70	16.2	-	-	-	-	1	1	.061	1	.062	1	.062	-	---
Salem 1	1090	50-272	12/25/76	10.0	-	-	-	-	-	-	---	3	.299	-	---	-	---
Salem 2	1115	50-311	6/ 3/81	5.6	1	-	-	3	1	5	1.030	4	.717	6	1.075	-	---
San Onofre 1	436	50-206	7/16/67	19.5	1	-	-	-	-	1	.051	-	---	-	---	-	---
Sequoyah 1**	1148	50-327	7/22/80	6.4	-	-	-	-	-	-	---	-	---	-	---	-	---
Sequoyah 2**	1148	50-328	12/23/81	5.0	-	-	-	-	-	-	---	-	---	-	---	-	---
Summer*	900	50-395	11/16/82	4.1	-	-	-	1	-	1	.244	-	---	-	---	-	---
Surry 1	775	50-280	7/ 4/72	14.5	3	3	-	-	1	7	.483	-	---	1	.069	1	.069
Surry 2	775	50-281	3/10/73	13.8	-	-	-	-	-	-	---	-	---	-	---	-	---
Trojan	1130	50-344	12/23/75	11.0	1	-	1	-	1	3	.273	-	---	-	---	1	.091
Turkey Pt. 3	728	50-250	11/ 2/72	14.2	-	-	1	-	-	1	.071	-	---	-	---	1	.071
Turkey Pt. 4	728	50-251	6/21/73	13.5	-	-	-	2	-	2	.148	1	.074	2	.148	2	.148
Wolf Creek#	1150	50-482	6/12/85	1.6	-	-	-	-	-	-	---	-	---	-	---	-	---
Yankee Rowe	175	50- 29	11/10/60	26.1	-	-	-	-	-	-	---	1	.038	-	---	-	---
Zion 1	1040	50-295	6/28/73	13.5	-	2	1	-	-	3	.222	-	---	-	---	2	.148
Zion 2	1040	50-304	12/26/73	13.0	2	-	2	-	1	5	.384	-	---	-	---	1	.077

(1) S-Safety injection
C-Charging/letdown
R-RHR isolation
P-RCP restart
Q-Other/oper. error
HP-High-pressure event, >500 psi
1O-One LTOP channel out
2O-Both LTOP channels out

Notes:
*-LTOP with 2 RHRS SRVs
**-Automatic LTOP
#-LTOP 2 PORVs or 2 SRVs

Table A.9(a) Combustion Engineering LTOP events summary - total data base.

Year	UNITS	R-Yrs	SI POST	SI PRE	CC POST	CC PRE	RHR POST	RHR PRE	RCP POST	RCP PRE	Others POST	Others PRE	Total Post-Com SUM	Total Post-Com Freq Per Unit	Total Post-Com Freq Per R-Yr	Total Pre-Com SUM	Total Pre-Com Freq Per Unit	Total Pre-Com Freq Per R-Yr	Total History SUM	Total History Freq Per Unit	Total History Freq Per R-Yr
69	-	.0	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
70	-	.0	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
71	1	.0	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
72	2	1.1	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
73	3	2.4	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
74	3	3.0	-	-	-	-	-	-	-	-	1	-	1	.333	.333	-	--	--	1	.333	.333
75	5	4.1	-	-	-	1	-	-	-	-	-	-	-	--	--	1	.200	.244	1	.200	.244
76	7	5.7	-	-	-	-	-	-	1	-	-	-	1	.143	.175	-	--	--	1	.143	.175
77	7	7.0	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
78	8	7.1	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
79	8	8.0	-	-	-	-	2	-	-	-	-	-	2	.250	.250	-	--	--	2	.250	.250
60-79	8	38.4	-	-	-	1	2	-	1	-	1	-	4	.500	.104	1	.125	.026	5	.625	.130
80	8	8.0	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
81	8	8.0	1	-	-	-	-	-	-	-	-	-	1	.125	.125	-	--	--	1	.125	.125
82	9	8.2	-	-	-	1	-	-	-	-	-	-	-	--	--	1	.111	.122	1	.111	.122
83	11	9.9	-	-	-	-	-	-	-	-	2	-	2	.182	.202	-	--	--	2	.182	.202
84	11	11.0	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
85	13	12.3	-	1	-	-	-	-	1	-	-	-	1	.077	.081	1	.077	.081	2	.154	.163
86	14	13.6	1	-	-	-	-	-	-	-	-	-	1	.071	.074	-	--	--	1	.071	.074
80-86	14	71.0	2	1	-	1	-	-	1	-	2	-	5	.357	.070	2	.143	.028	7	.500	.099
60-86	14	109.4	2	1	-	2	2	-	2	-	3	-	9	.643	.082	3	.214	.027	12	.857	.110

Table A.9(b) Combustion Engineering LTOP events summary - without precursor data.

Year	UNITS	R-Yrs	SI POST	SI PRE	CC POST	CC PRE	RHR POST	RHR PRE	RCP POST	RCP PRE	Others POST	Others PRE	Total Post-Com SUM	Total Post-Com Freq Per Unit	Total Post-Com Freq Per R-Yr	Total Pre-Com SUM	Total Pre-Com Freq Per Unit	Total Pre-Com Freq Per R-Yr	Total History SUM	Total History Freq Per Unit	Total History Freq Per R-Yr
69	-	.0	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
70	-	.0	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
71	1	.0	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
72	2	1.1	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
73	3	2.4	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
74	3	3.0	-	-	-	-	-	-	-	-	1	-	1	.333	.333	-	--	--	1	.333	.333
75	5	4.1	-	-	-	1	-	-	-	-	-	-	-	--	--	1	.200	.244	1	.200	.244
76	7	5.7	-	-	-	-	-	-	1	-	-	-	1	.143	.175	-	--	--	1	.143	.175
77	7	7.0	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
78	8	7.1	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
79	8	8.0	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
60-79	8	38.4	-	-	-	1	-	-	1	-	1	-	2	.250	.052	1	.125	.026	3	.375	.078
80	8	8.0	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
81	8	8.0	1	-	-	-	-	-	-	-	-	-	1	.125	.125	-	--	--	1	.125	.125
82	9	8.2	-	-	-	1	-	-	-	-	-	-	-	--	--	1	.111	.122	1	.111	.122
83	11	9.9	-	-	-	-	-	-	-	-	1	-	1	.091	.101	-	--	--	1	.091	.101
84	11	11.0	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
85	13	12.3	-	-	-	-	-	-	1	-	-	-	1	.077	.031	-	--	--	1	.077	.081
86	14	13.6	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
80-86	14	71.0	1	-	-	1	-	-	1	-	1	-	3	.214	.042	1	.071	.014	4	.286	.056
60-86	14	109.4	1	-	-	2	-	-	2	-	2	-	5	.357	.046	2	.143	.018	7	.500	.064

Table A.10(a) Westinghouse LTOP events summary - total data base.

Year	UNITS	R-Yrs	SI		CC		RHR		RCP		Others		Total Post-Com			Total Pre-Com			Total History		
			POST	PRE	POST	PRE	POST	PRE	POST	PRE	POST	PRE	SUM	Freq Per Unit	Freq Per R-Yr	SUM	Freq Per Unit	Freq Per R-Yr	SUM	Freq Per Unit	Freq Per R-Yr
69	4	3.1	-	-	-	1	-	-	-	-	-	-	-	--	--	1	.250	.323	1	.250	.323
70	6	4.4	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
71	6	6.0	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
72	9	7.1	-	-	-	3	-	-	-	1	1	-	1	.111	.141	4	.444	.563	5	.556	.704
73	15	11.4	1	-	-	2	-	-	-	1	-	-	1	.067	.088	3	.200	.263	4	.267	.351
74	17	15.8	4	-	-	1	1	-	1	-	-	-	6	.353	.380	1	.059	.063	7	.412	.443
75	19	17.9	-	-	-	-	2	1	-	-	-	-	2	.105	.112	1	.053	.056	3	.158	.168
76	22	20.2	1	2	2	1	2	-	-	-	-	-	5	.227	.248	3	.136	.149	8	.364	.396
77	23	22.4	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
78	25	24.5	-	-	-	-	-	-	-	-	1	1	1	.040	.041	1	.040	.041	2	.080	.082
79	25	25.0	1	-	-	-	-	-	-	-	-	-	1	.040	.040	-	--	--	1	.040	.040
60-79	25	168.8	7	2	2	8	5	1	1	2	2	1	17	.680	.101	14	.560	.083	31	1.240	.184
80	27	25.8	3	-	1	-	-	-	-	-	-	-	4	.148	.155	-	--	--	4	.148	.155
81	31	28.7	1	4	2	-	-	-	2	-	-	1	5	.161	.174	5	.161	.174	10	.323	.348
82	32	31.1	-	-	-	-	-	-	2	-	-	-	2	.063	.064	-	--	--	2	.063	.064
83	33	32.6	3	-	2	-	-	-	1	-	-	-	6	.182	.184	-	--	--	6	.182	.184
84	35	33.3	1	-	2	2	-	-	2	-	1	-	6	.171	.180	2	.057	.060	8	.229	.240
85	39	37.6	4	-	2	-	-	-	3	-	-	-	9	.231	.239	-	--	--	9	.231	.239
86	41	40.5	-	-	2	1	1	-	1	-	4	-	8	.195	.198	1	.024	.025	9	.220	.222
80-86	41	229.6	12	4	11	3	1	-	11	-	5	1	40	.976	.174	8	.195	.035	48	1.171	.209
60-86	41	398.4	19	6	13	11	6	1	12	2	7	2	57	1.390	.143	22	.537	.055	79	1.927	.198

Table A.10(b) Westinghouse LTOP events summary - without precursor data.

Year	UNITS	R-Yrs	SI		CC		RHR		RCP		Others		Total Post-Com			Total Pre-Com			Total History		
			POST	PRE	POST	PRE	POST	PRE	POST	PRE	POST	PRE	SUM	Freq Per Unit	Freq Per R-Yr	SUM	Freq Per Unit	Freq Per R-Yr	SUM	Freq Per Unit	Freq Per R-Yr
69	4	3.1	-	-	-	1	-	-	-	-	-	-	-	--	--	1	.250	.323	1	.250	.323
70	6	4.4	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
71	6	6.0	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
72	9	7.1	-	-	-	3	-	-	-	1	-	-	-	--	--	4	.444	.563	4	.444	.563
73	15	11.4	1	-	-	2	-	-	-	1	-	-	1	.067	.088	3	.200	.263	4	.267	.351
74	17	15.8	4	-	-	1	1	-	1	-	-	-	6	.353	.380	1	.059	.063	7	.412	.443
75	19	17.9	-	-	-	-	2	1	-	-	-	-	2	.105	.112	1	.053	.056	3	.158	.168
76	22	20.2	-	2	2	1	2	-	-	-	-	-	4	.182	.198	3	.136	.149	7	.318	.347
77	23	22.4	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
78	25	24.5	-	-	-	-	-	-	-	-	1	1	1	.040	.041	1	.040	.041	2	.080	.082
79	25	25.0	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
60-79	25	168.8	5	2	2	8	5	1	1	2	1	1	14	.560	.083	14	.560	.083	28	1.120	.166
80	27	25.8	-	-	-	-	-	-	-	-	1	-	1	--	--	-	--	--	-	--	--
81	31	28.7	1	-	1	-	-	-	2	-	-	1	4	.129	.139	1	.032	.035	5	.161	.174
82	32	31.1	-	-	-	-	-	-	2	-	-	-	2	.063	.064	-	--	--	2	.063	.064
83	33	32.6	3	-	2	-	-	-	1	-	-	-	6	.182	.184	-	--	--	6	.182	.184
84	35	33.3	-	-	2	2	-	-	2	-	-	-	4	.114	.120	2	.057	.060	6	.171	.180
85	39	37.6	1	-	2	-	-	-	3	-	-	-	6	.154	.160	-	--	--	6	.154	.160
86	41	40.5	-	-	2	1	1	-	1	-	1	-	5	.122	.123	1	.024	.025	6	.146	.148
80-86	41	229.6	5	-	9	3	1	-	11	-	2	1	27	.659	.118	4	.098	.017	31	.756	.135
60-86	41	3:8.4	10	2	11	11	6	1	12	2	3	2	41	1.000	.130	18	.439	.045	59	1.439	.148

Table A.11(a) Total LTOP events summary - total W and CE data base.

			SI		CC		RHR		RCP		Others		Total Post-Com			Total Pre-Com			Total History		
Year	UNITS	R-Yrs	POST	PRE	POST	PRE	POST	PRE	POST	PRE	POST	PRE	SUM	Freq Per Unit	Freq Per R-Yr	SUM	Freq Per Unit	Freq Per R-Yr	SUM	Freq Per Unit	Freq Per R-Yr
60-79	33	207.2	7	2	2	9	7	1	2	2	3	1	21	.636	.101	15	.455	.072	36	1.091	.174
80-86	55	300.6	14	5	11	4	1	-	12	-	7	1	45	.818	.150	10	.182	.033	55	1.000	.183
60-86	55	507.8	21	7	13	13	8	1	14	2	10	2	66	1.200	.130	25	.455	.049	91	1.655	.179

Table A.11(b) Total LTOP events summary without precursor data - total W and CE data base.

			SI		CC		RHR		RCP		Others		Total Post-Com			Total Pre-Com			Total History		
Year	UNITS	R-Yrs	POST	PRE	POST	PRE	POST	PRE	POST	PRE	POST	PRE	SUM	Freq Per Unit	Freq Per R-Yr	SUM	Freq Per Unit	Freq Per R-Yr	SUM	Freq Per Unit	Freq Per R-Yr
60-79	33	207.2	5	2	2	9	5	1	2	2	2	1	16	.485	.077	15	.455	.072	31	.939	.150
80-86	55	300.6	6	-	9	4	1	-	12	-	3	1	30	.545	.100	5	.091	.017	35	.636	.115
60-86	55	507.8	11	2	11	13	6	1	14	2	5	2	46	.838	.091	20	.364	.039	66	1.200	.130

Table A.12(a) Combustion Engineering one LTOP channel unavailable summary.

			Maint.		Op Err		Compnt		Leaks		Air/N2		Total Post-Com			Total Pre-Com			Total History		
Year	UNITS	R-Yrs	POST	PRE	POST	PRE	POST	PRE	POST	PRE	POST	PRE	SUM	Freq Per Unit	Freq Per R-Yr	SUM	Freq Per Unit	Freq Per R-Yr	SUM	Freq Per Unit	Freq Per R-Yr
80	8	8.0	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
81	8	8.0	1	-	-	-	-	-	-	-	-	-	1	.125	.125	-	--	--	1	.125	.125
82	9	8.2	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
83	11	9.9	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
84	11	11.0	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
85	13	12.3	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
86	14	13.6	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
80-86	14	71.0	1	-	-	-	-	-	-	-	-	-	1	.071	.014	-	--	--	1	.071	.014

Table A.12(b) Combustion Engineering both LTOP channels unavailable summary.

			Maint.		Op Err		Compnt		Leaks		Air/N2		Total Post-Com			Total Pre-Com			Total History		
Year	UNITS	R-Yrs	POST	PRE	POST	PRE	POST	PRE	POST	PRE	POST	PRE	SUM	Freq Per Unit	Freq Per R-Yr	SUM	Freq Per Unit	Freq Per R-Yr	SUM	Freq Per Unit	Freq Per R-Yr
80	8	8.0	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
81	8	8.0	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
82	9	8.2	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
83	11	9.9	-	-	2	-	-	-	-	-	-	-	2	.182	.202	-	--	--	2	.182	.202
84	11	11.0	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
85	13	12.3	2	-	1	-	-	-	-	-	-	-	3	.231	.244	-	--	--	3	.231	.244
86	14	13.6	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
80-86	14	71.0	2	-	3	-	-	-	-	-	-	-	5	.357	.070	-	--	--	5	.357	.070

Table A.13(a) Westinghouse one LTOP channel unavailable summary.

			Maint.		Op Err		Compnt		Leaks		Air/N2		Total Post-Com			Total Pre-Com			Total History		
Year	UNITS	R-Yrs	POST	PRE	POST	PRE	POST	PRE	POST	PRE	POST	PRE	SUM	Freq Per Unit	Freq Per R-Yr	SUM	Freq Per Unit	Freq Per R-Yr	SUM	Freq Per Unit	Freq Per R-Yr
80	27	25.8	-	-	-	-	-	-	-	-	1	1	1	.037	.039	1	.037	.039	2	.074	.078
81	31	28.7	1	-	-	-	-	-	2	3	-	-	3	.097	.105	3	.097	.105	6	.194	.209
82	32	31.1	1	-	-	-	1	-	1	-	1	-	4	.125	.129	-	--	--	4	.125	.129
83	33	32.6	2	1	-	-	1	-	-	-	3	-	6	.182	.184	1	.030	.031	7	.212	.215
84	35	33.3	-	-	-	-	1	-	-	-	-	-	1	.029	.030	-	--	--	1	.029	.030
85	39	37.6	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
86	41	40.5	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
80-86	41	229.6	4	1	-	-	3	-	3	3	5	1	15	.366	.065	5	.122	.022	20	.488	.087

Table A.13(b) Westinghouse both LTOP channels unavailable summary.

			Maint.		Op Err		Compnt		Leaks		Air/N2		Total Post-Com			Total Pre-Com			Total History		
Year	UNITS	R-Yrs	POST	PRE	POST	PRE	POST	PRE	POST	PRE	POST	PRE	SUM	Freq Per Unit	Freq Per R-Yr	SUM	Freq Per Unit	Freq Per R-Yr	SUM	Freq Per Unit	Freq Per R-Yr
80	27	25.8	-	-	1	-	-	-	-	-	-	-	1	.037	.039	-	--	--	1	.037	.039
81	31	28.7	2	-	-	-	-	-	2	-	4	-	8	.258	.279	-	--	--	8	.258	.279
82	32	31.1	1	-	-	-	-	-	-	-	-	-	1	.031	.032	-	--	--	1	.031	.032
83	33	32.6	1	-	-	-	1	-	2	-	3	-	7	.212	.215	-	--	--	7	.212	.215
84	35	33.3	-	-	1	-	-	-	-	-	1	-	2	.057	.060	-	--	--	2	.057	.060
85	39	37.6	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
86	41	40.5	-	-	-	-	1	-	-	-	-	-	1	.024	.025	-	--	--	1	.024	.025
80-86	41	229.6	4	-	2	-	2	-	4	-	8	-	20	.488	.087	-	--	--	20	.488	.087

Table A.14(a) Total for one LTOP channel unavailable summary.

			Maint.		Op Err		Compnt		Leaks		Air/N2		Total Post-Com			Total Pre-Com			Total History		
Year	UNITS	R-Yrs	POST	PRE	POST	PRE	POST	PRE	POST	PRE	POST	PRE	SUM	Freq Per Unit	Freq Per R-Yr	SUM	Freq Per Unit	Freq Per R-Yr	SUM	Freq Per Unit	Freq Per R-Yr
80	27	33.8	-	-	-	-	-	-	-	-	1	1	1	.029	.030	1	.029	.030	2	.057	.059
81	31	36.7	2	-	-	-	-	-	2	3	-	-	4	.103	.109	3	.077	.082	7	.179	.191
82	32	39.3	1	-	-	-	1	-	1	-	1	-	4	.098	.102	-	--	--	4	.098	.102
83	33	42.5	2	1	-	-	1	-	-	-	3	-	6	.136	.141	1	.023	.024	7	.159	.165
84	35	44.3	-	-	-	-	1	-	-	-	-	-	1	.022	.023	-	--	--	1	.022	.023
85	39	49.9	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
86	41	54.1	-	-	-	-	-	-	-	-	-	-	-	--	--	-	--	--	-	--	--
80-86	41	300.6	5	1	-	-	3	-	3	3	5	1	16	.291	.053	5	.091	.017	21	.382	.070

Table A.14(b) Total for both LTOP channels unavailable summary.

			Maint.		Op Err		Compnt		Leaks		Air/N2		Total Post-Com			Total Pre-Com			Total History		
Year	UNITS	R-Yrs	POST	PRE	POST	PRE	POST	PRE	POST	PRE	POST	PRE	SUM	Freq Per Unit	Freq Per R-Yr	SUM	Freq Per Unit	Freq Per R-Yr	SUM	Freq Per Unit	Freq Per R-Yr
80	27	33.8	-	-	1	-	-	-	-	-	-	-	1	.029	.030	-	--	--	1	.029	.030
81	31	36.7	2	-	-	-	-	-	2	-	4	-	8	.205	.218	-	--	--	8	.205	.218
82	32	39.3	1	-	-	-	-	-	-	-	-	-	1	.024	.025	-	--	--	1	.024	.025
83	33	42.5	1	-	2	-	1	-	2	-	3	-	9	.205	.212	-	--	--	9	.205	.212
84	35	44.3	-	-	1	-	-	-	-	-	1	-	2	.043	.045	-	--	--	2	.043	.045
85	39	49.9	2	-	1	-	-	-	-	-	-	-	3	.058	.060	-	--	--	3	.058	.060
86	41	54.1	-	-	-	-	1	-	-	-	-	-	1	.018	.018	-	--	--	1	.018	.018
80-86	41	300.6	6	-	5	-	2	-	4	-	8	-	25	.455	.083	-	--	--	25	.455	.083

Table A.15 Pressure/temperature data summary.

	Post Commercial Data									Pre-Commercial Data								
Yr	P psi	T F	U	P psi	T F	U	P psi	T F	U	P psi	T F	U	P psi	T F	U	P psi	T F	U
69										2485	100	(W)						
72										640	115	(W)	650	180	(W)	670	140	(W)
73	590	80	(W)							575	130	(W)	1100	132	(W)	1290	105	(W)
										1860	300	(BW)						
74	525	190	(W)	560	115	(W)	800	105	(W)	900	155	(W)						
	960	150	(CE)	840	90	(W)	1400	170	(W)									
75	1100	115	(W)	1300	80	(W)				600	105	(CE)	3326	100	(W)			
76	515	110	(W)	815	100	(W)	830	168	(W)	495	190	(W)	1000	130	(W)	1150	150	(W)
	1040	110	(W)	2250	185	(W)												
78	560	155	(W)															
79	360	200	(BW)															
80	330	140	(BW)															
81	410	190	(W)	750	110	(W) (1)	1100	110	(W) (1)	360	175	(W)						
83	425	198	(CE)	480	170	(W) (2)	522	120	(W)									
	700	170	(W) (2)															
84	380	325	(W)	410	88	(W)	412	145	(W)	425	140	(W)	425	140	(W)			
85	395	135	(W)	410	150	(W)	368	180	(W)									
86	368	180	(W)	463	104	(W)												

(1) Turkey Point 4 events of November 28 and 29, 1981.
(2) Farley 2 events of October 15, 1983.

Table A.16 Pressure data by event initiator summary.

	Safety Injection		Charging/Letdown /No Letdown		RHR Isolation		RCP Restart		Other Events Op. Errors	
Period	Post Com	Pre-Com	Post Com	Pre-Com	Post Com	Pre-Com	Post Com	Pre-Com	Post Com	Pre-Com
60-79	560	495	360 (BW)	575	800	3326	525	640	560	575
	590	1150	515	600 (CE)	830		815 (CE)	1100	960 (CE)	1860 (BW)
	840		1040	650	1100	1400			670	1300
				680	2250				900	
				1000				1290		
				2485						
80-86	330 (BW)		325	399	435		350		368	360
	375		376	400 (CE)			375 (CE)		368	
	387		395	425			380		425 (CE)	
	400 (CE)		410	425			380		435	
	430		410				405			
	522		412				405			
			435				410			
			450				450			
			450				450			
			463				480 (1)			
			700 (1)				750 (2)			
							1100 (2)			

Notes: Unless otherwise indicated data are for Westinghouse plants.
(1) Farley 2 events of October 15, 1983.
(2) Turkey Pointt 4 events of November 28 and 29, 1981.

APPENDIX B

SOURCE TERM EVALUATION

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The low-temperature overpressure transient source term was obtained from NUREG/CR-4999 (Ref. B.1), using the Source Term Code Package (STCP) for a late core melt with containment bypass from NUREG/CR-4551 (Ref. B.2). The generic value was calculated to be 9 million person-rems over a 30-year exposure period for a typical eastern site with an assumed population density of 100 persons per square mile over a 50-mile radius.

The release estimates were obtained for a late core melt with containment bypass. Table B.1 provides a comparison of the release fractions employed for this analysis as compared to PWR-2 and PWR-5 release categories.

Because of the differences in the vessel failure probability and because of differences between sites, it was not reasonable for the staff to select either a "typical" plant or use the "average" plant for this analysis (for example, use the values and impact for the "typical" or "average" plant and multiply the results by the number of plants within a group). The variation in plant-specific vessel failure probability, as well as the variation in site-specific consequence based on population density and environmental factors, are considered in this evaluation of risk.

To account for site-specific variables, population density, environmental conditions, and reactor size, the NUREG/CR-4999 generic consequence has been scaled to the Siting Source Term data provided in NUREG/CR-2723 (Ref. B.3).

For the 55 reactors considered in this detailed evaluation, the average value of the mean offsite health effect (in person-rem) was calculated for both the SST1 and SST2 release categories. (SST1 being similar to PWR-2 and SST2 similar to PWR-5.) Each plant-specific value (person-rem) was then scaled to the average value, in effect yielding a conversion factor to account for site-specific variability in population density and environmental conditions with the average value being considered as the typical, generic result.

The plant-specific consequence for the low-temperature overpressure event was then calculated by multiplying the NUREG/CR-4999 generic value by the scaling factor.

The results obtained were then multiplied by the power scale factor to obtain the final low-temperature overpressure event value in person-rem. The power scale factor accounts for differences in the source term resulting from different power levels between units.

SST1 and SST2 source terms were also evaluated as part of this effort. Since the NUREG/CR-2723 results were obtained for an infinite radius, the NUREG/CR-2723 SST1 and SST2 values were divided by three to adjust the values to a 50-mile radius. To confirm this assumption, comparison to recently calculated results (NUREG/CR-5015, Ref. B.4) for a 50-mile radius are provided in Table B.2. The scaling approach is shown to be reasonable and differs from the newer calculations by about a factor of two for the SST1 release. For the SST2 release, there is good agreement between the two calculations.

A comparison of the base case consequences, and averted dose, for the five methods of source term evaluation are provided in Table B.3. The scaling approach, based on fission product releases, is further demonstrated by comparing the results of scaling the generic release to both the higher SST1 and the lower SST2 release consequence.

The generic value assumption overpredicts the source term because site-specific variables such as population density, environmental conditions, and reactor power levels are not accounted for. The scaled results yield similar results and indicate the source term is less than the SST1 release category, as is expected based on the fission product release fractions (Table B.1). The SST2 value is used to estimate the consequences of a low-temperature overpressure event with containment isolation failure but with the fission product release mitigating systems (sprays and fan coolers) functional. Table B.4 presents the results of the scaling study as used in this evaluation.

A comparison of the consequence estimates for various plants and release categories is provided in Table B.5. The scaled SST1, LTOP, and scaled SST2 consequences, in person-rem, are listed. As seen, this evaluation adjusts the generic source term from NUREG/CR-4999 to account for site variables, including power and population densities.

REFERENCES FOR APPENDIX B

B.1 C. Hsu et al., "Estimation of Risk Reduction from Improved PORV Reliability in PWRs," Brookhaven National Laboratory, NUREG/CR-4999, BNL-NUREG-52101, Final Report, March 1988.

B.2 M. Khatib-Rahbar et al., "Evaluation of Severe Accident Risks and Potential Risk Reduction: Zion Power Plant," Brookhaven National Laboratory, NUREG/CR-4551, Vol. 5, Draft Report for Comment, BNL-NUREG-52029, February 1987.

B.3 D. R. Strip, "Estimates of the Financial Consequences of Nuclear Power Reactor Accidents," Sandia Laboratories, NUREG/CR-2723, SAND82-1110, November 1982.

B.4 T. L. Chu et al., "Improved Reliability of Residual Heat Removal Capability in PWRs As Related to Resolution of Generic Issue 99," Brookhaven National Laboratory, NUREG/CR-5015, BNL-NUREG-52121, May 1988.

B.5 L. T. Ritchie et al., "Calculations of Reactor Accident Consequences, Version 2, CRAC2 Computer Code, Users Guide," Sandia Laboratories, NUREG/CR-2326, SAND81-1994, April 1982.

B.6 D. C. Aldrich et al., "Technical Guidance for Siting Criteria Development," Sandia Laboratories, NUREG/CR-2239, SAND81-1549, December 1982.

Table B.1 Estimated environmental release fractions for a core melt accident resulting from a low-temperature overpressure event.

Category	Species								
	Kr	I	Cs	Te	Sr	Ru	La	Ce	Ba
PWR-2	0.9	0.7	0.5	0.3	0.06	0.02	0.004	0.004	0.05
LTOP	1.0	0.12	0.088	0.17	0.05	0.005	0.0014	0.003	0.005
PWR-5	0.3	0.03	0.009	0.005	0.001	0.0006	0.00007	0.00007	0.001

Table B.2 Comparison of 50-mile radius consequences.

Plant	Category	GI-99 Data NUREG/CR-5015 Values		GI-94 Data Scaled NUREG/CR-2723 Values
		MACCS P-Rem	CRAC2 P-Rem	CRAC2 P-Rem
Zion	PWR-2	2.37×10^7	3.04×10^7	2.03×10^7
	PWR-5	1.99×10^6	2.14×10^6	1.85×10^6
Indian Point	PWR-2	7.10×10^7		3.59×10^7
	PWR-5	7.22×10^6		3.16×10^6
Generic Site	PWR-2	4.38×10^6		8.90×10^6
	PWR-5	6.10×10^5		6.40×10^5

MACCS - "MELCOR Accident Consequence Code System (MACCS)," D.I. Chanin et al., Sandia National Laboratories, NUREG/CR-4691 (to be published).

CRAC2 - "Calculations of Reactor Accident Consequences Version 2 - CRAC2," Reference B.5.

Table B.3 Consequences evaluation comparisons (40 PORV plus 15 RHR SRV plants).

	Generic Value P-Rem	SST1 Scaled Value P-Rem	SST2 Scaled Value P-Rem	SST1 Value P-Rem	SST2 Value P-Rem
Base Case	41,900	29,600	29,500	36,400	2,600
Averted	37,400	26,700	26,700	32,900	2,300

Generic Value Case - All plants at 9.0×10^6 person-rems.

Table B.4 Consequences estimates in person-rem for low-temperature overpressure events (40 PORV plus 15 RHR SRV plants).

	Best Estimate (50% Scaled SST1 plus 50% SST2)	High Estimate (Scaled SST1)	Low Estimate (10% Scaled SST1 plus 90% SST2)
Base Case **Before Improvements**	16,000	29,600	5,300
Averted Dose **For Proposed Resolution**	14,500	26,700	4,700

Table B.5 Comparison of consequences for various sites and releases.

	Release Category			50-Mile Radius Population[1]	
Plant Site	SST1 P-Rem	LTOP P-Rem	SST2 P-Rem	Per Sq. Mile in 1982	Per Sq. Mile in 2000
Byron	16.00×10^6	13.20×10^6	1.20×10^6	112	175
North Anna	9.39×10^6	7.63×10^6	0.35×10^6	109	185
Fort Calhoun	2.30×10^6	1.87×10^6	0.28×10^6	91	155
Zion	20.30×10^6	16.50×10^6	1.85×10^6	888	1369
Calvert Cliffs	12.00×10^6	9.80×10^6	0.58×10^6	310	501
Indian Point	31.60×10^6	25.60×10^6	2.78×10^6	2099	2998

Note: (1) Estimated from NUREG/CR-2239 (Ref. B.6).

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APPENDIX C

INDUSTRY IMPLEMENTATION COST ANALYSIS DATA BASE

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The proposed resolution for GI-94 would require a revision to the plant technical specification for overpressure protection. It is also assumed that the cooldown and heatup procedures will be revised to reflect the changes to the technical specification.

The basis for the industry cost estimates are Abstract 2.2.1, "Licensee Costs for Technical Specification Change," and Abstract 2.2.2, "Industry Costs for Writing or Rewriting Procedures," from NUREG/CR-4627 (Ref. C.1). Abstract 6.4, "Time-Based Cost Adjustments," from NUREG/CR-4627 was used to escalate the costs to 1988 dollars.

Table C.1 provides the current cost estimates for these changes for each classification. Under the complex cost assumption, it is also assumed that only one of the two procedure modifications will be costed as complex. Modification to the second procedure will be considered as simple, based on completion of a similar task.

In addition to costs associated with changes to the technical specification and cooldown and heatup procedures, the required operability of both low-temperature overpressure protection channels could increase the duration of a nonrefueling shutdown. The cost is associated with providing additional replacement power. The present value of the replacement cost is evaluated based on a 5% discounting over the remaining average plant lifetime.

Specifically, replacement power costs would be incurred if an inoperable channel were discovered during shutdown and if reactor restart were delayed by the repair of the inoperable channel. Replacement power costs are applicable only for plants in the PORV category for low-temperature overpressure protection, where these costs may result from potential failure of the PORV actuation mechanisms detected by required surveillance. Safety relief valve surveillances are not required except during a refueling outage and are assumed not to extend the duration of the shutdown. It is assumed that there are four nonrefueling shutdowns each year of reactor operation. According to the current technical specifications, PORV actuation channel circuits must be tested within 31 days after entering a mode where the PORV is required to be operable for low-temperature overpressure protection, and every 31 days thereafter. Since most shutdowns will be unscheduled, surveillance is assumed to occur immediately before entering the low-temperature overpressure protection mode. If the surveillance fails, it is assumed that the failed channel can be repaired in parallel with the required shutdown activity without extending the shutdown duration.

It is assumed that there are four nonrefueling shutdowns per reactor year per plant. In most cases the shutdown mode will be exited prior to the need for repeated surveillance. It is assumed that 5% of the time (once every five years) surveillance is required prior to restart. Further, assuming that the probability of fixing the channel actually delays the startup 5% of the time and that the channel unavailability is 0.087 per demand, the frequency of delayed startup is estimated to be:

(4 shutdowns/year) x (0.05 delays) x
(2 channels) x (0.087/demand) x (0.05 repair delays)

$= 1.74 \times 10^{-3}$ delays per reactor year.

The average annual cost of a delayed startup, based on a 4-hour delay, is estimated to be (4 hr/24 hr) x \$500,000/day x 1.74×10^{-3} per reactor year, or \$145. At a discount rate of 5%, the present value of the replacement power cost is \$2,000 per PORV plant, over the average remaining lifetime of the PORV plants (24 years). At a 10% discount, the present value is \$1,400. If the need to return an inoperable channel to service occurs once per reactor year, then the cost of replacement power would be five times greater than assumed, or \$10,000 per plant (at a 5% discount rate).

The number of Westinghouse and Combustion Engineering plants considered in the consequence evaluation is 55 units, 41 Westinghouse and 14 Combustion Engineering units. The proposed resolution for GI-94 will also impact on plants in the construction phase or licensed after the end of 1986. These new units total 12, 11 Westinghouse plants and one Combustion Engineering plant. It is assumed that these new Westinghouse units will allow either PORVs or SRVs for low-temperature overpressure protection and will use the standard technical specification format. They are accordingly assigned to the RHR SRV STS category.

REFERENCE FOR APPENDIX C

C.1 Science and Engineering Associates, Inc., et al., "Generic Cost Estimates: Abstracts from Generic Studies for Use in Preparing Regulatory Impact Analyses," NUREG/CR-4627, June 1986.

Table C.1 Industry unit costs for technical specification and procedure revisions.

	Simple	Complex
Technical Specification	$16,000 (1985) $17,400 (1988)	$32,000 (1985) $34,800 (1988)
Cooldown Procedure	$ 900 (1986) $ 950 (1988)	$ 3,600 (1986) $ 3,800 (1988)
Heatup Procedure	$ 900 (1986) $ 950 (1988)	$ 900 (1986) $ 950 (1988)
Total (1988 $s)	$19,300 (1988)	$39,600 (1988)

APPENDIX D

NRC IMPLEMENTATION COST ANALYSIS DATA BASE

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The proposed resolution for GI-94 would require a revision to the plant technical specification for overpressure protection. The NRC implementation cost is primarily associated with the review and approval of the revision and the costs incurred for Federal Register notices.

The basis for the NRC cost estimate is Abstract 5.1, "NRC Costs for Technical Specification Change," from NUREG/CR-4627 (Ref. D.1). Abstract 6.4, "Time-Based Cost Adjustments," from NUREG/CR-4627 was used to escalate the cost to 1988 dollars.

The simple cost estimate is $14,200 per unit and the complex cost estimate is $27,400 per unit.

REFERENCE FOR APPENDIX D

D.1 Science and Engineering Associates, Inc., et al., "Generic Cost Estimates: Abstracts from Generic Studies for Use in Preparing Regulatory Impact Analyses," NUREG/CR-4627, June 1986.

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APPENDIX E

PRESENT VALUE COST ANALYSIS DATA BASE

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Including costs of averted plant damage, replacement power, and offsite costs can significantly affect the overall cost-benefit evaluation. In addition, the present value associated with these factors can serve as a measure of the worth of a proposed alternative. If two or more proposed alternatives could achieve similar risk reduction, but with markedly different costs, then the present value estimates could be used to evaluate the relative worth of an alternative.

The estimated cost for cleanup and repair of a plant following a core damage accident is estimated at $1.2 billion. The present value associated with cleanup and repair is summed over each unit based on the core damage frequency reduction estimate for the proposed resolution for GI-94 and with a 10-year period for cleanup and repair. Discounts of 10% and 5% are assumed. The methodology described in Section 3.6, "Onsite Property," of NUREG/CR-3568 (Ref. E.1) is used for this evaluation.

The present value for replacement power following a core damage accident is estimated based on the summation of the discounted cost for each unit. The replacement power costs, by region, used in this analysis are provided in Table E.1 (taken from NUREG/CR-4568 -- Ref. E.2). The methodology described in Section 3.6, "Onsite Property," of NUREG/CR-3568 (Ref. E.1) is used for this evaluation. The estimated present value costs for cleanup and repair and for replacement power are provided in Table E.2. Discounts of 10% and 5% are assumed.

In addition to onsite property damage, offsite costs can be incurred as a result of the accident. Both offsite health and offsite property damages are evaluated. The present value costs are obtained over the remainder of plant life, based on the expected reduction in accident frequency resulting from the proposed resolution for GI-94. The plant-specific costs are obtained from NUREG/CR-2723 (Ref. E.3) by first calculating the damage values by removing the discount factor (4% used in NUREG/CR-2723) to obtain the equivalent 1982 costs. A constant 7.5% inflation rate is assumed to obtain 1988 values. The present values are then obtained based on 10% and 5% discount rates using the methodology described in Section 3.5, "Offsite Property," of NUREG/CR-3568. Table E.3 summarizes the plant costs obtained, and Table E.4 summarizes the present value costs associated with avoided offsite damage.

The present value costs for the 40 PORV and 15 RHR SRV plants are provided in Table E.5. Discount rates of 10% and 5% are shown. The cleanup and repair and the replacement power costs are discounted over a 10-year period, assuming that the plant would be returned to operation. The offsite costs, health and property damages, are discounted over the remaining life of the plants. These data represent the estimated costs associated with the "No Action" alternative, that is, they are calculated for a 100% reduction in the current base case risk, 3.24×10^{-6} per reactor year frequency of a through wall crack leading to core damage and fission product release.

REFERENCES FOR APPENDIX E

E.1 S. W. Heaberlin et al., "A Handbook for Value/Impact Assessment," Pacific Northwest Laboratories, NUREG/CR-3568, PNL-4646, December 1983.

E.2 J. R. Ball, "A Handbook for Quick Estimates: A Method for Developing Quick Approximate Estimates of Costs for Generic Actions for Nuclear Power Plants," Argonne National Laboratory, NUREG/CR-4568, ANL/EES-TM-297, April 1986.

E.3 D. R. Strip, "Estimates of the Financial Consequences of Nuclear Power Reactor Accidents," Sandia Laboratories, NUREG/CR-2723, SAND82-1110, November 1982.

Table E.1 Daily replacement power cost estimates by region.

NERC Regions		Rate ($/kW-hr) (1984 $s)	Daily Cost(1) (1988 $s)
ECAR	East Central Area Reliability Coordination Agreement	0.020	457,000
ERCOT	Electric Reliability Council of Texas	0.035	801,000
MAAC	Mid-Atlantic Area Council	0.030	686,000
MAIN	Mid-America Interpool Network	0.024	549,000
MARCA	Mid-Continent Area Reliability Coordination Agreement	0.037	845,000
NPCC	Northeast Power Coordinating Council	0.023	526,000
SERC	Southeastern Electric Reliability Council	0.011	252,000
SPP	Southeast Power Pool	0.040	815,000
WSCC	Western Systems Coordinating Council	0.024	549,000
Average		0.026	594,000

Note: (1) Assume 5% year inflation in costs. Cost applies to an 1120 M(e) unit with an average capacity factor of 0.70. Specific-plant costs are multiplied by power scaling factor.

Table E.2 Estimated present value costs for avoided onsite property damage (40 PORV plus 15 RHR SRV plants).

	10% Discount Over 10 Years	5% Discount Over 10 Years
Cleanup and Repair	$1,200,000	$2,200,000
Replacement Power	$1,300,000	$2,400,000
Total	$2,500,000	$4,600,000

Table E.3 Comparison of offsite property damage costs.

Plant	Year of Operation	SST1 Offsite Cost Health ($)	SST1 Offsite Cost Property ($)	SST2 Offsite Cost Health ($)	SST2 Offsite Cost Property ($)
Average	1980	4.42×10^8	2.78×10^9	1.68×10^7	4.30×10^7
Indian Point	1974	24.10×10^8	14.20×10^9	7.29×10^7	17.50×10^7
Zion	1973	16.40×10^8	7.40×10^9	6.06×10^7	11.70×10^7
Palo Verde	1984	1.01×10^8	1.30×10^9	0.70×10^7	1.57×10^7

Table E.4 Estimated present value costs for avoided offsite health and property damage (40 PORV plus 15 RHR SRV plants).

	Based On SST1 Costs Over Plant Life		Based On SST2 Costs Over Plant Life	
	10% Discount	5% Discount	10% Discount	5% Discount
Offsite Health	$ 640,000	$ 970,000	$ 23,000	$ 36,000
Offsite Property	$4,060,000	$6,180,000	$ 63,000	$ 86,000
Total	$4,700,000	$7,150,000	$ 86,000	$ 122,000

Table E.5 Present value cost summary for 40 PORV and 15 RHR SRV plants (based on base case frequency - total value of averted damages).

	Present Value at 10% Discount ($1,000,000s)			Present Value at 5% Discount ($1,000,000s)		
Averted Cost Factor	PORV	RHR SRV	Total	PORV	RHR SRV	Total
Replace Power over 10 years	0.87	0.46	1.33	1.64	0.86	2.50
Cleanup/Repair over 10 years	0.98	0.41	1.39	1.87	0.79	2.66
SST1 Health over plant life	0.65	0.06	0.71	0.98	0.09	1.07
SST1 Property over plant life	3.92	0.57	4.49	5.94	0.88	6.82
SST2 Health over plant life	0.023	0.003	0.026	0.036	0.004	0.040
SST2 Property over plant life	0.059	0.010	0.069	0.090	0.016	0.106
Total Best Estimate	3.2	0.8	4.0	7.0	2.2	9.2
Total High Estimate	6.4	1.5	7.9	10.4	2.6	13.0
Total Low Estimate	0.6	0.2	0.8	4.0	2.1	6.1

U.S. NUCLEAR REGULATORY COMMISSION

STANDARD REVIEW PLAN

OFFICE OF NUCLEAR REACTOR REGULATION

3.2.2 SYSTEM QUALITY GROUP CLASSIFICATION

REVIEW RESPONSIBILITIES

Primary - Mechanical Engineering Branch (MEB)

Secondary - None

I. AREAS OF REVIEW

Nuclear power plant systems and components important to safety should be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety function to be performed.

The MEB reviews the applicant's classification system for pressure-retaining components such as pressure vessels, heat exchangers, storage tanks, pumps, piping, and valves in fluid systems important to safety, and the assignment by the applicant of quality groups to those portions of systems required to perform safety functions. Where required, specific information or assistance may be required from the ICSB to review electrical and instrumentation systems needed for functioning of plant features important to safety. This review which is coordinated with each branch that has primary review responsibility for these plant features is performed for both construction permit (CP) and operating license (OL) applications. Excluded from this review are: structures; internal parts of mechanical components such as shafts, seals, impellers, packing, and gaskets; fuel, electrical, and instrumentation systems, electrical valve actuation devices, and pump motors.

The applicant presents data in his safety analysis report (SAR) in the form of a table which identifies the fluid systems important to safety; the system components such as pressure vessels, heat exchangers, storage tanks, pumps, piping, and valves; the associated quality group classification, ASME Code and code class; and the quality assurance requirements. In addition, the applicant presents on suitable piping and instrumentation diagrams the system quality group classifications.

The MEB also performs the following reviews for the SRP sections indicated:

1. Determines the acceptability of the seismic classification of system components in accordance with SRP Section 3.2.1. The information may be combined with the information in this SRP section which may result in cross-referencing rather than repetition of the information,

2. Verifies that systems and components important to safety that are designated as Quality Groups A, B, C, or D items are constructed in accordance with the regulatory guides, industry codes and standards that are referenced in SRP Sections 3.2.1, 3.9.1 through 3.9.3, and

3. Determines the adequacy of the inservice testing program for pumps and valves in accordance with SRP Section 3.9.6.

II. ACCEPTANCE CRITERIA

Acceptance criteria is based on meeting the relevant requirements of the following regulations:

> 10 CFR Part 50, Appendix A, General Design Criterion 1 and 10 CFR Part 50, § 50.55a, as they relate to the requirement that structures, systems, and components important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety function to be performed.

To meet the requirements of General Design Criterion 1 and 10 CFR Part 50, § 50.55a, the following regulatory guide is used:

> Regulatory Guide 1.26, "Quality Group Classification and Standards." This guide describes an acceptable method for determining quality standards for Quality Group B, C, and D water- and steam-containing components important to safety of water-cooled nuclear power plants.

III. REVIEW PROCEDURES

Selection and emphasis of various aspects of the areas covered by this SRP section will be made by the reviewer on each case. The judgement on the areas to be given attention during the review is to be based on an inspection of the material presented, the similarity of the material to that recently reviewed on other plants, and whether items of special safety significance are involved.

Section 50.55a of 10 CFR Part 50 identifies those ASME Section III, Code Class 1 components of light-water-cooled reactors important to safety which are part of the reactor coolant pressure boundary. These components are designated in Regulatory Guide 1.26 as Quality Group A. In addition, Regulatory Guide 1.26 identifies, on a functional basis, water- and steam-containing components of those systems important to safety that are Quality Groups B and C. Quality Group D applies to water- and steam-containing components of systems that are less important to safety. An applicant may use the NRC Group Classification system identified in Regulatory Guide 1.26 or, alternately, the corresponding ANS classification system of Safety Classes which can be cross-referenced with the classification groups in Regulatory Guide 1.26. There are also systems of light-water-cooled reactors important to safety that are not identified in Regulatory Guide 1.26 and which the staff considers should be classified Quality Group C. Examples of these systems are: diesel fuel oil storage and transfer system; diesel engine cooling water system, diesel engine lubrication system, diesel engine starting system, diesel engine combustion air intake and exhaust system, and instrument and service air systems required to perform a safety function; and certain ventilation plant systems. Gas treatment systems which are considered as engineered safeguards systems should be classified Quality Group B.

The information supplied in the application identifying fluid systems important to safety is reviewed for completeness, and the quality group classification, ASME Code and code class, and quality assurance requirements of each individual major component are checked for compliance with the above criteria. The various modes of system operation are checked to assure that the assigned NRC quality groups are acceptable.

The piping and instrumentation diagrams are reviewed to assure that the applicant has delineated in detail the system quality group classification boundaries for systems important to safety. Each individual line on a diagram is checked to assure the accuracy of the assigned quality group classification, including branch lines such as vent lines, drain lines, fill lines, test lines, and sample lines. Changes in quality group classification are permitted normally only at valve locations, with the valve assigned the higher classification. A change in quality group classification with no valve present is permitted only when it can be demonstrated that the safety function of the system is not impaired by a failure on the lower-classification side of the boundary.

The following fluid systems important to safety for pressurized water reactor (PWR) and boiling water reactor (BWR) plants are reviewed by the MEB with regard to quality group classification.

FLUID SYSTEMS IMPORTANT TO SAFETY FOR PWR PLANTS

Reactor Coolant System — Power Operated Relief Valves, Block Valves and Interconnecting Piping. 2.4.
Emergency Core Cooling System
Containment Spray System
Chemical and Volume Control System
Boron Thermal Regeneration System[1,2]
Boron Recycle System[1,2]
Residual Heat Removal System
Component Cooling Water System[2]
Spent Fuel Pool Cooling and Cleanup System[2]
Sampling System[3]
Service Water System[2]
Compressed Air System[1,2]
Emergency Diesel Engine Fuel Oil Storage and Transfer System
Emergency Diesel Engine Cooling Water System
Emergency Diesel Engine Starting System
Emergency Diesel Engine Lubrication System
Emergency Diesel Engine Combustion Air Intake and Exhaust System
Main Steam System[3]
Feedwater System[3]
Auxiliary Feedwater System
Steam Generator Blowdown System[3]
Containment Cooling System
Containment Purge System

Ventilation Systems for Areas such as Control Room and Engineered Safety Features Rooms
Combustible Gas Control System
Condensate Storage System[1]

FLUID SYSTEMS IMPORTANT TO SAFETY FOR BWR PLANTS

Reactor Recirculation System
Main Steam System (up to but not including the turbine)
Feedwater System (up to outermost containment isolation valve or shutoff valve, as applicable)
Relief Valve Discharge Piping
Control Rod Drive Hydraulic System[2]
Standby Liquid Control System
Reactor Water Cleanup System
Fuel Pool Cooling and Cleanup System[2]
Sampling System[3]
Residual Heat Removal System
High Pressure Core Spray System
Low Pressure Core Spray System
Reactor Core Isolation Cooling System
RHR Service Water System
Emergency Equipment Service Water System
Compressed Air System[1,2]
Emergency Diesel Engine Fuel Oil Storage and Transfer System
Emergency Diesel Engine Cooling Water System
Emergency Diesel Engine Starting System
Emergency Diesel Engine Lubrication System
Emergency Diesel Engine Combustion Air Intake and Exhaust System
Standby Gas Treatment System
Combustible Gas Control System
Containment Cooling System
Main Steam Isolation Valve Leakage Control System
Condensate and Refueling Water Storage System[2]
Ventilation Systems for Areas such as Control Room and Engineered Safety Features Rooms

Clarification of the Quality Group Classification provided in Regulatory Guide 1.26 and applicable to those portions of BWR main steam and feedwater systems (other than the reactor coolant pressure boundary) on the turbine side of the containment isolation valves, are given in Appendices A and B, attached to this SRP section.

Additional guidance on the quality group classification of systems and components important to safety for a typical PWR plant is given in Appendix C attached to this SRP section. Similarly, additional guidance on the quality group classification of systems and components important to safety for a typical BWR plant is given in Appendix D attached to this SRP section. Appendices C and D, in part, identify individual system components including appropriate interconnecting piping and valves, by quality group and the applicable code and

[1]On some plants this system may be non-safety-related, providing it complies with the requirements of Regulatory Guide 1.26.
[2]Portions of the system that perform a safety-related function.
[3]Portions of the system to outermost containment isolation valve.
[4]See insert attached.

INSERT FOR SRP 3.2.2, PAGE 3.2.2-3, FOOTNOTE 4 TO BE ADDED.

4. For PWR CP or PDA applications docketed on or after (date) these components should be identified as safety related if required to perform a safety-related function and a minimum of two PORVs and block valves, and associated controls should be provided. This would also include redundant and diverse control systems, designed to Seismic Category I requirements and environmentally qualified; increased technical specification surveillance requirements; increased inservice testing requirements; and inclusion within the scope of a quality assurance program that is in compliance with 10 CFR Part 50, Appendix B, in accordance with the guidance provided in Generic Letter 89-XX. The safety grade designation would include those improvements that were imposed subsequent to the TMI-2 accident, such as requirements to be powered from Class 1E buses and to provide valve position indication in the control room.

For all PWR operating reactors and all other PWR plants (custom or standard) for which issuance of the OL is expected before (date), these components should be in accordance with the guidance provided in Generic Letter 89-XX.

code class. Table 3.2.2-1 attached to this SRP section provides a summary of the construction Codes and Standards for components of water-cooled nuclear power plants and is based on the NRC quality group classification system in Regulatory Guide 1.26.

In the event an applicant intends to take exception to Regulatory Guide 1.26 and has not provided adequate justification for his proposed quality group classification, questions are prepared by the staff which may require additional documentation or an analysis to establish an acceptable basis for his proposed quality group classification. Staff comments may also be prepared requesting clarification, in order to assure a clear understanding of the quality group classifications assigned to a system by the applicant.

Exceptions and alternatives to the specified quality group classifications of Regulatory Guide 1.26 are unacceptable unless "equivalent quality level" is justified. In such cases, justification can be demonstrated if: the component is classified to meet the requirements of a higher group classification than specified in Regulatory Guide 1.26 or alternative design rules are based on the use of a more conservative design; the extent of component nondestructive examination is equal to or greater than required by the specified code; and the quality assurance requirements of Appendix B, 10 CFR Part 50 are met.

If the staff's questions are not resolved in a satisfactory manner, a staff position is taken requiring conformance to Regulatory Guide 1.26.

IV. EVALUATION FINDINGS

The staff's review should verify that adequate and sufficient information is contained in the SAR and amendments to arrive at a conclusion of the following type, which is to be included in the staff's safety evaluation report:

> Pressure-retaining components of fluid systems important to safety such as pressure vessels, heat exchangers, storage tanks, pumps, piping and valves have been classified Quality Group A, B, C, or D and have been identified in an acceptable manner in Table 3.X.X and on system piping and instrumentation diagrams in the SAR. These components have been constructed to quality standards commensurate with the importance of the safety function to be performed. The review of Quality Group A and B (ASME Section III, Class 1 and 2) reactor coolant pressure boundary components is discussed in Section 5.2.1.1 of the SER. Other Quality Group B components of systems identified in Position C.1.a through C.1.e of Regulatory Guide 1.26 are constructed to ASME Section III, Class 2. Components in systems identified in Postion C.2.a through C.2.d of Regulatory Guide 1.26 are constructed to Quality Group C standards, ASME Section III, Class 3. Components in systems identified in Position C.3 of Regulatory Guide 1.26 are constructed to Quality Group D standards such as, ASME Section VIII and ANSI B31.1.
>
> The staff concludes that pressure-retaining components of fluid systems important to safety have been properly classified as Quality Group A, B, C, or D items and meets the requirements of General Design Criterion 1, "Quality Standards and Records." This conclusion is based on the applicant having met the requirements of General Design Criterion 1 by having properly classified these

pressure-retaining components important to safety Quality Group A, B, C, or D in accordance with the positions of Regulatory Guide 1.26, "Quality Group Classifications and Standards," and by our conclusion that the identified pressure-retaining components are those necessary (1) to prevent or mitigate the consequences of accidents and malfunctions originating within the reactor coolant pressure boundary, (2) to permit shutdown of the reactor and maintain it in a safe shutdown condition, and (3) to contain radioactive materials.

V. IMPLEMENTATION

The following is intended to provide guidance to applicants and licensees regarding the NRC staff's plan for using this SRP section.

Except in those cases in which the applicant proposes an acceptable alternative method for complying with specified portions of the Commission's regulations, the method described herein will be used by the staff in its evaluation of conformance with Commission regulations.

Implementation schedules for conformance to parts of the method discussed herein are contained in the referenced Regulatory Guide.

V. REFERENCES

1. 10 CFR Part 50, Appendix A, General Design Criterion 1, "Quality Standards and Records."

2. Regulatory Guide 1.26, "Quality Group Classifications and Standards."

3. ASME Boiler and Pressure Vessel Code, 1980 Edition, Section III, "Nuclear Power Plant Components," American Society of Mechanical Engineers (1980).

4. ASME Boiler and Pressure Vessel Code, 1980 Edition, Section VIII, Division 1, "Pressure Vessels," American Society of Mechanical Engineers (1980).

5. ANSI/ASME B31.1-1980, "Power Piping," American National Standards Institute (1980).

6. API Standard 620, Sixth Edition, "Recommended Rules for Design and Construction of Large, Welded, Low-Pressure Storage Tanks," American Petroleum Institute (1977).

7. API Standard 650, Sixth Edition, Revision 1, "Welded Steel Tanks for Oil Storage," American Petroleum Institute (1978).

8. AWWA D100-79, "AWWA Standard for Steel Tanks-Standpipes, Reservoirs, and Elevated Tanks for Water Storage," American Water Works Association (1979).

9. ANSI B96.1-1980, "Specification for Welded Aluminum-Alloy Field-Erected Storage Tanks," American National Standards Institute (1980).

10. Appendix A, "Classification of Main Steam Components Other Than the Reactor Coolant Pressure Boundary for BWR Plants," attached to this SRP section.

11. Appendix B, "Classification of BWR/6 Main Steam and Feedwater Components Other Than the Reactor Coolant Pressure Boundary," attached to this SRP section.

TABLE 3.2.2-1

SUMMARY OF CONSTRUCTION[1] CODES AND STANDARDS FOR COMPONENTS OF WATER-COOLED NUCLEAR POWER PLANTS BY NRC QUALITY CLASSIFICATION SYSTEM[2]

Components	NRC Quality Classification System			
	Quality Group A	Quality Group B	Quality Group C	Quality Group D
Pressure Vessels	ASME Boiler and Pressure Vessel Code, Section III, Division 1, Subsection NB -Class 1, Nuclear Power Plant Components[3,4]	ASME Boiler and Pressure Vessel Code, Section III, Division 1, Subsection NC -Class 2, Nuclear Power Plant Components[3,4]	ASME Boiler and Pressure Vessel Code, Section III, Division 1, Subsection ND -Class 3, Nuclear Power Plant Components[3,4]	ASME Boiler and Pressure Vessel Code, Section VIII, Division 1.
Piping	As above	As above	As above	ANSI B31.1 Power Piping
Pumps	As above	As above	As above	Manufacturers standards.
Valves	As above	As above	As above	ANSI B31.1 Power Piping and ANSI B16.34
Atmospheric Storage Tanks	Not applicable	As above	As above	API-650, AWWA D100, or ANSI B96.1
0-15 psig Storage Tanks	Not applicable	As above	As above	API-620
Supports	As above except Subsection NF	As above except Subsection NF	As above except Subsection NF	Manufacturers standards
Metal Containment Components	Not applicable	As above except Subsection NE, Class MC	Not applicable	Not applicable
Core Support Structures	Not applicable	As above except Subsection NG	Not applicable	Not applicable

NOTES:

[1]As defined in Subsubarticle NCA-1110 of Section III, of the ASME Boiler and Pressure Vessel Code, construction is an all-inclusive term comprising materials, design, fabrication, examination, testing, inspection, and certification required in the manufacture and installation of components.

[2]As defined in Regulatory Guide 1.26, the NRC Quality Classification System identifies on a functional basis components of fluid systems by Quality Groups A, B, C, and D.

[3]See Section 50.55a, "Codes and Standards," of 10 CFR Part 50 for guidance with regard to the Code Edition and Addenda to be applied

[4]The specific applicability of ASME Code Cases is covered separately in SRP Section 5.2.1.2, Regulatory Guides 1.84 and 1.85, or in Commission regulations, where appropriate. Applicants proposing the use of ASME Code Cases not covered by these SRP and Regulatory Guides should receive approval from the Commission prior to their use and should demonstrate that an acceptable level of quality and safety would be achieved.

APPENDIX A*

CLASSIFICATION OF MAIN STEAM COMPONENTS OTHER THAN THE REACTOR COOLANT PRESSURE BOUNDARY FOR BWR PLANTS

A. BACKGROUND

A pipe classification of "D + QA" for main steam line components of BWR plants was proposed by the General Electric Company in 1971 as an alternative to Quality Group B and has been accepted by the staff in a number of licensing case reviews.

However, we have recently identified a number of potential problems which are applicable to main steam lines of BWR plants. These problems relate to postulated breaks in high-energy fluid-containing lines outside the containment. The criteria pertaining to protection required for structures, systems, and components outside containment from the effects of postulated pipe breaks, as contained in the Director of Licensing's letter to utilities dated July 12, 1973, reference ASME Section III, Class 2, which corresponds to NRC Quality Group B.

The recent ASME Code Section XI revision contains in-service inspection requirements for Class 2 components. Steam lines classified as "D + QA" could be interpreted to be exempt from these inspection requirements. Such interpretations would be contrary to the intent of the code and inconsistent with requirements of the NRC Codes and Standards rule, Section 50.55a of 10 CFR Part 50.

Furthermore, the applicability of the following NRC Regulatory Guides, Standard Review Plan section, and Regulations, as they relate to ASME Section III, Class 2 components is not always clearly identified or implemented in case applications wherever "D + QA" classification is adopted:

1. SRP Section 3.9.3, "ASME Code Class 1, 2, and 3 Components, Component Supports, and Core Support Structures."

2. Regulatory Guide 1.26, "Quality Group Classifications and Standards."

3. 10 CFR Part 50, § 50.55a, "Codes and Standards for Nuclear Power Plants."

4. 10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants."

In view of the foregoing, we find it necessary to clarify the quality group classification criteria for main steam components for BWR plants.

B. BRANCH TECHNICAL POSITION

The main steam line components of BWR plants should conform to the criteria listed in the attached Table A-1 of SRP Section 3.2.2.

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*Formally BTP RSB No. 3-1

C. REFERENCES

1. Letter of March 22, 1973, J. A. Hinds to J. M. Hendrie.

2. Letters of August 13, 1973 and November 26, 1973, J. M. Hendrie to J. A. Hinds.

Table A-1

CLASSIFICATION REQUIREMENTS FOR MAIN STEAM COMPONENTS OTHER THAN THE REACTOR COOLANT PRESSURE BOUNDARY

Item	System or Component	Classification Quality Group
1.	Main Steam Line from 2nd Isolation Valve to Turbine Stop Valve.	B
2.	Main Steam Line Branch Lines to First Valve.	B
3.	Main Turbine Bypass Line to Bypass Valve.	B
4.	First Valve in Branch Lines Connected to Either Main Steam Lines or Turbine Bypass Lines.	B
5.	a. Turbine Stop Valves, Turbine Control Valves, and Turbine Bypass Valves.	D + QA[1] or Certification[2]
	b. Main Steam Leads from Turbine Control Valves to Turbine Casing.	D + QA[1,3] or Certification[2]

[1] The following requirements shall be met in addition to the Quality Group D requirements:

1. All ~~cost~~ CAST pressure-retaining parts of a size and configuration for which volumetric examination methods are effective shall be examined by radiographic methods by qualified personnel. Ultrasonic examination to equivalent standards may be used as as alternate to radiographic methods.

2. Examination procedures and acceptance standards shall be at least equivalent to those specified as supplementary types of examination in ANSI B31.1-1973, Par. 136.4.

[2] The following qualification shall be met with respect to the certification requirements:

1. The manufacturer of the turbine stop valves, turbine control valves, turbine bypass valves, and main steam leads from turbine control

valves to the turbine casing shall utilize quality control procedures equivalent to those defined in General Electric Publication GEZ-4982A, "General Electric Large Steam Turbine - Generator Quality Control Program."

2. A certification shall be obtained from the manufacturer of these valves and steam leads that the quality control program so defined has been accomplished.

[a]The following requirements shall be met in addition to the Quality Group D requirements:

1. All longitudinal and circumferential butt weld joints shall be radiographed (or ultrasonically tested to equivalent standards). Where size or configuration does not permit effective volumetric examination, magnetic particle or liquid penetrant examination may be substituted. Examination procedures and acceptance standards shall be at least equivalent to those specified as supplementary types of examinations, Paragraph 136.4 in ANSI B31.1-1973.

2. All fillet and socket welds shall be examined by either magnetic particle or liquid penetrant methods. All structural attachment welds to pressure retaining materials shall be examined by either magnetic particle or liquid penetrant methods. Examination procedures and acceptance standards shall be at least equivalent to those specified as supplementary types of examinations, Paragraph 136.4 in ANSI B31.1-1973.

3. All inspection records shall be maintained for the life of the plant. These records shall include data pertaining to qualification of inspection personnel, examination procedures, and examination results.

APPENDIX B*

CLASSIFICATION OF BWR/6 MAIN STEAM AND FEEDWATER COMPONENTS OTHER THAN THE REACTOR COOLANT PRESSURE BOUNDARY

A. BACKGROUND

At various times the NRC staff has discussed with the General Electric Company the subject of appropriate classification requirements in boiling water reactor (BWR) plants for main steam system components. These discussions have included consideration of components that are (a) not classified as safety-related items but are located downstream of the isolation valves, (b) not specifically designed to seismic Category I standards, and (c) not housed in Seismic Category I structures.

To date, BWR plant reviews have resulted in various approaches for different individual applications. While these different approaches have resulted in acceptable levels of safety in each case, they have required time-consuming case-by-case reviews. The GESSAR (PDA) BWR/6 application which was reviewed as part of our standardization program, includes this portion of the BWR plant.

In the course of the GESSAR PDA review, we have identified a systematic basis for classification of such components that will result in an acceptable and uniform design basis for the main steam lines (MSL) and feedwater lines (MFL) in BWR/6 plants.

B. BRANCH TECHNICAL POSITION

The main steam and feedwater system components of BWR/6 plants should be classified in accordance with SRP Section 3.2.2, Appendix A, or alternately, in accordance with the attached Table B-1 of SRP Section 3.2.2. The classifications indicated are consistent with the guidelines currently specified in Regulatory Guide 1.26 and Regulatory Guide 1.29.

As an additional requirement, a suitable interface restraint should be provided at the point of departure from the Class I structure where the interface exists between the safety and nonsafety-related portions of the MSL and MFL.

A sketch is attached (Figure B-1) to clarify the specified alternate classification system.

C. REFERENCES

1. Letter of April 19, 1974, J. M. Hendrie to J. A. Hinds.

*Formally BTP RSB No. 3-2

Table B-1

CLASSIFICATION REQUIREMENTS FOR BWR/6 MAIN STEAM AND FEEDWATER SYSTEM COMPONENTS OTHER THAN THE REACTOR COOLANT PRESSURE BOUNDARY

Item	SYSTEM OR COMPONENT	QUALITY GROUP CLASSIFICATION
1.	Main Steam Line (MSL) from second isolation valve to and including shutoff valve.	B
2.	Branch lines of MSL between the second isolation valve and the MSL shutoff valve, from branch point at MSL to and including the first valve in the branch line.	B
3.	Main feedwater line (MFL) from second isolation valve and including shutoff valve.	B
4.	Branch lines of MFL between the second isolation valve and the MFL shutoff valve, from the branch point at MFL to and including the first valve in the branch line.	B
5.	Main steam line piping between the MSL shutoff valve and the turbine main stop valve.	D (1)
6.	Turbine bypass piping.	D
7.	Branch lines of the MSL between the MSL shutoff valve and the turbine main stop valve.	D
8.	Turbine valves, turbine control valves, turbine bypass valves, and main steam leads from the turbine control valves to the turbine casing.	D (1,2) or Certification (3)
9.	Feedwater system components beyond the MFL shutoff valve.	D

(1) All inspection records shall be maintained for the life of the plant. These records shall include data pertaining to qualification of inspection personnel, examination procedures, and examination results.

(2) All cast pressure-retaining parts of a size and configuration for which volumetric methods are effective shall be examined by radiographic methods by qualified personnel. Ultrasonic examination to equivalent standards may be used as an alternate to radiographic methods. Examination procedures and acceptance standards shall be at least equivalent to those defined in Paragraph 136.4, "Examination Methods of Welds - Non-Boiler External Piping," ANSI B31.1-1973.

Table B-1 (cont'd)

(3) The following qualifications shall be met with respect to the certification requirements:

1. The manufacturer of the turbine stop valves, turbine control valves, turbine bypass valves, and main steam leads from turbine control valves to the turbine casing shall utilize quality control procedures equivalent to those defined in General Electric Publication GEZ-4982A, "General Electric Large Steam Turbine-Generator Quality Control Program."

2. A certification shall be obtained from the manufacturer of these valves and steam leads that the quality control program so defined has been accomplished.

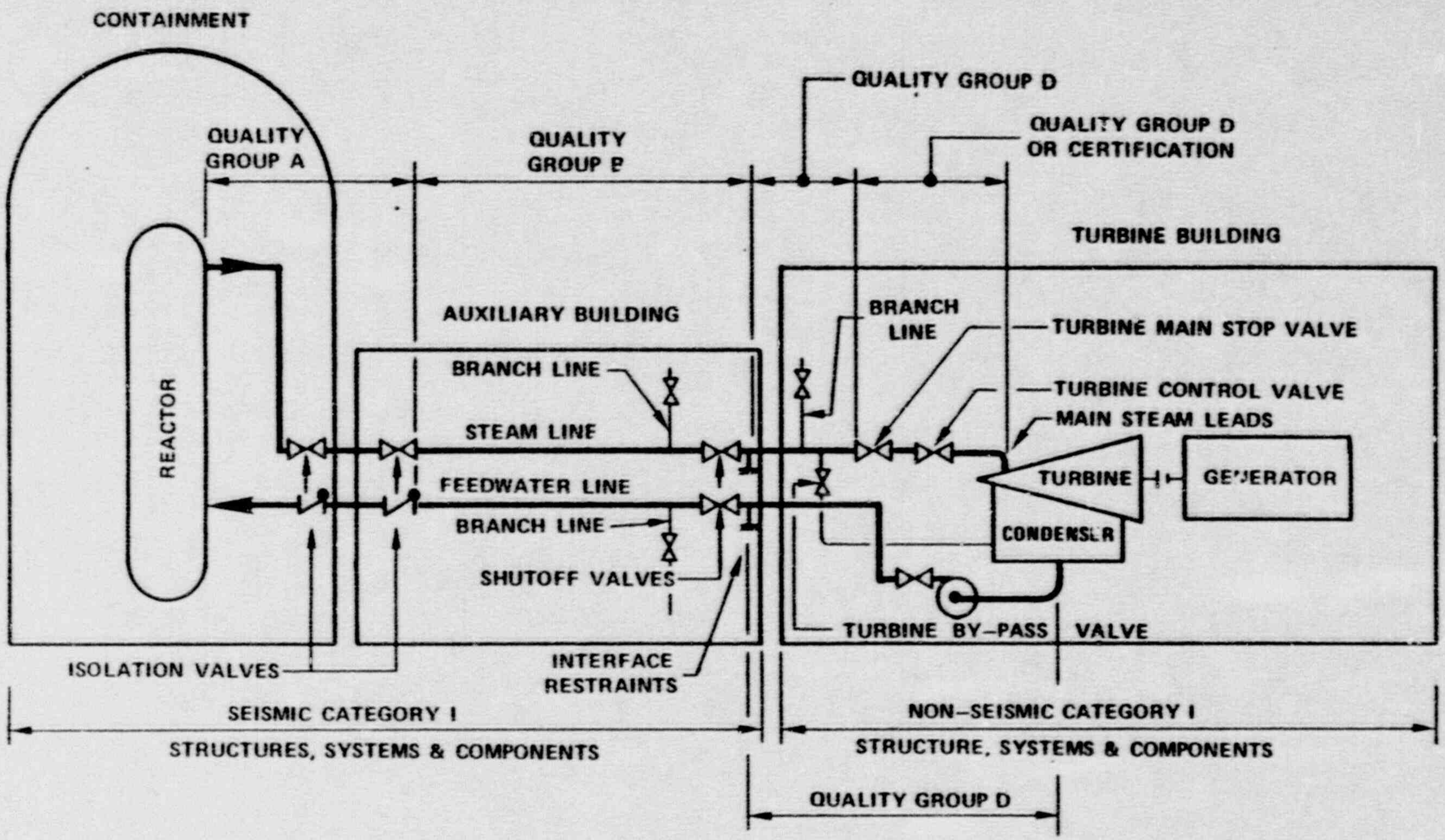

Figure B-1 NRC Quality Group and Seismic Category Classifications Applicable to Power Conversion System Components in BWR/6 Plants.

Appendix C

PWR Plants

Classification of Systems and Components

In Course of Preparation

Classification of Structures

In Course of Preparation

Appendix D

BWR Plants

Classification of Systems and Components

In Course of Preparation

Classification of Structures

In Course of Preparation

Enclosure 5

(Formerly NUREG-75/087)

U.S. NUCLEAR REGULATORY COMMISSION

STANDARD REVIEW PLAN

OFFICE OF NUCLEAR REACTOR REGULATION

5.2.2 OVERPRESSURE PROTECTION

REVIEW RESPONSIBILITIES

Primary - Reactor Systems Branch (RSB)

Secondary - None

I. AREAS OF REVIEW

A. Overpressure protection for the reactor coolant pressure boundary (RCPB), during power operation of the reactor, is ensured by application of relief and safety valves and the reactor protection system. For boiling water reactors (BWRs), the area of review includes relief and safety valves on the main steam lines and piping from these valves to the suppression pool. For pressurized water reactors (PWRs), the area of review includes pressurizer relief and safety valves and the piping from these valves to the quench tank, on the primary and steam generator relief and safety valves on the secondary.

The adequacy of the proposed preoperational and initial startup test programs is examined as a part of this review. The reviewer also evaluates the proposed technical specifications to assure that they are adequate with regard to limiting conditions of operation and periodic surveillance testing.

B. Overpressure protection for the RCPB, during low temperature operation of the plant (startup, shutdown), is ensured by the application of pressure relieving systems that function during the low temperature operation. For PWRs the area of review includes relief valves with piping to the quench tank, the makeup and letdown system, and the RHR system which may be operating when the primary system is water solid. For BWRs, no special area of review is required since BWRs never operate in water-solid conditions.

In addition, the RSB will coordinate its review with the evaluations of other branches that have primary review responsibility for other portions of the overpressure protection as follows: The Procedures and Test Review Branch (PTRB), as part of its primary review responsibility for SRP Section 14.2, reviews proposed preoperational and initial startup test programs to assure that overpressure components will perform their safety function. The Mechanical Engineering Branch (MEB), as part of its primary review responsibility for SRP Sections 3.2.1 and 3.2.2, reviews seismic design criteria for components of the overpressure protection system. The Equipment Qualification Branch (EQB), as part of its primary review responsibility for SRP Sections 3.10 and 3.11, reviews installation criteria for components of the overpressure protection system. The Instrumentation and Control Systems Branch (ICSB), as part of its primary review responsibility for SRP Section 7.6, reviews the adequacy of controls and instrumentation for the automatic and manual actuation of overpressure protection components. The Licensing Guidance Branch (LGB), as part of its primary review responsibility for SRP Section 16.0, reviews technical specifications. The Quality Assurance Branch (QAB), as part of its primary review responsibility for SRP Sections 17.1 and 17.2, reviews quality assurance requirements.

For those areas of review identified above as being reviewed as part of the primary review responsibility of other branches, the acceptance criteria necessary for the review and their methods of application are contained in the referenced SRP section of the corresponding primary branch.

II. Acceptance Criteria

The RSB acceptance criteria for the overpressure protection system are based on meeting the relevant requirements of the following regulations:

1. General Design Criterion 15, as it relates to the reactor coolant system and associated auxiliary, control, and protection systems being designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.

2. General Design Criterion 31, as it relates to the reactor coolant pressure boundary being designed with sufficient margin to assure that boundary behaves in a nonbrittle manner and the probability of rapidly propagating fracture is minimized.

Applications for construction permit should meet recommendations of Task Action Plan items II.D.1 and II.D.3 of NUREG-0718 (Ref. 4). Applications for operating license shall meet recommmendations of Task Action Plan items II.D.1 and II.D.3 of NUREG-0737 (Ref. 5). Other specific acceptance criteria necessary to meet the requirements of GDC 15 and 32 are as follows:

A. For overpressure protection, during power operation of the reactor, the relief valves shall be designed with sufficient capacity to preclude actuation of safety valves, during normal operational transients, when assuming the following conditions at the plant:

   a. The reactor is operating at licensed core thermal power level.

   b. All system and core parameters are at values within normal operating range that produce the highest anticipated pressure.

   c. All components, instrumentation, and controls function normally.

Safety valves shall be designed with sufficient capacity to limit the pressure to less than 110% of the RCPB design pressure (as specified by the ASME Boiler and Pressure Vessel Code [Ref. 2]), during the most severe abnormal operational transient and the reactor scrammed. Also, sufficient margin shall be available to account for uncertainties in the design and operation of the plant assuming:

i. The reactor is operating at a power level that will produce the most severe overpressurization transient.

ii. All system and core parameters are at values within normal operating range, including uncertainties and technical specification limits that produce the highest anticipated pressure.

iii. The reactor scram is initiated by the second safety-grade signal from the reactor protection system.

iv. The discharge flow is based on the rated capacities specified in the ASME Boiler and Pressure Vessel Code (Ref. 2), for each type of valve.

3. Full credit is allowed for spring-loaded safety valves designed in accordance with the requirements of the ASME Boiler and Pressure Vessel Code (Ref. 7)

B. The overpressure protection system, during low temperature operation of the plant (startup, shutdown), shall be designed in accordance with the requirements of Branch Technical Position RSB 5-2 attached to this SRP section (Ref. 3).

III. Review Procedures

The procedures below are used during the construction permit (CP) review to assure that the design criteria and bases and the preliminary design as set forth in the preliminary safety analysis report meet the acceptance criteria given in subsection II of this SRP section.

For operating license (OL) applications, the procedures are used to verify that the initial design criteria and bases have been appropriately implemented in the final design as set forth in the final safety analysis report and in the report on overpressure protection. The latter report is required by the ASME Code (Ref. 2) and is used as the basis for many of the individual review steps outlined below during the OL review. The OL review also includes the proposed technical specifications, to assure that they are adequate in regard to limiting conditions of operation and periodic surveillance testing.

The following steps are taken by the RSB reviewer in determining that the acceptance criteria of subsection II have been met. These steps should be applied to CP and OL reviews as appropriate. Previously reviewed designs may be used as a guide; however, the reviewer must verify that any changes are justified.

1. The piping and instrumentation diagrams are examined to determine the number, type, and location of the safety and relief valves in both the primary and secondary systems, and of discharge lines, instrumentation, and other components.

2. All other functions of the components, instruments, or controls used for overpressure protection and the interfaces with all other systems are identified. The effects of these other functions or systems on operation of the overpressure protection system are determined. For PWRs, failure of the makeup and letdown system or the RHR system is examined to assure overpressure protection during low temperature operation of the plant.

3. The capacities, setpoints, and setpoint tolerances for all safety and relief valves are identified.

4. All of the reactor trip signals which occur during overpressure transients, including their setpoints and setpoint tolerances, are identifed.

5. All transients analyzed in Chapter 15 of the SAR that result in an increase in the pressure experienced by the RCPB are examined. The predicted peak pressures are identified and the operating conditions and setpoints used in the analysis are reviewed to assure that they are suitably conservative.

6. The proposed plant technical specifications are reviewed to:

   a. Confirm the suitability of the limiting conditions of operation, including the proposed time limits and reactor operating restrictions for periods when system equipment is inoperable due to repairs and maintenance.

   b. Verify that the frequency and scope of periodic surveillance testing is adequate.

IV. Evaluation Findings

The reviewer verifies that the SAR contains sufficient information and the review supports the following kinds of statements and conclusions, which should be included in the staff's safety evaluation report:

The staff concludes that the overpressurization protection system is acceptable and meets the relevant requirements of GDC 15 and 31 and Appendix G to 10 CFR Part 50. This conclusion is based on the following:

1. BWRs

   The overpressure protection system prevents overpressurization of the reactor coolant pressure boundary under the most severe transients and limits the reactor pressure during normal operational transients. Overpressure protection is provided by __________ safety and relief valves located on the four main steam lines between the reactor vessel and the first isolation valve inside the drywell. The relief and safety valves are distributed among the four main steam lines such that a single accident cannot disable the automatic overpressure protection function. The valves discharge through piping to the suppression pool. The valves have setpoints that range from ________ to __________ psig. Their total capacity at their setpoint is ________% of rated steam flow.

   To determine the ability of the overpressure protection system to prevent overpressurization, the applicant has analyzed the most severe overpressure transients. The analysis was performed assuming that: (a) the plant is in operation at design conditions (*% of rated steam flow and a reactor vessel dome pressure of * psig), and (b) the reactor is shut down by __________. The calculated peak pressure at the bottom of the vessel is __________ psig, a value within the code allowable of _______ psig (110% of vessel design pressure).

2. PWRs

The overpressure protection system prevents overpressurization of the reactor coolant pressure boundary under the most severe transients and limits the reactor pressure during normal operational transients. Overpressurization protection is provided by __________ safety valves. These valves discharge to the pressurizer quench tank through a common header from the pressurizer. The safety and relief valves in the primary, in conjunction with the steam generator safety and relief valves in the secondary, and the reactor protection system, will protect the primary system against overpressure in the event of a complete loss of heat sink.

The peak primary system pressure following the worst transient is limited to the ASME Code allowable (110% of the design pressure) with no credit taken for nonsafety-grade relief systems. The __________ plant was assumed to be operating at design conditions (% of rated power) and the reactor is shut down by a ______ scram. The calculated pressure at the bottom of the vessel is _______ psig, a value within the code allowable of _______ psig (110% of vessel design pressure).

Overpressure protection during low temperature operation of the plant is provided by __________.

The applicant has met GDC 15 and 31 and Appendix G since they have implemented the guideline of BTP RSB 5-2. In addition, the applicant has incorporated into their design the recommendations of Task Action Plan items II.D.1 and II.D.3 of NUREG-0718 and NUREG-0737.

V. Implementation

The following is intended to provide guidance to applicants and licensees regarding the NRC staff's plans for using this SRP section.

Except in those cases in which the applicant proposes an acceptable alternative method for complying with specified portions of the Commission's regulations, the method described herein will be used by the staff in its evaluation of conformance with Commission regulations.

Implementation schedules for conformance to parts of the method discussed herein are contained in the referenced NUREGs.

VI. References

1. 10 CFR Part 50, Appendix A, General Design Criterion 15, "Reactor Coolant System Design."

*Normally, BWRs are analyzed at 105% rated steam flow at a pressure of 1040 psig.

2. ASME Boiler and Pressure Vessel Code, Section III, Article NM-7000, "Protection Against Overpressure," American Society of Mechanical Engineers.

3. Branch Technical Position RSB 5-2, "Overpressurization Protection of Pressurized Water Reactors While Operating at Low Temperatures," attached to this SRP section.

4. NUREG-0718, "Licensing Requirements for Pending Applications for Construction Permits and Manufacturing License."

5. NUREG-0737, "Clarification of TMI Action Plan Requirements."

6. 10 CFR Part 50, Appendix G, "Fracture Toughness Requirements."

7. ASME Boiler and Pressure Vessel Code, Section III," Article NB-7611, "Spring-Loaded Safety Valves."

8. 10 CFR Part 50, Appendix A, General Design Criterion 31," Fracture Prevention of Reactor Coolant Pressure Boundary."

BRANCH TECHNICAL POSITION RSB 5-2

OVERPRESSURIZATION PROTECTION OF PRESSURIZED WATER REACTORS WHILE OPERATING AT LOW TEMPERATURES

A. Background

General Design Criterion 15 of Appendix A of 10 CFR Part 50 requires that "the Reactor Coolant System and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences."

Anticipated operational occurrences, as defined in Appendix A of 10 CFR Part 50, are "those conditions of normal operation which are expected to occur one or more times during the life of the nuclear power unit and include but are not limited to loss of power to all recirculation pumps, tripping of the turbine generator set, isolation of the main condenser, and loss of all offsite power."

Appendix G of 10 CFR Part 50 provides the fracture toughness requirements for reactor pressure vessels under certain conditions. To assure that the Appendix G limits of the reactor coolant pressure boundary are not exceeded during any anticipated operational occurrences, technical specification pressure-temperature limits are provided for operating the plant.

The primary concern of this position is that during startup and shutdown conditions at low temperature, especially in a water-solid condition, the reactor coolant system pressure might exceed the reactor vessel pressure-temperature limitations in the technical specifications established for protection against brittle fracture. This inadvertent overpressurization could be generated by any one of a variety of malfunctions or operator errors. Many incidents have occurred in operating plants as described in Reference 1.

Additional discussion on the background of this position is contained in Reference 1.

B. Branch Position

1. A system should be designed and installed which will prevent exceeding the applicable technical specifications and Appendix G limits for the reactor coolant system while operating at low temperatures. The system should be capable of relieving pressure during all anticipated overpressurization events at a rate sufficient to satisfy the technical specification limits, particularly while the reactor coolant system is in a water-solid condition.

2. The system should be able to perform its function assuming any single active component failure. Analyses using appropriate calculational techniques must be provided which demonstrate that the system will provide the required pressure relief capacity assuming the most limiting single active failure. The cause for initiation of the event, e.g., operator error, component malfunction should not be considered as the single active failure. The analyses should assume the most limiting allowable operating conditions and systems configuration at the time of the postulated cause of the overpressure event.

All potential overpressurization events should be considered when establishing the worst-case event. Some events may be prevented by protective interlocks or by locking out power. These events should be identified on an individual basis. If the events are excluded from the analyses, the controls to prevent these events should be in the plant technical specifications.

3. The system should be designed using IEEE Std.-279 as guidance (see implementation). The system may be manually enabled, however, an alarm to alert the operator to enable the system at the correct plant condition during cooldown, should be provided. Positive indication should be provided to indicate when the system is enabled. An alarm should be provided when the protective action is initiated.

4. To assure operational readiness, the overpressure protection system should be testable. Technical specification surveillance requirements should include:

   a. A test performed to assure operability of the system (exclusive of relief valves) prior to each shutdown.

   b. A test for valve operability, as a minimum, be conducted as specified in the ASME Code Section XI.

5. The system must meet the requirements of Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants," and Section III of the ASME Code.

6. The overpressure protection system should be designed to function during ~~an~~ Safe Shutdown Earthquake. It should not compromise the design criteria of any other safety-grade system with which it would interface, such that the requirements of Regulatory Guide 1.29, "Seismic Design Classification," are met.

7. The overpressure protection system should not depend on the availability of offsite power to perform its function. The system should be operable from battery-backed power sources, not necessarily Class 1E buses.

8. Overpressure protection systems which take credit for an active component(s) to mitigate the consequences of an overpressurization event should include additional analyses considering inadvertent system initiation/actuation or provide justification to show that existing analyses bound such an event.

9. If pressure relief is from a low pressure system, not normally connected to the primary system, the overpressure protection function should not be defeated by interlocks which would isolate the low pressure system from the primary coolant system. (See BTP ICSB3)

10. See Insert attached.

D. References

1. NUREG-0138, Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum from Director, NRR, to NRR Staff.

INSERT FOR SRP 5.2.2, PAGE 5.2.2-8, ITEM 10 TO BE ADDED.

10. If pressure relief is from power operated relief valves (including the associated block valves) connected to the primary system and a part of the reactor coolant pressure boundary, these components should be in conformance with SRP 3.2.2, Footnote 4.

U.S. NUCLEAR REGULATORY COMMISSION

STANDARD REVIEW PLAN

OFFICE OF NUCLEAR REACTOR REGULATION

5.4.7 RESIDUAL HEAT REMOVAL (RHR) SYSTEM

REVIEW RESPONSIBILITIES

Primary - Reactor Systems Branch (RSB)

Secondary - None

I. AREAS OF REVIEW

The residual heat removal (RHR) system is used in conjunction with the main steam and feedwater systems (main condenser), or the reactor core isolation cooling (RCIC) system in conjunction with the safety/relief valves in a boiling water reactor (BWR), or auxiliary feedwater sytem in conjunction with the atmospheric dump valves in a pressurized water reactor (PWR) to cool down the reactor coolant system following shutdown. Parts of the RHR system also act to provide low pressure emergency core cooling and are reviewed as described in SRP Section 6.3. Some parts of the RHR system also provide containment heat removal capability and are reviewed as described in SRP Section 6.2.2. The review by RSB is to ensure that the design of the RHR system is in conformance with General Design Criteria 2 (Ref. 1), 5 (Ref. 2), 19 (Ref. 3), and 34 (Ref. 4).

Both PWRs and BWRs have RHR systems which provide long-term cooling once the reactor coolant temperature has been decreased by the main condenser, RCIC, or auxiliary feedwater systems. In both types of plants, the RHR is typically a low pressure system which takes over the shutdown cooling function when the reactor coolant system (RCS) temperature is reduced to about 300°F. Although the RHR system function is similar for the two types of plants, the system design are different.

The RHR system in PWRs takes water from the RCS hot legs, cools it, and pumps it back to the cold legs or core flooding tank nozzles. The suction and discharge lines for the RHR pumps have appropriate valving to assure that the low pressure RHR system is always isolated from the RCS when the reactor coolant pressure is greater than the RHR system design pressure. The heat

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removed in the heat exchangers is transported to the ultimate heat sink by the component cooling water or service water system. In PWRs, the RHR system is also used to fill, drain, and remove heat from the refueling canal during refueling operations, to circulate coolant through the core during plant startup prior to RCS pump operation, and in some to provide an auxiliary pressurizer spray.

The RHR system in BWRs is typically composed of four subsystems. The containment heat removal and low pressure emergency core cooling subsystems are discussed in SRP Sections 6.2.2 and 6.3. The shutdown cooling and steam condensing (via RCIC) subsystems are covered by this SRP section. These subsystems make use of the same hardware, consisting of pumps, piping, heat exchangers, valves, monitors, and controls. In the shutdown cooling mode, the BWR RHR system can also be used to supplement spent fuel pool cooling. As in the PWR, the low pressure RHR piping is protected from high RCS pressure by isolation valves.

The steam condensing mode of RCIC operation in BWRs (when included in the plant design) provides an alternative to the main condenser or normal RCIC mode of operation during the initial cooldown. Steam from the reactor is transferred to the RHR heat exchangers where it is condensed. The condensate is piped to the suction side of the RCIC pump. The RCIC pump returns the condensate to the reactor vessel. The heat removed in the heat exchangers is transported to the ultimate heat sink by the service water system.

Other means of removing decay heat in the event that the RHR system is inoperable have been proposed for some BWRs. These approaches use some of the piping that is used for the steam condensing mode of RCIC. These approaches are also covered by this SRP section.

The reactor coolant temperatures and pressure must be decreased before the low pressure RHR system can be placed in operation; therefore, the review of the decay heat removal function must consider all conditions from shutdown at normal reactor operating pressure and temperature to the cold depressurized condition. RSB reviews the requirements for reliability and capability of removing decay heat identified in NUREG-0660 (II.E.3.2 and II.E.3.3), NUREG-0718 (II.B.7), and NUREG-0737 (III.D.1.1). With respect to the staff review for compliance with Branch Technical Position RSB 5-1 (Ref. 5), the Auxiliary Systems Branch (ASB), Chemical Engineering Branch (CMEB), and RSB effort is divided as follows:

1. For BWRs, the RSB reviews the processes and systems used in the cooldown of the reactor for the entire spectrum of potential reactor coolant system pressures and temperatures during decay heat removal.

2. For PWRs, the RSB reviews the approach used to meet the functional requirements of BTP RSB 5-1 with respect to cooldown to the conditions permitting operation of the RHR system. Since an alternate approach to that normally used for cooldown may be specified, the reviewers identify all components and systems used. The CMEB has primary review responsibility for the review of the pertinent portions of the CVCS (SRP Section 9.3.4). The ASB, as part of its primary review responsibility for SRP Sections 10.3 and 10.4.9 reviews the atmospheric dump valves and the source for auxiliary feedwater, respectively, for conformance to BTP RSB 5-1. The RSB reviews the pressurizer relief valve and ECCS, if used. In addition, the RSB reviews the tests and supporting analysis concerning mixing of borated water and cooldown under natural circulation as required in BTP RSB 5-1.

3. For both PWRs and BWRs, the ASB reviews the component cooling or service water systems that transfer decay heat from the RHR system to the ultimate heat sink as part of its primary review responsibility for SRP Sections 9.2.1 and 9.2.2.

4. The RSB reviews the design and operating characteristics of the RHR system with respect to its shutdown and long-term cooling function. Where the RHR system interfaces with other systems (e.g., RCIC system, component cooling water system) the effect of these systems on the RHR system is reviewed. Overpressure protection provided by the valving between the RCS and RHR system is also reviewed.

In addition, the Reactor Systems Branch will coordinate evaluations of other branches that interface with the overall review of the RHR system as follows: The Containment Systems Branch verifies that portions of the RHR system penetrating the containment barrier are designed with acceptable isolation features to maintain containment integrity for all operating conditions including accidents as part of its primary review responsibility for SRP Section 6.2.4; The Structural Engineering Branch (SEB) determines the acceptability of the design analysis, procedures and criteria used to establish the ability of seismic Category I structures housing the system and supporting systems to withstand the effects of natural phenomena such as safe shutdown earthquake (SSE), the probable maximum flood (PMF), and tornado missiles as part of its primary review responsibility for SRP Sections 3.3.1, 3.3.2, 3.5.3, 3.7.1 thru 3.7.4, 3.8.4 and 3.8.5. The Materials Engineering Branch (MTEB) verifies that inservice inspection requirements are met for system components as part of its primary review responsibility for SRP Section 6.6 and, upon request, verifies the compatibility of the materials of construction with service conditions as part of its primary review responsibility for SRP Section 6.1. The Mechanical Engineering Branch (MEB) determines that the components, piping and structures are designed and tested in accordance with applicable codes and standards as part of its primary review responsibility for SRP Sections 3.9.1 through 3.9.3. The MEB also determines the acceptability of the seismic and quality group classifications for system components as part of its primary review responsibility for SRP Sections 3.2.1 and 3.2.2 The effects of pipe breaks inside and outside of containment, such as pipe whip and jet impingement, are reviewed by MEB and ASB as part of their primary review responsibilities for SRP Sections 3.6.2 and 3.6.1, respectively. The MEB also reviews adequacy of the inservice testing program of pumps and valves as part of its primary review responsibility for SRP Section 3.9.6. The Procedure and Test Review Branch (PTRB) reviews the proposed preoperational and startup test programs to confirm that they are in conformance with the intent of Regulatory Guide 1.68 as part of its primary review responsibility for SRP Section 14.2. The PTRB also has primary review responsibility for Task Action Plan items II.K.1 (C.1.10) of NUREG-0737 (OLs only) and I.C.6 of NUREG-0718 (CPs only) regarding procedures to ensure that system operability status is known. The ASB reviews flood protection as part of its primary review responsibility for SRP Section 3.4.1. The ASB identifies the structures systems and components to be protected against externally generated missiles and reviews the adequacy of protection against such missiles as part of its primary review responsbility for SRP Section 3.5.1.4 and 3.5.2. The ASB also reviews protection against internally generated missiles both inside and outside of containment as part of its primary review responsibility for SRP Sections 3.5.1.1 and 3.5.1.2.

The Power Systems Branch (PSB) identifies the safety-related electrical loads and determines that power systems supplying motive or control power for the RHR system meet acceptable criteria and will perform these intended functions during all plant operating and accident conditions as part of its primary review responsibility for SRP Sections 8.1, 8.2, 8.3.1, and 8.3.2. The Instrumentation and Control Systems Branch (ICSB), as part of its primary review responsibility for SRP Sections 7.1 and 7.4 reviews the instrumentation and control systems for the RHR system to determine that it will perform its design function as required and conform to all applicable acceptance criteria. The ICSB also reviews the provisions taken to meet GDC 19 with respect to equipment outside of the control room for hot and cold shutdown. The Radiological Assessment Branch (RAB) has primary review responsibility for SRP Section 12.1 through 12.5 including Task Action Plan items II.B.2 of NUREG-0737 and NUREG-0718 which involve a radiation and shielding design review and corrective actions taken to ensure adequate access to vital areas and protection of safety equipment (CPs and OLs). The review for Fire Protection, Technical Specifications, and Quality Asurance are coordinated and performed by the CMEB, Licensing Guidance Branch (LGB) and Quality Assurance Branch (QAB) as part of their primary review responsibility for SRP Sections 9.5.1, 16.0 and 17.0, respectively.

For those areas of review identified above as being reviewed as part of the primary review responsibility of other branches, the acceptance criteria necessary for the review and their methods of application are contained in the referenced SRP Section of the corresponding primary branch.

II. ACCEPTANCE CRITERIA

The Reactor Systems Branch acceptance criteria are based on meeting the requirements of the following regulations:

A. General Design Criterion 2 with respect to the seismic design of systems, structures and components whose failure could cause an unacceptable reduction in the capability of the residual heat removal system. Acceptability is based on meeting position C-2 of Regulatory Guide 1.29 or its equivalent.

B. General Design Criterion 5 which requires that any sharing among nuclear power units of structures, systems and components important to safety will not significantly impair their safety function.

C. General Design Criterion 19 with respect to control room requirements for normal operations and shutdown, and;

D. General Design Criterion 34 which specifies requirements for a residual heat removal system.

Specific criteria necessary to meet the requirements of General Design Criteria 2, 5, 19, and 34 are as follows:

1. The system or systems are to satisfy the functional, isolation, pressure relief, pump protection and test requirements specified in Branch Technical Position RSB 5-1.

2. Interfaces between the RHR system and RCIC and component or service water systems should be designed so that operation of one does not interfere

with, and provides proper support (where required) for, the other. In relation to these and other shared systems (e.g., emergency core cooling and containment heat removal systems), the RHR system must conform to GDC 5.

3. The requirements for the reliability and capability of removing decay heat under the following Task Action Plan items must also be satisfied:

   a. Meeting Task Action Plan item II.E.3.2 of NUREG-0660 which involves systems reliability. NRR will conduct a generic study to assess the capability and reliability of shutdown heat removal systems under various transients and degraded plant conditions including complete loss of all feedwater. Deterministic and probabilistic methods will be used to identify design weaknesses and possible system modifications that could be made to improve the capability and reliability of these systems under all shutdown conditions. (CPs and OLs). Specific requirements will be based on the results of this study.

   b. Meeting Task Action Plan item II.E.3.3 of NUREG-0660 which involves a coordinated study of shutdown heat removal requirements. An effort to evaluate shutdown heat removal requirements in a comprehensive manner is required, thereby permitting a judgment of adequacy in terms of overall system requirements. As part of this project, NRR will conduct a study to assess the desirability of and possible requirement for a diverse heat-removal path, such as feed and bleed, particularly if all secondary-side cooling is unavailable. The NRC staff will work with the recently established ACRS Ad Hoc Subcommittee on this matter to develop a mutually acceptable overall study program. (CPs and OLs). Specific requirements will be based on the results of this study.

   c. Meeting Task Action Plan item II.B.8 of NUREG-0718 (Ref. 7) which involves description by the applicants of the degree to which the designs conform to the proposed interim rule on degraded core accidents. (CPs only)

   d. Meeting Action Plan item III.D.1.1 of NUREG-0737 (Ref. 8) and NUREG-0718 (Ref. 7) which involves primary coolant sources outside of containment (CPs and OLs).

4. When the RHR system is used to control or mitigate the consequences of an accident, it must meet the design requirements of an engineered safety feature system. This includes meeting the guidelines of Regulatory Guide 1.1 regarding net positive suction head.

III. REVIEW PROCEDURES

The procedures below are used during the construction permit (CP) review to assure that the design criteria and bases and the preliminary design as set forth in the Preliminary Safety Analysis Report meet the acceptance criteria given in subsection II.

For operating license (OL) reviews, the procedures are utilized to verify that the initial design criteria and bases have been appropriately implemented in the final design as set forth in the Final Safety Analysis Report. The OL review also includes the proposed technical specifications, to assure that they are adequate in regard to limiting conditions of operation and periodic surveillance testing.

As noted in subsections I and II, the RSB review for PWRs is limited to the low pressure - low temperature RHR system. For BWRs, the review is to include all of the systems used to transfer residual heat from the reactor over the entire range of potential reactor coolant temperatures and pressures. The following steps are to be applied by the reviewer for the appropriate systems, depending on whether a PWR or BWR is being reviewed. These steps should be adapted to CP or OL reviews as appropriate.

1. Using the description given in the applicant's Safety Analysis Report (SAR), including component lists and performance specifications, the reviewer determines that the system(s) piping and instrumentation are such to allow the system(s) to operate as intended, with or without offsite power and given any single active component failure. This is accomplished by reviewing the piping and instrumentation diagrams (P&IDs) to confirm that piping arrangements permit the required flow paths to be achieved and that sufficient process sensors are available to measure and transmit required information. A failure modes and effects analysis (or similar system safety analysis) provided in the SAR is used to determine conformance to the single failure criterion.

2. Using the comparison tables of SAR Section 1.3, the RHR system is compared to designs and capacities of such systems in similar plants to see that there are no unexplained departures from previously reviewed plants. Where possible, comparisons should be made with actual performance data from similar systems in operating plants.

3. From the system description and P&IDs, the reviewer determines that the isolation requirements of Branch Technical Position RSB 5-1 (Ref. 5) are satisfied.

4. The reviewer determines that the RHR system design has provisions to prevent damage to the RHR pumps in accordance with Branch Technical Position RSB 5-1 (Ref. 5). The reviewer checks the isolation valves in the suction line for potential closure, NPSH requirements, pump runout, and potential loss of miniflow line during pump testing. If operator action is required to protect the pumps, the reviewer evaluates the instrumentation required to alert the operator and the adequacy of the time frame for operator action.

5. Using the system process diagrams, P&IDs, failure modes and effects analysis, and component performance specifications, the reviewer determines that the system(s) has the capacity to bring the reactor to conditions permitting operation of the RHR system in a reasonable period of time, assuming a single failure of an active component with only either onsite or offsite electric power available. For the purposes of this review, 36 hours is considered a reasonable time period. The ASB is responsible for the review of the initial cooldown phase for PWRs. Therefore, this review effort is to be coordinated with that branch. For the purposes of the review of both PWRs and BWRs, only the operation of safety grade equipment is to be assumed.

6. The cooldown function is to be reviewed to determine if it can be performed from the control room assuming a single failure of an active component, with only either onsite or offsite electric power available. Any operation required outside of the control room is to be justified by the applicant. Like Item 5, the initial cooldown for PWRs is to be reviewed by ASB.

7. By reviewing the system description and the P&IDs, the reviewer confirms the RHR system satisfies the pressure relief requirements of Branch Technical Position RSB 5-1 (Ref. 5).

8. By reviewing the piping arrangement and system description of the RHR system, the reviewer confirms that the RHR system meets the requirements of GDC 5 (Ref. 2) concerning shared systems.

9. The RSB reviewer contacts the ASB reviewer in conjunction with his review of the RHR system heat sink and refueling system interaction to interchange information and assure that the reviews are consistent with regard to the interfacing parameters. For example, the ASB review determines the maximum service or component cooling water temperature. The RSB reviewer then reviews the RHR system description to determine that this maximum temperature has been allowed for in the RHR system design.

10. The RSB reviewer contacts his counterpart in the ICSB to obtain any needed information from their review. Specifically, ICSB confirms that automatic actuation and remote-manual valve controls are capable of performing the functions required, and that sensor and monitoring provisions are adequate. The instrumentation and controls of the RHR system are to have sufficient redundancy to satisfy the single failure criterion.

11. The RSB reviewer contacts his counterpart in CSB so that the information needed concerning their reviews will be interchanged.

12. The RSB reviewer contacts his counterpart in PTRB to discuss any special test requirements and to confirm that the proposed preoperational test program for the RHR system is in conformance with the intent of Regulatory Guide 1.68.

13. The proposed plant technical specifications are reviewed to:

    a. Confirm the suitability of the limiting conditions of operation, including the proposed time limits and reactor operating restrictions for periods when system equipment is inoperable due to repairs and maintenance.

    b. Verify that the frequency and scope of periodic surveillance testing is adequate.

14. The reviewer contacts the SEB reviewer to confirm that the systems employed to remove residual heat are housed in a structure whose design and design criteria provide adequate protection against wind, tornadoes, floods, and missiles, as appropriate.

15. For PWRs, the reviewer confirms that the auxiliary feedwater supply satisfies the requirements of Branch Technical Position RSB 5-1.

16. The RSB reviewer provides information to other branches in those areas where the RSB has a review responsibility that is not explicitly covered in steps 1-15 above. These additional areas of review responsibility include:

a. Identification of engineered safety features (ESF) and safe shutdown electrical loads, and verification that the minimum time intervals for the connection of th ESF to the standby power systems are satisfactory.

b. Identification of vital auxiliary systems associated with the RHR system and determination of cooling load functional requirements and minimum time intervals.

c. Identification of essential components associated with the main steam supply and the auxiliary feedwater system that are required to operate during and following shutdown.

17. The RSB review evaluates the applicant responses to the following Task Action Plan items:

a. II.E.3.2 of NUREG-0660 (CPs and OLs)

b. II.E.3.3 of NUREG-0660 (CPs and OLs)

c. II.B.8 of NUREG-0718 (CPs only)

d. II.D.1.1 of NUREG-0737 and NUREG-0718 (CPs and OLs)

IV. EVALUATION FINDINGS

The reviewer verifies that the SAR contains sufficient information and his review supports the following kinds of statements and conclusions, which should be included in the staff's Safety Evaluation:

For PWRs

The residual heat removal function is accomplished in two phases: the initial cooldown phase and the residual heat removal (RHR system) operation phase. In the event of loss of offsite power, the initial phase of cooldown is accomplished by use of the auxiliary feedwater system and the atmospheric dump valves. This equipment is used to reduce the reactor coolant system temperature and pressure to values that permit operation of the RHR system. The review of the initial cooldown phase is discussed in Section ____ of the SER. The review of the RHR system operational phase is discussed below. The residual heat removal (RHR) system removes core decay heat and provides long-term core cooling following the initial phase of reactor cooldown. The scope of review of the RHR system for the ____ plant included piping and instrumentation diagrams, equipment layout drawings, failure modes and effects analysis, and design performance specifications for essential components. The review has included the applicant's proposed design criteria and design bases for the RHR system and his analysis of the adequacy of those criteria and bases and the conformance of the design to these criteria and bases.

The staff concludes that the design of the Residual Heat Removal System is acceptable and meets the requirements of General Design Criteria 2, 5, 19, and 34. This conclusion is based on the following:

(1) The applicant has met the General Design Criterion 2 with respect to position C-2 of Regulatory Guide 1.29 concerning the seismic design of systems, structures and components whose failure could cause an unacceptable reduction in the capability of the residual heat removal system.

(2) The applicant has met the requirements of General Design Criterion 5 with respect to sharing of structure, systems and components by demonstrating that such sharing does not significantly impair the ability of the Residual Heat Removal System to perform it safety function including in the event of an accident to one unit, an orderly shutdown and cooldown of the remaining units.

(3) The applicant has met General Design Criterion 19 with respect to the main control room requirements for normal operations and shutdown and General Design Criterion 34 which specifies requirements for the residual heat removal system by meeting the regulatory position in Branch Technical Position RSB 5-1.

In addition, the applicant has met the requirements of the following Task Action Plan Items:

(1) Task Action Plan item II.E.3.2 of NUREG-0660 (Ref. 10) as it relates to systems capability and reliability of shutdown heat removal systems under various transients.

(2) Task Action Plan item II.E.3.3 of NUREG-0660 (Ref. 10) as it relates to a coordinated study of shutdown heat removal requirements.

(3) Task Action Plan item II.B.8 of NUREG-0718 (Ref. 7) as it relates to description by the applicants of the degree to which the designs conform to the proposed interim rule on degraded core accidents (CPs only).

(4) Task Action Plan item III.D.1.1 of NUREG-0737 (Ref. 8) and NUREG-0718 (Ref. 7) as they relate to primary coolant sources outside of containment (CPs and OLs).

<u>For BWRs</u>

The residual heat removal function is accomplished in two phases: the initial cooldown phase and a low pressure-temperature operation phase. In the event of loss of offsite electrical power, the initial cooldown phase is accomplished using the reactor core isolation cooling (RCIC) system and the safety/ relief valves. The low pressure-temperature mode of operation is usually accomplished by the residual heat removal (RHR) system. However, certain single failures can render the RHR system inoperative. In that event, two alternate systems that use components of the RCIC and RHR system are available to bring the reactor to cold shutdown conditions.

The scope of review of these systems for the plant included piping and instrumentation diagrams, equipment layout drawings, failure modes and effects analysis, and design performance specifications for essential components The review has included the applicant's proposed design criteria and design bases for these systems and his analysis of the adequacy of those criteria and bases and of the conformance of the design to these criteria and bases.

The staff concludes that the design of the Residual Heat Removal System is acceptable and meets the requirements of General Design Criteria 2, 5, 19, and 34. This conclusion is based on the following:

(1) The applicant has met General Design Criterion 2 with respect to position C-2 of Regulatory Guide 1.29 concerning the seismic design of systems, structures and components whose failure could cause an unacceptable reduction in the capability of the residual heat removal system.

(2) The applicant has met the requirements of General Design Criterion 5 with respect to sharing of structures, systems, and components by demonstrating that such sharing does not significantly impair the ability of the Residual Heat Removal System to perform its safety function including in the event of an accident to one unit, an orderly shutdown and cooldown of the remaining units.

(3) The applicant has met General Design Criterion 19 with respect to the main control room requirements for normal operations and shutdown and General Design Criterion 34 which specifies requirements for the residual heat removal system by meeting the regulatory position in Branch Technical Position RSB 5-1.

In addition, the applicant has met the requirements of the following Task Action Plan Items:

(1) Task Action Plan item II.E.3.2 of NUREG-0660 as it relates to systems capability and reliability of shutdown heat removal systems under various transients.

(2) Task Action Plan item II.E.3.3 of NUREG-0660 as it relates to a coordinated study of shutdown heat removal requirements.

(3) Task Action Plan item II.B.8 of NUREG-0718 (Ref. 7) as it relates to description by the applicants of the degree to which the designs conform to the proposed interim rule on degraded core accidents (CPs only).

(4) Task Action Plan item III.D.1.1 of NUREG-0737 (Ref. 8) and NUREG-0718 (Ref. 7) as they relate to primary coolant sources outside of containment (CPs and OLs).

In addition to the above criteria, the acceptability of the RHR system may be based on the degree of design similarity with previously approved plants. Deviations from these criteria from other types of RHR systems (e.g., systems that are designed to withstand reactor coolant system operating pressure or systems located entirely inside containmnt) will be considered on an individual basis.

V. IMPLEMENTATION

The following is intended to provide guidance to applicants and licensees regarding the NRC staff's plans for using this SRP section.

Except in those cases in which the applicant proposes an acceptable alternative method for complying with specified portions of the Commission's regulations, the method described herein will be used by the staff in its evaluation of conformance with Commission regulations.

Implementation schedules for conformance to parts of the method discussed herein are contained in the referenced BTP RSB 5-1, regulatory guides, and NUREGs.

VI. REFERENCES

1. 10 CFR Part 50, Appendix A, General Design Criterion 2, "Design Bases for Protection Against Natural Phenomena."
2. 10 CFR Part 50, Appendix A, General Design Criterion 5, "Sharing of Structures, Systems and Components."
3. 10 CFR Part 50, Appendix A, General Design Criterion 19, "Control Room."
4. 10 CFR Part 50, Appendix A, General Design Criterion 34, "Residual Heat Removal."
5. Branch Technical Position RSB 5-1, "Design Requirements of the Residual Heat Removal System," attached to SRP Section 5.4.7.
6. Reglatory Guide 1.29, "Seismic Design Classification."
7. NUREG-0718, "Licensing Requirements for Pending Applications for Construction Permits and Manufacturing License."
8. NUREG-0737, "Clarification of TMI Action Plan Requirements."
9. Regulatory Guide 1.1, "Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Systems."
10. NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident."

BRANCH TECHNICAL POSITION RSB 5-1
DESIGN REQUIREMENTS OF THE RESIDUAL HEAT REMOVAL SYSTEM

BACKGROUND

GDC 19 states that, "A control room shall be provided from which actions can be taken to operate the nuclear power unit under normal conditions. . ."

Normal operating conditions including the shutting down of a reactor; therefore, since the residual heat removal (RHR) system is one of several systems involved in the normal shutdown of all reactors, this system must be operable from the control room.

GDC 34 states that "Suitable redundance. . .shall be provided to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electrical power system operation (assuming onsite power is not available), the system safety function can be accomplished, assuming a single failure."

In most current plant designs the RHR system has a lower design pressure than the reactor coolant system (RCS), is located outside of containment and is part of the emergency core cooling system (ECCS). However, it is possible for the RHR system to have different design characteristics. For example, the RHR system might have the same design pressure as the RCS, or be located inside of containment. Plants which may have RHR systems that deviate from current designs will be reviewed on a case-by-case basis. The functional, isolation, pressure relief, pump protection, and test requirements for the RHR system are included in this position.

BRANCH POSITION

A. Functional Requirements

The system(s) which can be used to take the reactor from normal operating conditions to cold shutdown* shall satisfy the functional requirements listed below.

1. The design shall be such that the reactor can be taken from normal operating conditions to cold shutdown using only safety-grade systems. These systems shall satisfy General Design Criteria 1 through 5.

2. The system(s) shall have suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electrical power system operation (assuming onsite power is not available) the system function can be accomplished assuming a single failure.

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*Processes involved in cooldown are heat removal, depressurization, flow circulation, and reactivity control. The cold shutdown condition, as described in the Standard Technical Specifications, refers to a subcritical reactor with a reactor coolant temperature no greater than 200°F for a PWR and 212°F for a BWR.

3. The system(s) shall be capable of being operated from the control room with either only onsite or only offsite power available. In demonstrating that the system can perform its function assuming a single failure, limited operator action outside of the control room would be considered acceptable if suitably justified.

4. The system(s) shall be capable of bringing the reactor to a cold shutdown condition, with only offsite or onsite power available, within a reasonable period of time following shutdown, assuming the most limiting single failure.

B. <u>RHR System Isolation Requirements</u>

The RHR system shall satisfy the isolation requirements listed below.

1. The following shall be provided in the suction side of the RHR system to isolate it from the RCS.

   (a) Isolation shall be provided by at least two power-operated valves in series. The valve positions shall be indicated in the control room.

   (b) The valves shall have independent diverse interlocks to prevent the valves from being opened unless the RCS pressure is below the RHR system design pressure. Failure of a power supply shall not cause any valve to change position.

   (c) The valves shall have independent diverse interlocks to protect against one or both valves being open during an RCS increase above the design pressure of the RHR system.

2. One of the following shall be provided on the discharge side of the RHR system to isolate it from the RCS:

   (a) The valves, position indicators, and interlocks described in item 1(a) thru 1(c) above,

   (b) One or more check valves in series with a normally closed power-operated valve. The power-operated valve position shall be indicated in the control room. If the RHR system discharge line is used for an ECCS function, the power-operated valve is to be opened upon receipt of a safety injection signal once the reactor coolant pressure has decreased below the ECCS design pressure.

   (c) Three check valves in series, or

   (d) Two check valves in series, provided that there are design provisions to permit periodic testing of the check valves for leak tightness and the testing is performed at least annually.

C. Pressure Relief Requirements

The RHR system shall satisfy the pressure relief requirements listed below.

1. To protect the RHR system against accidental overpressurization when it is in operation (not isolated from the RCS), pressure relief in the RHR system shall be provided with relieving capacity in accordance with the ASME Boiler and Pressure Vessel Code. The most limiting pressure transient during the plant operating condition when the RHR system is not isolated from the RCS shall be considered when selecting the pressure relieving capacity of the RHR system. For example, during shutdown cooling in a PWR with no steam bubble in the pressurizer, inadvertent operation of an additional charging pump or inadvertent opening of an ECCS accumulator valve should be considered in selection of the design bases.

2. Fluid discharged through the RHR system pressure relief valves must be collected and contained such that a stuck open relief valve will not:

   (a) Result in flooding of any safety-related equipment.

   (b) Reduce the capability of the ECCS below that needed to mitigate the consequences of a postulated LOCA.

   (c) Result in a non-isolatable situation in which the water provided to the RCS to maintain the core in a safe condition is discharged outside of the containment.

3. If interlocks are provided to automatically close the isolation valves when the RCS pressure exceeds the RHR system design pressure, adequate relief capacity shall be provided during the time period while the valves are closing.

D. Pump Protection Requirements

The design and operating procedures of any RHR system shall have provisions to prevent damage to the RHR system due to overheating, cavitation or loss of adequate pump suction fluid.

E. Test Requirements

The isolation valve operability and interlock circuits must be designed so as to permit on line testing when operating in the RHR mode. Testability shall meet the requirements of IEEE Standard 338 and Regulatory Guide 1.22.

The preoperational and initial startup test program shall be in conformance with Regulatory Guide 1.68. The programs for PWRs shall include tests with supporting analysis to (a) confirm that adequate mixing of borated water added prior to or during cooldown can be achieved under natural circulation conditions and permit estimation of the times required to achieve such mixing, and (b) confirm that the cooldown under natural circulation conditions can be achieved within the limits specified in the emergency operating procedures. Comparison with performance of previously tested plants of similar design may be substituted for these tests.

F. Operational Procedures

The operational procedures for bringing the plant from normal operating power to cold shutdown shall be in conformance with Regulatory Guide 1.33. For pressurized water reactors, the operational procedures shall include specific procedures and information required for cooldown under natural circulation conditions.

G. Auxiliary Feedwater Supply

The seismic Category I water supply for the auxiliary feedwater system for a PWR shall have sufficient inventory to permit operation at hot shutdown for at least 4 hours, followed by cooldown to the conditions permitting operation of the RHR system. The inventory needed for cooldown shall be based on the longest cooldown time needed with either only onsite or only offsite power available with an assumed single failure.

H. Implementation

For the purposes of implementing the requirements for plant heat removal capabilitity for compliance with this position, plants are divided into the following three classes:

Class 1 - Full compliance with this position for all plants (custom or standard) for which CP or PDA applications are docketed on or after January 1, 1978. See Table 1 for possible solutions for full compliance.

Class 2 - Partial implementation of this position for all plants (custom or standard) for which CP or PDA applications are docketed before January 1, 1978, and for which an OL issuance is expected on or after January 1, 1979. See Table 1 for recommended implementation for Class 2 plants.

Class 3 - The extent to which the implementation guidance in Table 1 will be backfitted for all operating reactors and all other plants (custom or standard) for which issuance of the OL is expected before January 1, 1979, will be based on the combined I&E and DOR review of related plant features for operating reactors.

TABLE 1. POSSIBLE SOLUTION FOR FULL COMPLIANCE WITH BTP RSB 5-1
AND RECOMMENDED IMPLEMENTATION FOR CLASS 2 PLANTS

Design Requirements of BTP RSB 5-1	Process and [System or Component]	Possible Solution for Full Compliance	Recommended Implementation for Class 2 Plants (see Note 1)
I. Functional Requirement for Taking to Cold Shutdown a. Capability Using Only Safety Grade Systems b. Capability with either only onsite or only offsite power and with single failure (limited action outside CR to meet SF) c. Reasonable time for cooldown assuming most limiting SF and only offsite or only onsite power.	Long-term cooling [RHR drop line]	Provide double drop line (or valves in parallel) to prevent single valve failure from stopping RHR cooling function. (Note: This requirement in conjunction with meeting effects of single failure for long-term cooling and isolation requirements involve increased number of independent power supplies and possibly more than four valves).	Compliance will not be required if it can be shown that correction for single failure by manual actions inside or outside of containment or return to hot standby until manual actions (or repairs) are found to be acceptable for the individual plant.
	Heat removal and RCS circulation during cooldown to cold shutdown (Note: Need SG cooling to maintain RCS circulation even after RHR in operation when under natural circulation [steam dump valves].)	Provide safety-grade dump valves, operators, and power supply, etc. so that manual action should not be required after SSE except to meet single failure.	Compliance required.
	Depressurization (Pressurizer auxiliary spray or power-operated relief valves).	Provide upgrading and additional valves to ensure operation of auxiliary pressurizer spray using only safety-grade subsystem meeting single failure. Possible alternative may involve using pressurizer power-operated relief valves which have been upgraded. Meet SSE and single failure without manual operation inside containment.	Compliance will not be required if a) dependence on manual actions inside containment after SSE or single failure or b) remaining at hot standby until manual actions or repairs are complete are found to be acceptable for the individual plant.

(See SRP 3.2.2, Footnote 4.)

TABLE 1. POSSIBLE SOLUTION FOR FULL COMPLIANCE WITH BTP RSB 5-1
AND RECOMMENDED IMPLEMENTATION FOR CLASS 2 PLANTS

Design Requirements of BTP RSB 5-1	Process and [System or Component]	Possible Solution for Full Compliance	Recommended Implementation for Class 2 Plants (see Note 1)
	Boration for cold shutdown [CVCS and boron sampling].	Provide procedure and upgrading where necessary such that boration to cold shutdown concentration meets the requirements of I. Solution could range from (1) upgrading and adding valves to have both letdown and charging paths safety grade and meet single failure to (2) use of backup procedures involving less cost. For example, boration without letdown may be acceptable and eliminate need for upgrading letdown path. Use of ECCS for injection of borated water may also be acceptable. Need surveillance of boron concentration (boronometer and/or sampling). Limited operator action inside or outside of containment if justified.	Same as above.
II. RHR Isolation	RHR System	Comply with one of allowable arrangements given.	Compliance required. (Plants normally meet the requirement under existing SRP Section 5.4.7).
III. RHR Pressure Relief			
Collect and contain relief discharge	RHR System	Determine piping, etc., needed to meet requirement to provide in design.	Compliance will not be required, if it is shown that adequate alternate methods of disposing of discharge are available.

TABLE 1. POSSIBLE SOLUTION FOR FULL COMPLIANCE WITH BTP RSB 5-1 AND RECOMMENDED IMPLEMENTATION FOR CLASS 2 PLANTS

Design Requirements of BTP RSB 5-1	Process and [System or Component]	Possible Solution for Full Compliance	Recommended Implementation for Class 2 Plants (see Note 1)
V. Test Requirement			
Meet R.G. 1.68. For PWRs, test plus analysis for cooldown under natural circulation to confirm adequate mixing and cooldown within limits specified in EOP.		Run tests confirming analysis to meet requirement.	Compliance required.
VI. Operational Procedure			
Meet R.G. 1.33. For PWRs, include specific procedures and information for cooldown under natural circulation.		Develop procedures and information from tests and analysis.	Compliance required.
VII. Auxiliary Feedwater Supply			
Seismic Category I supply for auxiliary FW for at least four hours at hot shutdown plus cooldown to RHR cut-in based on longest time for only onsite or only offsite power and assumed single failure.	Emergency Feedwater Supply	From tests and analysis obtain conservative estimate of auxiliary FW supply to meet requirement and provide seismic Category I supply.	Compliance will not be required, if it is shown that an adequate alternate seismic Category I source is available.

Note 1: The implementation for Class 2 plants does not result in a major impact while providing additional capability to go to cold shutdown. The major impact results from the requirement for safety-grade steam dump valves.