March 5, 2004

EA-04-049
EA-04-050

Mr. Lew W. Myers
Chief Operating Officer
FirstEnergy Nuclear Operating Company
Davis-Besse Nuclear Power Station
5501 North State Route 2
Oak Harbor, OH 43449-9760

SUBJECT: DAVIS-BESSE NUCLEAR POWER STATION
NRC SPECIAL TEAM INSPECTION – CORRECTIVE ACTION PROGRAM IMPLEMENTATION – REPORT 05000346/2003010(DRS) AND NOTICE of VIOLATION

Dear Mr. Myers:

On January 7, 2004, the U.S. Nuclear Regulatory Commission (NRC) completed a special corrective action team inspection (CATI) at your Davis-Besse Nuclear Power Station to assess the effectiveness of the implementation of your corrective action program. This inspection represented a significant input into the NRC's Davis-Besse Oversight Panel's (Panel) review of Restart Checklist Item 3.a, "Corrective Action Program" and also contributed to the Panel's review of Restart Checklist Items No. 2.c, "Structures, Systems, and Components Inside Containment," and 5.b, "Systems Readiness for Restart." The enclosed inspection report documents the CATI findings which were discussed with you and other members of your staff on September 9 and November 10, 2003, and on January 7, 2004.

The CATI was accomplished by eleven NRC inspectors and contractors over a period of ten months involving five weeks of onsite effort and multiple additional weeks of in-office review. The CATI evaluated the effectiveness of the implementation of various aspects of your corrective action program (CAP), including: (1) identifying and documenting plant design-related deficiencies; (2) categorizing and prioritizing safety issues for resolution; (3) conducting apparent and root cause analyses; (4) determining extent of condition and (5) implementing appropriate and timely corrective actions to ensure adequate resolution of problems. Overall, the CATI team reviewed the resolution of several hundred conditions adverse to quality. Many of the deficiencies reviewed by the CATI involved safety system design engineering issues.

In addition, the CATI reviewed management involvement in and oversight of the implementation of the corrective action program, including the routine performance indicators utilized to monitor the program implementation, and the effectiveness of conditions adverse to quality trending analyses and quality assessment audits of the CAP implementation. Finally, due to the nature of multiple NRC inspection findings, the team focused additional effort on assessing the adequacy of engineering work products, including analyses and calculations.

Notwithstanding a significant number of performance deficiencies identified during the inspection, based on input from the CATI team, the Panel concluded that the corrective action program was sufficiently acceptable for plant restart. The significance of each performance deficiency identified during the inspection was evaluated in accordance with the NRC's Significance Determination Process and concluded to be of very low safety significance. While the individual risk significance of each performance deficiency was low, two themes emerged from a collective evaluation of the number and nature of the CATI findings:

- A weakness in identifying and evaluating the nature and extent of issues when performing apparent cause evaluations to identify the cause(s) and full scope of necessary corrective actions, particularly in the area of safety system design deficiencies; and

- A weakness in the quality of engineering work products, including design calculations and analyses, to correct conditions adverse to quality.

In addition, the CATI noted that during early part of the extended shutdown of the Davis-Besse facility, you suspended the conditions adverse to quality trending program intended to provide early identification of broader plant equipment and organizational concerns. Your resumption of the trending program was not timely. Further, your corrective action program required the review of the effectiveness of corrective action taken to address significant conditions adverse to quality six months after implementation of those actions. Sufficient actions had not been completed for six months for the CATI to evaluate this area.

Following the conclusion of the onsite phase of the inspection in September 2003, your staff implemented actions to further assess the specific areas identified by the CATI and develop improvement initiatives to address those areas. Those activities were presented publicly to the NRC on November 12, 2003 and discussed further during a public meeting on December 10, 2003. Continuing actions to further address the areas of corrective action program effectiveness and engineering product quality are documented in your Operational Improvement Plan, Operating Cycle 14, Revision 3, submitted on February 19, 2003.

The CATI team has reviewed these ongoing and planned actions and concluded that, if properly implemented, they should address the concerns identified during this inspection and further improve the corrective action program effectiveness at Davis-Besse. However, the effectiveness of the actions could not be evaluated by the NRC at this time due to the relatively short implementation time of many of those corrective actions.

The team noted that, in general, the Nuclear Quality Assurance (NQA) assessments of corrective action program effectiveness identified problems pertaining to corrective action program implementation that were similar to the issues identified by the CATI. However, resolution of NQA's findings was not sufficiently prompt or effective to address the identified problems and to prevent the underlying deficiencies that led to these NRC findings. Continuing diligence by Davis-Besse management will be necessary to assure lasting effective corrective action program implementation. The NRC will continue to closely monitor Davis-Besse's performance to assess the effectiveness of the Davis-Besse corrective actions.

In addition to documenting the results of the CATI, this inspection report documents the closure of Davis-Besse Restart Checklist Items 2.c, "Structures, Systems, and Components Inside

Containment," and 3.a, "Corrective Action Program." Restart checklist item 5.b, “Systems Readiness for Restart,” is not closed in this inspection report.

Based on the results of this inspection, the NRC identified two violations which are cited in the enclosed Notice of Violation (Notice) and the circumstances surrounding them are described in detail in the subject inspection report. The violations are being cited because your staff failed to restore compliance after the violations were identified.

Additionally, the NRC identified twenty-six NRC-identified violations of very low safety significance (Green) and one NRC-identified Severity Level IV violation. These violations are being treated as Non-Cited Violations (NCVs) consistent with Section VI.A of the Enforcement Policy. These NCVs are described in the subject inspection report. The violations were evaluated in accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," (Enforcement Policy), NUREG -1600. The current Enforcement Policy is included on the NRC’s web site at www.nrc.gov; select “What we do, Enforcement,” then “Enforcement Policy.”

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. The NRC will use your response, in part, to determine whether further enforcement action is necessary to ensure compliance with regulatory requirements.

If you contest the severity level or significance of the NCVs described in the report, you should also provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U. S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, Region III, 801 Warrenville Road, Suite 255, Lisle, IL 60532-4351; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-001.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

To the extent possible, your response should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the Public without redaction.

Sincerely,

/RA/

John A. Grobe, Chairman
Davis-Besse Oversight Panel

Docket No. 50-346
License No. NPF-3

Enclosures: 1. Notice of Violation
2. Inspection Report No. 05000346/2003010(DRS)

cc w/encl: The Honorable Dennis Kucinich
G. Leidich, President - FENOC
Plant Manager
Manager - Regulatory Affairs
M. O'Reilly, Attorney, FirstEnergy
Ohio State Liaison Officer
R. Owen, Administrator, Ohio Department of Health
Public Utilities Commission of Ohio
President, Board of County Commissioners
Of Lucas County
Steve Arndt, President, Ottawa County Board of Commissioners
D. Lochbaum, Union Of Concerned Scientists
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P. Gunter, N.I.R.S.

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NOTICE OF VIOLATION

First Energy Nuclear Operating Company
Davis-Besse Nuclear Power Station

Docket No. 50-346
License No. NPF-3
EA-04-049
EA-04-050

During an NRC inspection conducted from March 17, 2003 through January 7, 2004, violations of NRC requirements was identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," NUREG-1600, the violations are listed below:

(a) Title 10 CFR Part 50, Appendix B, Criterion III, requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions. It also requires that measures be provided for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to the above, as of August 12, 2003, the licensee failed to verify that the design of the service water system discharge path swapover setpoints was adequate. Specifically, the analysis performed by the licensee showed that the established setpoints were not adequate and the evaluation of the analysis accepted the inadequate setpoint based on non-safety-related equipment performing a safety-related function under design basis conditions. Neither the analysis nor the evaluation corrected the nonconforming condition previously identified in Inspection Report 05000346/2002014.

This is a violation of very low safety significance (Green).

(b) Technical Specification Section 4.05a requires, in part, that the licensee perform inservice testing of valves in accordance with the ASME OM Code and applicable addenda as required by 10 CFR 50.55a.

10 CFR 50.55a(f)(4) requires that pumps and valves which are classified as ASME Code Class 1, 2, and 3 meet the inservice test requirements set forth in the appropriate edition and addenda of the ASME OM Code. It further requires that, during 120-month intervals successive to the initial 120-month interval, tests must comply with the requirements in the latest Code edition and addenda incorporated by reference in paragraph (b) of 10 CFR 50.55a 12 months prior to the start of the 120-month interval. Paragraph 50.55a(f)(5)(i) requires that the inservice test program be revised as necessary to meet the requirement of paragraph 50.55a(f)(4).

The ASME OM Code, 1995 edition through the 1996 addenda, Section ISTC 4.5.1 requires, in part, that check valves be exercised nominally every three months. Section ISTC 4.5.4(a) requires, in part, that check valves be exercised by initiating flow and observing that the obturator traveled to its full open position. Observations shall be made by observing a direct indicator (e.g., a position-indicating device) or by other positive means (e.g., changes in system pressure, flow rate, level, temperature, seat leakage, testing, or non-intrusive testing results).

Contrary to the above, the NRC identified that on September 12, 2003, and other dates, the licensee did not observe by a direct indicator or other positive means that the ASME Class 3 service water pump discharge check valve obturator traveled to its full open position during its quarterly surveillance test. Specifically, on September 12, 2003, the licensee observed a flow rate of 9718 gpm through valve SW-19, which was less than the test acceptance criterion of 10,000 gpm, and less than the approximately 10,300 gpm used in the licensee's most recent accident analysis. Observing flow rates less than required for the valve to perform its safety function was not a positive means to determine that the obturator traveled to its full open position and no other direct indicator or positive means was used. The NRC approved use of the 1995 Code edition through the 1996 addenda for the third inservice testing 120-month interval on March 28, 2003 . Prior to that date, the licensee was committed to the 1986 Edition (no Addenda) of the ASME Boiler and Pressure Vessel Code, Section XI. The 1986 Code Edition contains similar requirements.

This is a violation of very low safety significance (Green).

Pursuant to the provisions of 10 CFR 2.201, FirstEnergy Nuclear Operating Company is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555 with a copy to the Regional Administrator, Region III, and a copy to the NRC Resident Inspector at the Davis-Besse Nuclear Power Plant, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation; EA-04-049 and EA-04-050," and should include for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation or severity level; (2) the corrective steps that have been taken and the results achieved; (3) the corrective steps that will be taken to avoid further violations; and (4) the date when full compliance will be achieved. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, an order or a Demand for Information may be issued as to why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

If you contest this enforcement action, you should also provide a copy of your response, with the basis for your denial, to the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.

Because your response will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html, to the extent possible, it should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the public without redaction. If personal privacy or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such material, you must specifically identify the portions of your response that you seek to have withheld and provide in detail the basis for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.390(b) to support a request for withholding confidential commercial or financial information). If safeguards information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR 73.21.

Dated this 5th day of March, 2004

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-346
License No:	NPF-3
Report No:	05000346/2003010
Licensee:	FirstEnergy Nuclear Operating Company
Facility:	Davis-Besse Nuclear Power Station
Location:	5501 North State Route 2 Oak Harbor, OH 43449
Dates:	March 17, 2003 through January 07, 2004
Inspection Team:	Z. Falevits, Lead Senior Reactor Engineering Inspector M. Farber, Senior Reactor Engineering Inspector P. Lougheed, Senior Reactor Engineering Inspector A. Walker, Senior Reactor Engineering Inspector D. Chyu, Reactor Engineering Inspector R. Daley, Reactor Engineering Inspector F. Baxter, Electrical Consultant W. Bennett, Corrective Action Consultant Dr. O. Mazzoni, Electrical Consultant J. Panchison, Mechanical Consultant W. Sherbin, Mechanical Consultant
Approved by:	Julio F. Lara, Chief Electrical Engineering Branch Division of Reactor Safety

Enclosure

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SUMMARY OF FINDINGS

IR 05000346/2003010(DRS); 03/17/2003 - 01/07/2004; Davis-Besse Nuclear Power Station; Corrective Action Program Implementation Effectiveness

The inspection consisted of five weeks of on-site activities over a six month period. The specific on-site weeks were the weeks of: March 17, March 31, May 18, August 11, and August 25, 2003. This report documents a special corrective action program implementation team inspection. The inspection was conducted to assess the adequacy of the licensee's implementation of the facility's corrective action program. The inspection was conducted by regional engineering inspectors and supplemented by consultants. Two Green findings associated with two cited violations, one Severity Level IV Non-Cited Violation (NCV), and twenty-six (26) Green findings associated with 26 NCVs were identified.

The significance of most findings is indicated by their color (Green, White, Yellow, Red) using NRC Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, July 2000.

A. Inspector-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Appendix R, Section III.L.2.d, having very low safety significance. Specifically, the licensee failed to provide the process monitoring function, capable of providing direct readings of the process variables necessary to perform and control the alternative shutdown, for a control room or cable spreading room fire. Following discovery, the licensee entered the issue into the corrective action program and performed a modification to resolve the issue. The primary cause of this violation was related to the cross-cutting area of problem identification and resolution because the licensee had previously identified this issue as an enhancement and did not recognize that it was a violation of regulatory requirements.

  This issue was more than minor because it affected the initiating events cornerstone and, by not providing the direct indications necessary for the operators to determine the status of the idle SG, the probability of experiencing unacceptable stresses on the SG tubes during the limiting Appendix R scenario was increased. The team determined this finding to be of very low significance, based upon the low probability of a serious control room fire combined with the low probability that such a fire would affect this specific instrumentation detrimentally. Additionally, even in the event that such a fire had affected this instrumentation, it was likely that the operators still would have been able to prevent these tube stresses through use of manual actions, although this was not a credited action in the Fire Protection procedures for this scenario. (Section 4OA3(5)b.1)

Cornerstone: Mitigating Systems

- Green. The team identified a Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control." Specifically, the licensee failed to provide a basis for the setpoint to swap the service water system discharge path. This issue was previously identified as a Non-Cited Violation in Inspection Report 05000346/2002014 and the corrective actions taken by the licensee failed to correct the originally identified condition. The primary cause of this violation was related to the cross-cutting areas of problem identification and resolution and human performance, because the licensee did not recognize that the corrective actions taken needed to restore compliance with the identified violation of NRC requirements.

  The issue was determined to be more than minor because the licensee had not corrected a previous violation and was relying on non-safety-related equipment to perform a safety function under design bases conditions. Because the issue was previously determined to be of very low safety significance, NRC management concluded that the violation could be categorized as having very low safety significance. (Section 4OA3(3)b.11)

- Green. The team identified a Cited Violation of Technical Specifications Section 4.05a and 10 CFR 50.55a. Specifically, the licensee failed to ensure that the service water discharge check valve was tested in accordance with the American Society of Mechanical Engineers Code. The primary cause of this violation was related to the cross-cutting areas of problem identification and resolution and human performance, because the licensee did not recognize that the corrective actions taken needed to ensure compliance with NRC requirements.

  The issue was determined to be more than minor because the inadequate test acceptance criteria allowed the licensee to accept a check valve as performing its intended function at less than full system flow. The issue was of very low safety significance using the Phase 1 of the significance determination process based on the licensee's determination that the system was operable but degraded. (Section 4OA3(3)b.12)

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," having very low safety significance. Specifically, the licensee failed to translate instrument uncertainties into the undervoltage time delay setting specification for the 4160 Vac buses C1 and D1. Following discovery, the licensee confirmed the settings were acceptable and re-evaluated the potential temperature effects to the time delay relays.

  This issue was more than minor because the licensee had to perform calculations to show that the relays were within their allowable values, and because the licensee determined that the increased temperature could cause the time delay to operate outside of Technical Specifications limits. The issue was of very low safety significance using the Phase 1 of the significance determination process since the licensee considered the instruments to be operable. (Section 4OA3(2)b.1)

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” having very low safety significance. Specifically, the licensee failed to provide motor thermal overload protection for the Class 1E 480 alternating current voltage (Vac) distribution system. Following discovery, the licensee physically modified approximately 53 thermal overload circuits to resolve the discrepancy. The primary cause of this violation was related to the cross-cutting area of human performance because the licensee did not realize the lack of thermal overload protection was an unanalyzed condition and that the station was not in compliance with the updated safety analysis report until identified by the team.

  This issue was more than minor because the licensee failed to ensure that bypassing the thermal overload protection would result in completion of safety functions and subsequently had to install thermal overload protection in order to meet the design requirement. The issue was determined to be of very low safety significance using Phase 1 of the significance determination process because there was reasonable assurance that the condition did not result in a loss of system function. (Section 4OA3(2)b.2)

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XI, “Test Control,” having very low safety significance. Specifically, the licensee failed to adequately test direct current contactors related to two safety related motor operated steam valves associated with the auxiliary feedwater system. Following discovery, the licensee entered the issue into the corrective action program and was re-evaluating the basis for acceptability of these valves. The primary cause of this violation was related to the cross-cutting area of problem identification and resolution because, although the issue was identified in 2002, the licensee did not see the need to take corrective action until prompted by the team in 2003.

  This issue was more than minor because the licensee had relied upon an inadequate test to show that the contactors were qualified to perform under required conditions and because the contactors were installed in the plant during previous operating cycles. The issue was of very low safety significance using the Phase 1 of the significance determination process because the licensee determined that the valves were operable. (Section 4OA3(2)b.3)

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” having very low safety significance. Specifically, the licensee failed to identify and correct inadequate short circuit protection for direct current (DC) circuits. Following discovery, the licensee issued a condition report to document the deficient circuit protection for valves with extremely long circuit lengths. The primary cause of this violation was related to the cross-cutting area of problem identification and resolution because the licensee had missed several opportunities to identify it as part of corrective actions for previously identified DC circuit deficiencies.

  This issue was more than minor because the licensee had to perform calculations to show that the fuses would adequately protect the equipment and because modifications to those fuses were required. The issue was of very low safety significance using Phase 1 of the significance determination process because the licensee concluded the equipment was operable. (Section 4OA3(2)b.4)

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” having very low safety significance. Specifically, the licensee failed to confirm operability of direct current (DC) contactors by ensuring that minimum voltage was available at the safety related device terminals. The licensee missed several opportunities to correct this design deficiency. Following discovery, the licensee issued a condition report to evaluate the adequacy of available voltage. The primary cause of this violation was related to the cross-cutting area of problem identification and resolution because, although the issue was identified in 2002, the licensee did not see the need to take corrective action until prompted by the team in 2003.

  This issue was more than minor because the licensee had to perform calculations to determine if the devices had sufficient voltage to perform their safety function. The issue was of very low safety significance using Phase 1 of the significance determination process because the licensee determined that all components were operable. (Section 4OA3(2)b.5)

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” having very low safety significance. Specifically, the licensee failed to verify that the high pressure injection pumps could operate under design basis minimum flow requirements since initial plant startup. The primary cause of this violation was related to the cross-cutting area of problem identification and resolution because the licensee missed several opportunities to identify and correct the deficiency.

  This issue was more than minor because the licensee had to perform a test to demonstrate that design basis requirements could be met and because the test results determined that the design basis requirements needed to be changed to ensure that the HPI pumps could perform their accident required function. The issue was of very low safety significance because surveillance test results indicated the lowest flow rate for either pump was slightly outside the licensee's new operability band, and therefore, it was deemed likely that the pumps would have performed had they been called upon. The issue screened out of Phase 1 of the significance determination process. (Section 4OA3(3)b.1)

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” having very low safety significance. Specifically, the licensee failed to consider worst case minimum pressure differential between service water and component cooling water systems when determining required service water makeup flow to the component cooling water system heat exchangers. Following discovery, the licensee entered the issue into the corrective action program and performed the necessary calculations. The primary cause of this violation was related to the cross-cutting area of human performance because the licensee used test data collected during normal operation rather than taking the worst case design conditions and because there was a lack of rigor in the calculation review process.

  This issue was more than minor because the licensee needed to perform a new calculation to demonstrate that the service water flow to the component cooling water system was adequate to perform its design function under accident conditions. The issue was of very low safety significance because the licensee determined the system was operable. Therefore, the issue screened out of Phase 1 of the significance determination process. (Section 4OA3(3)b.6)

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," having very low safety significance. Specifically, the licensee failed to verify the adequacy of the design of the service water (SW) pump room ventilation system. Following discovery that the design basis calculations were non-conservative, the licensee entered the issue into the corrective action program, re-performed the calculations, and made appropriate modifications to correct the issues. The primary cause of this violation was related to the cross-cutting area of corrective action because the licensee failed to correct all of the originally identified issues until identified by team.

  This issue was more than minor because inadequacies in the calculations resulted in a modification which was required to ensure winter operation was within the allowable temperature range, and because the revised calculation did not include all the summer heat loads which could potentially impair the SW pump room ventilation system to perform its safety function. The issue was of very low safety significance because the licensee determined that past non-procedurally-required compensatory actions had prevented the equipment from actually being inoperable. Therefore, the issue screened out of Phase 1 of the significance determination process. (Section 4OA3(3)b.7)

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," having very low safety significance. Specifically, the licensee failed to ensure that the service water system could perform its design function under all required conditions. Following discovery, the licensee documented the issue in the corrective action program and performed the necessary calculations.

  This issue was more than minor because the licensee did not initially have a calculation which showed that the service water (SW) system could fulfill its design function under design basis conditions and because, when the calculation was prepared, it identified circumstances where the system would not be able to perform its safety function and those circumstances were not evaluated to ensure that the safety function could be met. The issue was of very low safety significance because the licensee concluded that the SW system had never been unable to perform its safety function. Therefore, the issue screened out of Phase 1 of the significance determination process.
  (Section 4OA3(3)b.8)

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," having very low safety significance. Specifically, the licensee failed to have provisions in place to protect the service water pump room from flooding. Following discovery, the licensee placed the issue in the corrective action program, evaluated the issue and established procedures to address the issue.

  This issue was more than minor because the licensee had to make procedural changes in order to ensure that safety-related equipment was capable of performing its safety functions. The issue was of very low safety significance because the deficiency only dealt with a lack of procedural guidance. Therefore, the issue screened out of Phase 1 of the significance determination process. (Section 4OA3(3)b.9)

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XI, “Test Control,” having very low safety significance. Specifically, the licensee failed to account for a number of conditions in the service water system flow balance testing procedures. Following discovery, the licensee placed the issue in the corrective action program, evaluated the issue and established procedures to address the issue.

  This issue was more than minor because procedural changes were necessary in order to ensure that the safety-related service water (SW) system branch flow rates were adequate for the system to perform its safety functions. The issue was of very low safety significance because the licensee concluded that the system was previously capable of meeting its design requirements. Therefore, the issue screened out of Phase 1 of the significance determination process. (Section 4OA3(3)b.10)

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” having very low safety significance. Specifically, the licensee failed to provide an analysis which addressed the service water valve single failure assumptions described in the updated safety analysis report. Following discovery, the licensee entered the issue in the corrective action program. The primary cause of this violation was related to the cross-cutting area of problem identification and resolution because the licensee had not recognized the impact of the issue on the design basis and had not corrected it after it was identified in 2002.

  This issue was more than minor because the current calculations were non-conservative and the licensee was not able to show that the service water system could perform its safety function under design basis conditions. The issue was of very low safety significance because the team determined that it was unlikely that the service water system would not function during a design basis accident, as there would need to be a maximum service water temperature or minimum ultimate heat sink level and a specific valve single failure. This issue was a design deficiency that would not likely result in the loss of function; therefore, the issue screened out of Phase 1 of the significance determination process. (Section 4OA3(3)b.13)

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” having very low safety significance. Specifically, the licensee failed to ensure that design analyses showed that the auxiliary feedwater (AFW) system could perform its safety function under design basis conditions. Following discovery, the licensee entered the issue into the corrective action program. The primary cause of this violation was related to the cross-cutting area of human performance, as the licensee used the results of a vendor calculation without verifying that it was adequate.

  This issue was more than minor because the calculations were non-conservative and the calculation of record did not demonstrate that the AFW system could perform its safety function under design basis conditions. Based on further analysis, the licensee concluded the AFW system was operable. Therefore, the issue screened out of Phase 1 of the significance determination process and was of very low safety significance. (Section 4OA3(3)b.14)

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," having very low safety significance. Specifically, the licensee failed to recognize that flushing the system and blowing down the strainers upstream of the turbine driven pump bearing cooling water strainers prior to routine surveillances constituted preconditioning of the auxiliary feedwater system. Following discovery, the licensee entered the issue into the corrective action program. The primary cause of this violation was related to the cross-cutting area of problem identification and resolution because the licensee had failed to recognize the consequences of the preconditioning when evaluating an earlier issue.

  This issue was more than minor because there was not sufficient information to show that test requirements would have been met had the strainers not been blown down. The issue was of very low safety significance because the licensee considered the system operable. Therefore, the issue screened out of Phase 1 of the significance determination process. (Section 4OA3(3)b.15)

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," having very low safety significance. Specifically, the licensee failed to ensure that emergency core cooling system pump motors were environmentally qualified for the stated mission time, as stated in a license amendment request submitted to the NRC. Following discovery, the licensee entered the issue into the corrective action program. The primary cause of this violation was related to the cross-cutting area of human performance as the licensee did not ensure that personnel developing license documents had the necessary information.

  This issue was more than minor because, if left uncorrected, this weakness could result in a repeat failure of the corrective action program to adequately identify, evaluate and correct problems. The issue was of very low safety significance because the licensee considered that the motors could be environmentally qualified. Therefore, the issue screened out of Phase 1 of the significance determination process.
  (Section 4OA3(3)b.21)

- Severity Level IV. The team identified a Non-Cited Violation of 10 CFR 50.59, "Changes, Tests and Experiments." Specifically, the licensee failed to preform an adequate evaluation of a defacto modification to the plant where the underlying change may have required NRC approval prior to implementation. The design change involved degraded or missing physical barriers that could result in one or more of the diesel generators failing to fulfill their design function during a tornado. Following discovery, the licensee entered the issue into the corrective action program and re-performed the analysis. The licensee also repaired those barriers which were physically degraded. The primary cause of this violation was related to the cross-cutting area of human performance as the licensee appeared to selectively choose information from the guidance document in order to achieve the desired outcome.

  Because this issue affected the NRC's ability to perform its regulatory function, this finding was evaluated with the traditional enforcement process. The finding was determined to be of very low safety significance based on a significance determination process analysis of a loss of offsite power concurrent with loss of one emergency diesel generator. (Section 4OA3(3)b.23)

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” having very low safety significance. Specifically, the licensee failed to include environmental effects of a decay heat removal pump seal failure in the moderate energy line break analysis. Following discovery, the licensee entered the issue into the corrective action program and re-performed the analysis.

  This issue was more than minor because the licensee had to perform calculations to show that the environmental effects were acceptable. The issue was of very low safety significance because, upon completing the analysis, the licensee determined that the moderate energy line break heat loads were acceptable and that the system could perform its design function. Therefore, the issue screened out of Phase 1 of the significance determination process. (Section 4OA3(3)b.24)

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Section III.L.2.e, having very low safety significance. Specifically, the licensee failed to provide the process cooling and lubrication necessary to permit the operation of the equipment used for safe shutdown functions. Following discovery, the licensee entered the issue into the corrective action program and performed a modification to resolve the issue. The primary cause of this violation was related to the cross-cutting area of problem identification and resolution because the licensee had previously identified this issue as an enhancement and did not recognize that it was a violation of regulatory requirements.

  This issue was more than minor because, if left uncorrected, the finding would become a more significant safety concern. By not providing containment air cooling as per the governing alternative shutdown procedure, the probability of the failure of equipment relied upon for safe shutdown was increased. This issue was screened to be of very low safety significance because there was not a total loss of safety function for an assumed control room fire with evacuation. (Section 4OA3(5)b.2)

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50.48(a)(1), having very low safety significance. Specifically, the licensee failed to evaluate the adequacy of emergency diesel generator common floor drains following sprinkler system actuation in the fire affected emergency diesel generator room. Following discovery, the licensee entered the issue into the corrective action program and revised the fire response procedures to address the issue.

  This issue was more than minor because it affected the mitigating systems cornerstone and the potential existed that a fire in one emergency diesel generator room would potentially impact the redundant emergency diesel generator following sprinkler actuation in the fire affected emergency diesel generator room. The finding was of very low safety significance since this issue was a design deficiency that was confirmed not to result in the loss if function per Generic Letter 91-18, Revision 1. Therefore, the issue screened out of Phase 1 of the significance determination process. (Section 4OA3(5)b.3)

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” having very low safety significance. Specifically, the licensee failed to provide for the original plant design to incorporate a safety-related recirculation path for the high pressure injection (HPI) pumps in the high pressure recirculation (HPR) mode of operation. Following discovery, the licensee installed an additional minimum flow recirculation line for each HPI pump.

This issue was more than minor because the original plant design did not incorporate a safety-related recirculation path for the HPI pumps in the HPR mode of operation and this finding affected the mitigating systems cornerstone. The issue was of very low safety significance because the HPR safety-function would not actually have been lost because of existing procedure actions for feed and bleed operations in situations where the steam generators could not be used to remove decay heat. Therefore, the finding screened out as having very low safety significance. Section (4OA3(6)b.3)

Cornerstone: Barrier Integrity

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," having very low safety significance. Specifically, the licensee failed to correctly identify and translate the design basis requirements into the containment air coolers airflow analyses and motor horsepower sizing calculations. The primary cause of this violation was related to the cross-cutting area of problem identification and resolution as the licensee had previously identified issues with the motors, but had not reviewed the design calculation of record. Following discovery, the licensee entered the issue into the corrective action program and performed a new analysis for the motor.

  This issue was more than minor because the licensee had to revise the associated calculation to evaluate the existing motor to ensure the containment air coolers (CAC) would be able to perform their design function. The issue was evaluated in a Phase 1 analysis in the significance determination process. Because the issue involved both the mitigating system and barrier integrity cornerstones, a Phase 2 analysis was also performed. A final evaluation was obtained that the issue was of very low safety significance. (Section 4OA3(3)b.3)

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," having very low safety significance. Specifically, the licensee failed to evaluate a potential overstressing condition on the reactor coolant pump casing-to-cover studs. Following discovery, the licensee entered the issue into the corrective action program. The primary cause of this violation was related to the cross-cutting area of problem identification and resolution as the licensee closed a condition report without recognizing that the apparent condition adverse to quality had not been addressed.

  This issue was more than minor because the NRC had to perform calculations to determine if the reactor coolant pump studs were within ASME Code allowables. The issue was of very low safety significance based on the NRC determination that the studs were always functional. Therefore, the issue screened out of the Phase 1 significance determination process as having very low safety significance. (Section 4OA3(3)b.19)

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” having very low safety significance. Specifically, the licensee failed to take adequate corrective actions to previous events to prevent damage to a new fuel assembly spacer grid strap during the final reload of the core in February 2003. Following discovery, the licensee entered the issue into the corrective action program. The primary cause of this violation was related to the cross-cutting areas of corrective action and human performance, because, despite earlier events, the licensee failed to adequately address the human performance issues that contributed to this and other fuel spacer grid events.

  This issue was more than minor because the licensee failed to prevent recurrence of a significant condition adverse to quality resulting in damage occurring to previously undamaged fuel assembly grid straps. The issue only involved the fuel barrier and it screened out of the Phase 1 significance determination process as having very low safety significance. (Section 4OA3(4)b)

Non-Significance Determination Process Issues

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” having very low safety significance. Specifically, the licensee failed to assess an increase in the offsite dose to the public following a postulated design basis accident due to increased containment pressure. Following discovery, the licensee entered the issue into the corrective action program and performed the necessary analysis. The primary cause of this violation was related to the cross-cutting area of problem identification and resolution, because, although the issue had been previously identified, the licensee had failed to identify that a revised dose assessment was needed until prompted by the NRC.

  This issue was more than minor because the licensee had to perform calculations to show that the increased time at higher containment pressures did not result in doses being above regulatory guide allowables. The mitigating system cornerstone was not affected since the finding pertained to offsite dose calculations rather than containment air coolers performance. Based on this review, the team determined that the issue was not covered by any of the revised oversight cornerstones and was, therefore, not suitable for SDP analysis. This determination was due to the issue regarded containment pressure and related to offsite dose consequences. Regional management determined that this regulatory issue was of very low safety significance because projected offsite doses remained less than Regulatory Guide 1.4 allowances. (Section 4OA3(3)b.2)

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” having very low safety significance. Specifically, the licensee failed to implement effective design control measures to check and verify the adequacy of the design basis calculation performed for sizing the new accumulators used to hold the service water containment isolation valves closed on a loss of instrument air. Following discovery, the licensee entered the issue into the corrective action program, revised calculations, and changed the accumulator medium from compressed air to nitrogen.

This issue was more than minor because the licensee had to change the modification design from having accumulators containing pressurized air to accumulators containing pressurized nitrogen. This finding was evaluated in Phase 1 of the significance determination process. The mitigating system cornerstone was not affected since the finding pertained to the sizing of accumulators associated with containment isolation valves. Therefore, the issue was not covered by any of the revised oversight cornerstones and was, therefore, not suitable for SDP analysis. This determination was based on the issue affecting containment isolation valves which provide a barrier to breach of containment and potential offsite dose consequences. Regional management determined that this regulatory issue was of very low safety significance. (Section 4OA3(3)b.4)

- Green. The team identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," having very low safety significance. Specifically, the licensee failed to translate the postulated radiological consequences of leakage from engineered safety feature components outside containment into calculations of record for post-accident control room dose and offsite boundary dose. Following discovery, the licensee entered the issue into the corrective action program and provided a bounding evaluation which demonstrated that the increase in dose was within acceptable limits.

  This issue was more than minor because the licensee had to perform calculations to show that the increased doses remained within the post accident dose level requirements. The issue could not be assessed through the significance determination process, because none of the cornerstone objectives addressed design issues dealing with postulated doses following a design basis accident. After determination that the increase in dose did not involve an issue requiring a license amendment, Regional Management concluded the regulatory issue was of very low safety significance. (Section 4OA3(3)b.18)

B. Licensee-Identified Violations

No findings of significance were identified.

REPORT DETAILS

4. OTHER ACTIVITIES (OA)

4OA2 Identification and Resolution of Problems (71152B)

Background

On March 6, 2002, Davis-Besse personnel notified the NRC of degradation (corrosion) of the reactor vessel head material adjacent to a control rod drive mechanism (CRDM) nozzle. This condition was caused by coolant leakage and boric acid corrosion of the head material induced by an undetected crack in the adjacent CRDM nozzle. The degraded area covered in excess of 20 square inches where the low-alloy carbon structural steel was corroded away, leaving the thin stainless steel cladding layer. This condition represented a loss of the reactor vessel’s pressure retaining design function, since the cladding was not considered as pressure boundary material in the structural design of the reactor pressure vessel. While the cladding did provide a pressure retaining capability during reactor operations, the identified degradation represented an unacceptable reduction in the margin of safety of one of the three principal fission product barriers at Davis-Besse. This issue was documented in inspection report (IR) 05000346/2002003. The event was captured in the licensee's corrective action program (CAP) as condition report (CR) 02-00891, "Failure to Identify Significant Degradation of the Reactor Pressure Vessel Head." The root cause analysis report for the CR documented that one of the root causes of the event was "less than adequate implementation of the corrective action program."

As part of the licensee’s return to service plan and as corrective action for the circumstances that led to the vessel head degradation, the licensee implemented the Davis-Besse system health assurance (SHA) plan. This plan described activities to review plant systems prior to restart to ensure that plant systems were in a condition that would support safe and reliable operation.

In an effort to identify adverse trends and problem areas, the licensee performed a collective review of approximately 600 relatively significant CRs and developed approaches to correct the discrepancies, evaluate the extent of condition, address any trends, and resolve the issues. The licensee used a three-phase corrective action process to identify and resolve deficiencies:

- Path A – Resolution of each condition identified and determination of the extent of condition. This approach used the station’s CAP to determine cause, extent of condition, and implement specific corrective actions for discrepancies

- Path B – Evaluation to provide additional assurance of significant safety function capabilities. The collective review identified numerous deficiencies in the areas of calculations and testing which validated or verified the capability of safety systems to perform their functions.

- Path C – Resolution of design-related programmatic issues. The collective review identified numerous discrepancies in five design-related programmatic areas (station flooding, high energy line break, environmental qualification, seismic qualification, and 10 CFR Part 50, Appendix R – Safe Shutdown) within each of the five systems selected for a detailed latent issues review. The licensee conducted a specific detailed examination of CRs to identify, characterize, determine the extent of condition, and correct the problems in each of those programmatic areas.

The licensee's review efforts identified numerous discrepancies involving an inadequate CAP, inadequate configuration control, degraded hardware conditions, inconsistent and potentially non-conservative assumptions in design basis and licensing basis documents, deficient or unavailable calculations, and non-conservative operating and test procedures which did not reflect design and licensing basis documents. The identified discrepancies were documented in new CRs and these CRs were assessed for operability impact and significance in accordance with the station's CAP.

As part of the NRC's inspection of the SHA plan, a safety system design and performance capability inspection (SSDI) was conducted on three systems: the service water (SW), high pressure injection (HPI), and 4160 volt alternating current (AC) electrical distribution systems. This inspection identified numerous deficiencies, which mirrored the licensee's findings in a number of areas. This inspection, and the resultant findings, were documented in IR 05000346/2002014.

(1) Corrective Action Program Implementation

a. Inspection Scope

To assess the licensee's corrective actions to adequately address the numerous plant deficiencies identified in 2002 during the licensee's and NRC reviews, the NRC conducted an in-depth corrective action team inspection (CATI) of the CAP implementation. This inspection was intended to assess the effectiveness of the licensee's actions to identify the deficiencies, evaluate the cause(s) and correct the problems in order to prevent recurrence.

In order to make the above assessment, the team reviewed selected CRs which evaluated the licensee's actions to address deficiencies documented in licensee event reports (LERs), NRC Non-Cited Violations (NCVs), and NRC unresolved items (URIs) from previous inspections. The selected CRs also involved issues identified by the licensee as part of their system health readiness or latent issue reviews. The team's focus was on CRs which the licensee had identified as requiring resolution prior to the restart of the plant, with a further emphasis on those CRs which the licensee had determined to be "significant conditions adverse to quality (SCAQ)."

The team specifically assessed the licensee's CAP in four separate areas:

- Identifying problems; including recognizing performance issues within the CAP itself;

- Categorizing and prioritizing problems, with a specific emphasis on the licensee's use of a process termed as "rollovers";
- Evaluating those problems; including assessing root and apparent causes, extent of conditions, operability and reportability;
- Correcting problems, including not only the originally identified problem but any issues identified as part of the evaluation, assessment of effectiveness of the corrective actions and actions taken to prevent recurrence.

In addition, the team assessed two areas where a number of problems were identified. These were:

- Engineering Resolution of Design Deficiencies and
- Procedure Quality and Adherence

b. <u>Observations and Findings</u>

The corrective action program was described in procedure NOP-LP-2001, "Condition Report Process." This procedure was significantly revised in March 2003, and again in May 2003. The CAP consisted of a process to identify and resolve potential adverse or undesirable conditions. It included issues, concerns, observations, equipment deficiencies, human performance problems, equipment failures and programmatic deficiencies.

The team began its inspection in March 2003. However, due to the licensee not being ready for the inspection at that time, the inspection was delayed until May 2003, and the most effective inspection actually occurred in August 2003, when the licensee had completed sufficient packages for the team to review.

As described below, at the conclusion of the inspection, the team determined that, overall, the licensee's program for identifying, prioritizing, evaluating, and correcting performance deficiencies was acceptable. However, the team also observed that the licensee's actions to identify non-conforming issues and prevent recurrence were often minimally effective. The team also identified evaluations which were narrowly focused and not probing in nature. Consequently, the resulting corrective actions were also narrowly focused. In areas where the licensee had established corrective actions, the effectiveness of these actions could not be readily determined at the end of the inspection due to the short time frame since implementation.

During the inspection, the team reviewed approximately 150 CRs. Of these, the team determined that approximately 120 had weaknesses or deficiencies, of some type. As a result of the team's findings, the licensee initiated approximately 120 additional CRs to document and address the team's findings. Overall, the team determined that approximately 80 percent of the CRs actually reviewed by the team had weaknesses or deficiencies to some degree. The weaknesses and deficiencies identified by the team resulted in the identification of findings documented in this inspection report.

Subsequent to the onsite inspection, on November 12 and December 10, 2003, the licensee presented to the NRC, the planned actions to address the issues and concerns identified by the CATI. As part of these meetings, the licensee made a number of commitments to further improve the CAP as part of its Operational Improvement Plan for Cycle 14, Revision 3. The team recognized that the improvement plan described actions that should address the team's areas of concerns. Additionally, the licensee implemented some improvements in the CAP. Examples included the revised CAP procedure and the newly established CR analyst positions.

.1 Adequacy of Licensee's Efforts to Identify and Document Problems

The team determined that the licensee, overall, was adequately identifying and documenting problems. However, a number of examples were identified where the licensee had failed to identify or to document problems, particularly in the area of design-related deficiencies. The team attributed these issues to a lack of attention to detail, weak knowledge of system design basis, and a failure to follow CAP procedures. Specific examples are listed below, and the more significant ones are discussed in Sections 4OA3(2) and 4OA3(3) of this report.

- Failure to identify the lack of thermal overload protection for safety related motors (See Section 4OA3(2)b.2 for additional details);
- Failure to identify oversized fuses in safety related motor operated circuits (See Section 4OA3(2)b.4 for additional details);
- Failure to identify the main steam safety valve (MSSV) setpoint drift and accumulation, and the potential affect on auxiliary feedwater (AFW) pump flow (See Section 4OA3(3)b.14 for additional details);
- Failure to identify potential design problems with the containment air coolers (CACs) (See Sections 4OA3(3)b.2 and 4OA3(3)b.3 for additional details);
- Failure to write a CR for SW calculational deficiencies. (See CR 03-03977);
- Failure to generate a CR to address a problem identified during the SSDI and which was documented in that IR as NCV 02-014-01b (See Section 4OA3(3)b.5 for additional details);
- Failure to identify lack of breaker coordination (CR 03-03572); and
- Failure to identify configuration control discrepancies (CR 03-02699).

.2 Adequacy of Licensee's Efforts to Categorize and Prioritize Problems

The team determined that the licensee, overall, was adequately categorizing items in regard to their safety significance and impact upon plant operation. The licensee also generally appeared to be assigning an appropriate priority both to performing evaluations and completing corrective actions prior to restart of the plant.

However, early in the inspections the team did identify a concern with a process the licensee was using as part of their categorization process. This process, referred to as "rollovers", allowed the licensee to disposition CRs by transferring either a portion or the entire issue to one or more additional other open CRs. The licensee did place a condition that the "rolled-into" CRs had to be of equal or greater category and had to address the same issues. However, the issues described in the "rolled-out-of" CRs could be broken into several different "rolled-into" CRs and "rolling" could occur on multiple occasions (i.e., CR 1 was rolled into CR 2 which was rolled into CR 3, which then rolled out part of CR 1's issues to CR 4...). This was especially true in regard to specified corrective actions. As an example, the team identified that more than 25 corrective actions were rolled over into CRs 02-00891, "Failure to Identify Significant Degradation of the Reactor Pressure Vessel Head," and CR 02-04884, "Ineffective Corrective Action Problem Resolution." Some problems were identified, and the extent of the rollover process early in the inspection made it extremely difficult for the team to accurately assess whether the overall process was adequately controlled and that corrective actions were effectively implemented.

The team also noted that the CAP defined that a CR should only be listed as "closed" when the evaluation was completed and all corrective actions were implemented. However, the licensee frequently classified a "rolled out of" CR as "Closed", because the evaluation and/or the corrective actions were transferred to another CR. This gave a somewhat artificial characterization as to the status of resolution of identified issues. The team was concerned that the complexity of the rollover process, the inability to easily track resolution of identified concerns, and the lack of adequate guidance could have resulted in inappropriate resolution of problems. Other examples of rollover problems included: improper implementation of corrective actions, lack of cross references and flawed cause analysis.

Specific examples of rollover problems identified by the team are listed below, and the more significant ones are discussed in Sections 4OA3(2) and 4OA3(3) of this report.

- The resolution to the trisodium phosphate (TSP) post-accident concerns were difficult to evaluate due to the number of rollovers (See Section 4OA3(3)b.17 for details);

- Three CRs on fuel spacer grid damage were rolled into a SCAQ CR, but were not addressed in the root cause analysis (See Section 4OA3(4)b for details);

- Corrective action 13 in CR 02-05385 was not related to the identified issue. Licensee determined that, due to rollovers, the corrective action ended up in the wrong CR (CR 02-05385);

- There were informal rollovers in CRs 02-07657, 02-05904, 02-05881, and 02-06779 (See Sections 4OA3(3)b.12, 4OA3(3)b.16, and 4OA3(3)b.19 for further discussions regarding rollovers); and

- In addition there was an inadequate rollover of overload protection concerns in CR 03-02616 to CR 03-03572 (Section 4OA3(2)b.2).

The team identified that the licensee had issued seventeen CRs within a six month period related specifically to licensee-identified concerns with the rollover process. As a result of the team's review of rollover CRs, the licensee identified a specific issue, as documented in CR 03-01955, "CR Rollover Discrepancies," regarding rollover of concerns as part of the containment health review.

Based on both the team's and the licensee's own internal findings in regard to the rollover process, the licensee revised the CAP procedure to place limits on the number of times an issue could be rolled and to strengthen the rollover process.

.3 Adequacy of Licensee's Efforts to Evaluate Identified Conditions

During the inspection, the team found examples where the licensee was not fully effective in evaluating problems, particularly in regard to determining the apparent cause of issues. The team determined that this failure to adequately evaluate issues could be attributed to a narrow evaluation focus, weak knowledge of the design basis, and lack of attention to detail.

At the start of the inspection, the licensee divided CR evaluations into three categories: SCAQ CRs, which required a root cause evaluation; "CA" CRs which required an apparent cause evaluation; and "CF" CRs which required the deficiency to be fixed and did not require a cause evaluation.

While generally adequate, the team determined that some root cause evaluations did not always use a formal method to arrive at a root cause. In at least one case, the root cause did not arrive at a cause for the discrepant condition. In another, information used to arrive at the conclusion was not discussed in the evaluation. In contrast, the team identified that the root cause evaluation for SCAQ CR 02-00891, performed to determine root and contributing causes of the head event, was well done.

In regard to the apparent causes, the team identified that the majority of the stated apparent causes were one-line sentences and appeared to address the symptoms of the deficiency and did not address why the condition happened.

The team noted that the CAP listed timeliness expectations as to when the evaluation (either apparent or root cause) would be completed. During the inspection, the team noted that some CR evaluations were granted multiple time extensions and that other evaluations were overdue by several months. The team frequently was unable to determine the basis for the extensions being granted. Additionally, the team noted that, in some cases, the licensee did not have a documented basis for delaying evaluation of a discrepant condition until after restart. These issues were discussed with the licensee for resolution.

Another concern relating to the CAP identified by the team was that the licensee's electronic system permitted previously approved CRs to be rejected and re-evaluated. The team was concerned that the process of rejecting a previously reviewed and accepted evaluation was a potential deficiency in the CAP. The licensee took corrective actions to discontinue this practice.

The team also noted that, in general, the licensee did not perform extent of condition reviews and that the few reviews done lacked thoroughness. Revision 4 of the licensee's CAP procedure called for an assessment of generic implications on those

CRs requiring an apparent cause evaluation. The team noted that the lack of such reviews created the potential for not identifying other problem areas.

Specific examples of the above problems are listed below, and the more significant ones are discussed in Sections 4OA3(2) and 4OA3(3) of this report.

Root Cause Findings

- Root cause for CR 02-06178 didn't contain sufficient information to support conclusions. It also failed to address three CRs which were rolled into it. Additionally, the extent of condition review was not well documented (See Section 4OA3(4)b for details);

- Downgrade of SCAQ CRs 02-06356 and 02-06677 were not adequately justified and, in the case of the first issue, no cause evaluation was performed at all. (See Section 4OA3(3)b.22 for details);

- Root cause was not identified for SCAQ CR 02-04673 because the finding was historical, also the evaluation failed to identify issues of pre-conditioning and component limitations (See Section 4OA3(3)b.15 for details);

Apparent Cause Evaluation Findings

- Evaluation of the HPI pump minimum flow issue was inadequate (See Section 4OA3(3)b.1 for details);

- Evaluation was inadequate in that the consequences of potentially increased offsite doses due to the degraded condition were not addressed (See Section 4OA3(3)b.2 for details);

- Evaluation failed to address issue identified in the CR (See Section 4OA3(3)b.12 for details);

- Evaluation on allowable reactor coolant pump (RCP) stud elongation was flawed (See Section 4OA3(3)b.19 for details);

- Evaluation provided weak basis for not identifying issues (See Section 4OA3(3)b.21 for details);

- Evaluation contained incorrect information and inadequately assessed issue (See Section 4OA3(3)b.20 for details);

- Evaluation of the causes for missing or degraded emergency diesel generator (EDG) tornado missile protection was poor (See Section 4OA3(3)b.23 for details);

- Evaluation for CR 02-05640 was weak and referenced corrective action documents appeared incorrect;

- Inadequate evaluation for CR 02-05727;
- Inadequate evaluation for CR 02-05738;
- Evaluation for CR 02-05885 referenced an incorrect calculation and had a wrong revision for other another calculation;
- Cause analysis for CR 02-06723 did not address that struts were not supposed to be greased; and
- Evaluation did not address temperature increase for CR 02-06893 (Section 4OA5(1)b.2.7).

Extent of Condition Findings

- Extent of condition review for CR 02-00412 was inadequate (See Section 4OA3(2)b.4 for details); and
- Required extent of condition reviews for CRs 02-01129 and 02-07188 were not performed (See Section 4OA3(3)b.7 for details of the latter issue).

At the conclusion of the inspection, the licensee initiated a collective significance review CR, 03-06908, to address the team's findings regarding CAP deficiencies, especially in the area of apparent cause evaluations.

.4 Adequacy of Licensee's Efforts to Correct Identified Problems

The team identified examples where inadequate corrective actions were due to the inadequate cause evaluations. The team also identified examples where corrective actions were prematurely closed based on unapproved calculations; where actions were closed without actually completing the work; and where the specified corrective actions did not resolve the originally identified issue. The team also identified several items where the corrective actions appeared untimely. Very few effectiveness reviews had been done at the time of the inspection, so the team was unable to assess the overall effectiveness of the implemented corrective actions. Most effectiveness reviews for corrective action items that were implemented via CR 02-00891 had not been completed by the end of the inspection.

Specific examples of the above problems are listed below, and the more significant ones are discussed in Sections 4OA3(2) and 4OA3(3) of this report.

- A hardware change for CR 02-04680 was indicated as complete when it was not actually done;
- Three examples were identified where the corrective actions were closed before the calculations were issued (See Sections 4OA3(3)b.17, 4OA3(3)b.19 and 4OA5(1)b.2.23 for details);

- The diesel driven fire pump heat load was not included in the SW ventilation system calculation, even though the NRC identified that specific heat load as one which been missed (See Section 4OA3(3)b.7 for details);

- Corrective actions to a Nuclear Quality Assurance (NQA) finding did not address defined problem – NQA initiated a second CR to address the issue (Section 4OA3(3)b.19);

- An NRC identified issue regarding a procedure deficiency was not corrected until the team questioned the issue (See Section 4OA3(3)b.12 for details);

- Corrective action 15 to CR 02-04884 was closed even though not all required individuals were trained;

- Corrective action 30 of SCAQ CR 02-00891 was closed out prior to performing the required operations confidence reviews.

.5 Review of Engineering Products and Corrective Actions

The team determined that the licensee's effectiveness in resolving design deficiencies was inconsistent. The most difficult area for the licensee appeared to be in regard to quality of calculations, as many of the calculations reviewed by the team required multiple iterations to correct team-identified problems. The team attributed this observation to weak engineering knowledge of the design and licensing basis of the plant and a lack of attention to detail.

Based on a review of recently approved mechanical engineering design calculations, the team determined that about 40 percent of the calculations reviewed required generation of a new CR to fix a calculation problem. Included in the problems were configuration control issues where design analysis was not controlled. The team also noted use of non-conservative assumptions, omissions, and errors in recently approved design calculations.

In the electrical area, the team determined that the electric transient analysis profile (ETAP) calculations which were completed in 2003, appeared to be well performed.

As a result of the numerous calculational issues identified by the team, the licensee initiated CR 03-06907 to perform a collective significance review on calculation quality. Additionally, the licensee initiated CR 03-06909 to perform a collective significance review of overall engineering design control issues.

Subsequent to the onsite inspection, on November 12 and December 10, 2003, the licensee presented to the NRC, the planned actions to address the issues and concerns identified by the CATI. As part of these meetings, the licensee made a number of commitments to further improve the quality of engineering products such as calculations and cause analyses. These efforts included expanding the scope of the Engineering Assessment Board (EAB) reviews to include calculations which supported modifications. The process improvements were incorporated as part of the licensee's Operational Improvement Plan for Cycle 14, Revision 3.

.6 Adequacy of Licensee's Efforts to Resolve Procedure Adherence and Quality Issues

The team noted that there were several programmatic procedural improvements, including the CAP procedure, the boric acid corrosion control (BACC) program procedure, and the self-assessment guideline. Additionally, engineering procedures also improved. Typically, it appeared that the licensee staff did a good job on procedure development. The team also noted that the licensee identified a number of procedural adherence problems. The licensee initiated a SCAQ CR in 2002 to evaluate and address multiple procedure issues.

Many of the team's findings resulted from the licensee's failure to adhere to the corrective action procedure and other procedural requirements. Specific examples of the above problems are listed below, and the more significant ones are discussed in Sections 4OA3(2) and 4OA3(3) of this report.

- The licensee failed to follow trending and self evaluation procedures and guidelines (See Section 4OA2(2)b.1).

- The licensee's NQA organization identified numerous problems with procedures (See Section 4OA2(2)b.3 for detail).

(2) Review of the Licensee's Internal Assessment Activities

a. Inspection Scope

The team examined the licensee's program, and implementation thereof, to trend CRs and analyze the results as delineated in procedures NG-NA-00711, NOBP-LP-2001 and NOBP-LP-2004. In addition, the team examined the licensee's implementation of the self assessment program. Trending and self assessments were required by the licensee's procedures. The team also reviewed the licensee's implementation of CAP performance indicators (PIs) to determine their intended use and adequacy in measuring effectiveness of corrective action implementation. The team also evaluated the effectiveness of the licensee's internal assessment capability by reviewing selected NQA audits and available self evaluation reports, which were specifically performed to assess the implementation of the CAP and which were conducted between January 2002 and August 2003. In addition, the team reviewed the licensee's follow-up on selected NQA findings to determine whether the licensee's response was adequate and timely, and corrective actions were properly prioritized and implemented to prevent recurrence. The procedure for audit activities performed by the NQA organization was described in procedure NOP-LP-2004.

b. Observations and Findings

.1 Trending, Self-Assessment, and Evaluation Program Implementation

Introduction: The team identified that the licensee failed to perform the required CR trending analysis and to ensure that condition reports were regularly assessed for indications of adverse trends, generic problems, and repetitive conditions requiring corrective actions. The licensee entered the issue into its corrective action program in December 2002 and again in July 2003 to re-evaluate the issue, and began the required trending at the end of the inspection.

<u>Description:</u> The team determined, through reviews of CRs and via interviews that the licensee had not implemented the CR trending program which was required by procedure NG-NA-00711. In April 2003, the team determined that trending of equipment CRs stopped in December 2001, prior to the plant shutting down for refueling outage (RFO). Departmental and performance improvement group trending activities stopped in March 2002. This latter cessation was a licensee management decision because of the number of issues which were being identified during the various programmatic reviews. However, once the programmatic reviews were completed, the trending program was not reinitiated in a timely fashion.

Procedure NG-NA-00711 required that CR trending analysis be performed regularly. Section 6.2 of the procedure stated that the performance improvement manager was to ensure that CRs were regularly assessed for indications of adverse trends, generic problems, and repetitive conditions requiring corrective actions. The procedure also required that indications of potential adverse conditions were to be discussed with management of the responsible organization to ensure that generic problems, repetitive conditions or adverse trends were classified as conditions adverse to quality. In addition, the procedure stated that a quality trend summary was to be prepared at least quarterly and distributed to managers, directors and the Vice President – Nuclear.

The team determined that a licensee engineer initiated CR 02-10369 on December 19, 2002, to document that the CR trend analysis had not been reinitiated even though the discovery phase of the various programmatic reviews was finished. The CR identified that procedural requirements for trend analysis were not being followed. The CR also stated that a regular review of CR issues was also required as a corrective action to a previous audit finding. The licensee’s evaluation of CR 02-10369 noted that, although the procedurally required trend analysis and trend reporting had not been resumed, other tasks enacted under the Davis-Besse return to service plan could have identified generic problems, adverse trends and repetitive conditions. Therefore, the licensee concluded that no immediate corrective actions were necessary to reinstate the CR trending program.

The team noted that trend analysis and reporting should contribute to the identification of potential adverse trends, repetitive conditions, and generic problems before those trends become significant issues. Programmatic issues were identified by the team during the inspection, such as inappropriate use of rollovers, calculation problems and design issues. The team noted that the licensee initiated three condition reports to evaluate the collective significance of the team's findings.

On July 23, 2003, NQA independently initiated CR 03-05925 which documented concerns identical to the team's concerns in regard to weaknesses in implementation of trending and non-compliance with trending requirements. NQA identified that, in most organizations, activity codes and trend codes were not routinely trended or analyzed and that management involvement with trending, in some organizations, was minimal or nonexistent.

The team determined that the framework for an effective trending program existed, but it was not being implemented and that management attention and focus was needed in order to ensure that the programs were reinstated. Due to the team identifying potential trends in several areas, the team was unable to confirm the licensee's position that reliance on processes developed for the extended shutdown could substitute for the trending analysis process. The licensee entered the issue into its corrective action program in December 2002 and again in July 2003 to re-assess the issue, and re-instituted the required trending at the end of the inspection.

The team also assessed the licensee's self assessment program implementation. The need for a self assessment and evaluation program was delineated in NOBP-LP-2001, NOBP-LP-2004, and the Davis-Besse self evaluation process guide. The purpose of these self assessment and evaluation guidelines was to continue plant improvement through implementation of learning organization behaviors by the Davis-Besse management team to periodically critically assess organizational performance against established standards/expectations of performance and industry-best practices. The self evaluation was intended to identify organizational strengths, weaknesses, challenges, and areas of improvements.

The self evaluation process guideline stated that each quarter, the section managers and directors were to present the results from their self-evaluations to the Davis-Besse Vice President. In April 2003, the team noted that the licensee stopped performing the required self evaluations by the different plant departments after the first quarter in 2002. In July 2003, NQA identified in CR 03-05925 that most site organizations were not actively performing self-evaluations. The licensee was in the process of replacing the guideline and reinstating the self-evaluations at the end of the inspection.

<u>Analysis</u>: The team determined that a performance deficiency existed because the licensee failed to perform the required CR trending. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was minor because the lack of CR trending occurred while the unit was shutdown.

<u>Enforcement:</u> The failure to perform CR trending and department self evaluations from March 2002 until the end of the CATI on-site inspection in September 2003, constitutes a violation of 10 CFR Appendix B, Criterion V, which has minor significance and is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy.

While minor violations are not normally documented in inspection reports, the team determined that documentation was appropriate in this case based on the length of time the licensee was not in compliance.

.2 <u>Corrective Action Program Performance Indicators</u>

During the period when the licensee was not performing trending or self-evaluations, PIs on the restart performance and CAP effectiveness were published weekly. The CAP effectiveness PIs included corrective action effectiveness, CR category accuracy, CR evaluations, corrective action resolution, CR self identification, and management observations. Restart PIs relating to CAP implementation included CR evaluations, CR resolution, root cause evaluation quality, program and process error rate, CR category accuracy, CR operations review, corrective action resolution and CR self-identified rate.

The team noted that the indicators generally showed improving trends and that, in most cases, the licensee was meeting established goals. Action plans were in place for those PIs which were not meeting their goal in order to improve performance prior to restart.

The team reviewed these PIs and determined that the PIs generally reflected CAP performance. The team noted that, for example, PI P-01, "Corrective Action Program Implementation," rated CAP implementation from January to September 2003 as Red for six of the nine months and as Yellow for the remaining three months. During the review of P-01, the team noted that the licensee has routinely determined that the "Repeat Events" element was Green. This meant that there were no repeat SCAQ events in the last two years. The team determined that, in 2002, the licensee initiated six SCAQ CRs for what appeared to be a recurring trend of untimely and ineffective CAP resolution and program implementation. These included CRs 02-02419, 02-02584, 02-03497, 02-03674, 02-04884 and 02-07328. The licensee stated that the above SCAQ CRs could not be considered repeat events because the events did not involve similar tasks, causes and consequences. Based on the licensee's definition, SCAQ CRs had to be identical in all three (tasks, causes and consequences) as well as occurring within two years of each other in order for them to be considered as a repeat event. The team considered the licensee's definition to be limiting, as the above CRs appeared to the team to document repeat events and an adverse trends. The team also noted that, because the licensee limited the definition of repeat events to SCAQ CRs, low level issues that were occurring on a repeat basis (such as repeat CRs) did not show up in the PI.

The team noted that the PIs did not always provide an accurate indication of the health of the CAP implementation. For example, the team identified a number of examples where CRs were indicated as closed in the system when, in reality, the issues were transferred to other CRs and may not have been either evaluated or corrected.

Finally, the team noted that the PI which assessed quality of engineering products had shown a negative trend for five weeks from the end of July to the beginning of August 2003. Despite the negative trend, the indicator stated that engineering product quality had significantly improved since initiation of the EAB. The team questioned the licensee as to the positive statement on the trend report when the graph had been showing a declining trend in quality of engineering products. After questioning by the team, the licensee examined additional engineering products and informed the team that the products had improved and the latest trend information reflected that improvement.

.3 Nuclear Quality Assessment Audits and Self Assessments of Corrective Action Program Implementation

The NQA organization conducted various performance-based and program-based audits of the CAP and its implementation. Some audits evaluated specific activities, while other audits were broad evaluations of processes or department performance. Generally, the team found NQA audits to be of a critical nature and to adequately identify CAP implementation deficiencies. The NQA auditors identified conditions adverse to quality which were documented on CRs and tracked in the CR database.

NQA used the following performance categories to rate effectiveness of the implementation of CAP: Good Performance, Satisfactory Performance, Marginal Performance and Unacceptable Performance. The table below documents the results of the six NQA audits reviewed by the team:

NQA Rating of Corrective Action Program Implementation

Report Number	Date Completed	Primary Rating	Elements Rating
DB-C-02-02	August 9, 2002	Marginal	Unacceptable
DB-C-02-03	November 14, 2002	Marginal	Unacceptable
DB-C-02-04	February 19, 2003	Not Rated	Marginal
DB-C-03-01	May 28, 2003	Not Rated	Marginal
DB-C-03-02	September 1, 2003	Satisfactory[1]	Not Rated
DB-C-03-03	November 17, 2003	Marginal	Not Rated

[1]Note: The "satisfactory" rating was for the overall CAP and did not focus on implementation.

The team noted that the selected CAP implementation areas assessed by NQA from March 2002 to October 2003 were rated as either "marginal" or "unacceptable." For example, a NQA CAP focused assessment was conducted between April 4 through July 4, 2003, and identified CAP and implementation deficiencies which were similar to those identified by the NRC CATI (NQA initiated 24 CRs). Examples included: lack of trending activities to identify adverse to quality conditions, use of PI to assess CAP, less than adequate cause evaluations, corrective action item implementation timeliness, poor documentation of corrective actions, inadequate peer reviews, lack of rigor, configuration control issues, rollovers concerns, and failure to comply with administrative requirements of the NOP (mostly by engineering). Similar findings were noted during the November 2003 NQA audit.

Overall, the team concluded that NQA was performing sufficiently probing assessments of the licensee’s corrective action program implementation.

(3) Management CAP Meetings

a. Inspection Scope

One of the key building blocks in the licensee’s return to service plan was the management and human performance excellence plan. The purpose of this plan was to address the fact that, "management ineffectively implemented processes, and thus failed to detect and address plant problems as opportunities arose." One of the primary management contributors to this failure was the ineffective implementation of the CAP.

During this inspection, the team attended and assessed the licensee management activities and involvement in selected corrective action related meetings. During these meetings the licensee conducted a review and classification of CRs, evaluated and performed a critique of root cause and engineering products, prioritized work activities, and provided work completion schedule extensions for ongoing work activities. The team attended and observed various corrective action management oversite meetings including the corrective action review board (CARB), the restart station review board (RSRB), and the management review board (MRB).

b. Observations and Findings

Corrective Action Review Board Meetings: The purpose of the meetings was to evaluate completed root causes performed to identify and address causes of more significant plant related issues which were documented in CRs. The team concluded that the CARB was comprised of experienced individuals with a wide range of knowledge. The CARB was primarily involved in reviewing the cause analysis packages for completeness and adequacy of technical information. The CARB also concentrated on potential design and safety issues and ensured that the engineering recommendations for resolution of the identified issues appeared adequate to address the causes.

Restart Station Review Board: One of the purposes of the RSRB was to screen and classify CRs as to whether they needed to be addressed prior to restart. The team noted that CRs were screened and classified into one of four categories based on whether the corrective actions: (1) were necessary to address NRC Manual Chapter (MC) 0350, "Oversight of Operating Reactor Facilities in an Extended Shutdown as a Result of Significant Performance Problems" issues; (2) were necessary to address Davis-Besse restart expectations; (3) could be implemented following plant restart; or (4) could be addressed at a time unrelated to plant restart. Once the licensee staff developed corrective actions to address the issues documented in the CRs, the RSRB also screened the proposed corrective actions to ensure that the underlying issues were fully addressed. The team observed RSRB members interactions and noted good questioning attitude and generally appropriate classification of CRs.

Management Review Board: During the MRB meetings, the licensee discussed corrective action items including review of latest initiated CRs and the potential for indications of adverse trends. Management appeared to be engaged in the CAP during these meetings.

Three Day Look-Ahead Committee: This committee discussed CR status and due dates. The team attended several meetings at the beginning of the inspection and noted that many due dates were being extended without formal justification or documented management approval. After the team commented on this practice, the licensee no longer allowed informal extensions.

The team concluded that the management meetings and processes had an appropriate approach for evaluating and characterizing newly identified issues. The members appeared to be qualified and knowledgeable of the requirements.

4OA3 Event Response Follow-up – Special Inspection (71153 and 93812)

(1) Background

Davis-Besse CAP Compliance Review
As part of the licensee's restart action plan to identify, monitor and complete all actions necessary for safe and reliable return to service the licensee initiated various teams which were tasked with reviewing selected plant programs to ensure that the programs were fulfilling required obligations and were acceptable to support plant restart. The CAP was selected as one of the plant programs to receive a comprehensive Phase 2 review as described in the Davis-Besse program compliance plan and procedure NG-EN-00385.

The review was conducted between June 10 and August 9, 2002. Results were documented in the "Corrective Action Program Review" report and included numerous concerns relative to the CAP process and implementation. The Phase 2 review team determined that the CAP generally met regulatory requirements and that the identified problems were primarily associated with program implementation. However, the review team also concluded that the CAP was not consistently implemented in full compliance with the spirit and letter of the governing and implementing documents and that the CAP needed to be strengthened prior to restart of the plant.

The primary problem identified during this review was summarized as, "inadequate implementation of the CAP." Examples of ineffective CAP implementation issues identified as a result of this review included: (1) a reluctance to identify conditions adverse to quality relating to organizational, human performance and programs in a CR; (2) a recurring trend of inadequate CR cause evaluations and corrective actions; (3) a recurring trend of inadequate, untimely, ineffective and improperly closed corrective actions; (4) MRB deficiencies; (5) a need for improvement in the trending program; (6) untimely resolution of issues and supervisory and senior reactor operator reviews; (7) ineffective corrective action to preclude repetition; and (8) recurring trend of procedure non-compliance. These and other findings were determined to be consistent with the root cause analysis reports for CR 02-00891.

To resolve the identified deficiencies and to improve program implementation, the licensee generated numerous CRs that included recommended corrective actions to resolve and correct the noted deficiencies. The majority of the CRs from the review were classified as requiring evaluation and resolution prior to restart, although some were classified as post restart. Many of the corrective action items were rolled into CR 02-04884. As part of the corrective actions to address these findings the licensee determined that training of staff and changes to the program documents were necessary in order to restore an effective CAP.

Assessment of the Corrective Action Program Compliance Review

The CATI team reviewed selected corrective actions to determine the effectiveness of the licensee's implementation of the specified corrective actions. The team determined the licensee's Phase 2 review of the CAP was comprehensive and in accordance with procedure NG-EN-00385. The team concluded that the CAP appeared to contain many of the programmatic elements needed for a successful program; however, station personnel did not consistently identify or effectively resolve plant issues. This was demonstrated by the team identifying many of the same issues as those identified in the Phase 2 review.

(2) Detailed Team Review of Licensee Corrective Actions Implemented to Address Electrical Issues Previously Identified by NRC or the Licensee

a. Inspection Scope

The team assessed effectiveness of the licensee's CAP to identify, categorize, evaluate, and resolve the identified equipment, human performance and/or programmatic adverse to quality plant conditions. The team mainly focused on plant systems design and licensing basis requirements issues which were previously identified by the NRC, the licensee and others during various design reviews conducted in 2002. The team assessed effectiveness of the licensee's corrective actions implemented to address previously identified electrical engineering design issues.

b. Observations and Findings

.1 Undervoltage Time Delay Relay Setting Did Not Account For Instrument Uncertainties

Introduction: The team identified a NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," having very low safety significance (Green). Specifically, the licensee failed to translate instrument uncertainties into the undervoltage time delay setting specification for the 4160 Vac buses C1 and D1. Following discovery, the licensee re-evaluated the potential temperature effects to the time delay relays.

Description: The licensee identified in CR 02-05632 that the time delay relays for the 59 percent undervoltage condition on 4160 Vac buses C1 and D1 may not have met the allowable value of 0.5 ± 0.1 seconds contained in technical specification (TS) Table 3.3-4 because instrument uncertainties were not included. The licensee later initiated CR 03-01448 to specifically determine if the TS value had been exceeded in the past. The licensee determined that the primary cause for fluctuations in the time delays were temperature variations in the room where the relays were located. The licensee determined that during periods of cool weather, the room would maintain a temperature of approximately 70 degrees Fahrenheit (°F), because the fans in the room would recirculate air from the turbine building to warm the switchgear room when the fan outlet temperature dropped below 70°F. However, the licensee stated that, during the summer, the effects on the time delay relays would be insignificant. Specifically, CR 03-01448 stated, "Only during summer does the room temperatures increase, and even then it does not typically vary during the day. . . Based upon the operation of the ventilation system, there is very little potential for the relays to experience a significant temperature rise between the monthly tests."

The team questioned this logic, because it was not apparent that temperature effects, particularly in the summer when outside temperatures could regularly exceed 90°F, would not affect the time delay relays, especially when past experience, which showed that some room temperatures could exceed 120°F on hot days, was considered. Based upon the team questions, the licensee re-evaluated the potential temperature effects to the time delay relays. After performing additional calculations, the licensee determined that increased temperature could cause the time delay to operate outside of its TS limits. Also, the licensee determined that in the past, there was at least one occasion where the temperature in the room was so high that the time delay could have been outside of its TS allowed value. The team was informed by the licensee that, even if the allowable value requirement had been exceeded, the additional time delay would have had negligible effect on the capability to achieve timely emergency core cooling system (ECCS). As the licensee concluded that the relay would have been able to function even though it did not meet its TS allowable value, the licensee did not consider the relay to have been inoperable. The team did not independently verify this conclusion.

Analysis: The team determined that a performance deficiency existed because the licensee failed to translate instrument uncertainty into the specification for undervoltage time delay relays for the 4160 Vac buses C1 and D1. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because this was a design issue which affected the mitigating system cornerstone. The licensee had to perform calculations to show that the relays were within the TS allowable values and the licensee determined that the increased temperature could cause the time delay to operate outside of TS limits. Although the licensee acknowledged that there had been at least one occasion where inclusion of instrument uncertainties into the allowable value would have resulted in an instrument being technically inoperable, the licensee believed the instrument would still have performed its safety function. Therefore, the licensee did not consider the instrument to have been inoperable. The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process," and answered “no” to all five screening questions in the Phase 1 Screening Worksheet under the Mitigating Systems column. The team concluded the issue was of very low safety significance (Green).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis were correctly translated into specifications, drawings, procedures, and instructions. Furthermore, it requires that measures be provided for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to the above, the licensee failed to assure that the regulatory requirements and the design basis of the plant were accurately translated into specifications. Specifically, the instrument uncertainty was not translated into specification for the undervoltage time delay relays for the C1 and D1 4160 Vac buses. The licensee had previously entered the issue into its CAP as CRs 02-05632 and 03-01448. Because this violation was of very low safety significance and because it was entered into the licensee's CAP, this violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000346/2003010-03)

.2 Lack of 480 Vac Class 1E Motor Thermal Overload Protection

Introduction: The team identified a NCV of 10 CFR Part 50, Appendix B, Criterion III, having very low safety significance (Green). Specifically, the licensee failed to provide motor thermal overload protection for the Class 1E 480 Vac distribution system. Following discovery, the licensee physically modified approximately 53 thermal overload circuits to resolve the discrepancy. The primary cause of this violation was related to the cross-cutting area of human performance because the licensee did not identify the lack of thermal overload protection was an unanalyzed condition and that the station was not in compliance with the updated safety analysis report until identified by the team.

Description: The team reviewed the design criteria manual for the 480 Vac distribution system. Section 5.4.3.2, "460V Motors Fed from Motor Control Centers," of this design criteria stated that, "Starters should be equipped with overload relays to provide motor overload protection. For Class 1E motor operated valves, dampers, pumps, and fans, the thermal overload relays should be bypassed to avoid tripping during emergency conditions." This design criteria contradicted Updated Safety Analysis Report (USAR) Section 8.3.1.2.11, "Protection Systems," which stated, "Protection systems are provided and designed to initiate automatically the operation of the appropriate equipment. Necessary protective devices are provided to isolate failed equipment and to identify the equipment that has failed. For the protection system related to engineered safety features and essential functions, complete redundancy, independence, and inservice testability is maintained."

The team determined that as a consequence of following the design criteria manual guidance, the licensee had failed to ensure that the 480V Class 1E circuits were designed so that the protection systems would automatically initiate appropriate equipment, including motor operated valves, dampers, pumps, and fans, as required by the USAR.

The team asked the licensee to provide verification that each circuit fed by a Class 1E 480V motor control center which had its overload protection bypassed or inactivated would be capable of carrying overloads ranging from full load amperes to locked rotor amperes on a continuous basis, or until interrupted, without exceeding the ratings of the circuit breaker, the contactor, the bypassed overload device, or the cable. The team also asked the licensee to assure that when overload protection was bypassed, it did not result in jeopardizing the safety function, or in degrading other safety systems.

As a result of the team's questioning, the licensee identified that, despite the numerous programmatic design reviews that were completed, engineering had not identified this discrepancy and there were many circuits where completion of the safety function could not be demonstrated due to bypassing the thermal overload protection. An overload condition in a single circuit could result in opening of the upstream circuit breaker to the bus, thus removing 480V power to all other Class 1E equipment connected to that bus. The team also identified additional bypassing of thermal overload protection on Class 1E 480V loads, where the design criteria did not allow such bypassing.

The licensee characterized this issue as having "potential for a significant impact on safety" and wrote numerous CRs to address the issue. Subsequently, the licensee modified approximately 53 thermal overload circuits as part of the issue resolution. There was reasonable assurance that the condition did not result in a loss of system function

During review of this issue, the team also noted an example of an ineffective roll-over in that some of the concerns identified in CR 03-02616 were rolled over to CR 03-03572 and were not adequately addressed. The team was concerned about this issue because it had occurred after the licensee had revised its roll-over process to address concerns expressed by the team earlier in the inspection.

Analysis: The team determined that a performance deficiency existed because the licensee failed to provide protective devices, such as thermal overloads, for 480V Class 1E circuits as specified in design documents. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because this was a design issue which affected the mitigating systems cornerstone. The licensee failed to ensure that bypassing the thermal overload protection would result in completion of safety functions and subsequently had to install thermal overload protection in order to meet the design requirements. The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process," and answered "no" to all five screening questions in the Phase 1 Screening Worksheet under the Mitigating Systems column. The team concluded the issue was of very low safety significance (Green).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions. USAR Section 8.3.1.2.11, "Protection Systems," stated, in part, that, protective devices are provided to isolate failed equipment and to identify the equipment that has failed. Furthermore, for the protection system related to engineered safety features and essential functions, complete redundancy, independence, and inservice testability is maintained.

Contrary to the above, the licensee failed to correctly translate the design basis into specifications. Specifically, the licensee failed to provide the necessary protective devices, such as thermal overload protection for the for 480V Class 1E circuits. The protection was required to isolate failed equipment and limit fault propagation. The licensee entered the issue into its CAP as CRs 03-02597, 03-02616, 03-03572, 03-04264, 03-04303, 03-04375, 03-06475, 03-06567 and 03-07031. Because this violation was of very low safety significance and because it was entered into the licensee's CAP, the violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000346/2003010-04)

.3 Failure to Perform Direct Current Contactor Testing to Ensure Minimum Voltage at Motor Operated Valves

Introduction: The team identified a NCV of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," having very low safety significance (Green). Specifically, the licensee failed to adequately test direct current (DC) contactors related to two safety related motor operated steam valves associated with the AFW system. Following discovery, the licensee entered the issue into the corrective action program and was re-evaluating the basis for acceptability of these valves. The primary cause of this violation was related to the cross-cutting area of problem identification and resolution because, although the issue was identified in 2002, the licensee did not take corrective action until prompted by the team in 2003.

Description: The team reviewed CR 01-03059,which documented the issue of minimum voltage available at two safety related motor operated steam valves associated with the AFW system. One of the valves was normally closed and was required to be opened under certain conditions to allow the AFW system to perform its intended function. It had a cable conductor circuit length of 6,814 feet for the automatic opening function. The licensee's corrective action to the issue was to revise calculation C-EE-002.02-010 to include the valves which had not been previously addressed in the calculation. This corrective action was implemented in April 2002. In review of the calculation, the team noted that Attachment 27 of the calculation included the test data used to establish a minimum voltage for the DC contactors. The team ascertained that the testing was based on a single device and lacked sufficient basis to conclude that other contactors would actuate under similar conditions. In addition, the test used an uncalibrated meter to collect data. The team also noted that no adjustment had been made to factor plant environmental conditions into the results. The licensee issued CR 03-07069 during the inspection to document this deficiency in testing methodology.

As a result of the deficiencies in the testing methodology, the team could not conclude that the valves had sufficient minimum voltage at the component to perform their safety function. The team also noted that the licensee's evaluation of the team-identified deficiency was that it was acceptable because of the single failure criteria (i.e., that even if one valve failed, the other train would be available because the single failure had already occurred). The team informed the licensee that this appeared to be an inappropriate application of the single failure criteria.

Analysis: The team determined that a performance deficiency existed because the licensee failed to ensure proper testing of DC contactors. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because the licensee had relied upon an inadequate test to demonstrate that the contactors were qualified to perform under required conditions and because the contactors were installed in the plant during previous operating cycles. The licensee determined that the valves had always been operable. This was a design qualification issue which affected the mitigating systems cornerstone. The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process," and answered "no" to all five screening questions in the Phase 1 Screening Worksheet under the Mitigating Systems column. The team concluded the issue was of very low safety significance (Green).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion XI requires, in part, that a test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written procedures. Test procedures shall include provisions for assuring that all prerequisites for the given test have been met, that adequate test instrumentation is available and used, and that the test is performed under suitable environmental conditions.

Contrary to the above, during the testing for establishing a minimum voltage for DC contactors, the licensee failed to: ensure the components would perform satisfactorily in service; failed to use adequate test instrumentation; and failed to ensure the test was performed under suitable environmental conditions. Specifically, the licensee used a sample size of one DC contactor to justify pick-up voltages of other DC contactors in the plant. In addition, the licensee used uncalibrated instrumentation and failed to consider actual plant environment to which the DC contactors would be subject.

The licensee entered the issue into its CAP as CR 03-07069. Because this violation was of very low safety significance and because it was entered into the licensee's CAP, the violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000346/2003010-05)

.4 Failure to Verify Adequacy of Short Circuit Protection for Direct Current Circuits

Introduction: The team identified a NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," having very low safety significance (Green). Specifically, the licensee failed to identify and correct inadequate short circuit protection for DC circuits. Following discovery, the licensee issued Condition Report 03-06944 to document the deficient circuit protection for valves having extremely long circuit lengths. The primary cause of this violation was related to the cross-cutting area of problem identification and resolution because the licensee had missed several opportunities to identify it as part of corrective actions for previously identified DC circuit deficiencies.

Description: While reviewing CRs 01-03059 and 02-00412 and calculation C-EE-002.01-010, the team questioned the adequacy of DC circuit protection for long DC circuits, such as the one described in Section 4OA3(2)b.3, which had a cable conductor circuit length of 6,814 feet. Subsequently, the licensee evaluated the adequacy of the fuse sizing and identified that, in the case of short circuits, the circuit resistance could be high enough to preclude operation of the fuses protecting circuit, i.e., the fuses protecting the circuits were oversized for the application. Thus, a short circuit current could be allowed to flow for an indeterminate length of time. The short circuit current would only be interrupted after considerable damage had been made to safety related equipment and could result in damaging fires which could affect redundant safety related trains. The licensee issued CR 03-06944 to document the deficient circuit protection for valves having extremely long circuit lengths. Subsequent to the inspection, the licensee developed an engineering package to replace the fuses in March 2004. The inspectors reviewed the licensee's engineering package and concluded that the projected completion date appears reasonable and commensurate with the safety significance of the issue.

Analysis: The team determined that a performance deficiency existed because the licensee failed to verify the adequacy of short circuit protection for DC circuits. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because the licensee had to perform calculations to determine if the fuses would adequately protect the equipment and because modifications to those fuses were required. This was a design issue which affected the mitigating systems cornerstone. The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process," and answered "no" to all five screening questions in the Phase 1 Screening Worksheet under the Mitigating Systems column. The team concluded the issue was of very low safety significance (Green).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion XVI requires, in part, that conditions adverse to quality be promptly identified and corrected.

Contrary to the above, as of August 25, 2003, the licensee did not promptly identify and correct a condition adverse to quality in that DC circuits were not adequately protected against short circuits, a condition adverse to quality. Specifically, the licensee missed several opportunities in 2001 and 2002 to identify that there was no basis ensuring adequate short circuit protection for DC circuits and did not initiate corrective actions to ensure that fuse sizing was adequate for long DC circuits such as those for motor operated valves MV0106 and MV3870. The licensee entered this issue into its corrective action as CR 03-06944. Because this violation was of very low safety significance and because it was entered into the licensee's CAP, this violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000346/2003010-06)

.5 Lack of Calculations to Ensure Minimum Voltage Availability at Device Terminals

Introduction: The team identified a NCV of 10 CFR Part 50, Appendix B, Criterion III, having very low safety significance (Green). Specifically, the licensee failed to confirm operability of DC contactors by ensuring that minimum voltage was available at the safety related device terminals. The licensee missed several opportunities to correct this design deficiency. Following discovery, the licensee issued Condition Report 03-06956 and evaluated the issue. The primary cause of this violation was related to the cross-cutting area of problem identification and resolution because, although the issue was identified in 2002, the licensee failed to take appropriate corrective action to thoroughly evaluate the problem until prompted by the team in 2003.

Description: As a part of CR 01-03059, the licensee performed an extent of condition evaluation and identified that the DC voltages in calculation C-EE-002.01-010 evaluated available voltage to the panel terminals only. The calculation did not confirm sufficient voltage at device terminal for proper operation. The licensee issued CR 02-00412 to document this deficiency. In response to this CR, the licensee issued a revision to the calculation.

During review of calculation C-EE-002.01-010, the team determined that the lowest voltage was 106.38V, which would occur during the first one minute discharge period. The calculation was potentially non-conservative because it failed to address resistance of contacts and fuses which would contribute to additional voltage drop in the circuits. Conservatism existed in the calculation since all loads were assumed to run continuously and simultaneously during the first minute of battery discharge. Additional conservatism was identified during service testing of the battery with the plant anticipated loads. Nevertheless, the team could not conclude that the conservatism was sufficient to bound the undetermined voltage drop in part of the circuits. Therefore, it was not known whether the device terminal voltage present under the design basis conditions would be sufficient to ensure proper operation of safety related devices.

Upon determination that the actual voltage at the devices had not been evaluated in the calculation, the licensee identified a potential SCAQ because potential operability concerns were raised that could have affected numerous pieces of safety related equipment, the licensee did not take actions to ensure operability. Specifically, the licensee did not have a documented basis for resolving the operability concern for equipment which might not have sufficient voltages to ensure proper operation. The CR stated that, "preliminary reviews indicate that there are no operability concerns" and the due date for the corrective action to evaluate the loads connected to the panels was assigned as a post-restart action. After the operability issue was raised by the team, the licensee issued CR 03-06956 for the lack of basis for deferring corrective action. The licensee performed additional analysis and extent of condition reviews. The licensee determined that there were no operability issues based on the results of the re-analysis. The team reviewed these re-analyses and concluded there is reasonable assurance that the affected components are operable.

Analysis: The team determined that a performance deficiency existed because the licensee failed to ensure the availability of minimum voltage at the safety related device terminals. Specifically, the licensee had not performed design analyses or calculations to demonstrate that end devices would have sufficient voltage available to perform the design function. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because the licensee had to perform calculations to demonstrate that the devices had sufficient voltage to perform their safety function. Based on the evaluation performed as a corrective action to CR 03-06956, the team had reasonable assurance that affected components were operable. This was a design issue which affected the mitigating systems cornerstone. The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process," and answered “no” to all five screening questions in the Phase 1 Screening Worksheet under the Mitigating Systems column. The team concluded the issue was of very low safety significance (Green).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions. measures be established to assure that applicable regulatory requirements and the design basis were correctly translated into specifications, drawings, procedures, and instructions. Furthermore, it requires that measures be provided for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to the above, the licensee had failed to ensure that minimum voltage would be available at the safety related device terminals. The calculation performed by the licensee did not confirm that sufficient voltage would exist at the device terminals for proper operation of safety related components during design basis events. The licensee issued CR 03-06956 to address this deficiency. Because this violation was of very low safety significance and because it was entered into the licensee's CAP, this violation is being treated as a NCV consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000346/2003010-07)

.6 Raychem™ Splice Removal on Containment Air Cooler Motor Cables

Introduction: The team identified a performance deficiency involving the failure to properly remove Raychem™ splices during the CACs motor replacement. Following discovery, the licensee entered the issue into its corrective action process. After NRC identified the cause of the condition, the licensee took corrective actions. This was a minor violation.

Description: During CAC motor replacement, the licensee identified splitting of the motor cable insulation as documented in CR 02-05459. The cable jacket and insulation to the three CAC motor high speed windings were found to be split at the ends which were normally covered by Raychem™ heat shrink sleeves. The damage was observed after the Raychem™ sleeves were removed for de-terminating the motors. In 2002, the NRC examined this issue and concluded that the CAC cable had apparently been cut by a sharp instrument, rather than the result of an aging or contamination related mechanism as initially assumed by the licensee. The NRC determined that the splitting was in fact a deep gash and the licensee subsequently determined the gash was inflicted by a contractor when removing the Raychem™ sleeves with a knife. To address this concern, the licensee initiated work orders to replace the section of the high speed cable of the three CAC motors between the motor and the penetrations with an equivalent cable. The work procedures were revised, and the workers received training on the revised procedures.

The approved method for removal of Raychem™ sleeves was prescribed in maintenance procedure DB-ME-09500, "Installation and Termination of Electrical Cables," which required that Raychem™ sleeves be removed by lightly scoring the sleeve with a knife and then applying heat to remove the sleeve. During the licensee investigation of the issue, the contractor performing this activity stated that he was not trained on the Raychem™ removal technique and was not aware of the applicable procedure. However, the licensee's cause analysis determined that the contractor performing the task had been trained and qualified. Nevertheless, the contractor did not perform the Raychem™ sleeve removal in accordance with appropriate and applicable procedures. At the time of the inspection, the team noted that the licensee had not documented whether an extent-of-condition review was performed to determine if other maintenance activities were incorrectly performed. On March 2, 2004, the licensee informed the team that the individual had not removed any other Raychem™ splices in the past and the subject work activity was limited to this individual only.

Analysis: The team determined that a performance deficiency existed because the licensee failed to follow the maintenance procedure for removing Raychem™ sleeves. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was minor because it was identified while the system was out of service, and it was corrected before the system was returned to service.

Enforcement: The failure to follow the maintenance procedure for removing Raychem™ sleeves constituted a violation of 10 CFR Appendix B, Criterion V, which has minor significance and is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. The licensee entered the issue into its CAP as CR 02-05459.

While minor violations are not normally documented in inspection reports, the team determined that documentation was appropriate in this case since the licensee had not documented whether any extent-of-condition review had been performed and the underlying cause is similar to that of other findings in this report.

.7 Review of Calculation on the Electric Transient Analysis Profile

Introduction: The team reviewed ETAP calculation C-EE-015.03-008, Revision 2, to evaluate technical adequacy.

Description: A third revision to the calculation was under way during the inspection and was not scheduled to be completed until after the inspection was over. The fact that the licensee was continuing to revise the calculation hampered the team's overall ability to assess its acceptability. However, the calculation appeared to be generally well performed and did successfully resolve a multitude of issues. The licensee also performed a very good self-assessment with an industry group comprised of outside independent consultants. However, the team considered the ETAP calculation development to be very slow in regards to implementation of corrective actions. For example, changes in auto transfer functions and the EDG calculation which were completed in January 2003 had not yet been incorporated into the main ETAP calculation. The team also observed that the calculation was performed by contractors and that the licensee's internal knowledge of the calculation appeared limited.

Analysis: As a minor issue, the team noted that procedure NOP-CC-3002 required that calculations be entered into the calculation database prior to issuing of a new revision. However, the team identified that document control was not notified upon issuance of a new revision to calculation C-EE-015.03-008 (Revision 2).

Enforcement: The failure to enter the revision of a procedure into the database prior to its issuance constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. The licensee documented the issue in CR 03-06989.

While minor violations are not normally documented in inspection reports, the team determined that documentation was appropriate in this case it represented an example of calculation weakness and the underlying cause is similar to that of other findings in this report.

.8 Inadequate Grid Voltage Calculations

Introduction: The team identified that the licensee failed to consider the worst case grid voltages in the short circuit analyses. Following discovery, the licensee entered the issue into their corrective action program and performed new calculations to address the issue.

Description: The licensee initiated CR 02-06302 to document that the licensee had not considered the worst case grid voltage. This CR described the issue as being administrative in nature and having no effect on the results. This conclusion was incorrect and was so recognized in CR 02-06837.

The team ascertained that the maximum grid voltage was an important parameter which affected the accuracy of the short circuit calculations. The postulated short circuit current would proportionally increase for higher grid voltage, therefore, calculations performed for lower grid voltages would be non-conservative. The team reviewed this item and determined that calculation C-EE-015.03-003 was superseded with calculation C-EE-015.03-008, which utilized the ETAP program described in Section 4OA3(2)b.7. The new calculation had taken into account the worst grid voltage conditions.

Analysis: The team determined that a performance deficiency existed because the licensee failed to analyze the grid voltage under worst case design conditions. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was minor because although the licensee had to perform calculations, the new calculation had taken into account the worst grid voltage conditions and the results were acceptable.

Enforcement: The failure to translate the worst case grid voltage into calculations of record constituted a violation of 10 CFR Appendix B, Criterion III, which has minor significance and is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. The licensee entered the issue into its CAP as CRs 02-06302 and 02-06837.

While minor violations are not normally documented in inspection reports, the team determined that documentation was appropriate in this case it represented an example of calculation weakness and the underlying cause is similar to that of other findings in this report.

(3) Detailed Team Review of Licensee Corrective Actions Implemented to Address Mechanical Issues Previously Identified by NRC or the Licensee

a. Inspection Scope

The team assessed effectiveness of the licensee's CAP to identify, categorize, evaluate, and resolve the identified equipment, human performance or programmatic adverse to quality plant conditions. The team mainly focused on plant systems design and licensing basis requirements issues which were previously identified by the NRC, the licensee and others during various design reviews conducted in 2002. The team assessed effectiveness of the licensee's corrective actions implemented to address previously identified mechanical engineering design issues.

b. Observations and Findings

.1 High Pressure Injection Pump Operation Under Long Term Minimum Flow

Introduction: The team identified a NCV of 10 CFR Part 50, Appendix B, Criterion III, having very low safety significance (Green). Specifically, the licensee failed to verify that the HPI pumps could operate under design basis minimum flow requirements since initial plant startup. Following discovery that the design basis minimum flow requirements were significantly below industry standards, the licensee entered the issue into its corrective action program, performed a test which demonstrated satisfactory pump operation for an extended period of time at a higher flow rate, and began the steps to change the design basis minimum requirement. The primary cause of this violation was related to the cross-cutting area of corrective action because although this issue was identified by the NRC in Information Notice (IN) 87-59, "Potential RHR Pump Loss," in 1987 and in Bulletin 88-04, "Potential Safety-Related Pump Loss," in 1988, the licensee failed to take action to correct it until it was specifically identified as applying to Davis Besse during the SSDI in 2002, and yet again during the CATI in 2003.

Description: On November 17, 1987, the NRC issued an information notice describing two concerns identified by a Nuclear Safety System Supply vendor which had the potential to impact safety operation of ECCS pumps. Specifically, IN 87-59 described two concerns, the second of which involved the adequacy of the minimum flow recirculation line capacity even for single pump operation. The IN noted that the vendor specifically stated that these concerns might also be applicable to high pressure safety injection pumps. On May 5, 1988, the NRC followed the IN with an NRC Bulletin addressing the same concerns. Item 3 of the bulletin requested that licensees evaluate the adequacy of the minimum flow bypass lines for safety-related centrifugal pumps with respect to damage resulting from operation and testing in the minimum flow mode. It stated that the evaluation should include consideration of both the effects of cumulative operating hours in the minimum flow mode over the lifetime of the plant and during the postulated accident scenario involving the largest time spent in the minimum recirculation flow mode. It also requested that the evaluation include verification from the pump suppliers that current minimum flow rates were sufficient to ensure that there will be no pump damage from low flow operation.

During the SSDI, the NRC reviewed the HPI pump minimum flow capacity and raised two concerns related minimum flow and no flow conditions. The NRC determined that the adequacy of the minimum recirculation flow value of 35 gallons per minute (gpm) was questionable and that there was a potentially unanalyzed condition during a small break loss of coolant accident (LOCA). For certain small break LOCAs, the NRC determined that the HPI pumps potentially could be required to operate under conditions where the reactor coolant system (RCS) pressure would be very close to or possibly greater than the pressure under which the HPI pumps could inject. During the recirculation phase, after the contents of the borated water storage tank (BWST) were injected, the return line to the BWST was procedurally required to be manually isolated from the control room to prevent an unmonitored release of radiation. The HPI pumps had a defined mission time of 30 days (720 hours) where the pumps were required to remain operable. The licensee issued CRs 02-07684 (for the adequacy of the 35 gpm) and 02-06702 (on the potentially unanalyzed lack of flow condition) to evaluate these concerns.

The licensee resolved the issue of not having a minimum flow recirculation path during the sump recirculation phase by implementing a modification to provide a new minimum recirculation flow path for the HPI pumps via a connection through the decay heat removal (DHR) injection line. This modification was designed to the same 35 gpm flow rate as the original recirculation line because, in evaluating CR 02-07684, the licensee concluded that the 35 gpm was adequate. During the 2003 CATI, the team again questioned the adequacy of the 35 gpm minimum flow, especially in light of the 1988 Bulletin. Although the licensee had not reviewed the Bulletin response as part of their evaluation of CR 02-07684, they resurrected the document in response to team questions. The team determined that the licensee’s response to the Bulletin was based on the results from three 10-minute vibration runs; these tests showed no appreciable increase in vibration. The licensee also had contacted the pump vendor, who was unable to confirm that the 35 gpm flow was adequate to ensure that HPI pumps would not experience degradation as a result of hydraulic instability or impeller recirculation. The team noted that industry experience indicated that long term pump minimum flow value should be close to 25 percent of flow at the pump’s best efficiency point. For the HPI pumps, the flow at the best efficiency point was 600 gpm, which would indicate that a minimum flow on the order of 150 gpm would be appropriate as compared to the 35 gpm which was in the licensee's design specification at the time of the inspection.

In response to the team again raising the issue on the adequacy of the HPI pump minimum flow value of 35 gpm, the licensee wrote CRs 03-06526 and 03-06519. As part of the investigation summary in CR 03-06526, the licensee provided evaluations by three pump experts. These evaluations appeared to only justify continued operation based on the effects of cumulative operating hours in the minimum flow mode over the experienced lifetime of the plant. The team was unable to find any evaluation of the ability of the HPI pumps to function on minimum flow during the licensee's stated mission time of 30 days; this included any evaluation by the licensee that a shorter mission time was appropriate for operating entirely on minimum flow. The team noted that this issue was assigned a priority of "CF" which meant that the licensee did not believe that any cause evaluation was required, just that the issue had to be resolved. The licensee's basis for designating the CR as a "CF" was that the pump only had to operate "occasionally" in the minimum flow configuration – which did not recognize the pump's safety function. At the end of the on-site inspection, the licensee was still evaluating the issue.

In December 2003, the team performed a limited review of the licensee's evaluation of a test performed on one of the HPI pumps. This test was run for 6 hours at a flow of 53 gpm. The basis for establishing a test duration of 6 hours appeared to be that the pump shaft would experience a million cycles of operation and that, if pump failure was going to occur, it should occur within that time period. However, the licensee did not either extrapolate the number of cycles to the stated mission time of 30 days nor did they provide any basis statement as to why 6 hours would be the maximum time that the pump would spend on minimum flow. The basis for establishing the flow of 53 gpm was that it was the actual flow through the installed orifice. However, the licensee did not extrapolate the flow back to the design basis minimum or take steps to change the design basis. While it was highly unlikely that the pump would experience flows below the 53 gpm for the current orifice, the team noted that this test was run on only one of four recirculation lines (including the two new ones installed during the 13th refueling outage). The team noted that the newly installed lines had throttle valves which could be adjusted to a flow rate anywhere in the acceptance criteria band, including a value well below the demonstrated flow rate. The team also noted that the surveillance test data for the 1-2 HPI pump (the one not tested) showed the recirculation flow rates on this pump were closer to the high end of the acceptance criteria band where the licensee was supposed to evaluate replacement of the orifice.

As a result of the team's questions, on February 8, 2004, the licensee provided an operability determination which addressed pump operability under the design conditions. The licensee concluded that the HPI pumps are capable of providing the necessary flow over the mission time of 30 days with extended periods at minimum recirculation flow.

Analysis: The team determined that a performance deficiency existed because the licensee failed to demonstrate that the pump could successfully perform its safety function for the stated mission time of 30 days and under the initial design minimum flow rate of 35 gpm by either test or evaluation prior to 2004. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because the licensee had to perform a test to demonstrate that design basis requirements could be met and because the test results determined that the design basis requirements needed to be changed to ensure that the HPI pumps could perform their accident required function. This was an issue which affected the mitigating systems cornerstone. The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process." Although the pumps had not been tested at the minimum design flow valve, the team was unable to conclude that the safety function of the pumps had actually been lost. This was based on a review of surveillance test results from June 2001 through December 2003. These test results showed the lowest flow rate for either pump to be 49 gpm. Although this was slightly outside the licensee's new operability band, the team deemed it likely that the pumps would have performed had they been called upon. Therefore, the team answered "no" to all five screening questions in the Phase 1 Screening Worksheet under the Mitigating Systems column. The team concluded the issue was of very low safety significance (Green).

The performance deficiency of not having any recirculation lines once the BWST emptied is addressed in Section 4OA3(6)b.3.

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis were correctly translated into specifications, drawings, procedures, and instructions. Furthermore, it requires that measures be provided for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to the above, the licensee failed to verify the adequacy of the design of the minimum recirculation line flow rate of 35 gpm. Specifically, on December 23, 2003, the licensee determined that the minimum flow rate of 35 gpm could not be verified and the minimum value which had been verified by a suitable testing program was 53 gpm. Because this violation was of very low safety significance and because it was entered into the licensee's CAP as CRs 03-11268, 03-11431 and 04-01050, this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000346/2003010-08)

.2 Increased Dose Consequences Due to Degraded Thermal Performance Operation of Degraded Containment Air Coolers

Introduction: The team identified a NCV of 10 CFR Part 50, Appendix B, Criterion III, having very low safety significance. Specifically, the licensee failed to assess an increase in the offsite dose to the public following a postulated design basis accident due to increased containment pressure. Following discovery, the licensee entered the issue into its corrective action process and performed the necessary analysis. The primary cause of this violation was related to the cross-cutting area of problem identification and resolution, because, although the issue had been previously identified, the licensee had failed to identify that a revised dose assessment was needed until prompted by the NRC.

Description: In 2002, the licensee identified that the CACs were significantly degraded and required replacement. In December 2002, the licensee issued LER 05000346/2002-008-00, which discussed the degradation. During the review of CR 03-00120 and LER 05000346/2002-008-00 and -01, the team noted that the issue of potentially increased offsite doses due to the degraded CACs was not addressed with a technical basis in the evaluation of CR 03-00120. In particular, the time to reach half containment design pressure after a design basis LOCA increased from 16.7 hours to 58.3 hours because of degraded CAC performance. The specified acceptance criteria was that the containment pressure be reduced to 50 percent of the containment design pressure within 24 hours as recommended by Regulatory Guide 1.4, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident for Pressurized Water Reactors." The analyses performed for the degraded CAC operability assessment did not meet this requirement. However, the licensee concluded in CR 03-00120 that exceeding the half containment design pressure rating within 24 hours had no impact on dose consequences analyzed in accordance with Regulatory Guide 1.4 assumptions, without documenting any basis for the statement.

When first questioned by the team, the licensee acknowledged that there was no formal dose assessment to support the conclusion documented in CR 03-00120. The licensee then performed a calculation which indicated that, although the offsite radiological doses increased, they were still less than the Regulatory Guide 1.4 allowables when accounting for the increase in containment pressure. The team did not review this calculation.

Analysis: The team determined that a performance deficiency existed because the licensee failed to verify that increased containment pressure due to degraded CAC performance would not result in unacceptable offsite dose consequences. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because the licensee had to perform calculations to show that the increased time at higher containment pressures did not result in doses being above regulatory guide allowables. The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process."

The team reviewed the SDP questions for reactor safety, occupation radiation safety and public radiation safety contained in MC 0612, Appendix B, "Issue Screening." The team assessed the finding through Phase 1 of the SDP. According to the Davis-Besse Risk-informed Inspection Notebook, the CACs had both a barrier integrity and mitigating system cornerstone function. However, the team determined that the issue was not covered by any of the revised oversight cornerstones and was not suitable for SDP analysis since the finding pertained to offsite dose calculations rather than CAC performance. Therefore, this finding was reviewed by Regional Management, in accordance with IMC 0612. The finding was determined to be of very low safety significance (Green) because the issue regarded increased containment pressure, related to offsite dose consequences, and although the offsite radiological doses increased, the values were still less than the Regulatory Guide 1.4 allowables.

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis were correctly translated into specifications, drawings, procedures, and instructions. Furthermore, it requires that measures be provided for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to the above, the licensee failed to implement design control measures to verify the adequacy of design basis calculations. Specifically, the licensee failed to demonstrate that increased containment pressure due to degraded CAC performance did not result in unacceptable offsite dose consequences. The licensee entered this issue into its CAP as CR 03-03980. Because this violation was of very low safety significance and because it was entered into the licensee's CAP, this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000346/2003010-09)

.3 Containment Air Cooler Air Flow Calculation Concerns

Introduction: The team identified a NCV of 10 CFR Part 50, Appendix B, Criterion III, having very low safety significance (Green). Specifically, the licensee failed to correctly identify and translate the design basis requirements into the CACs airflow analyses and motor horsepower sizing calculations. Following discovery, the licensee entered the issue into its corrective action program and performed a new analysis for the motor. The primary cause of this violation was related to the cross-cutting area of problem identification and resolution as the licensee had previously identified issues with the motors, but had not reviewed the design calculation of record.

Description: During review of CR 03-00120, which was the licensee's collective significance review in regard to the degraded condition of the CACs, the team also reviewed calculation 28.003. This calculation was used to size the existing CAC motor. The team determined that the calculation was performed in 1970 and applied design information from the Oconee Nuclear Power Plant to Davis-Besse without correction for actual Davis-Besse conditions. The NRC team questioned the design values for system resistance, airflow, and density used in the calculation for sizing CAC motors since there was no reference to Davis-Besse equipment or systems.

Calculation 28.003 specified a requirement for a 45 horsepower motor, whereas at Davis-Besse, a 40 horsepower motor was actually installed. In addition, the density used in calculation 28.003 was different than that used for the postulated breaks analyzed in calculation C-NSA-060.05-010. For example, C-NSA-060.05-010, the computed density profile remained at or below 0.132 pounds per cubic foot (lb/ft^3) for the first 6 seconds, increased to 0.152 lb/ft^3 from 7 to 16 seconds, then dropped to 0.132 lb/ft^3 at approximately 250 seconds. In contrast, calculation 28.003 used the less conservative density profile of 0.132 lb/ft^3 throughout. Following the team's questioning, the licensee performed a new calculation which showed that the CAC motors were appropriately sized.

The team also noted that the vendor who supplied the CAC motors had submitted a Part 21 notice to the licensee in May 2002. According to LER 05000346/2002-008, this issue was entered into the CAP but was determined to not be of significance due to the CAC motors being refurbished as part of the overall CAC refurbishment. The team considered this to be an example of poor engineering response to an issue specifically, the licensee had determined that the CAC motors needed to be refurbished, but had either not looked at the design basis calculation for the motors prior to beginning the refurbishment, or had not performed an adequate review.

Analysis: The team determined that a performance deficiency existed because the licensee failed to analyze CAC fan sizing with respect to actual airflow, air density, pressure drop, and motor size. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because the licensee had to revise the associated calculation to evaluate the existing motor to ensure the CACs would be able to perform their design function. The team assessed the finding through Phase 1 of the SDP. According to the Davis-Besse Risk-informed Inspection Notebook, the CACs had both a barrier integrity and mitigating system function. The team determined that this issue affected both functions. Because the issue involved both the mitigating system and barrier integrity cornerstones, the team entered Phase 2 of the reactor safety SDP.

The team completed the Phase 2 worksheets for the following scenarios: Transients, Transients with Loss of the Power Conversion System, Small LOCA, Loss of Offsite Power (LOOP), Steam Generator (SG) Tube Rupture (SGTR), Main Steam Line Break (MSLB), Loss of Instrument Air, Loss of a 4 kilovolt (kV) Bus, Loss of DC Buses D1P and D2P and Loss of One Emergency AC Train. Completion of these worksheets resulted in two sequences rated as "12", three sequences rated as "11", four sequences rated as "10", two sequences rated as "9", and three sequences rated as "8". This information was entered into the "Counting Rule Worksheet" and a final evaluation was obtained that the issue was of very low safety significance (Green).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis were correctly translated into specifications, drawings, procedures, and instructions. Furthermore, it requires that measures be provided for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to this requirement, the licensee failed to correctly translate the design basis into specifications, drawing, procedures, and instructions. Specifically, the licensee failed to correctly identify and translate the design basis requirements such as actual airflow, air density, pressure drop, and motor size, into the CAC airflow analyses and motor horsepower sizing calculations that demonstrated the ability of the safety-related CACs to deliver the required design basis air flow rate to the containment during an accident. The licensee entered this issue into its CAP as CR 03-07009. Because this violation was of very low safety significance and because it was entered into the licensee's CAP, this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000346/2003010-10)

.4 Accumulator Sizing Calculation Errors

Introduction: The team identified a NCV of 10 CFR Part 50, Appendix B, Criterion III, having very low safety significance (Green). Specifically, the licensee failed to implement effective design control measures to check and verify the adequacy of the design basis calculation performed for sizing the new accumulators used to hold the SW containment isolation valves closed on a loss of instrument air. Following discovery, the licensee entered the issue into its corrective action program, revised the calculations, and changed the accumulator medium from compressed air to nitrogen.

Description: In 2002, SSDI team identified a NCV for failing to correctly translate the design basis requirements for sizing of the safety-related backup air supplies for containment isolation valves SW-1356, SW-1357, and SW-1358 into the design. The licensee's corrective action was to install new accumulators sized to hold the valves closed. The team reviewed several revisions of calculation C-ME-011.06-007 which sized the new accumulators.

The team identified numerous errors in the calculation which required the calculation to be revised. For example, in Revisions 0 and 1 of the calculation, the new accumulators were intended to be filled with air as the licensee thought the valves only had to remain closed for 30 minutes. The licensee initially did not appear to recognize that the valves had a containment isolation design function which required the valves to remain closed for 30 days until questioned by the team during the inspection. Following the team's questions, the licensee changed the design to require that the new accumulators be filled with nitrogen rather than air. In the last revision reviewed, the calculation erroneously used the ideal gas law equations when sizing the nitrogen bottles without consideration of the compressibility of nitrogen at a pressure of 2000 pounds per square inch (psig). The calculation also indicated that the valve actuators were double acting when other documents indicated that actuators were single acting. Additionally, the calculation could not stand alone without recourse to the author because certain calculation steps were missing. The licensee revised the calculation to correct the errors identified by the team. The team noted that the licensee was addressing past operability of the accumulators separately as part of LER 05000346/2003-001. This LER will be addressed in a separate IR.

Analysis: The team determined that a performance deficiency existed because the licensee failed to verify the adequacy of the design basis calculation performed for sizing the accumulators prior to approving the calculation. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because the licensee had to re-perform calculations and had to change the modification design from having accumulators containing pressurized air to accumulators containing pressurized nitrogen. The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process."

The team reviewed the SDP questions for reactor safety, occupation radiation safety and public radiation safety contained in MC 0612, Appendix B, "Issue Screening." The team assessed the finding through Phase 1 of the SDP. However, the team determined that the issue was not covered by any of the revised oversight cornerstones and was, therefore, not suitable for SDP analysis. This determination was based on the issue affecting containment isolation valves which provide a barrier to breach of containment and potential offsite dose consequences. Therefore, this finding was reviewed by Regional Management, in accordance with IMC 0612. The finding was determined to be of very low safety significance (Green) because the issue regarded increased containment pressure and related to offsite dose consequences.

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis were correctly translated into specifications, drawings, procedures, and instructions. Furthermore, it requires that measures be provided for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to the above, the licensee failed to implement design control measures to check and verify the adequacy of the design basis calculation performed for sizing the accumulators used to hold containment isolation valves closed on a loss of instrument air. The licensee entered the issue into its CAP as CR 03-06556. Because this violation was of very low safety significance and because it was entered into the licensee's CAP, this violation is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. (NCV 05000346/2003010-11)

.5 Inadequate Blowdown Provisions for Containment Isolation Valve Accumulators

Introduction: The team identified a performance deficiency involving the licensee's failure to initiate a CR or to implement corrective actions to address a previously identified NRC finding. Following discovery, the licensee entered the issue into its corrective action program.

Description: Non-Cited Violation 05000346/2002014-01b was issued by the NRC during the 2002 SSDI to document that there were no provisions to blow down the SW containment isolation valve accumulators although USAR Section 9.3.1.5 stated that the accumulators contained a provision to allow removal of excessive moisture. IR 54-346/2002014 documented that this NCV was captured in the licensee's CAP as CR 02-07750. When the CATI team reviewed CR 02-07750, the team determined that the CR did not document this concern. The licensee was unable to identify any CR which addressed the NCV and could not find any indication that corrective actions had been taken to address the issue.

The valves discussed in the NCV were containment isolation valves equipped with backup air accumulators (air volume tanks). These valves had dual safety functions in that they were required to open during a LOCA to provide maximum SW flow through the CACs as well as being required to close to provide containment isolation. The team noted that, although the licensee was in the process of designing the new accumulators, they had not specifically considered or addressed providing accumulator blowdown capability. The failure to include blowdown provisions meant that any moisture intrusion into the accumulator would not be identifiable and would not be removable. This would result in the reduction in the amount of air available to maintain the containment isolation valves closed and would result in rust and other debris in the accumulator.

In response to the team's finding, the licensee issued CR 03-02475 on March 28, 2003, to document this concern and ensure that it was included in the Davis-Besse CAP. The licensee informed the team that MOD 99-0039, Revision 1 should address this concern, when completed. In November 2003, the team reviewed the corrective actions generated for CR 03-02475 and determined that the specified modification had been canceled and a new modification package generated. Based on the wording in the corrective action cancellation, it was not apparent that the blowdown issue was reassessed as part of the new modification.

The team independently determined that, due to the change in accumulator medium from air to nitrogen, that there was no longer any need for blowdown provisions. While the NRC concluded that the lack of blowdown no longer presented a safety issue.

Analysis: The team determined that a performance deficiency existed because the licensee's program required it to initiate a CR and implement corrective actions to address NRC identified NCVs. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was minor because the licensee changed the accumulator medium to one which would not contain moisture, such that the failure to take corrective actions had no consequences.

Enforcement: The failure to take corrective actions for an identified condition adverse to quality constituted a violation of 10 CFR Appendix B, Criterion XVI, which has minor significance and is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy.

While minor violations are not normally documented in inspection reports, the team determined that documentation was appropriate in this case due to the issue not initially being in the CAP and then due to the corrective actions being canceled without reconciliation of the original issue. Additionally, the underlying cause is similar to that of other findings in this report.

.6 Non-conservative Calculation Used in Design Analysis to Determine Required Service Water Makeup Flow to Component Cooling Water

Introduction: The team identified a NCV of 10 CFR Part 50, Appendix B, Criterion III, having very low safety significance. Specifically, the licensee failed to consider worst case minimum pressure differential between SW and component cooling water (CCW) systems when determining required SW makeup flow to the CCW system heat exchangers. Following discovery, the licensee entered the issue into its corrective action process and performed the necessary calculations. The primary cause of this violation was related to the cross-cutting area of human performance because the licensee used test data collected during normal operation rather than taking the worst case design conditions and because there was a lack of rigor in the calculation review process.

Description: Hydraulic calculation C-ME-011.01-140 was developed as part of a corrective action to CR 02-07378. This calculation determined the pressure differential required in the SW line for makeup to the CCW system to create a minimum flow of 30 gpm. This flowrate was used to estimate the stay time and exposure rate while using SW to makeup to the CCW system. The NRC team reviewed the calculation, and determined that it was non-conservative in that it did not consider worst-case minimum pressure differential between SW and CCW systems during accident conditions, but used test data collected during normal operation. In addition, the calculation assumed a fully turbulent fouling factor for clean piping. Finally, there was a minor math error in the calculation. Although the math error did not appreciably affect the results of the calculation, it indicated a lack of rigor in the calculation review process. In response to the NRC's questions, the licensee performed additional calculations. The licensee stated that these new calculations showed that, even with the lower predicted differential pressures while in the accident alignment, the makeup capability of SW to CCW exceeded the acceptance criteria. The team did not review these additional calculations.

Analysis: The team determined that a performance deficiency existed because the licensee failed to verify the adequacy of the design basis calculation performed for the SW and CCW system interface. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because the licensee had to perform a new calculation to demonstrate that the SW flow to CCW was adequate to perform its design function. This finding was considered a design deficiency which affected the mitigating systems cornerstone. The licensee determined that the SW flow was adequate to perform its design function and was operable The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process," and answered "no" to all five screening questions in the Phase 1 Screening Worksheet under the Mitigating Systems column. The team concluded the issue was of very low safety significance (Green).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis were correctly translated into specifications, drawings, procedures, and instructions. Furthermore, it requires that measures be provided for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to the above, the licensee failed to implement design control measures to check and verify the adequacy of the design basis calculation performed for the SW/CCW system crosstie hydraulic analyses for all postulated accidents. The licensee entered the issue into its CAP as CR 03-04010. Because this violation was of very low safety significance and because it was entered into the licensee's CAP, the violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000346/2003010-12)

.7 Calculation Concerns for Service Water Pump Room Ventilation System

Introduction: The team identified a NCV of 10 CFR Part 50, Appendix B, Criterion III, having very low safety significance (Green). Specifically, the licensee failed to verify the adequacy of the design of the SW pump room ventilation system. Following discovery that the design basis calculations were non-conservative, the licensee entered the issue into its corrective action program, re-performed the calculations, and made appropriate modifications to correct the issues. The primary cause of this violation was related to the cross-cutting area of problem identification and resolution because the licensee failed to correct all of the originally identified issues until identified by team.

Description: During the SSDI inspection in 2002, the NRC identified a concern regarding calculation 67.005. The calculation analyzed the heat loads in the SW pump room and the ability of the ventilation system to maintain the pump room temperatures within a required operating range. The team determined that the calculation contained multiple non-conservative attributes, including failing to analyze heat loss through open penthouse louvers during the winter, and failing to account for heat load contribution of diesel driven fire pump during the summer. The licensee initiated CR 02-07188 to document this issue.

The calculation was revised to address these concerns and was issued as Revision 4 in early 2003. At the same time, another CR, 02-08281, was issued because CR 02-07188 failed to do an extent of condition review to verify the adequacy of the SW ventilation system for all operating conditions. The extent of condition review was reported to have included a walkdown of the SW pump room and review of the revised SW ventilation calculation.

Upon review of the revised calculation in 2003, the team noted that the summer maximum analyzed temperature in the pump house did not include the heat load contribution of the diesel driven fire pump, which was one of the deficiencies noted in the earlier revision to the calculation. This deficiency was not addressed in the new revision to the calculation, either by including it or by providing a rationale for excluding the heat load. The team noted that the licensee had previously had to take actions to open the diesel generator room doors and provide alternate ventilation during the summer months. The new calculation also concluded that the penthouse louvers had to be modified (blocked) for winter operation. The NRC team noted that past operability had been assured for winter operation by regularly recording pump room ambient temperature.

Calculation C-NSA-085.00-002, Auxiliary Steam Blowdown in the Intake Structure, concluded that the maximum temperature within the SW pump room was 109 degrees F. This temperature was not considered a significant difference from the normal operating temperature in the room. Additionally, the safety related equipment in the room was specified for operation in an environment with 100 percent relative humidity, which would be experienced in the room during a postulated steam break. An evaluation performed in CR 02-05262 concluded that the amount of condensing moisture would fill the smallest electrical junction box by only 0.05 inches. Therefore, the functionality of the cables and connections was not likely to be affected. The team also noted that the licensee had initiated engineering change request (ECR) 02-0682 to remove the auxiliary steam line from the SW pump room, although it stated that this modification was an enhancement which was not required.

Analysis: The team determined that a performance deficiency existed because the licensee failed to verify the adequacy of the SW pump room ventilation system for all operating conditions. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because inadequacies in the calculations identified during the 2002 SSDI resulted in a modification to ensure winter operation was within the allowable temperature range, and because the revised calculation did not include all the summer heat loads which could potentially impair the SW pump room ventilation system. This was a design issue which affected the mitigating systems cornerstone. The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process," and answered “no” to all five screening questions in the Phase 1 Screening Worksheet under the Mitigating Systems column. The team concluded the issue was of very low safety significance (Green).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis were correctly translated into specifications, drawings, procedures, and instructions. Furthermore, it requires that measures be provided for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to the above, the licensee failed to implement design control measures to check and verify the adequacy of the design. Specifically, the licensee failed to verify the adequacy of the SW pump room ventilation system for all operating conditions.

The licensee entered this issue into its CAP as CRs 02-07188 and 03-06870. Because this violation was of very low safety significance and because it was entered into the licensee's CAP, this violation is being treated as a NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. (NCV 05000346/2003010-13)

.8 Inadequate Service Water System Flow Analysis

Introduction: The team identified a NCV of 10 CFR Part 50, Appendix B, Criterion III, having very low safety significance. Specifically, the licensee failed to ensure that the SW system could perform its design function under all required conditions. Following discovery, the licensee entered the issue into its corrective action program and performed the necessary calculations.

Description: In IR 05000346/2002014, several URIs were identified dealing with the SW system and ultimate heat sinks. These deficiencies included failure to account for the lowest acceptable performance of the SW pumps, failure to consider the USAR described single failure of the forebay return valve to open, failure to include the design basis strainer resistance, and strainer blowdown losses. Additionally, the design basis lowest ultimate heat sink level was not used and the flow diverted to the AFW was not considered. Because of these deficiencies, the ability of the system to provide the required design basis flows to the safety-related heat exchangers could not be verified.

In response to the issues identified by the SSDI, as well as other issues identified internally, the licensee determined that there was not sufficient design basis documentation to demonstrate operability of the SW system under all required conditions. The licensee had a consultant perform two new calculations, 02-113 and 02-123, to address a large number of SW flow issues, including those issues discussed above.

The team reviewed these calculations and noted that the calculations determined that, under a certain combination of design basis conditions, design basis flow rates and pump net positive suction head (NPSH) were not achievable. The specific combination included having design basis low ultimate heat sink levels, design basis high SW temperatures and the SW strainers going into backwash while the system was responding to a design basis accident. The team determined that the strainer operation was automatic such that this set of circumstances was one which the licensee should have included as part of its design basis.

The team noted that the licensee had reviewed and approved the calculation without comment. This issue negatively reflected on the adequacy of the licensee's engineering department to oversee the engineering contractor performing the calculations and on the engineering staff's ability to identify engineering issues and non-conforming conditions. The team independently evaluated the issue and determined that the system would most likely be able to perform its design function as the inadequate conditions would only exist for short periods of time. The licencee initiated CR 03-03977 to revise the calculations. Following evaluation of CR 03-03977, the licensee concluded that the SW system was able to perform its safety related function. The team agreed with the licensee's conclusions.

Analysis: The team determined that a performance deficiency existed because the licensee failed to ensure the adequacy of the SW system to supply required flow rate to safety related components and failed to ensure the required NPSH for the SW pumps. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because the licensee did not initially have a calculation which demonstrated that the SW system could fulfill its design function under design basis conditions and when a calculation was subsequently prepared, system deficiencies were not evaluated to ensure that the safety function could be met. This was a design issue which affected the mitigating systems cornerstone. The licensee concluded that the SW system had been able to perform its safety function. The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process," and answered "no" to all five screening questions in the Phase 1 Screening Worksheet under the Mitigating Systems column. The team concluded the issue was of very low safety significance (Green).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis were correctly translated into specifications, drawings, procedures, and instructions. Furthermore, it requires that measures be provided for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to the above, the licensee failed to ensure that design requirements were correctly translated into specifications, drawings, procedures, and instructions. Specifically, the licensee did not have design calculations to show the SW system could perform its required safety function under design basis conditions.

The licensee entered the issue into its CAP as CRs 02-06337, 03-07006, and 03-07042. Because this violation was of very low safety significance and because it was entered into the licensee CAP, this violation is being treated as a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy. (NCV 05000346/2003010-14)

.9 Inadequate Flooding Protection for the Service Water System

Introduction: The team identified a NCV of 10 CFR Part 50, Appendix B, Criterion III, having very low safety significance (Green). Specifically, the licensee failed to have provisions in place to protect the SW pump room from flooding. Following discovery, the licensee placed the issue in its corrective action program, evaluated it and put procedures in place to address the issue.

Description: During the SSDI in 2002, the NRC identified that no procedures were in place to isolate equipment open for maintenance in the SW pump room that could flood the room in the event of high lake water level. USAR Section 2.4.8.2 stated, "The Probable Maximum Flood Water is elevation 583.7 feet..." USAR Section 9.2.1.3 stated, "In the event of high water levels,...the pump room is sealed to prevent flooding." Finally USAR Section 3D.1.4, "[General Design Criteria (GDC)] Criterion IV - Environmental and Missile Design Basis," stated, "These [safety-related] structures, systems, and components are appropriately protected against dynamic effects...and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit." Therefore, the NRC questioned whether the SW system was adequately protected against flooding effects that could result from high lake water levels, from internal flooding, and from other threats to the system that could result from failure of non-seismically qualified equipment, as described in the USAR.

In response to this concern, the licensee determined that operator actions were necessary in order to ensure that the USAR statements were met. In order to ensure that the operator actions occurred, several changes to operating procedures were required. These procedural actions were taken. During the 2003 CATI, the team verified that the corrective actions were implemented and appropriately resolved.

Analysis: The team determined that a performance deficiency existed because the licensee failed to translate design basis requirements into procedures for flood protection in the SW pump room. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because the licensee had to make procedural changes in order to ensure that safety-related equipment was capable of performing its safety functions. This was a procedural deficiency which affected the mitigating systems cornerstone. The licensee determined that the system remained operable since the deficiency only dealt with a lack of procedural guidance. The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process," and answered "no" to all five screening questions in the Phase 1 Screening Worksheet under the Mitigating Systems column. The team concluded the issue was of very low safety significance (Green).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis were correctly translated into specifications, drawings, procedures, and instructions. Furthermore, it requires that measures be provided for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to the above, the licensee failed to correctly translate the design basis into procedures. Specifically, the licensee failed to have procedures in place to isolate equipment opened during maintenance in the SW pump room that could potentially flood the room in the event of rising lake water level.

The licensee had previously entered this issue into its CAP as CR 02-07714. Because this violation was of very low safety significance and because it was entered into the licensee's CAP, the violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000346/2003010-15)

.10 Inadequate Service Water System Flow Balance Testing Procedure

Introduction: The team identified a NCV of 10 CFR Part 50, Appendix B, Criterion XI, having very low safety significance (Green). Specifically, the licensee failed to account for a number of conditions in the SW system flow balance testing procedures. Following discovery, the licensee placed the issue in its corrective action program, evaluated it and put procedures in place to address the issue.

Description: Surveillance procedures DB-SP-03000 and 03001, "Service Water Integrated Train I (II) Flow Balance Procedure," were performed every refueling outage to balance the system flows. During the 2002 SSDI, the NRC identified that this procedure did not establish flows to the safety-related heat exchangers based on worst-case design basis conditions, such as degraded SW pumps, lowest ultimate heat sink (UHS) level, highest resistance SW system lineup, or system resistance degradation. Further, no analyses existed that established the test acceptance criteria for design basis conditions. Therefore, the flow balance procedure did not verify that the system was capable of providing the required flows to its safety-related heat exchangers under design basis conditions.

The licensee performed SW flow model calculations that conservatively predicted the required flow to each safety-related load. The model addressed all SW branch lines in service during various accident scenarios and accounted for the flow rate issues described in CR 02-06337. Separately, the licensee computed the required instrument inaccuracies for the instrumentation used during the SW flow balance.

However, the licensee's design organization did not ensure that this information was properly transmitted to the plant engineering group in a format that would ensure that the procedures had adequate acceptance criteria. The design engineering organization did not perform a formal calculation which documented the minimum acceptance criteria to ensure that the test procedure would demonstrate that the SW flows met their design basis requirements. Instead, design engineering transmitted the design information in two separate evaluations which then had to be combined by plant engineering and corrected for the instrument measurement uncertainty. Because the plant engineering department had to interpret the results from design engineering, the plant engineering personnel applied considerable conservatism when establishing the test acceptance criteria. The licensee issued CR 03-07006 to provide a design record file for test acceptance criteria.

During SW testing performed in the summer and fall 2003, the licensee determined that the newly established test acceptance criteria could not be met for some components. This resulted in numerous CRs being written and the design engineering organization having to prepare a number of operability evaluations justifying the use of lower acceptance criteria. The team determined that the design engineering failure to establish appropriate acceptance criteria prior to the SW testing occurring contributed to the number of CRs and subsequent operability evaluations.

The team determined that the licensee planned to perform a flow balance twice each refueling outage, once on as found basis, and once on an as-left basis. Collecting as-found data would provide evidence that the SW system branch flows were adequate during the previous operating cycle to remove the design basis heat loads. The team considered this a positive step by plant engineering to ensure operability of the SW system.

Analysis: The team determined that a performance deficiency existed because the licensee failed to properly account for a number of required conditions in the SW system flow balance testing procedure. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because procedural changes were necessary in order to ensure that the safety-related SW system branch flow rates were adequate for the system to perform its safety functions. The team assessed the finding through Phase 1 of the SDP. This was a design issue which affected the mitigating systems cornerstone. At the end of the inspection, the licensee was performing a new flow balance. The licensee concluded that the system was previously capable of meeting its design requirements. The flow balance test results were reviewed by the resident inspectors and document in IR 2003025. The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process", and answered “no” to all five screening questions in the Phase 1 Screening Worksheet under the Mitigating Systems column. The team concluded the issue was of very low safety significance (Green).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," requires, in part, that a test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with the written test procedures which incorporate the requirements and acceptance limits contained in the applicable design documents.

Contrary to the above, the licensee failed to adequately test the SW system because the licensee’s SW system flow balance testing procedure failed to account for a number of required conditions. The testing failed to verify that adequate flow was provided to safety related components under all accident conditions.

The licensee entered the issue into its CAP as CRs 02-06064 and 03-07006. Because this violation was of very low safety significance and because it was entered into the licensee's CAP, this violation is being treated as a NCV consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000346/2003010-16)

.11 Service Water Discharge Path Swapover Setpoint

Introduction: The team identified a violation of 10 CFR Part 50, Appendix B, Criterion III, involving the licensee's failure to provide a basis for the setpoint to swap the service water system discharge path. This issue was previously identified as an NCV in IR 05000346/2002014 and the corrective actions taken by the licensee failed to correct the originally identified condition. The primary cause of this violation was related to the cross-cutting areas of problem identification and resolution and human performance, because the licensee did not recognize that the corrective actions taken needed to restore compliance with the identified violation of NRC requirements.

Description: The 2002 SSDI identified a Green finding and NCV of 10 CFR Part 50, Appendix B, Criterion III, regarding the licensee's failure to provide a calculational basis for the 50 psig setpoint to swap SW system discharge path. The licensee did not contest the violation and entered the issue into the corrective action system as CR 02-07802. During the CATI, the team reviewed the evaluation and corrective actions taken for this NCV. The team determined that the licensee had evaluated the condition and confirmed that no analysis initially existed. The evaluation reviewed by the team was initially approved on March 9, 2003 and had a corrective action also accepted on March 9, 2003. This evaluation focused on the fact that no setpoint calculation existed which showed that instrument uncertainty values had been properly incorporated, not on providing the calculational basis for the 50 psig setpoint itself. The team determined that this evaluation and proposed corrective action were not responsive to the violation identified during the SSDI.

On November 10, 2003, the licensee provided the team a revised copy of CR 02-07802. The originally approved condition report was apparently rejected and replaced with a new evaluation and new corrective actions on March 30, 2003. The new evaluation documented a vendor calculation which showed that with the 50 psig setpoint, there would be inadequate flow to certain safety related components under design basis conditions. The new evaluation also concluded that the setpoint was adequate if a failure of the non-seismically qualified discharge piping did not have to be postulated during a loss of coolant event. Relying upon this latter conclusion, the licensee determined that the 50 psig setpoint was acceptable. The team did not agree with the licensee's reliance on non-seismically qualified piping to ensure that safety related components had adequate flow. Therefore, the team determined that the revised evaluation still did not address the SSDI violation in that the calculational basis for the 50 psig issue still did not exist.

The team noted that the evaluation contained in the revised CR 02-07802 was similar to that documented in CR 02-05748. Both CRs articulated a view that, unless there was a seismic event, non-seismic lines did not have to be assumed to have failed. The team questioned this premise, based on the information in 10 CFR Part 50, Appendix A, GDC. The team noted that the licensee had committed to following the draft version of these criteria, as documented in NUREG 0153, and committed to in the USAR. Draft General design criteria 2, in that NUREG, stated, in part, that components important to safety were to be designed to withstand the effects of natural phenomena without loss of their safety function.

The team presented this information to the licensee engineers as part of the review of CR 02-05748. The engineers sought the advice of the regulatory assurance department via CR 03-04018. The regulatory assurance department responded, in part, that, "It was not appropriate to apply the single failure criterion to non-safety systems," confirming the team position. The licensee then wrote a new CR (03-06507) and took compensatory measures to close the SW discharge valve leading to the cooling tower. The licensee also stated in CR 03-06507 that the issue involved application of single failure assumptions for existing systems. The team noted that this appeared to be a continuation of the misunderstanding of application of design basis assumptions.

Following the inspection, the licensee performed a PRA study on the likelihood of failure of the non-safety-related piping and then applied the results of this analysis to justify the issue described in CR 02-07802. As this analysis was performed significantly after the end of the inspection, it was not reviewed by the team, and the team was not able to evaluate the impact of this analysis on the licensing basis of the plant.

Analysis: The team determined that a performance deficiency existed because the licensee failed to correct a previously identified violation of NRC requirements. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because the licensee had not corrected a previous violation and was relying on non-safety-related equipment to perform a safety function under design bases conditions.

The previously identified violation was evaluated in IR 05000346/2002014 as having very low safety significance (Green). This assessment has not changed. This finding was reviewed by Regional Management, in accordance with IMC 0612. The finding was determined to be of very low safety significance and concluded that the violation could be categorized as Green.

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis were correctly translated into specifications, drawings, procedures, and instructions. Furthermore, it requires that measures be provided for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to the above, as of August 12, 2003, the licensee failed to verify that the design of the SW system discharge path swapover setpoints were adequate. Specifically, the analysis performed by the licensee showed that the established setpoints were not adequate and the evaluation of the analysis accepted the inadequate setpoint based on non-safety-related equipment performing a safety-related function under design basis conditions. Neither the analysis nor the evaluation corrected the non-conforming condition previously identified in IR 05000346/2002014.

This is a violation of 10 CFR Part 50, Appendix B, Criterion III. The NRC Enforcement Policy, Section VI.A.1, provides guidance on dispositioning of violations. Normally, violations of very low safety significance are not cited. However, the Enforcement Policy notes four conditions under which an issued notice of violation with a reply will be considered. The first of these conditions is, "The licensee failed to restore compliance within a reasonable time after a violation was identified." As the corrective action generated in response to the NCV did not restore compliance, this condition has been met. (VIO 05000346/2003010-01)

.12 Service Water Discharge Check Valve Test Acceptance Criteria

Introduction: The team identified a violation of TS 4.05a an 10 CFR 50.55a, having very low safety significance. Specifically, the licensee failed to ensure that the service water discharge check valve was tested in accordance with ASME Code. The primary cause of this violation was related to the cross-cutting areas of problem identification and resolution and human performance, because the licensee did not recognize that the corrective actions taken needed to ensure compliance with NRC requirements.

Description: The 2002 SSDI described a Green finding and NCV of 10 CFR Part 50, Appendix B, Criterion XVI, regarding the licensee's failure to adequately correct the SW pump discharge check valve acceptance criteria. This was entered into the licensee's corrective action system as CR 02-07657. The team determined that the licensee evaluated the concern in the NCV and determined that the valves were full open at flow rates greater than 7270 gpm. Therefore, the licensee concluded that no corrective actions to the procedure were necessary. The CR evaluation stated that CR 02-05784 would address the differences in the stated flow rates in the USAR and system description. No formal calculation was prepared to support the 7270 gpm value and no corrective actions were generated for the CR. This CR was accepted as being ready for closure on January 28, 2003.

The team noted the licensee's evaluation of the flow rate at which the valves were full open could not be reproduced as it relied on oral information provided by the valve vendor. The team identified that numerous check valve failures had been identified in the industry which were not detected during inservice testing of check valves to values less than the required accident flow rate. Furthermore, the evaluation did not follow any of the methods listed in GL 89-04, "Guidance on Developing Acceptable Inservice Testing Programs" or NUREG 1482, "Guidelines for Inservice Testing Programs at Nuclear Power Plants" for ensuring that the valves were full open.

The team reviewed the licensee's technical specification 4.05a and confirmed that the licensee was required to test their check valves in accordance with the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code) as required by 10 CFR 50.55a. The team confirmed that the licensee was committed to the 1996 Addenda of the OM Code. Section ISTC 4.5.4a of this addenda stated that check valves which had a safety function to open were to be tested by initiating flow and observing that the valve had traveled to the full open position or to the position required to perform its intended function. Using the guidance in GL 89-04, the team ascertained that "the position required to perform its intended function" would be one which passed the required accident flow rate.

The team noted that the GL provided guidance for cases where a full flow test on a check valve could not be performed. For these cases, the licensee should submit a relief request from the ASME requirements to the NRC and have the request granted prior to implementing the requested relief.

Based on the above, the team concluded that the licensee's evaluation in CR 02-07657 was inadequate in it did not demonstrate that 7270 gpm flow would ensure that the check valve was in the full open position. Because of this inadequate evaluation, the licensee did not take appropriate corrective actions to bring the surveillance procedure acceptance criteria into compliance with the requirements.

The team further reviewed CR 02-05784 and noted that it did not contain any references to CR 02-07657 and did not address the corrective actions which CR 02-05784 had stated would be addressed by the CR. Specifically, there were no corrective actions addressing the USAR and system description issues as stated by CR 02-07657. Furthermore, the implementing organization had determined that the initially recommended corrective actions to 02-05784 were not necessary and had recommended that they be canceled, although this recommendation had not been formally accepted by the end of the inspection. The team ascertained that the accident analyses of record required a SW flow rate of approximately 10,300 gpm in order to ensure sufficient cooling of safety related systems.

Following the on-site inspection, the team performed a limited review of CR 03-07656. This CR noted that the SW pump #3 discharge check valve had not met the procedurally required acceptance criteria. The operability evaluation for this CR accepted the deficiency as operable based on the inadequate evaluation in CR 02-07657. Use of the evaluation from CR 02-07657 to justify operability resulted in the licensee using an alternate means of verifying that the check valve was full open without obtaining the necessary NRC approval for relief from the Code requirements.

Analysis: The team determined that a performance deficiency existed because the licensee failed to demonstrate that the check valve could perform its intended function in accordance with NRC requirements. The team concluded that the issue was more than minor because the inadequate test acceptance criteria allowed the licensee to accept a check valve as performing its intended function at less than full system flow. The licensee did not request NRC approval to use an alternate means of demonstrating the valve was capable of performing its intended function. The team concluded that the issue involved traditional enforcement because the licensee had not sought NRC approval prior to using an alternate means of demonstrating that a check valve could perform its intended function.

In 2002, the issue was determined to be of very low safety significance. However, because the licensee accepted a valve as being full open with less than the accident required flow rate, the team re-evaluated the safety significance. The team determined that the licensee had an operability determination which concluded that the SW system was operable but degraded, as it could not achieve design flow rates. This operability determination was reviewed by the resident inspectors and determined to be acceptable, as documented in IR 05000346/2003025. The team concluded that, as the valve was part of the SW system, it was covered by this operability determination. As the licensee concluded the system was operable, the issue screened out of the Phase 1 worksheet (Green).

Enforcement: Technical specification 4.05a requires, in part, that the licensee perform inservice testing of valves in accordance with the ASME OM Code and applicable addenda as required by 10 CFR 50, Section 50.55a.

Title 10 CFR 50.55a(f)(4) requires, in part, that, during successive 120 month intervals, a licensee must comply with the requirements in the latest edition and addenda listed in paragraph (b) of 10 CFR 50.55a 12 months prior to the start of the 120 month interval. Paragraph 50.55a(f)(5)(i) requires that the inservice test program be revised as necessary to meet the requirement of paragraph 50.55a(f)(4). Paragraph 50.55a(f)(5)(iii) requires that if a licensee determines that conformance with certain code requirements is impractical, the licensee is to submit information to support the determination, in accordance with 10 CFR 50.4.

The ASME OM Code, 1996 addenda, Section ISTC 4.5.4(a) requires, in part, that check valves be exercised by initiating flow and observing that the obturator traveled to its full open position. The NRC approved use of the 1995 Code edition through the 1996 addenda for the third inservice testing 120-month interval on March 28, 2003 . Prior to that date, the licensee was committed to the 1986 Edition (no Addenda) of the ASME Boiler and Pressure Vessel Code, Section XI. The 1986 Code Edition contains similar requirements.

Contrary to the above, on September 12, 2003, and other dates, the licensee did not observe by a direct indicator or other positive means that the ASME Class 3 service water pump discharge check valve obturator traveled to its full open position during its quarterly surveillance test. Specifically, on September 12, 2003, the licensee observed a flow rate of 9718 gpm through valve SW-19, which was less than the test acceptance criterion of 10,000 gpm, and less than the approximately 10,300 gpm used in the licensee’s most recent accident analysis. Observing flow rates less than required for the valve to perform its safety function was not a positive means to determine that the obturator traveled to its full open position and no other direct indicator or positive means was used.

This is a violation of TS 4.05a and 10 CFR 50.55a. The NRC Enforcement Policy, Section VI.A.1, provides guidance on dispositioning of violations. Normally, violations of very low safety significance are not cited. However, the Enforcement Policy notes four conditions under which an issued notice of violation with a reply will be considered. One of these conditions is, "The licensee failed to restore compliance within a reasonable time after a violation was identified." As the CR addressing this issue was accepted for closure without restoring compliance by either revising the test acceptance criteria or submitting a license amendment to the NRC to use an alternate means of verifying that the valves were full open, this condition has been met. At the time of the exit, no new CR had been written to address this issue. (VIO 05000346/2003010-02)

.13 Lack of Design Basis Calculations to Support Service Water Single Failure Assumptions

Introduction: The team identified an NCV of 10 CFR Part 50, Appendix B, Criterion III, having very low safety significance. Specifically, the licensee failed to provide an analysis which addressed the service water valve single failure assumptions mentioned in the updated safety analysis report. Following discovery, the licensee entered the issue in its corrective action program. The primary cause of this violation was related to the cross-cutting area of problem identification and resolution because the licensee had not recognized the impact of the issue on the design basis and had not corrected it after it was identified in 2002.

Description: In IR 05000346/2002014, two URIs were identified dealing with the ultimate heat sink's temperature and level analyses. A concern expressed in both URIs dealt with single failure assumptions of the SW discharge path valves to redirect flow in the most conservative manner. These single failure assumptions were described in the USAR as being the most limiting events for the SW system. For example, for the maximum ultimate heat sink temperature case, a single failure of the forebay return valve (SW 2930) to open would result in the SW discharge being directed approximately 17 feet from the intake, rather than some 500 feet away. This would increase the SW temperature returning to the plant. For the minimum level case, a single failure of the cooling water makeup valve (SW 2931) to close would result in water being diverted to the cooling towers instead of being returned to the ultimate heat sink, which would lower the available level.

Both valves were butterfly valves, and the licensee determined that the only credible failure was an electrical failure of the valve to change position. The licensee did have procedures which addressed the operators opening (or closing) the valves manually as needed. The team noted that the USAR stated that the operators needed to close the valves within three hours. However, the calculations for the ultimate heat sink maximum temperature and minimum water level started with the valves already opened (or closed). Because these calculations did not account for the three hour time delay, and because the licensee did not have any calculation to support a different time period, the team considered them to be non-conservative in regard to both maximum temperature and minimum level. As an interim measure the licensee implemented changes to operations procedures to control the position of the valves to address the issue. The licensee is also performing additional review and evaluations of the facility's conformance with design and licensing basis documents. The actions resolved any immediate operability concerns regarding postulated single failures with maximum system temperatures and minimum heat sink level conditions.

The ultimate heat sink calculations supported a change to the TSs (amendment 242). The team identified other problems with this submittal, as discussed in Section 4OA3(3)b.21.

Analysis: The team determined that a performance deficiency existed because the licensee failed to analyze the effects on the ultimate heat sink of the forebay return valve not opening or of the cooling water makeup valve not closing for the time period necessary for an operator to take action. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in

Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because the current calculations were non-conservative and the licensee was not able to demonstrate that the SW system could perform its safety function under design basis conditions. This was a design issue which affected the mitigating systems cornerstone. The team determined that it was unlikely that the SW system would not function during a design basis accident, as there would need to be the unlikely combination of both the "right" single failure along with the maximum temperature or minimum level conditions. The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process." The finding screened as Green in the SDP Phase 1, since this issue was a design deficiency that would not likely result in the loss of function per Generic Letter (GL) 91-18, Revision 1. Therefore, the issue was determined to have a very low safety significance (Green).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis were correctly translated into specifications, drawings, procedures, and instructions. Furthermore, it requires that measures be provided for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to the above, as of August 29, 2003, the ultimate heat sink maximum temperature and minimum level design basis, as described in the USAR had not been correctly translated into a specification. Specifically, the USAR described a limiting single failure for both the maximum temperature and minimum level condition, and the design basis calculations did not address the time necessary for the operators to recover from the single failure.

This issue was entered into the licensee's CAP as CRs 02-05372, 02-05986, 02-06337, 03-06507, and 03-07042. Because this issue was of very low safety significance and because it was entered into the licensee's CAP, this violation is being treated as a NCV consistent with Section VI.A.1 of the Enforcement Policy (NCV 05000346/2003010-17).

.14 Auxiliary Feedwater System Calculation Issues With Main Steam Safety Valves

Introduction: The team identified a NCV of 10 CFR Part 50, Appendix B, Criterion III, having very low safety significance (Green). Specifically, the licensee failed to ensure that design analyses showed that the AFW system could perform its safety function under design basis conditions. Following discovery, the licensee entered the issue into its corrective action system. The primary cause of this violation was related to the cross-cutting area of human performance, as the licensee used the results of a vendor calculation without verifying that it was adequate.

Description: The team reviewed CR 02-07236 and the licensee's calculation C-NSA-050.03-013 for AFW system hydraulic characteristics, which included calculating the hydraulic resistance of flow to the steam generators. When determining the hydraulic system resistance, it was noted that the calculation did not consider the increased backpressure caused by allowable MSSV drift and safety valve accumulation.

This could have a negative affect on analyzed AFW pump flow because the higher backpressure would decrease AFW flow to the steam generators and reduce heat removal capability for the AFW system. In resolving this issue, the licensee reviewed the loss of feedwater analysis of record, 32-1171148-00, and determined that the MSSV drift and accumulation had not been considered in this vendor calculation. The vendor calculation was used as an input to calculation C-NSA-050.03-013 for determining the AFW system resistance curve. Since the vendor calculation was in error, the licensee's calculation was in error as well.

Analysis: The team determined that a performance deficiency existed because the licensee failed to assess the effect of increased back pressure in the AFW system. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because the calculations were non-conservative and because the calculation of record did not demonstrate that the AFW system could perform its safety function under design basis conditions. Based on further analysis, the licensee concluded the AFW system was operable. This was a design issue which affected the mitigating systems cornerstone. The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process," and answered "no" to all five screening questions in the Phase 1 Screening Worksheet under the Mitigating Systems column. The team concluded the issue was of very low safety significance (Green).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis were correctly translated into specifications, drawings, procedures, and instructions. Furthermore, it requires that measures be provided for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to the above, the licensee failed to implement effective design control measures to check and verify the adequacy of the design basis calculation performed by the vendor of the AFW system hydraulic analyses for all postulated accidents. This issue negatively reflected on the adequacy of the licensee's oversight of the engineering contractor performing the calculations. The licensee entered the issue into its CAP as CR 03-02651. Because this issue was of very low safety significance and because it was entered into the licensee's CAP, this violation is being treated as a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy. (NCV 05000346/2003010-18)

.15 Auxiliary Feedwater Strainer Mesh Size and Preconditioning of Auxiliary Feedwater System During Testing

Introduction: The team identified a NCV of 10 CFR Part 50, Appendix B, Criterion XI, having very low safety significance (Green). Specifically, the licensee failed to recognize that flushing the system and blowing down the strainers upstream of the turbine driven pump bearing cooling water strainers prior to routine surveillances constituted preconditioning of the AFW system. Following discovery, the licensee entered the preconditioning issue into the corrective action program. The primary cause of this violation was related to the cross-cutting area of problem identification and resolution, because the licensee had failed to recognize the consequences of the preconditioning when evaluating an earlier issue and determining that a larger mesh size could be installed in the strainers.

Description: The licensee designated CR 02-04673 as a SCAQ CR which described discovery that the strainers in the SW supply to the turbine driven pump bearings had a smaller mesh size than that of the main SW strainers. It also addressed the possibility of blockage of the restricting orifices in the AFW system due to debris within the SW system. The following CRs were rolled into CR 02-04673: 02-05639 and 02-06861. Both an operability evaluation and a root cause report were required for CR 02-04673. In addition, an engineering change package was initiated to add new strainers upstream of the restricting orifices and to increase the mesh size in the existing strainers.

OPERABILITY DETERMINATION: Because the licensee had extensively cleaned the SW system piping during the outage, the team did not disagree with the conclusion reached in the operability determination that the AFW system was operable. However, the following non-conservatisms in the analysis were noted:

- The operability determination assumed that the AFW system would run on minimum recirculation flow until all of the SW in the "dead leg" leading to the pumps has passed through the lines. However, under the postulated seismic event causing a loss of offsite power (LOOP), AFW would be required to function since the main feedwater pumps would be unavailable. The accident analysis assumed that AFW flow to the steam generators would be supplied within 60 seconds. The starting sequence for the pumps would have the flow immediately being directed through the pumps and into the steam generators. In the short term, 100 percent of the AFW flow would be directed into the steam generators. Only after a period of time would the pumps be throttled back or the recirculation lines opened to divert water. Therefore, the team did not agree that this assumption was reasonable. Furthermore, it appeared that the licensee's analysis had not considered the actual design basis for the system.

- The operability determination noted that the bearing strainers had not shown any sign of clogging during periodic testing with SW. However, the licensee failed to note that this was because the procedures required the line to be flushed and the strainers to be blown down prior to and after each test, thus eliminating the potential for any clogging.

ROOT CAUSE REPORT: The licensee issued a root cause analysis in March 2003 which determined the cause of the limiting particle size for the AFW strainers. At that time, the licensee's CAP did not require use of a formal root cause process. Therefore, even though the issue was determined to be a SCAQ, the licensee did not determine the root cause because the issue was, as stated in the root cause report, "historical." The team ascertained that because the root cause report did not follow a formalized process, the report was actually more like an apparent cause analysis than a root cause evaluation.

Similar to the operability determination, the cause evaluation noted that the strainers to the coolers were periodically flushed and blown down during testing. However, the evaluation failed to recognize that this constituted preconditioning of the test. The report did not evaluate the beneficial impact that the pre-test flushing and strainer blowdown would have in regard to required maintenance of the coolers.

The modification history developed in the cause evaluation showed that the licensee had significantly increased the strainer mesh sizes in 1985 without discussion of the bearing oil cooler strainers. However, the evaluation did not address whether these modifications resulted in changes to the testing procedures, such as the currently imposed pre and post test flushing and strainer blowdown.

The evaluation did not address whether the cooler for the pump bearings could handle the increased particle size. There was no documentation in the evaluation which addressed the acceptability of the increased strainer mesh size on the components which the strainer was designed to protect. Although the evaluation discussed the need for operator attention to an alarm for a blocked strainer, it did not recognize that the larger particles could cause blockage of a downstream component that could not be cleared by back-washing of the strainer.

ENGINEERING CHANGE PACKAGE: The engineering change package, ECR 03-0074, stated that a conceptual design was not necessary due to the simplicity of the design and the great deal of study that went into producing the initiation report. The package acknowledged that the strainers were in the lines which supply cooling water to the pump and turbine bearing oil coolers, the turbine governor oil cooler and the pump mechanical seals. However, it did not discuss why the increased strainer size would not affect any of these components.

In response to the team’s questions, the licensee provided the team with a vendor manual which contained a single line which stated that the bearing oil coolers had openings greater than 0.0625 inches such that they could handle the larger size particles if the strainer mesh size was increased. The licensee engineers stated these coolers were the limiting components. However, this information was not documented and there was no evidence that the licensee had considered this information prior to the team's questions.

Further discussions with the licensee determined that the bearing oil coolers had never been opened for inspections and were not included in the GL 89-13 heat exchanger program. The team concluded this had not been a problem in the past because of the very small mesh strainer. The licensee wrote CR 03-06576 to address this issue. Nonetheless, the team concluded that the modification was a work in progress as it had not been implemented by the end of the inspection.

REVIEW OF PERIODIC TEST PROCEDURE: As discussed above, the issue of flushing the lines and blowing down the strainers both prior to and following a periodic surveillance was reviewed by the team. This issue was raised based on a review of periodic procedure DB-SP-04152, which used SW as the source of cooling water for the test duration. The licensee investigated the issue and determined that other AFW surveillance tests also flushed the lines and blew down the strainers prior to the test being performed. The team determined that the flushing of the lines blowing down of the strainers constituted pre-conditioning of the turbine driven AFW pumps because it masked any performance problems which could occur during an actual event. The availability and reliability of the system was intended to be ensured through the periodic testing. The team noted that the licensee had stated that no problems with the strainers had occurred as part of the justification for increasing the strainer mesh size. However, the team concluded that the licensee's procedural actions would have masked any problems. A violation of NRC requirements was identified.

Analysis: The team determined that a performance deficiency existed because the licensee's practice, as prescribed in site procedures, prevented the AFW system from being tested in its as-found condition. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because there was not sufficient information to demonstrate that test requirements would have been met had the strainers not been blown down. This was a procedural issue which affected the mitigating systems cornerstone. Because the licensee's practices prevented a true assessment of previous operability, the team could not determine if the turbine driven pumps would have been inoperable if the strainers were not blown down. However, discussions with the licensee did not indicate that a large amount of material was seen during the system flushes and strainer blowdowns. Therefore, the licensee considered the system to be operable. The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process," and answered "no" to all five screening questions in the Phase 1 Screening Worksheet under the Mitigating Systems column. The team concluded the issue was of very low safety significance (Green).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion XI requires, in part, that a test program be established to demonstrate that components will perform satisfactorily in service. Contrary to the above, as of September 29, 2003, the test procedures for the AFW turbine high speed stop and overspeed trip did not demonstrate that the system would perform satisfactorily in service because the test included a step to flush the cooling water lines and blow down the strainers prior to performing the test. These actions prevented any adverse effects due to strainer blockage from being discovered. Failure to adequately test the system was a violation of Appendix B, Criterion XI. This issue has been entered into the licensee's CAP as CR 03-06520. This violation is being treated as a NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. (NCV 05000346/2003010-19)

.16 Inadequate Evaluation of System Health Condition Report on Auxiliary Feedwater Design Bases Calculations

Introduction: The team identified a performance deficiency involving the licensee's failure to adequately evaluate a condition report written as part of the licensee's internal system health assessment. Following discovery, the licensee made corrections to the existing condition report evaluation. This was a minor violation.

Description: During review of CR 02-05904, the team identified that the cause evaluation was not adequately performed. This CR addressed a system health report issue on whether certain AFW design basis calculations existed or were outdated. The evaluation determined that all the questioned calculations did exist and that no further action was needed. The following deficiencies in the evaluation were identified:

- The evaluation listed an incorrect calculation number and an incorrect revision for another calculation.

- The evaluation identified a calculation for maximum steam pressure in the AFW system; however, it failed to recognize that the calculation was incorrect (this issue is discussed in Section 4OA3(3)b.14).

- The evaluation stated that CR 02-06356 identified the causes for the condition; therefore, no additional action needed to be taken. However, CR 02-06356, which had been evaluated three months prior to CR 02-05904, did not actually identify the causes, but rather assumed that the causes were known and that all appropriate corrective actions had been identified (this issue is discussed in Section 4OA3(3)b.22).

Analysis: The team determined that a performance deficiency existed because the licensee failed to evaluate a condition adverse to quality regarding calculations on the AFW system. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." Because the team independently identified the deficiencies which the licensee had failed to assess, the failure to properly evaluate an identified condition adverse to quality had no safety impact. Therefore, the team concluded this performance deficiency was minor.

Enforcement: The failure to perform an adequate cause evaluation for a condition adverse to quality constitutes a violation of 10 CFR Part 50, Appendix B, Criterion XVI, which has minor significance and is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy.

While minor violations are not normally documented in inspection reports, the team determined that documentation was appropriate in this case due to the licensee's inadequate evaluation. Additionally, the underlying cause is similar to that of other findings in this report.

.17 Containment Post-LOCA Trisodium Phosphate

Introduction: The team identified a performance deficiency involving the licensee failing to approve a calculation prior to relying on the results of the calculation. The calculation addressed the capability of the TSP in baskets in the lower level of containment to control the pH of sump water following a postulated design basis accident. Following discovery, the licensee entered the issue into its corrective action program and approved and issued the calculation.

Description: The team reviewed CRs 02-02943, 02-05300 and 02-05304. These CRs questioned the adequacy of the TSP design from three aspects:

- Capability of the TSP baskets to perform their function in light of a new calculation for containment flood level which revealed that the baskets would not be fully submerged;

- Two different calculations provided conflicting conclusion regarding the time when sump pH would be greater than 7.0; and

- Whether the amount of TSP in the baskets was sufficient to neutralize sump water with acidification from other post-LOCA sources such as degraded coatings and insulation.

Concerns were also raised regarding the impact of the additional boric acid in the containment during the previous operating cycle on the capability of the TSP baskets to fulfill its safety function.

The licensee addressed the concerns of all three CRs through the corrective actions specified for CR 02-05300. Re-analysis of the containment flood level and the TSP basket contents was performed in calculations C-NSA-059.01-019 and 86-5024418-01. These calculations demonstrated that, with the recalculated flood level, the amount of TSP in the baskets was sufficient to meet the sump pH-control requirements of the USAR. Analysis of the impact of the additional boric acid inside the containment was performed in calculation C-NSA-040.01-006. This calculation evaluated the amount of TSP needed to neutralize the boric acid deposited in the containment from a variety of RCS leakage scenarios, including RCS unidentified leakage over the previous three operating cycles plus the boric acid deposited as the result of head leakage. This calculation demonstrated that for the identified level of leakage, with the amount of boric acid deposited from the head leakage (conservatively assumed to be entirely dissolved into the sump), the TS required amount of TSP would neutralize all of the boric acid.

The team found the issue difficult to evaluate as a result of the number of rollovers involved in the resolution of these issues. The issues were ultimately consolidated into three corrective actions under CR 02-05300; all three corrective actions involved the completion of vendor calculation 86-5024418-01. The team determined that the three corrective actions had been marked as completed although one calculation had not been approved and had, in fact, been remanded to the vendor for revisions. This was not in accordance with the licensee's CAP procedure. Specifically, procedure NOP-LP-2001, "Condition Report Process," Revisions 3 and 4, required that corrective actions be completed prior to the corrective action being accepted and closed. The revisions to the calculation were determined to be minor and did not affect the results, and the licensee formally approved the calculation. The team did not review the final calculation results.

The team determined that a performance deficiency existed because the issue involved the licensee's failure to approve a calculation prior to relying on the results of the calculation and this issue was not identified during the corrective action closure process. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the performance deficiency was minor because the changes to the unapproved calculation were minor and did not affect the overall results.

Enforcement: The closure of all the corrective actions for CR 02-05300, contingent upon completion of vendor calculation 86-50244181-01, which had not been owner accepted, was considered a violation of 10 CFR Appendix B, Criterion V, which has minor significance and is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. The licensee entered the issue into its CAP as CR 03-07420.

While minor violations are not normally documented in inspection reports, the team determined that documentation was appropriate in this case due to the rollover issues which were identified and the underlying cause is similar to that of other findings in this report.

.18 Borated Water Storage Tank Calculation Issues

Introduction: The team identified a NCV of 10 CFR Part 50, Appendix B, Criterion III, having very low safety significance. Specifically, the licensee failed to translate the radiological consequences of leakage from engineered safety feature components outside containment into calculations of record for post-accident control room dose and offsite boundary dose. Following discovery, the licensee entered the issue into its corrective action program and provided a bounding evaluation which demonstrated that the increase in dose was within acceptable limits.

Description: During the SSDI, the NRC identified that the radiological consequences of leakage from engineered safety features components outside the containment were not included in the calculation of offsite dose for 10 CFR Part 100 nor in the calculation for control room dose per GDC 19. The concerns involved the impact on control room dose as a result of an airborne release from the assumed 500 gallons of containment sump water deposited in the BWST and the impact on both offsite and control room dose as a result of ECCS system pump seal leakage. The licensee wrote CRs 02-06701, 02-07713, and 02-07701 to address these issues.

The licensee performed an informal calculation in the cause analysis for CR 02-07701 to determine the increase in dose in the control room from the 500 gallons deposited in the BWST. The calculation was based on the site boundary base dose listed in the USAR which resulted from the airborne release associated with the 500 gallons of post-LOCA water deposited in the BWST. This dose was determined by the Bechtel calculation of record as 2.72 rem. Using control room ventilation system parameters and the site boundary dose, the control room dose was calculated as 0.07 rem. The licensee extrapolated the dose for the 40 gallon per hour pump seal leakage from the USAR dose rate for normal valve system leakage of 5890 cubic centimeters per hour (1.56 gallons per hour). The result was an additional control room dose of 0.5 rem and an additional site boundary dose of 1.5 rem.

The licensee then calculated that the total offsite dose, resulting from the USAR value of 232 rem accident dose plus the BWST dose of 2.72 rem plus the pump seal dose of 1.5 rem, was a total of 236.22 rem. The total control room dose was similarly summed:

USAR accident dose of 19.8 rem plus BWST dose of 0.066 rem plus pump seal leak dose of 0.5 rem for a total of 20.366 rem.

As a result of these calculations, the licensee specified post-restart corrective actions to update the Bechtel calculation of record and the USAR to incorporate these doses. Because the corrective actions had not yet been completed, the licensee had not completed a screening or evaluation under 10 CFR 50.59. The team performed a limited evaluation of the acceptability of the increased dose under 10 CFR 50.59(c)(2)(iii), "Result in more than a minimal increase in the consequences of an accident previously evaluated in the final safety analysis report (as updated)." The team reviewed the guidance provided in Nuclear Energy Institute (NEI) standard 96-07, "Guidelines for 10 CFR 50.59 Implementation," Revision 1, which NRC endorsed in Regulatory Guide 1.187.

Based on this guidance, the team determined the revised dose calculations did not result in more than a minimal increase in the consequences of an accident previously evaluated in the USAR. The team determined that a more than minimal increase would have occurred if:

- The increase in dose was more than or equal to ten percent of the difference between the previously calculated dose value and the regulatory guideline value (10 CFR Part 100 or GDC 19); and

- The increased dose exceeded the current standard review plan guideline value for the particular design basis event.

The team calculated that ten percent of the difference between the previously calculated dose total and the 10 CFR Part 100 and GDC 19 limits were 6.8 rem for the offsite dose increase and 1.02 rem for the control room dose. The team confirmed that the total increases in dose of 4.2 and 0.57 rem were below the guidance values in NEI 96-07; therefore, the first part of the guidance was satisfied. The team concluded that the second part of the guidance was met because the total offsite dose was less than the Part 100 limit of 300 rem and the control room dose was less than the GDC 19 limit of 30 rem. The team, therefore, deemed that the licensee had an acceptable rationale for delaying issuance of the formal calculations until after restart.

Analysis: The team determined that a performance deficiency existed because the licensee had not recognized that the radiological consequences of leakage from engineered safety features components outside the containment were not included in the calculation of offsite dose for 10 CFR Part 100 nor in the calculation for control room dose per GDC 19. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because the licensee had to perform calculations to show that the increased doses remained within the post accident dose level requirements.

The team reviewed the SDP questions for reactor safety, occupation radiation safety and public radiation safety contained in MC 0612, Appendix B, “Issue Screening,” and also consulted with the senior reactor analysts (SRAs). Based on this review, the team determined that the issue was not covered by any of the revised oversight cornerstones and was, therefore, not suitable for SDP analysis. This determination was based on the issue being a design issue that dealt with postulated doses following a design basis accident. The team also determined that the increase in dose did not involve an issue requiring a license amendment. Therefore, this finding was reviewed by Regional Management, in accordance with IMC 0612. The finding was determined to be of very low safety significance (Green) because the preliminary calculations concluded that the increased doses remained within the post accident dose level requirements and there were no actual releases.

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis were correctly translated into specifications, drawings, procedures, and instructions. Furthermore, it requires that measures be provided for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to the above, the licensee failed to translate the radiological consequences of leakage from engineered safety feature (ESF) components outside containment into calculations of record for post-LOCA control room dose and offsite boundary dose.

The licensee entered the issue into its CAP as CRs 02-06701, 02-07713, and 02-07701. Because this violation was of very low safety significance and because it was entered into the licensee’s CAP, this violation is being treated as a NCV consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000346/2003010-20)

.19 Inadequate Evaluation of Reactor Coolant Pump Casing-to-cover Stud Overstressing

Introduction: The team identified a NCV of 10 CFR Part 50, Appendix B, Criterion III, having very low safety significance. Specifically, the licensee failed to evaluate a potential overstressing condition on the reactor coolant pump casing-to-cover studs. Following discovery, the licensee entered the issue into its corrective action program. The primary cause of this violation was related to the cross-cutting area of problem identification and resolution as the licensee closed a condition report without recognizing that the apparent condition adverse to quality had not been addressed.

Description: The team reviewed CR 02-08759. This CR questioned whether the RCP casing-to-cover studs had been overstressed when the studs on all four pumps were retensioned in 1996. The RCP casing-to-cover studs are part of the reactor coolant pressure boundary (RCPB).

The team identified the following deficiencies with the licensee’s handling of this CR:

- The CR was closed based on a draft revision of a vendor calculation, SR-0964, Revision 1, which was not accepted by the licensee until after the CR was closed.

- The discrepant condition (possible overstressing of the studs) was neither analyzed as not being a concern nor field verified to not be a problem before the CR was closed. Instead the corrective action was canceled on the basis that the studs on pumps 1-1 and 1-2 had relaxed to within acceptable limits, therefore, the studs on the other two pumps were also deemed acceptable.

- The draft calculation only addressed the allowable stud tension for pumps 1-1 and 1-2, based on the new gaskets installed; it did not address the condition from 1996 for all four pumps or the continuing condition on pumps 2-1 and 2-2.

- When questioned by the NRC team the licensee had to go back to the vendor and obtain a new calculation to show that the previous stud elongation was acceptable. However, no new CR was written to address the fact that 02-08759 had been closed without addressing the concern for which it had been written.

- Instead of being provided with a new calculation, the vendor provided the licensee with a letter providing the maximum allowable stud elongation for the 1996 configuration.

- The actual 1996 as-left elongation values for some of the studs were greater than the 24 mils specified in the vendor letter, although they were within the 26 mils specified in 1996. The licensee verbally evaluated the condition, but did not actually document the acceptability of the 1996 condition.

- The vendor letter was appended to the CR file four months after the CR was closed and only after the team questioned why no CR was written about the issue.

Because of this sequence of events, the team performed a limited, independent verification of both the formal and informal calculation results, and then verified the actual installed stud elongation against the calculated allowable. The team determined that some studs were elongated to 25 mils; however, the quadrant average in all cases was between 23.2 and 23.4 mils. The team determined that an average elongation of 24.3 mils would keep the stress levels below the maximum American Society of Mechanical Engineers (ASME) boiler and pressure vessel code (the Code) allowable of 23.6 kilo-pounds per square inch (ksi). Based on this independent evaluation, the team concluded that the casing-to-cover studs on RCPs 2-1 and 2-2 were not overstressed and that none of the studs on any of the four RCPs not been overstressed in the past.

The team also noted that the licensee did not have a design basis calculation that supported the increased tensioning of the studs on all four reactor pumps in 1996 and still did not have such a calculation for RCPs 2-1 and 2-2 in 2003. However, the licensee planned to replace the gaskets on these pumps by no later than RFO 14 in 2005; once the gaskets are replaced, the stud tensioning would be addressed by calculation SR-0964.

Analysis: The team determined that a performance deficiency existed because the licensee failed to evaluate the acceptability of the RCP studs prior to closing the CR. Additionally, when the issue was brought to their attention, the licensee did not write a new CR to document the failure of the CAP. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because the licensee had to perform calculations to determine if the RCP studs were within ASME Code allowables. The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process." The team assessed the finding through Phase 1 of the SDP. The issue involved the barrier integrity cornerstone because it dealt with the acceptability of the RCPB. There was only one question related to the RCPB. The licensee had not evaluated the functionality of RCP studs for past operation or for current operation on two of the four pumps. Therefore, the team assessed the issue based on the team's evaluation described above. Based on this assessment, the RCP studs were always functional and the SDP RCPB question was answered as "no". Therefore, the finding screened out as having very low safety significance (Green).

<u>Enforcement</u>: Title 10 CFR Part 50, Appendix B, Criterion III, requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis were correctly translated into specifications, drawings, procedures, and instructions. Furthermore, it requires that measures be provided for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to the above, in March 2003, the licensee closed CR 02-08759 without ensuring that the ASME Code requirements were correctly translated into the torquing values for the RCP casing-to-cover studs and without ensuring that previous maintenance activities had not resulted in the studs being overstressed.

After being identified as a potential violation at the end of the inspection, the licensee wrote CR 03-07047 to enter the issue into the CAP. Since the issue was of very low safety significance and was captured in the licensee's CAP, it is being treated as a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy.
(NCV 05000346/2003010-21)

.20 <u>Reactor Coolant Pump Inner Gasket Leakage</u>

The team reviewed CRs 02-01523, 02-03668, and 03-04018, and associated evaluations, which documented an apparent continuing problem with RCP inner gasket leakage. The team determined that the licensee failed to adequately analyze the results of an apparent continuing leak past the inner gasket on the RCPs. Specifically, minor leakage past the inner gasket was noted on all four pumps during previous outages and the documented evaluation did not address why it was acceptable to not repair the gaskets. Furthermore, the licensee's analysis did not provide technical justification for either replacing or not replacing all four RCP gaskets.

The team performed extensive evaluation of the as-left leakages for all pumps by reviewing test results and test log books. The responsible test engineers were also interviewed by the team. The team determined that the licensee's evaluations were based on leak testing that: (1) did not use the same methodology from outage to outage; (2) did not attempt to normalize the data from outage to outage; (3) did not consider the impact of reactor coolant pressure and temperature conditions on the test results; and (4) was only intended to verify that the leak detection lines were open and not blocked. The team was concerned that the licensee did not recognize these inconsistencies in performing and approving the evaluation.

The team determined that the design of both the inner and outer gaskets was to seal against full reactor pressure. While normally the inner gasket provided the seal, the outer gaskets was also designed for this purpose. Only if the outer gasket failed would the RCPB, provided by the casing-to-cover studs, be affected.

The team also noted that leakage past either the inner or outer gasket was not pressure boundary leakage, per the ASME Code. The Code specifically excluded gaskets from RCPB leakage. Instead, any leakage past the outer gasket would be categorized as either identified or unidentified reactor coolant leakage, and would be subject to TS limits. Leakage past the inner gasket was not considered to be a safety concern. Neither the inner or the outer gasket was considered to be important to safety and neither component was credited with having a safety function in the USAR.

The team determined that a catastrophic failure of the inner gasket during an operational cycle should have no consequences, as the outer gasket should continue to provide a seal. If the outer gasket also failed, then the licensee would have to comply with the TS limiting conditions for operation and shut down the plant.

The team noted that the normal operating pressure and temperature (NOP/NOT) test performed by the licensee included inspections of the RCPs: both at the gasket leakoff lines and at the studs. These inspections were conducted prior to, during and following reaching NOP/NOT. This NOP/NOT test showed that there was no outer gasket leakage and that the inner gasket leakage was minor, occurred primarily during the pressurization period and stopped, or significantly slowed, once the pumps reached an equilibrium temperature.

Notwithstanding that the licensee failed to adequately analyze the results of an apparent continuing leak past the inner gasket on the RCPs, the team concluded that this did not present a safety issue since the inner gasket leakage would not affect the RCPB. No violation of NRC requirements were identified.

.21 Environmental Qualification of Equipment Not Supported by Analysis

Introduction: The team identified a NCV of 10 CFR Part 50, Appendix B, Criterion XVI, having very low safety significance (Green). Specifically, the licensee failed to ensure that emergency core cooling system pump motors were environmentally qualified for the stated mission time, as stated in a license amendment request (LAR) submitted to the NRC. Following discovery, the licensee entered the issue into its corrective action program. The primary cause of this violation was related to the cross-cutting area of human performance as the licensee did not ensure that personnel developing license documents had the necessary information.

Description: The team examined CR 02-05732, which was issued during the licensee's latent issues review of the SW system. The fundamental concern discussed in the CR was that LAR 96-0008, submitted to NRC by the licensee on July 28, 1999, contained statements that were unsupported by analyses.

The CR identified three specific concerns:

- Some equipment in the ECCS pump rooms was not qualified to higher temperatures, as stated in the request;

- There was no analysis to support a statement in the request that two room coolers were adequate even with substantially degraded flow rates; and

- The request stated that no changes were made in AFW flow, yet a calculation of record showed that the flow rate was changed from 1600 gpm to 800 gpm.

The team reviewed the condition description, immediate actions, and cause analysis. The cause analysis examined the three concerns and concluded that there was no discrepant condition, no apparent cause, and no corrective actions required.

The team disagreed with this conclusion based on a review of CR 02-05593 which identified a block of components that were not included in a calculation evaluating environmental qualification (EQ) qualification of equipment in the ECCS pump rooms. This CR also noted that no reference for qualification of the HPI and DHR pump motors existed and recommended that the EQ calculation be revised to address qualification of all these components.

The team identified that the first concern in CR 02-05732 was correct, in that two pieces of equipment in an ECCS pump room, the containment spray (CS) and HPI pump motors, were not environmentally qualified for the service time of 30 days which was stated in the LAR. Based on a review of the EQ folder, the team determined that the motors could most likely be qualified as required. CR 03-06588 was written to address this issue. However, the team later determined that the licensee had evaluated CR 03-06588 and concluded that no corrective actions needed to be taken as far as environmentally qualifying the ECCS motors.

Analysis: The team determined that a performance deficiency existed because the licensee failed to establish the environmental qualification of two ECCS motors at the time the license amendment request was submitted. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the failure to adequately evaluate the motor environmental qualification issue was more than minor because it reflected a weakness in the licensee's CAP in regard to correctly assessing issues. The team concluded that, if uncorrected, this continuing weakness could result in a repeat failure of the CAP to adequately identify, evaluate and correct problems. This was an equipment qualification issue which affected the mitigating systems cornerstone. Although the licensee had not qualified the equipment, the team deemed that the motors more likely than not could be qualified. Therefore, the team considered it reasonable that the motors would perform their safety function, if required to operate. The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process." The finding was screened in the SDP Phase 1 as a qualification deficiency that was confirmed not to result in the loss of function per Generic Letter 91-18, Revision 1. Therefore, the issue was determined to have a very low safety significance (Green).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion XVI, requires, in part, that conditions adverse to quality be promptly identified and corrected, commensurate with their safety significance.

Contrary to the above, in November 2003, the licensee evaluated CR 03-06588, which described a condition adverse to quality, and concluded that no corrective actions were necessary. The condition adverse to quality described in the CR dealt with LAR 96-008 which documented that the HPI and DHR pump motors were environmentally qualified for 30 days, when, in fact, those motors were not so qualified.

After being identified as a potential violation at the end of the inspection, the licensee wrote CR 03-06588 to enter the issue into the CAP. Since the issue was of very low safety significance and was captured in the licensee's CAP, it is being treated as a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy.
(NCV 05000346/2003010-22)

.22 Inadequate Justification for Downgrade of Significant Condition Adverse to Quality

Introduction: The team identified a performance deficiency involving the licensee's failure to evaluate an issue initially determined to be a significant condition adverse to quality prior to downgrading the issue. Following discovery, the licensee entered the issue into its corrective action program. This was a minor violation.

Description: Prior to the safety system design inspection in October 2002, and following completion of the system health reviews, the licensee initiated CR 02-06356 to document a repetitive concern regarding a difficulty in determining the status or location of design basis calculations. This CR was determined to be a SCAQ, primarily because a number of design basis calculations were discovered to be outdated or non-existent. Issues such as those discussed in Section 4OA3(3)b.16 exemplified the reason that the CR originally was rated as a significant condition.

The team reviewed CR 02-06356 and noted that it had been downgraded to a routine CR with minimal investigation or justification. The evaluator assumed that his department had the bulk of the calculations and that he knew the status of those calculations. The evaluator then concluded that there was not really a problem, based on these assumptions and apparently without considering other design engineering departments. Additionally, the team determined that the extent of condition review was based entirely on a word search for the word "calculation" in the title of CRs. This eliminated many of the CRs written on superceded or historical calculations and resulted in many of the CRs on design basis calculational issues not being found.

Analysis: The team determined that a performance deficiency existed because the licensee failed to adequately assess and justify the downgrade of a condition adverse to quality as required by procedure NOP-LP-2001. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the performance deficiency was minor because the team did not identify other examples where downgrades were performed without adequate justification and because no specific calculation deficiencies which resulted in inoperable equipment were associated with the CR.

Enforcement: The failure to provide adequate justification when downgrading a SCAQ constitutes a violation of 10 CFR Part 50, Appendix B, Criterion V. However, this violation was determined to have minor significance and is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. The licensee documented the issue in CR 03-06948.

While minor violations are not normally documented in inspection reports, the team determined that documentation was appropriate in this case due the underlying cause is similar to that of other findings in this report.

.23 Inappropriate Application of 10 CFR 50.59

Introduction: The team identified a NCV of 10 CFR 50.59, "Changes, Tests and Experiments." Specifically, the licensee failed to preform an adequate evaluation of a defacto modification to the plant where the underlying change may have required NRC approval prior to implementation. Following discovery, the licensee entered the issue into its corrective action program and re-performed the evaluation; the licensee also repaired those barriers which were physically degraded. The primary cause of this violation was related to the cross-cutting area of human performance as the licensee appeared to selectively choosing information from the guidance document.

Description: In IR 05000346/2002019, LER 05000346/2002-006 was closed and an URI was opened to track resolution of safety related structures which were unprotected against tornado missiles; specifically that six feet of the EDG exhaust stacks were unprotected and that portions of a concrete barrier were degraded. This issue was being tracked in the licensee's corrective action system under CRs 02-04146, 02-04147, 02-04700 and 02-05590. The team determined that the licensee had evaluated the non-conforming conditions using a computer code (TORMIS) discussed in Electric Power Research Institute (EPRI) Topical Report NP-2005, "Tornado Missile Risk Evaluation Methodology," Volumes I and II, August 1981. Based on use of this code, the licensee determined the probability of the unprotected areas being struck by a tornado missile was relatively low.

The licensee revised the USAR to incorporate the TORMIS methodology, including a provision which allowed it to be used to accept degraded or non-conforming conditions. On that basis, the licensee declared the diesel generators operable and determined that repairs were not needed for the non-conforming structures until 2004. In regard to the unprotected stacks, the licensee determined that no modifications were necessary.

Prior to the USAR change, Section 3.5.1 of the USAR stated that, "Protection against a potential missile may be provided by, but not necessarily limited to, any one or combination of the following protection methods: compartmentalization, barriers, separation, distance, restraints, strategic orientation and equipment design." The team noted that all these methods involved physical protection of the equipment, rather than methods of evaluation. Under change notice 02-063, the licensee changed this statement to add tornado missile probability as a protection method.

As part of the USAR change, the licensee performed an evaluation as required by 10 CFR 50.59. During review of this evaluation, the team questioned whether the licensee had appropriately followed the guidance in Nuclear Energy Institute standard NEI 96-07, which NRC endorsed in Regulatory Guide 1.187. Specifically, the licensee appeared to be incorporating use of the TORMIS methodology, using the methodology to accept a defacto change to the plant (where the plant did not match the description in the USAR) and then justifying the methodology's use for future non-conforming or degraded conditions all in the same 50.59 evaluation. The team noted that these differing applications affected how the 10 CFR 50.59, Section c.2, questions were answered in the licensee's 10 CFR 50.59 evaluation. The team also noted that the questions were answered based on the standard review plan, rather than on the Davis-Besse USAR.

The team consulted with the Office of Nuclear Reactor Regulation (NRR) and determined that the licensee should have evaluated the change from protecting equipment from tornado generated missiles by means of physical protection to relying upon analysis to demonstrate that such protection was not needed through use of a probabilistic computer methodology.

In discussions, the licensee stated that the above approach was not necessary because the TORMIS methodology was an "approved methodology and, therefore, wasn't a departure from a method of evaluation described in the FSAR (as updated) used in establishing the design bases or in the safety analyses" as defined in 10 CFR 50.59. However, the team noted that there was not an existing method of evaluation that applied to protection of the EDGs. Instead, the change was from "protection by means of a physical barrier," to "protection by means of a probabilistic approach," which appeared to have introduced a new failure mode not previously evaluated for the EDGs. The introduction of this new failure mode did not appear to be addressed by the licensee's 50.59 evaluation.

Specifically, the USAR previously stated that the diesel generators were not affected by tornado generated missiles due to physical features. Inclusion of the TORMIS methodology introduced the possibility that the diesels could be affected by tornado generated missiles. The licensee answered this question in its 10 CFR 50.59 evaluation by stating that "the probability of a tornado generated missile was incredible, that NRC accepted use of probability for Davis-Besse in analyzing the probability that turbine missile would penetrate containment, and by stating that the Davis-Besse acceptance criteria was the same as that licensed at other plants."

However, the team noted the following guidance in NEI 96-07, Section 4.3.6: "Malfunctions of SSCs are generally postulated as potential single failures to evaluate plant performance with the focus being on the result of the malfunction rather than the cause or type of malfunction. A malfunction that involves an initiator or failure whose effects are not bounded by those explicitly described in the USAR is a malfunction with a different result..."

Based on this description, because possibility for the diesel generators to be damaged by tornado missiles involved both an initiator and effects which were not bounded by those explicitly described in the USAR, the team deemed that this question should have been answered "yes" and prior NRC review of this change sought.

At the end of the inspection, the licensee had written a new CR, 03-06561, and was revising the 10 CFR 50.59 evaluation to address the above issues. The revised 10 CFR 50.59 analysis was not reviewed by the team.

The team also noted that the licensee had to physically repair the degraded concrete to restore its tornado protection capability. The licensee had not considered these physical changes necessary until the team identified the concern regarding inappropriately using 10 CFR 50.59 to correct non-conforming or degraded conditions. However, new physical barriers for tornado missile protection were not added to those areas which initially lacked such barriers.

Analysis: This issue was determined to involve a performance deficiency because the licensee misapplied the criteria of 10 CFR 50.59 and concluded that prior NRC approval was not required when such a conclusion could not be supported by the documented 50.59 evaluation. Because violations of 10 CFR 50.59 are considered to be violations that potentially impede or impact the regulatory process, they are dispositioned using the traditional enforcement process instead of the SDP. Typically, the Severity Level would be assigned after consideration of appropriate factors for the particular regulatory process violation in accordance with the NRC Enforcement Policy. However, the SDP is used, if applicable, in order to consider the associated risk significance of the finding prior to assigning a severity level. Using IMC 0612, Appendix B, "Issue Screening," the team determined that the finding was more than minor because physical barriers were degraded or missing and because those barriers being degraded could result in one or more of the diesel generators failing to fulfill their design function during a tornado. This was a design issue which affected the mitigating systems cornerstone.

The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process." The consequence of the design was assessed through Phase 1 of the SDP. The team answered the question, "Does this issue involve an actual loss of safety function," as "Yes," because under a design basis tornado, the diesel generator exhaust stacks were not physically protected. Based on this premise, the team entered Phase 2 of the SDP.

The team determined that the only event tree affected was LOOP concurrent with loss of one EDG. This was based on the assumption that a tornado missile hitting both EDG exhaust stacks would be an incredible event. The team decreased the initiating event frequency from a "5" (once in 100,000 years) to a "3" (once in 1,000 years) based on the fact that the Davis-Besse switchyard was struck by a tornado in 1998 (in this event, EDG 1 did not start from the control room and was declared technically inoperable due to the room design basis temperature of 120°F being exceeded). In reviewing the 1998 event, the team determined that one turbine driven AFW pump was out of service for maintenance. Therefore, the team assumed that a turbine driven AFW pump was out of service for purposes for the Phase 2 analysis. Based on these credible assumptions, the technical issue was determined to have very low safety significance and the violation is categorized as Severity Level IV.

Enforcement: Title 10 CFR 50.59(d)(1) requires that the licensees maintain records of changes in the facility, of changes in procedures, and of tests and experiments made pursuant to 10 CFR 50.59(c). It further requires that these records include a written evaluation which provides the bases for the determination that the change, test or experiment does not require a license amendment pursuant to 10 CFR 50.59(c)(2).

Contrary to the above, on November 7, 2002, the licensee approved a 50.59 evaluation incorporating a change in the design basis to accept not physically protecting the EDG exhaust stacks from tornado missiles. However, the evaluation did not provide the basis for why a possibility for a malfunction of the diesel generators due to impact on the diesel generator exhaust stacks by a tornado missile did not produce a different result than any previously evaluated in the final safety analysis report.

The failure to provide a written evaluation which described the basis for concluding a license amendment was not needed was a violation of 10 CFR 50.59(d)(1). This issue has been entered into the licensee's CAP as CR 03-06561. This Severity Level IV violation is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. (NCV 05000346/2003010-23)

.24 Failure to Perform Comprehensive Moderate Energy Line Break Analysis

Introduction: The team identified a NCV of 10 CFR Part 50, Appendix B, Criterion III, having very low safety significance (Green). Specifically, the licensee failed to include the environmental effects of a DHR pump seal failure in its moderate energy line break analysis. Following discovery, the licensee entered the issue into its corrective action program and performed the analysis.

Description: The licensee initiated CR 02-07757 to document the failure to perform a comprehensive moderate energy line break analysis. This CR was rolled over into CR 02-06370, which required that the concerns of additional heat generation caused by the moderate energy line break (DHR pump seal) be addressed in the new calculation being performed in response to CR 02-06370. The team determined that the heat load caused by failure of the DHR pump seal (an additional 21,000 btu/hr) was included in calculation C-NSA-032.02-006 and that the discrepant condition was adequately resolved.

Analysis: The team determined that a performance deficiency existed because the licensee failed to have a design analysis to demonstrate the ability to withstand moderate energy line breaks as specified in design documents. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because the licensee had to perform calculations to show that the environmental effects were acceptable. This was a design issue which affected the mitigating systems cornerstone. The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process," and, based on the determination that the moderate energy line break heat loads were acceptable and that the system could perform its design function, answered “no” to all five screening questions in the Phase 1 Screening Worksheet under the Mitigating Systems column. The team concluded the issue was of very low safety significance (Green).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis were correctly translated into specifications, drawings, procedures, and instructions. Furthermore, it requires that measures be provided for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to the above, the licensee failed to translate the consequences of leakage from the DHR pump seals into calculations of record for moderate energy line breaks. The licensee entered the issue into its CAP as CRs 02-07757 and 02-06370. Because this violation was of very low safety significance and because it was entered into the licensee’s CAP, this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000346/2003010-24)

(4) Detailed Team Review of Licensee Corrective Actions Implemented to Address Operational Issues Previously Identified by the Licensee

a. Inspection Scope

The team assessed effectiveness of the licensee’s CAP to identify, categorize, evaluate, and resolve the identified equipment, human performance or programmatic adverse to quality plant conditions. The team mainly focused on plant systems design and licensing basis requirements issues which were previously identified by the NRC, the licensee and others during various design reviews conducted in 2002. The team assessed effectiveness of the licensee’s corrective actions implemented to address previously identified operational issues.

b. Findings

Repetitive Spacer Grid Strap Damage

Introduction: The team identified a NCV of 10 CFR Part 50, Appendix B, Criterion XVI, having very low safety significance (Green). Specifically, the licensee failed to take adequate corrective actions to previous events to prevent damage to a new fuel assembly spacer grid strap during the final reload of the core in 2003. Following discovery, the licensee entered the issue into its corrective action program. The primary cause of this violation was related to the cross-cutting areas of corrective action and human performance, because, despite earlier events, the licensee failed to adequately address the human performance issues that contributed to this and other fuel spacer grid events.

Description: The licensee designated CR 02-06178 as a SCAQ CR. This CR described repetitive damage to fuel assembly grid straps and rolled in the following CRs: 02-05645, 02-05895, 02-05896, 02-06343, and 02-09829. A root cause report was required for CR 02-06178 as part of a NQA stop work order on fuel movements.

REVIEW OF ROOT CAUSE REPORT: The licensee issued a root cause analysis in January 2003 which determined the cause of the repetitive grid strap damage. At this time, the licensee's CAP did not require use of a formal root cause process; however, a formal TAPROOT process was used. Also, in May 2002, the licensee had completed a root cause of fuel damage identified earlier in the outage. In reviewing the January 2003 root cause report, the team noted several deficiencies:

- The discussion on what occurred appeared to rely extensively on the previous root cause, performed in May 2002, and on a 1999 Babcock and Wilcox (B&W) root cause. The explanations for the statements made in the January 2003 report required understanding of the earlier studies in order to comprehend their applicability.

- The January 2003 root cause primarily focused on the new fuel assembly which was discovered to be damaged in September 2002. It limited its discussion of the other fuel assemblies discovered to be damaged in the September 2002 time frame to listing the damage in a table and describing the disposition. This was despite these CRs for these fuel assemblies being "rolled into" the root cause report and a corrective action entry being closed with a statement that the root cause report addressed the damage to the fuel assemblies.

- The team noted that ten fuel assemblies were discovered to be damaged in September through December 2002. This was in addition to the seven fuel assemblies discovered to be damaged in March 2002. In one place in the January 2003 root cause report, the licensee stated that the damage had to occur during RFO 12, because there was no oxidation on fuel assemblies. The team ascertained that, if the first statement was true, then the extent of condition for the May 2002 root cause report must have been deficient in that it failed to identify a number of damaged fuel assemblies.

- In another section, the root cause report stated that review of the core loading sequence determined that assembly NJ125Y, "and a number of other assemblies," were loaded in a sequence that exposed those assemblies to undesired corner to corner interactions. This second statement implied that the damage might well have occurred during the fuel shuffle in March 2002. However, the root cause report did not specifically identify which assemblies were so loaded or otherwise follow up on this comment. The team determined that a possible contributing cause was not identified or corrected.

- The team noted that eight of the ten fuel assemblies discovered to be damaged in September through December had only been burned once, and two were new fuel assemblies. Thus, the assemblies should not have been overly "bowed and twisted," although this was listed as a possible reason for the damage.

- In regard to the extent of condition, the team noted that the licensee provided an extensive list of damage which occurred at other B&W sites. However, the only Davis-Besse information from previous outages was from cycle 11. Data from cycle 12 was missing from the table.

- Based on the information in the extent of condition table, the team noted that, approximately the same number of fuel assemblies were involved in both RFO 11 and 13. However, in RFO 11 the damaged fuel was mostly burned multiple times and to have damage to only one or two grid strap locations. In RFO 13 (the current outage), the damaged fuel was primarily unburned or burned only once and had damage to multiple grid strap locations.

- The discussion on the December grid strap damage gave little credence to the report that the fuel assembly was undamaged in September. Instead a statement was made that because spacer grid 2 was damaged, and it hadn't entered the pool, the damage must have occurred earlier. Given the extent of the damage to the fuel assembly, the information provided in the CR initiation statement from the personnel present, and the fact that only the northeast corner face was damaged, the team considered it more likely that the damage occurred all at one time.

- The root cause report did not provide any discussion of the impact that occurred during the December re-insertion. The team considered it unlikely that the impact would not have caused any damage. The team noted that CR 02-09829 stated that the assembly visibly moved to the south. The team also noted that all the damage occurred on the northeast corner. This indicated to the team that the damage likely occurred during the re-insertion since a deflection to the south would be an expected result if the northeast corner of the fuel assembly impacted the cell. The failure to address why the impact occurred and the result of the impact appeared to be a significant weakness in the root cause.

- The team determined that no mention was made in the root cause report of items such as whether the fuel handling personnel had the mast in fast or slow speed or what the routine practice was regarding the fuel insertion rate. Additionally, items such as length of time the crew had been working, schedule pressures, and other factors which would address human performance were not discussed, although these all could play a role in fuel handling mishaps.

FEBRUARY DAMAGE TO NEW FUEL ASSEMBLY: On February 24, 2003, during the final reload of the cycle 14 core, another new fuel assembly was damaged. This was documented in CR 03-01492. The licensee did an apparent cause evaluation for this event and concluded that the damage to this fuel assembly was likely due to the less than adequate design of the fuel assemblies. The team noted a number of issues that did not appear to have been adequately considered in reaching the apparent cause conclusion. For example:

- The damage occurred after the majority of the fuel assemblies were loaded and only a few remained; this was not addressed in the apparent cause analysis.

- The fuel handlers had spent approximately two hours unsuccessfully trying to load another fuel assembly into place before deciding to change the loading sequence to load another assembly in a potential corner to corner interaction pattern. There was no indication that anyone suggested stopping the process and evaluating the condition, before agreeing to the change in the loading sequence.

- Over the next three hours, multiple problems were experienced as the licensee attempted to load the fuel assembly, including multiple overload conditions and cable oscillations. The licensee reset the overload setpoints to the least limiting condition at least twice, and even this setpoint was reached. Again, when problems were encountered, the decision was to keep on trying to insert the assembly, rather than stopping and evaluating what was happening.

Analysis: The team determined that a performance deficiency existed because the licensee failed to take adequate corrective actions in response to previous events and as a result, a new fuel assembly spacer grid strap was damaged during the final reload of the core in February 2003. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because the licensee failed to prevent recurrence of a significant condition adverse to quality as evidenced by damage to previously undamaged fuel assembly grid straps. The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process." The barrier integrity cornerstone was affected as failure of the grid straps has led to fuel leaks. No other cornerstones were affected. There was one SDP Phase 1 worksheet question relating to the fuel barrier. As this issue related to fuel barrier, the team concluded the issue was of very low safety significance (Green).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion XVI, requires, in part, that measures be established to ensure that conditions adverse to quality, such as non-conformances, are promptly identified and corrected. For significant conditions adverse to quality, it further requires that the cause is determined and corrective action is taken to prevent recurrence.

Contrary to the above, as of February 5, 2003, the licensee had failed to take corrective actions which prevented recurrence of grid strap damage, a significant condition adverse to quality. Specifically on September 20, 2002, the licensee issued a stop work order and a SCAQ was identified and documented in CR 02-06178. The root cause for this report was completed in January 2003, prior to core reloading being allowed to recommence. On February 5, a new fuel assembly was damaged after the licensee made multiple unsuccessful attempts to insert the assembly into the core.

This issue was entered into the licensee's CAP as CR 03-06996 at the end of the inspection. Because this violation was of very low safety significance and because it was entered into the licensee's CAP, this violation is being treated as a NCV consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000346/2003010-25).

(5) Review of Fire Protection Corrective Action Items

a. Inspection Scope

The team reviewed the licensee's CAP to identify and address 10 CFR Part 50, Appendix R, related deficiencies.

b. Findings

.1 Process Monitoring Function for Alternative Shutdown Capability

Introduction: The team identified a Non-Cited violation of 10 CFR 50, Appendix R, Section III.L.2.d having very low safety significance. Specifically, the issue regarded the failure to provide necessary process monitoring readings for safe shutdown of the plant during a fire event. The primary cause of this violation was related to the cross-cutting area of problem identification and resolution because the licensee had previously identified this issue as an enhancement and did not recognize that it was a violation of regulatory requirements.

Description: During a review of the fire protection program, the licensee issued CR 03-01648 identifying at failure to provide necessary process monitoring readings for steam generator (SG) level and pressure necessary for safe shutdown of the plant during a fire event. For the limiting Appendix R scenario (control room or cable spreading room fire) where alternative shutdown was required, SG instrumentation would not have been available for the idle SG during safe shutdown of the plant. Without this SG level and pressure instrumentation, licensee operators would not have been able to support the shell-tube differential temperature determination which was required by the alternative shutdown procedure. This could have potentially resulted in the loss of the thermal communication between the tubes and shell of the idle SG resulting in unacceptable stresses on the tubes.

Even though the alternative shutdown procedures did not contain the necessary procedural steps to prevent this condition if a fire in these areas were to occur, operators could have taken temperature readings using a volt-meter to record the temperatures locally at the penetration room. While these actions could not be credited for the Appendix R analysis, they would be available. Additionally, after this non-conformance was identified, the licensee performed a modification (ECR 03-0267-00) to provide level and pressure indication for the idle SG on the auxiliary shutdown panel to support Appendix R safe shutdown.

Analysis: The team determined that a performance deficiency existed because the licensee failed to provide SG level and pressure indication required for alternative shutdown. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because it affected the initiating events cornerstone and, by not providing the direct indications necessary for the operators to determine the status of the idle SG, the probability of experiencing unacceptable stresses on the SG tubes during the limiting Appendix R scenario was increased.

The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process." The team determined this finding to be of very low significance, based upon the low probability of a serious control room fire combined with the low probability that such a fire would affect this specific instrumentation detrimentally. Additionally, even in the event that such a fire had affected this instrumentation, it was likely that the operators still would have been able to prevent these tube stresses through use of manual actions, although this was not a credited action in the Fire Protection procedures for this scenario. The team concluded the issue was of very low safety significance (Green).

Enforcement: Title 10 CFR Part 50, Appendix R, Section III.L.2.d states, in part, that the process monitoring function for the alternative shutdown capability shall be capable of providing direct readings of the process variables necessary to perform and control the alternative shutdown.

Contrary to the above, the licensee did not provide SG level and pressure indication that was required for the alternative shutdown scenario for the control room or cable spreading room fire. The licensee entered the issue into its CAP as CR 03-01648. Because this violation was of very low safety significance and because it was entered into the licensee’s CAP, the violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000346/2003010-26)

.2 Supporting Functions for Alternative Shutdown Capability

Introduction: The team identified a Non-Cited violation of 10 CFR Part 50, Appendix R, Section III.L.2.e having very low safety significance. Specifically, the licensee failed to provide the process cooling and lubrication necessary to permit the operation of the equipment used for safe shutdown functions. The licensee entered the issue into its corrective action program and performed a modification to resolve the issue. The primary cause of this violation was related to the cross-cutting area of problem identification and resolution because the licensee had previously identified this issue as an enhancement and did not recognize that it was a violation of regulatory requirements.

Description: During a control room fire scenario, the governing procedure, DB-OP-02519, “Serious Control Room Fire,” could not have been performed as written. During this scenario, the procedure directed the operator to restore containment cooling by resetting the #1 and #3 CACs. However, because of a modification to the control circuitry of these CACs, the reset button on the outside of the CAC switchgear cabinet was rendered non-functional.

Since the CACs were needed to ensure an acceptable containment atmosphere, without them the potential existed that Appendix R credited equipment might not be functional during a control room fire scenario due to heightened temperatures in the containment. However, since the heatup in the containment was not instantaneous and since the equipment would have to be subject to the heightened temperatures for a relatively long period of time, the team considered it unlikely that the plant would have progressed to an unrecoverable condition prior to the operators being able to recover containment cooling. The licensee implemented a modification (ECR 03-0243-00) that rewired the control circuitry for CAC fan 1-1 such that, in the case of a control room fire, this fan could be started in slow speed to provide cooling to the containment.

Analysis: The team determined that a performance deficiency existed because the licensee failed to provide containment air cooling for alternative shutdown. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because, if left uncorrected, the finding would become a more significant safety concern. By not providing containment air cooling as per the governing alternative shutdown procedure, the probability of the failure of equipment relied upon for safe shutdown was increased. The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process." The team assessed the finding through Phase 1 of the reactor safety mitigating systems SDP. This issue was screened to be of very low safety significance (Green) because there was not a total loss of safety function for an assumed control room fire with evacuation. This was evaluated using the transient without the secondary steam plant (TPCS) Phase 2 worksheet. Within the Phase 2 TPCS worksheet, the CAC supports the feed and bleed operation of the power operated relief valve (PORV) for decay heat removal if the SGs are not available. Given this fire scenario, the PORV block valve would be closed by procedure and the PORV not used, so there was no effect on a safety function.

Enforcement: Title 10 CFR Part 50, Appendix R, Section III.L.2.e, states, in part, that supporting functions shall be capable of providing the process cooling, lubrication, etc., necessary to permit the operation of the equipment used for alternative safe shutdown functions.

Contrary to the above, the licensee did not adequately provide containment air cooling, because the governing procedure did not reflect a recent modification that disabled the Appendix R reset buttons for the #1 and #3 CACs. The CACs were required to support operation of Appendix R equipment credited equipment. The licensee entered the issue into its CAP as CR 03-02699 and 03-04341. Because this violation was of very low safety significance and because it was entered into the licensee's CAP, the violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000346/2003010-27)

.3 Emergency Diesel Generator Floor Drains Design Deficiency

Introduction: The team identified a NCV of 10 CFR Part 50.48(a)(1), having very low safety significance (Green). Specifically, the licensee failed to evaluate the adequacy of EDG common floor drains following sprinkler system actuation in the fire affected EDG room. Following discovery, the licensee entered the issue into its corrective action process and revised the fire response procedures to address the issue.

Description: The team determined that the floor drains between the two EDG rooms were common, and that they had insufficient drainage capacity. Preliminary calculations by the licensee showed that the drains had a maximum capacity of 100 gpm, whereas the sprinkler system actuation resulted in 303 gpm in Room 318, and 286 gpm in Room 319.

Terminal blocks in both EDG control cabinets were located approximately seven inches above floor level. The common drain lines between the EDG rooms would have allowed suppression system water from a fire in one EDG room to enter and affect the integrity of the redundant EDG room. As a consequence of a fire in one EDG room with sprinkler system actuation, water would have backed up in both EDG rooms and would have increased above the elevation of the terminal blocks within approximately 30 minutes. Furthermore, no operator or fire brigade instructions were in place to facilitate drainage by opening of the doors to prevent equipment submergence. The licensee initiated CRs 03-02577, 03-06901, and 03-07256 to document, evaluate, and disposition these deficiencies in their CAP. As part of the corrective action, the licensee revised pre-fire plans AB-318 and AB-319 to provide compensatory measures to prevent flooding of the EDG rooms.

Analysis: The team determined that a performance deficiency existed because the licensee failed to evaluate the adequacy of EDG common floor drains following sprinkler system actuation. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because the finding affected the mitigating system cornerstone. This was a design deficiency that was confirmed not to result in the loss of function per Generic Letter 91-18, Revision 1. The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process," and determined that the issue was of very low safety significance (Green).

Enforcement: Title 10 CFR 50.48(a)(1) requires, in part, that each operating nuclear power plant have a fire protection plan that satisfies Criterion III of 10 CFR Part 50, Appendix A. Criterion III, requires, in part, that fire-fighting systems shall be designed to assure that their rupture or inadvertent operation does not significantly impair the safety capability of these structures, systems, and components.

Contrary to the above, because the EDG common floor drains were not evaluated by the licensee, nor verified for adequacy following sprinkler system actuation, the potential existed for an inadvertent sprinkler system actuation or rupture to adversely affect the capability of the EDGs to perform their safety function. The licensee entered this issue into its CAP as CRs 03-02577, 03-06901, and 03-07256. Because this violation was of very low safety significance and because it was entered into the licensee's CAP, the violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000346/2003010-28)

(6) Review of Licensee Event Reports

a. Inspection Scope

The team reviewed the licensee's CAP to identify and address problems previously identified and documented in licensee event reports.

b. Findings

.1 (Discussed) LER 05000346/2002-008-00 and -01: Containment Air Coolers Collective Significance of Degraded Conditions

Introduction: The team reviewed this LER which related to the operability of the CACs during previous operating cycles.

Description: Following unit shutdown in 2002, various degraded conditions were identified associated with the CACs, which were documented in several CRs. The issues were related to thermal performance degradation, and structural issues (CR 02-05563) related to seismic adequacy, boric acid corrosion, and post accident thermal stress. Thermal performance issues caused by cooling coil fouling conditions on the air (cooling fin) side, and water (inside tube) side were identified. Additionally, foreign material (plywood) was found in the SW supply piping to CAC # 2. In addition, two 10 CFR Part 21 reports were issued by the CAC control vendor and the motor vendor. The overall corrective action to resolve the physical degradation of the CAC units was the refurbishment of the units prior to plant restart. New CAC units were installed.

An engineering evaluation was performed to assess the effects of the degraded conditions on heat transfer capability from which past operability was determined. The licensee concluded that the effects of the degraded conditions (including foreign material in the cooling water line) on heat transfer capability of the CACs, when operating in conjunction with the CS system, would not have rendered the CACs inoperable with respect to the long term post-accident containment heat removal capability. These evaluations included containment pressure reduction, increased sump temperature effects on ECCS pumps NPSH, ECCS pump room heatup, equipment environmental qualification, and radiological release. A NCV was identified in Section 4OA3(3)b.3, for failure to implement effective design control measures to check and verify the adequacy of the design basis calculation performed for offsite dose consequences of degraded CACs.

The licensee performed an engineering evaluation of the structural issues and concluded that the issues resulted in a degraded condition, but the CACs were not rendered inoperable. The licensee stated that, while corrosion and pitting were observed, the "as found" condition would not have been sufficiently degraded to prevent the CACs from performing as seismically designed.

The licensee determined that the station had no safety related parts applicable to the 10 CFR Part 21 notification made by the controls vendor. At the time of receipt of the Part 21 notification from the motor vendor, the licensee stated that the plant was in Mode 6 and the CAC motors were being refurbished as part of the overall CAC refurbishment. The notification reported a deficiency with a stator winding, which could result in motor winding failure. According to the licensee, no winding failures or anomalies were experienced during fan operation.

During review of the LER, the team identified several concerns with the licensee's evaluation. For example:

- The licensee stated in the LER that "Since the service conditions for CACs #1 and #2 are similar to CAC #3, the degraded conditions on CAC #3 were considered to be representative of the other CAC cooling coils." However, the team determined that the #3 CAC was normally in standby, with CACs 1 and 2 being in operation. Therefore, the team could not agree that the condition in CAC 3 was representative of the condition of the other two CACs.

- The licensee noted that "a piece of plywood measuring approximately 5 inches by 7 inches was discovered in the 8-inch diameter supply line upstream of the transition to two 6-inch pipes, each of which supplies SW to one of two independent cooling coil manifolds." The licensee stated that the presence of the plywood was believed to be an isolated condition that occurred during RFO 12 in 2000. However, the licensee did not provide any information as to work performed during RFO 12 which would have resulted in leaving a piece of plywood behind. The licensee also noted that there were no intervening pipe fittings or valves between the as-found location of the foreign material and the two 6-inch transitions; however, the licensee did not provide any further justification why the SW flow to this CAC would not be disrupted during a design basis event.

- In the thermal performance analysis section the licensee stated that, "Air side degradation consisted of boric acid residue and dirt which may impede the heat transfer characteristic of the cooling fins." However, in the preceding section on structural issues, the air side was characterized as having "moderate to severe corrosion" and noted that "corrosion and pitting" were observed. The licensee did not explain why the two sections differed, much less explain difference in heat transfer characteristic impact from "residue and dirt" to that obtained from "corrosion and pitting."

- The LER also stated that, "operation of the CAC units was directly into high fan speed for normal operation." This statement did not address the fact that during response to an accident, the two operating fans would shift from high to low speed. Shifting from high to low speed was one of the factors mentioned in the Part 21 report on the motors as causing motor failures. It also did not mention that the motor on the normally operating CAC 1 was replaced during a mid-cycle outage in 1999.

- The licensee's conclusion that the effects of the degraded conditions on the heat transfer capability of the CACs, when operating in conjunction with the CS system did not address the fact that the CS system was also degraded due to the previously identified sump issues.

During the review of this LER, the team identified additional issues concerning the original motor sizing calculation and the lack of thermal relief valves on the CAC SW piping inside containment as described in Sections 4OA3(3)b.3. Because of the overall deficiencies in the licensee's evaluation, especially in regard to the thermal performance issue, the team was unable to agree with the licensee's conclusion that the CACs were operable during previous cycles.

The team determined that this LER will remain open pending further review of the CAC degradation; specifically the extent of degradation and effect on the safety function of the CACs. For this particular LER, the additional reviews will provide information as to the ability of the CACs to provide cooling for the PORVs during feed and bleed operations. The LER will remain open pending resolution of this issue.

.2 (Closed) LER 05000346/2002-009-00: Degradation of the High Pressure Injection Thermal Sleeves

On November 29, 2002, with the reactor defueled, it was discovered that the thermal sleeve connected to the 2-2 HPI /makeup nozzle had an axial crack. Inspection of the 2-1 HPI/makeup thermal sleeve also revealed a cracked thermal sleeve. No cracking was observed during the inspection of the remaining two HPI thermal sleeves. The licensee reported that the nozzles with undamaged thermal sleeves had not been used for RCS makeup. The licensee determined that the axial cracks identified in the thermal sleeves did not affect the ability of the HPI system to perform its design function nor did either crack provide a source for RCS pressure boundary leakage. Furthermore, since no loss of material occurred, this condition had no impact on the integrity of the fuel cladding.

Upon discovery of the cracks in both thermal sleeves, the sleeves were removed and new ones were installed. The licensee determined that high cycle thermal fatigue was the root cause of the identified cracking. A contributing cause was the rate and oscillation of makeup flow through the primary makeup nozzle. The licensee stated that the appearance of the cracked sleeves was consistent with cases observed at other B&W plants.

The remedial action was to replace the thermal sleeves. Inservice inspection procedures were developed to ensure proper inspection techniques were used in the future to verify the integrity of the HPI/makeup thermal sleeves. The licensee stated that the visual inspections will include the use of high resolution video equipment and verification that the video equipment was applied in accordance with ASME Section XI, sub-article IWA 2210, “Visual Exam for VT-1 Examination.” The licensee stated that the frequency of inspection would be every other refueling outage. This issue was entered into the licensee’s CAP as CRs 02-09739, 02-9928, and 03-02445.

The team reviewed the licensee's corrective actions and determined them to be acceptable. No violation of regulatory requirements was identified. This item is closed.

.3 (Closed) LER 05000346/2003-003-00 and -01: Potential Inadequate High Pressure Injection Pump Minimum Recirculation Flow Following a Small Break Loss of Coolant Accident

Introduction: The team identified a NCV of 10 CFR Part 50, Appendix B, Criterion III, having very low safety significance (Green). Specifically, the licensee failed to provide for the original plant design to incorporate a safety-related recirculation path for the HPI pumps in the HPR mode of operation. Following discovery, the licensee entered the issue into its corrective action process.

Description: Following the questioning during the 2002 NRC SSDI inspection of a potential deadhead condition of the HPI pumps and the adequacy of thermal protection (minimum flow) for the pumps, the licensee performed a study, 86-5022260-00, to determine whether HPI pump operability during post-LOCA sump recirculation could be assured for all break sizes and transient scenarios.

This study identified a range of small break sizes from 0.00206 ft^2 (leak-to-LOCA transition area) to 0.0045 ft^2, which would result in RCS re-pressurization cycles that could continue following HPI pump realignment to the containment emergency sump and closure of the minimum flow recirculation valves. The study concluded that for this newly analyzed range of break sizes, past operability of the HPI pumps was a concern. This was because the re-pressurization cycles would result in a higher RCS pressure than the shut-off head of the HPI pumps, resulting in pump dead heading (no flow), when HPI pump suction was from the sump. The licensee documented this condition in CR 02-06702 and LER 05000346/2003-003. The condition existed since the original design of Davis-Besse. The NRC had previously highlighted the potential for this concern as part of Information Notice (IN) 85-94.

Based on the results of the evaluation, several corrective actions were implemented. An additional minimum flow recirculation line was installed during RFO 13 for each HPI pump. For one pump, the line tapped off the previously existing minimum flow line and for the other a completely new recirculation line was installed. For both pumps, the new lines contained two isolation valves and a non-cavitating pressure breakdown orifice and connected to the low pressure injection (LPI) pump discharge upstream of its respective decay heat cooler for the corresponding safety train. These additional recirculation lines were designed to provide the original minimum flow protection of the HPI pumps, 35 gpm, when aligned to the emergency sump in "piggyback" operation with the DHR pumps. In this lineup, the decay heat coolers would provide cooling for the respective HPI Pumps without loss of sump inventory.

Operator action would be required to open the valves on these additional recirculation lines prior to pump realignment from the BWST to the emergency sump. Because the postulated transient was a very slow developing scenario, the team determined that ample time would be available for operators to take this action. Additionally, the team confirmed that this action did not replace any existing automatic action. The licensee revised the emergency procedures to provide direction on establishing the HPI alternate minimum recirculation flowpath and provided training to the operators on its use.

These corrective actions were deemed to be sufficient to resolve the concern addressed in the LER. See Section 4OA3(3)b.1, for further discussion regarding the adequacy of the 35 gpm minimum recirculation flow.

Analysis: The team determined that a performance deficiency existed because the original design did not incorporate a safety-related recirculation path for the HPI pumps in the high pressure recirculation (HPR) mode of operation. Since there was a performance deficiency, the team compared this performance deficiency to the minor questions contained in Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports." The team concluded that the issue was more than minor because the licensee failed to provide for the original plant design to incorporate a safety-related recirculation path for the HPI pumps in the HPR mode of operation and this finding affected the mitigating systems cornerstone. The team reviewed this finding in accordance with IMC 0609, "Significance Determination Process."

The Region III SRAs, evaluated this issue within Phase 1 of the SDP. Based on the review, the SRAs determined that the HPR safety-function would not actually have been lost because of reliance on procedure actions for feed and bleed operation of the PORV in situations where the SGs could not be used to remove decay heat. Specifically, for initiating events where RCS leakage was not sufficient to remove decay heat (transients, small LOCAs) the Phase 2 SDP plant specific notebook for Davis-Besse takes credit for opening of the non-safety-related PORV to remove decay heat from the RCS. Opening of the PORV would allow sufficient HPR flow to ensure adequate minimum flow to ensure pump cooling. Therefore, the finding screened out as having very low safety significance (Green).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis were correctly translated into specifications, drawings, procedures, and instructions. Furthermore, it requires that measures be provided for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to the above, the licensee failed to provide for the original plant design to incorporate a safety-related recirculation path for the HPI pumps in the HPR mode of operation. The licensee documented this condition in CR 02-06702. These corrective actions were deemed to be sufficient to resolve the concern addressed in the LER. Since the issue was of very low safety significance and was captured in the licensee's CR, it is being treated as a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy. (NCV 05000346/2003010-29)

4OA4 Cross-Cutting Aspects of Findings

The team's findings and observations, as documented in this report, revealed numerous examples where the licensee's corrective action program exhibited implementation weaknesses and a general lack of engineering rigor in the conduct of engineering activities. These concerns further represent deficiencies relating to the cross-cutting areas of human performance and corrective actions. Specific deficiencies and concerns supporting this conclusion are documented in sections listed below.

Findings Affecting Human Performance

4OA3(2)b.2 Lack of 480 Vac Class 1E Motor Thermal Overload Protection
4OA3(3)b.6 Non-conservative Calculation Used in Design Analysis to Determine Required Service Water Makeup Flow to Component Cooling Water
4OA3(3)b.11 Service Water Discharge Path Swapover Setpoint
4OA3(3)b.12 Service Water Discharge Check Valve Test Acceptance Criteria
4OA3(3)b.14 Auxiliary Feedwater System Calculation Issues With Main Steam Safety Valves

4OA3(3)b.21 Environmental Qualification of Equipment Not Supported by Analysis
4OA3(3)b.23 Inappropriate Application of 10 CFR 50.59
4OA3(4)b Repetitive Spacer Grid Strap Damage

Findings Affecting Corrective Action Program

4OA3(2)b.3 Failure to Perform Adequate Direct Current Contactor Testing to Ensure Minimum Voltage at Motor Operated Valves
4OA3(2)b.4 Failure to Verify Adequacy of Short Circuit Protection for Direct Current Circuits
4OA3(2)b.5 Lack of Calculations to Ensure Minimum Voltage Availability at Device Terminals
4OA3(3)b.1 High Pressure Injection Pump Operation Under Long Term Minimum Flow
4OA3(3)b.2 Increased Dose Consequences Due to Degraded Thermal Performance Operation of Degraded Containment Air Coolers
4OA3(3)b.3 Containment Air Cooler Air Flow Calculation Concerns
4OA3(3)b.7 Calculation Concerns for Service Water Pump Room Ventilation System
4OA3(3)b.11 Service Water Discharge Path Swapover Setpoint
4OA3(3)b.12 Service Water Discharge Check Valve Test Acceptance Criteria
4OA3(3)b.13 Lack of Design Basis Calculations to Support Service Water Single Failure Assumptions
4OA3(3)b.15 Auxiliary Feedwater Strainer Mesh Size and Preconditioning of Auxiliary Feedwater System During Testing
4OA3(3)b.19 Inadequate Evaluation of Reactor Coolant Pump Casing-to-cover Stud Overstressing
4OA3(4)b Repetitive Spacer Grid Strap Damage
4OA3.(5)b.1 Process Monitoring Function for Alternative Shutdown Capability
4OA3.(5)b.2 Supporting Functions for Alternative Shutdown Capability

4OA5 Other Activities

(1) Assessment of the Licensee's Corrective Actions to Address Previously Identified Findings Documented in NRC Reports

a. Inspection Scope

The team conducted a review of previously identified items to determine effectiveness of identification, evaluation and resolution of issues.

b. Findings

.1 Follow up on Findings Documented in Report 05000346/2002012

.1 (Closed) URI 05000346/2002012-02: Potential Impact of Corrosion on the Ground Function of Electrical Conduit in Containment

During a previous inspection conducted in October 2002, the NRC team noted that corrosion appeared to be particularly concentrated in areas where moisture and boric acid from the containment atmosphere had condensed and dripped onto electrical components. In particular, the NRC team noted substantial corrosion and deposits of crystallized boric acid on conduits. Based on this observation, the NRC team identified a concern that boric acid corrosion of conduit may create a high electrical resistence and challenge the ground function of the electrical conduit.

This condition was documented by the licensee in CR 02-06788. The CR described a condition where boric acid corrosion of conduits in the containment could inhibit the flow of ground fault currents through the conduits (conduits provide a supplementary grounding path for smaller motors).

The cause analysis for CR 02-06788 determined that, as a general rule, up to 50 percent loss of conduit cross sectional area was acceptable without loss of function as an electrical ground path. The conduits in question were determined to have only surface corrosion amounting to less than 25 percent reduction in cross sectional area and were therefore, deemed acceptable.

Subsequently, CR 03-05239 was issued stating that no loss in wall thickness was acceptable for1/2-inch and 3/4-inch conduits. Ultrasonic testing was performed to determine the wall thickness of corroded conduits; however, no decision had been made as to resolution of this issue. Following questions by the team, the licensee determined that all conduits were acceptable as-is. Based on this conclusion, the team determined that no violation of NRC requirements existed. This URI is considered closed.

.2 (Closed) URI 05000346/2002012-03: Potential Failure to Follow the Procedure for Raychem™ Splice Removal on Electrical Cables

During CAC motor replacement, the licensee identified splitting of the motor cable insulation as documented in CR 02-05459. The resolution of this issue is discussed in Section 4OA3(2)b.6. The URI is closed.

.2 Follow-up on SSDI Findings Documented in Report 05000346/2002014

.1 (Discussed) NCV 05000346/2002014-01a: Lack of a Design Basis Analysis for Containment Isolation Valve Backup Air Supplies

This violation was written to document an issue regarding the CAC outlet SW valves reliance on the availability of the non-seismic instrument air system to maintain pressure on the air operated valves so that they could perform their containment isolation function to remain closed. The resolution of this issue is discussed in Section 4OA3(3)b.4.

.2 (Discussed) NCV 05000346/2002014-01b: Inadequate Blowdown Provisions for Containment Air Cooler Backup Air Accumulators

This violation was written to document that there was no provisions to blow down the CACs to remove excessive moisture as required by the USAR. The acceptability of the corrective actions to this issue is discussed in Section 4OA3(3)b.5.

.3 (Closed) URI 05000346/2002014-01c: Failure to Perform Comprehensive Moderate Energy Line Break Analysis

This item dealt with the licensee's failure to perform a comprehensive moderate energy line break analysis. The resolution of this issue is discussed in Section 4OA3(3)b.24. The URI is closed.

.4 (Closed) URI 05000346/2002014-01d: Lifting of Service Water Relief Valves

This URI dealt with a continuing operating condition when the relief valves on the tube (SW) side of the CCW heat exchangers would open when the licensee changed which pump was operating under low flow conditions such as winter operation with low heat loads. The licensee resolved the problem of inadvertent openings by changing the operating procedures. The team concluded that relief valve lifting was not a concern during a design basis event because there would be an increased heat load. This would prevent the underlying pressure surge from occurring. No violation of NRC requirements was identified. This item is closed.

.5 (Closed) URI 05000346/2002014-01e: Inadequate Service Water Pump Room Temperature Analysis

This URI concerned non-conservatisms in the analysis which analyzed the heat loads in the SW pump room and the ability of the ventilation system to maintain the pump room temperatures within a required operating range. The resolution of this issue is discussed in Section 4OA3(3)b.7. The URI is closed.

.6 (Closed) URI 05000346/2002014-01f: Inadequate Service Water Pump Room Steam Line Break Analysis

This item dealt with the effects of a postulated auxiliary steam line break in the SW pump room and whether the licensee correctly translated the USAR commitments regarding the SW pump room environmental limits into analyses that demonstrated these limits would not be violated for design basis conditions. This issue is discussed in Section 4OA3(3)b.7. The URI is closed.

.7 (Closed) URI 05000346/2002014-01g: Inadequate Cable Ampacity Analysis

On September 24, 2002, the licensee issued CR 02-06893 to document an increase from 95°F to 124°F in Rooms 105 and 115 temperature as a result of an increase of SW temperature. The CR identified the need to reevaluate cable ampacity as a result of the higher room temperature. The team discussed the ampacity issue with the licensee, and determined there actually was not an ampacity concern. Therefore, this item is considered closed.

.8 (Closed) URI 05000346/2002014-01h: Inadequate Flooding Protection for Service Water Pump House

This URI dealt with deficiencies in correctly implementing USAR commitments regarding flood protection for the SW pump room. The resolution of this issue is discussed in Section 4OA3(3)b.9. The URI is closed.

.9 (Discussed) NCV 05000346/2002014-01i: Non-conservative Technical Specification Value for 90 Percent Undervoltage Relays

The licensee initiated CR 02-07766 to address the issue that the trip set point specified in calculation C-EE-004.01-049 was greater than the TS allowable value shown in Table 3.3-4. Therefore, the postulated TS allowable value could be violated for plant operating conditions where the voltage was just above the relay set point value. The team reviewed the issue and determined that the new calculation, C-EE-015.03-008, which utilized the ETAP program, properly addressed all issues included in the CR. Therefore, the corrective actions to this issue were deemed acceptable. Another issue related to allowable values is discussed in Section 4OA3(2)b.1.

.10 (Closed) URI 05000346/2002014-01j: Poor Quality Calculation for 90 Percent Undervoltage Relays

The licensee entered the issue into its CAP as CR 02-07633 which subsequently was rolled over to CR 02-07646. In order to resolve the concern, the licensee performed a new calculation, C-EE-015.03-008, to address this and other electrical issues. Review of the calculation is discussed in Sections 4OA3(2)b.7 and 4OA5(1)b.2.11. This item is closed.

.11 (Discussed) NCV 05000346/2002014-01k: Non-conservative Relay Setpoint Calculation for the 59 Percent Undervoltage Relays

The licensee initiated CR 02-06737 and CR 02-07646 to evaluate issues affecting the relay uncertainty in calculation C-EE-004.01.051. The postulated inconsistencies could have rendered the operation of the 59 percent relay inconsistent with requirements for continuous operation under-voltage transient conditions imposed by the motor inrush current.

The team reviewed CR 02-07646 and determined that calculation C-EE-015.03-008, which used the ETAP program described in Section 4OA3(2)b.7, had properly addressed the postulated inconsistencies and non-conservative assumptions in the uncertainty analysis. Therefore, the corrective actions to this issue were deemed acceptable.

.12 (Closed) URI 05000346/2002014-01l: Inadequate Calculations for Control Room Operator Dose (GDC-19) and Offsite Dose (10 CFR Part 100) Related to High Pressure Injection Pump Minimum Flow Values

This URI addressed concerns with the dose calculations for operators and the general public following a design basis accident. The resolution of this issue is discussed in Section 4OA3(3)b.18. The URI is closed.

.13 (Closed) URI 05000346/2002014-01m: Other GDC-19 and 10 CFR Part 100 Issues

This URI addressed concerns with the dose calculations for operators and the general public following a design basis accident. The resolution of this issue is discussed in Section 4OA3(3)b.18. The URI is closed.

.14 (Closed) URI 05000346/2002014-01n: High Pressure Injection Pump Operation Under Long Term Minimum Flow

This item dealt with the ability of the HPI pumps to perform as intended during extended operation on minimum flow. This issue is discussed in Sections 4OA3(3)b.1 and 4OA3(6)b.2. This URI is closed.

.15 (Closed) URI 05000346/2002014-01o: Some Small Break Loss of Coolant Accident Sizes Not Analyzed

This URI addressed concerns with the HPI pump potentially not having a flow path upon the suction being switched from the BWST to the sump. This issue is discussed in Section 4OA3(6)b.3. This URI is closed.

.16 (Closed) URI 05000346/2002014-01p: Inadequate Service Water System Flow Analyses

This URI dealt with deficiencies in the assumptions used in SW system flow calculations. The resolution of this issue is discussed in Section 4OA3(3)b.8. The URI is closed.

.17 (Closed) URI 05000346/2002014-01q: Inadequate Service Water System Thermal Analyses

This URI dealt with deficiencies in the maximum temperatures used in SW system and ultimate heat sink calculations. The resolution of this issue is discussed in Sections 4OA3(3)b.8 and 4OA3(3)b.13. The URI is closed.

.18 (Closed) URI 05000346/2002014-01r: Inadequate Ultimate Heat Sink Inventory Analysis

This URI dealt with deficiencies in the SW system flow and ultimate heat sink minimum level calculations. The resolution of this issue is discussed in Sections 4OA3(3)b.8 and 4OA3(3)b.13. The URI is closed.

.19 (Closed) URI 05000346/2002014-01s: No Valid Service Water Pump Net Positive Suction Head Analysis

This URI dealt with the licensee not having a calculation which showed that the SW pumps had adequate NPSH under all operating conditions. The resolution of this issue is discussed in Section 4OA3(3)b.8. The URI is closed.

.20 (Closed) URI 05000346/2002014-01t: Service Water Source Temperature Analysis for Auxiliary Feedwater

This item dealt with SW source for AFW which had not been analyzed with respect to its potentially higher temperature condition for various design basis events and the possible impact on the ability of the AFW system to perform its safety function. Such effects could include reduced heat absorption capability for AFW injected into the SGs and inadequate cooling of AFW lubricating oil. The licensee's evaluation concluded that temperature of AFW (seismic event with long term AFW supplied by SW) was lower than the design AFW temperature of 120°F as noted in the system description. In addition, the licensee determined that AFW equipment temperature limits were greater than 120°F. Therefore, the licensee concluded that there was no discrepant condition. The team agreed with this assessment. This URI is closed.

.21 (Closed) URI 05000346/2002014-01u: Inadequate Short Circuit Calculations

This URI was written to document that the licensee had not considered the worst case grid voltage. The resolution of this issue is discussed in Section 4OA3(2)b.8. The URI is closed.

.22 (Discussed) NCV 05000346/2002014-01v: No Analytical Basis for Setpoint to Swap Service Water System Discharge Path

There was no analytical basis for the setpoint used to swap the SW system discharge path from the normally used, but non-seismic lines, to a seismically qualified path. The setpoint for the swapover was 50 psig; however, there was no calculational bases for this setpoint. The acceptability of the corrective actions to this issue is discussed in Section 4OA3(3)b.11.

.23 (Discussed) NCV 05000346/2002014-02a: Service Water Surveillance Test Did Not Use Worst Case Values

This violation addressed the fact that a surveillance test did not demonstrate that worst-case post-accident conditions were bounded for the CAC discharge valves in the SW system.

The licensee was replacing these valves, due to a number of problems with them. The proposed corrective actions appeared to include appropriate acceptance criteria. The team identified a concern with the original evaluation and corrective action wording in CR 02-07781. The NCV writeup mentioned that the licensee's procedure did not declare the valves inoperable and write a CR if the valves failed the valve closure test. This issue was not originally addressed in the licensee's corrective actions. However, when it was brought to the licensee's attention, appropriate changes were made in the procedure to address declaring the valve inoperable and writing CRs when necessary. In responding to a team request for supporting calculations, the licensee also noted that a corrective action for the CR 02-07781 was closed prior to a calculation being reviewed and approved. Other examples where corrective actions were closed prior to the calculations being approved are discussed in Sections 4OA3(3)b.17 and 4OA3(3)b.19.

.24 (Closed) URI 05000346/2002014-02b: Inadequate Service Water Flow Balance Testing

This URI was written to document concerns with the flow balance testing for the SW system. The resolution of this issue is discussed in Section 4OA3(2)b.10. This URI is closed.

.25 (Closed) URI 05000346/2002014-03a: Inappropriate Service Water Pump Curve Allowable Degradation

In the 2002 NRC SSDI, the team identified an item associated with prompt corrective action to resolve a the licensee identified condition where the allowable degradation of the SW pumps did not match the design basis required flow rate for the SW pumps. In particular, the pump curve was allowed to degrade by 7 percent in accordance with IST acceptance criteria, without evaluating the required design basis flow requirement. Vendor calculations 02-123 and 02-113 were performed to address all SW hydraulic issues. The allowable SW pump degradation was included in the new calculations. The team did not identify any violation. This URI is closed.

.26 (Closed) URI 05000346/2002014-03b: Repetitive Failures of Service Water Relief Valves

This URI, URI 02-14-01d, and URI 02-14-06 all dealt with a continuing operating condition where the relief valves on the tube (SW) side of the CCW heat exchangers were opening under routine operating conditions, were failing due to the frequent opening, and to the licensee's stated plans to resolve the problem by removal of the valves from the system, contrary to the requirements of the ASME Code.

At the time of the inspection, the licensee had not yet removed the relief valves; therefore, the issues raised by the URI still existed. The licensee had taken a number of actions to reduce the frequency of undesired relief valve openings, primarily through changes in the operating procedures. The licensee stated that these procedural changes greatly decreased the times that the valves opened unexpectedly. The reduction in inadvertent openings also resulted in a reduction of valve failures.

The team considered The licensee's plans to remove the relief valves to be inappropriate as the team did not believe the ASME Code allowed for the valves to be removed. The team reviewed the applicable sections of both ASME Section III (the Code section applicable to the SW piping) and ASME Section VIII (the Code section under which the heat exchangers were purchased). Both sections clearly indicated that overpressure protection was required for any piping where heat was being introduced into the system. As the SW system was the cooling mechanism for the CCW heat exchangers, heat was being introduced into the system, and overpressure protection was required. The team also noted that the licensee had manual valves downstream of the relief valves on the CCW heat exchangers; another area which was not in strict compliance with the Code. Subsequent to the inspection, the licensee informed the team that a decision had not been made to replace the subject valves. Since the licensee has not removed the valves from service, this URI is closed.

The issues regarding URI 50-345/2002014-06 will be addressed in a separate report.

.27 (Closed) URI 05000346/2002014-03c: Non-conservative Difference in Ultimate Heat Sink Temperature Measurements

This URI dealt with a potential non-conservative temperature measurement for ultimate heat sink temperatures. The concern was that the temperature instrument used to measure the ultimate heat sink temperature might not be the most conservative and might contain up to 2°F of error, which was not accounted for in the SW design basis calculations.

The licensee performed a test which measured the temperature of the ultimate heat sink in two different locations – the normal input for the computer point, and a second one which had been reading higher during the October inspection – using sensitive, calibrated measuring and test equipment. Based on this test, the licensee determined that the two locations were reading the same temperature, at least at the time of the test. The licensee also noted that the normal temperature instrument had a much tighter accuracy band (0.75°F) as compared to the other instrument (3°F) such that, even if the second instrument appeared to be reading higher, it might actually be below the actual ultimate heat sink temperature.

The team determined that the licensee's procedures had been revised to incorporate the temperature instrument's uncertainty calculation results into them, and that the procedures required the plant to take appropriate actions should it appear that the ultimate heat sink temperature was being approached (such as measuring the temperature locally with sensitive measuring and test equipment). Therefore, the team determined that no violation existed. This URI is closed.

.28 (Discussed) NCV 05000346/2002014-03d: Inadequate Corrective Actions Related to Service Water Pump Discharge Check Valve Acceptance Criteria

This violation addressed an inadequate corrective action in that the acceptance criterion for the inservice full flow test for the SW pump discharge check valves was determined to be non-conservative, was corrected, and the new value was still not the full design flow rate. The acceptability of the corrective actions to this issue is discussed in Section 4OA3(2)b.12.

.29 (Closed) URI 05000346/2002014-03e: Non-conservative Containment Air Cooler Mechanical Stress Analysis

This item dealt with overestimation of nozzle flexibility by a factor of one thousand when analyzing the connection of the SW system to the CACs. This item was also briefly discussed in the section for LER 05000346/2002-008-00 and -01.

Stress analyses concluded that the CACs were operable in the past regarding structural concerns identified in CR 02-05563. The structural report concluded that, "...Based on the lack of significance or the continued structural acceptability identified with the numerous finding associated with the CAC coil modules and their support structure, the CAC operability assessment is considered to be unaffected by the composite findings of all currently identified, structural-related CAC concerns." The team determined that the licensee appropriately used ASME Code F stress criteria in the structural analysis. This item is closed.

.30 (Discussed) NCV 05000346/2002014-04: Failure to Perform Technical Specification Surveillance for High Pressure Injection Pump Following Maintenance

This item dealt with the failure to perform a surveillance in accordance with TS 4.5.2.H for HPI pump following maintenance. This TS could not be directly verified by test since system pressure could not be easily held at 400 pounds per square inch, absolute during full HPI injection. The licensee requested a TS amendment (No. 256) to relocate the surveillance requirement pertaining to flow balance testing of the HPI and LPI subsystems following system modifications to the technical requirement manual. Also, the amendment added ECCS pump operability conditions to the TS. The new surveillance requirement would require verifying each ECCS pump's developed head to be greater than or equal to the required developed head, when tested pursuant to TS 4.0.5 with regards to inservice testing requirements of the ASME Code. The team had no further concerns and did not identify other new issues.

.31 (Closed) URI 05000346/2002014-05: Question Regarding Definition of a Passive Failure

This URI dealt with the question on whether stem-to-disc separation of SW valve SW-82 was credible and whether stem-to-disc separation was required to be assumed as part of a passive failure analysis. The team determined that valve SW82 was a butterfly valve. Even if stem-to-disc separation occurred, it was extremely unlikely that flow would be blocked. Therefore, the team determined that this failure mode was not credible and did not need to be considered as part of a passive failure analysis. As discussed in Sections 4OA3(3)b.11 and 4OA3(3)b.13, the team identified other concerns with the licensee's consideration of passive failure assumptions; these concerns are addressed separately. This URI is closed.

.3 Follow-up on SSDI Findings Documented in Report 05000346/2002019

(Closed) URI 05000346/2002019-031: Final Evaluation of Apparent Cause Evaluation for LER 05000346/2002-006-00

This URI was opened to track the licensee's resolution of the issues identified in LER 05000346/2002-006 on EDG exhaust stack tornado protection. This issue is discussed in Section 4OA3(3)b.23, of this report. This URI is closed.

.4 Follow up on Augmented Inspection Team Findings Documented in the Cover Letter of Report 05000346/2003016

In the cover letter of IR 05000346/2003016, a number of URIs identified in IR 05000346/2002008 were converted from URIs to apparent violations (AVs). The numbering of the individual items remained the same. The team reviewed the status of each of the AVs, as documented below.

.1 (Discussed) AV 05000346/2003016-01: Technical Specification Reactor Coolant System Pressure Boundary Leakage

Introduction: The NRC team examined corrective actions for an AV of the Davis-Besse TS associated with operation of the plant with pressure boundary leakage from through-wall cracks in the RCS.

Description: The team determined that this AV was a product of the licensee's cultural and programmatic breakdowns. Operation with pressure boundary leakage beyond the TS action statement was a direct result of the licensee's failure to identify the control rod drive mechanism leakage. The cultural issues involved the failure to take appropriate corrective actions, to follow procedures, and to have appropriate procedures; issues that were identified in the subsequent findings of the AIT follow-up report. The specific programmatic issues were identified in LER 05000346/2002-002-00 as an inadequate BACC program and inadequate implementation of the ISI program.

Corrective actions for the cultural failures were addressed by globally by the licensee's management and human performance improvement plan and the program compliance plan. Corrective actions for the failure to take appropriate action were specified under CR 02-00891 and directed a complete overhaul and re-institution of the CAP. The NRC's assessment of the effectiveness of those actions is discussed in Sections 4OA2 and 4OA3 of this report.

Corrective action for the inadequate BACC program is discussed below in Section 4OA5(1)b.4.8. Inadequate implementation of the ISI program was addressed through licensee self-assessment 2002-081 and a Phase 2 program review by the project review committee (PRC).

Analysis: This issue represented a licensee performance deficiency because the licensee had multiple opportunities over a period of years to identify the leakage; consequently it was considered a finding. This finding was of more than minor safety significance because the RCPB and resultant cavity in the reactor vessel head represented a loss of the design basis barrier integrity. Two cornerstones were impacted by this issue. The barrier integrity cornerstone was affected because the through-wall CRDM cracks compromised the RCPB and the initiating events cornerstone was impacted because cracking of the CRDM nozzles resulted in an increase in the likelihood of a LOCA.

Enforcement: Davis-Besse TS, "Limiting Condition for Operation for Reactor Coolant System Operational Leakage," Paragraph 3.4.6.2, stated, in part, that RCS leakage shall be limited to no pressure boundary leakage, and that with any pressure boundary leakage, the unit was to be in cold shutdown within 36 hours. This issue was properly addressed by the licensee's CAP; however, corrective actions were only one of the inputs into the final characterization and resolution of this item. The NRC's investigation into the cause of this AV, which was referred to the Office of Investigations (OI), is still ongoing. The results of that investigation will be factored into the final enforcement deliberations. As a result, this item remains open.

.2 (Discussed) AV 05000346/2003016-02: Reactor Vessel Head Boric Acid Deposits

Introduction: The NRC team examined corrective actions for three AVs involving failure to take appropriate corrective actions for continuing or recurrent deficiencies associated with boric acid deposits on the reactor vessel head, boric acid deposits on the CACs, and clogging of radiation element filters.

Description: The team determined that these AVs were a product of the licensee's cultural and programmatic breakdowns. To understand the licensee's approach to correcting these problems, the team examined the licensee's root cause analysis report on failure to identify significant degradation of the reactor pressure vessel head. The causal factors for these issues were addressed in the root cause report and included:

- Less than adequate safety focus;
- Less than adequate implementation of the CAP; and
- No safety analysis performed for the existing condition.

Corrective actions for the cultural failure associated with the inadequate safety focus were addressed by globally by the licensee's management and human performance improvement plan and the program compliance plan. These were spelled out as corrective actions to CR 02-00891. Among the corrective actions for these safety culture issues were:

- Corrective Action 22: Development of a management field presence/involvement plan to improve management oversight;
- Corrective Action 41: Formal assessment of the safety conscious work environment at the plant based on criteria and attributes derived from NRC policy and guidance;
- Corrective Action 42: Changes in corporate and plant senior management;
- Corrective Action 45: Development of a management monitoring process to monitor and trend the performance of specific management oversight activities;
- Corrective Action 46: Case study training for site personnel to include how the event happened, what barriers broke down, and what must be different in the future;

- Corrective Action 74: Realignment of management incentives to place more reward for safety and safe operation of the station; and

- Corrective Action 75: Establish corporate-wide policy emphasizing the station's industrial and nuclear safety philosophy.

Corrective actions for the failure to properly implement the CAP or to perform requisite safety analyses were specified under CR 02-00891. These directed a complete overhaul and re-institution of the CAP. To ensure that safety analyses were performed as needed, corporate standards for analyses of safety issues were established and the use of a safety precedence sequence for root cause analyses was mandated. This was confirmed by the team and considered adequate.

The root cause report also identified other, more discrete, issues associated with these AVs. These included:

- Addressing symptoms rather than causes;

- Performing less than adequate cause determinations; and

- Having less than adequate corrective actions.

These were also addressed through corrective actions associated with CR 02-00891. Some of the corrective actions included a case study of this event with an emphasis on the need to find and address the causes of adverse conditions and the potential consequences of failure to do so, implementation of the CARB to assess adequacy of actions and enforce higher standards for cause evaluations and corrective actions, mandating the use of formal root cause techniques coupled with independent reviews and self-assessments of cause evaluations, and improvements in effectiveness reviews with emphasis on verifying that causes have been properly addressed. These were confirmed by the team.

The NRC's assessment of the licensee's effectiveness in implementing the revised CAP and the specific actions noted above is discussed in Sections 4OA2 and 4OA3 of this report.

Analysis: This issue represented a performance deficiency because the licensee failed to properly address, either individually or collectively, the cause for the continuing accumulation of large amounts of boric acid on the reactor head, the recurrent deposition of boric acid on CAC fins, and the repeated clogging of radiation element filters. This lack of adequate corrective action on the licensee's part contributed to their failure to detect existing through-wall CRDM nozzle cracks and the reactor pressure vessel head corrosion. This finding is more than minor because it affected the initiating events cornerstone objective in that cracking of CRDM nozzles represented an increase in the likelihood of a LOCA. The barrier integrity cornerstone was also affected in that CRDM cracks resulted in leakage through the RCPB.

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion XVI, requires, in part, that conditions adverse to quality be promptly identified and corrected, commensurate with their safety significance. Criterion XVI also requires that, for significant conditions adverse to quality, the measures assure that the cause of the condition is determined and that corrective actions were taken to preclude repetition.

The team determined that the failure to properly address the continuing accumulation of large amounts of boric acid on the reactor head, the recurrent deposition of boric acid on CAC fins, and the repeated clogging of radiation element filters, significant conditions adverse to quality, contributed to the corrosion of the reactor head. These issues have been properly addressed by the licensee's CAP; however, corrective actions were only one of the inputs into the final resolution of this item.

The NRC's investigation into the cause of this AV, which was referred to OI, is still ongoing. The results of that investigation will be factored into the final enforcement deliberations. As a result, these items remain open.

.3 <u>(Discussed) AV 05000346/2003016-03</u>: Containment Air Cooler Boric Acid Deposits

This issue is included as part of the discussion in Section 4OA5(1)b.4.2 above.

.4 <u>(Discussed) AV 05000346/2003016-04</u>: Radiation Filter Element Deposits

This issue is included as part of the discussion in Section 4OA5(1)b.4.2 above.

.5 <u>(Discussed) AV 05000346/2003016-05</u>: Service Structure Modification Delay

<u>Introduction</u>: The NRC team examined corrective actions for the licensee's failure to implement a modification that would have permitted complete inspection and cleaning of the reactor vessel head and control rod drive mechanism nozzles.

<u>Description</u>: This issue addressed the licensee's repeated deferral of the modification to install multiple access ports in the service structure to permit cleaning and inspection of the reactor head. Modification 90-0012 was initiated in March 1990 to accomplish this but was deferred twice and then canceled in 1993. The modification was reinitiated in May 1994 as 94-0025 and subsequently deferred four times before the head degradation was identified in 2002.

The licensee resolved one portion of the issue through installation of the modification. The repeated deferral was broadly addressed through the management and human performance improvement plan and the program compliance plan as part of the licensee's itinerary to improve safety culture. The specific issue of deferring modifications for economic reasons was addressed by corrective actions under CR 02-00891 for a revision to the PRC charter. The revision incorporated a requirement to include nuclear safety in the considerations when reviewing a plant modification.

<u>Analysis</u>: This issue represented a performance deficiency because the licensee failed to take corrective action (install the access port modification) for a condition adverse to quality. As of February 16, 2002, the modification had not been performed, the head had not been completely inspected, and the head had not been completely cleaned.

This lack of action on the licensee's part, contributed to their failure to detect existing through-wall CRDM nozzle cracks.

This finding is more than minor because it affected the initiating events cornerstone objective in that cracking of CRDM nozzles represented an increase in the likelihood of a LOCA. The barrier integrity cornerstone was also affected in that CRDM cracks resulted in leakage through the RCPB. Furthermore, the failure to provide for adequate inspection and cleaning of the head was a contributing factor to the head degradation.

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion XVI, requires, in part, that conditions adverse to quality be promptly identified and corrected. Criterion XVI also requires that for significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and that corrective actions were taken to preclude repetition.

The licensee failed to correct the condition identified on April 21, 1996 (inability to fully inspect the head and CRDM nozzles), in that, as of February 16, 2002, the corrective action (modification of the service structure) had not been accomplished. Although corrective actions were completed prior to the end of the inspection, corrective actions were only one of the inputs into the final characterization and resolution of this item.

The NRC's investigation into the cause of this AV, which was referred to OI, is still ongoing. The results of that investigation will be factored into the final enforcement deliberations. As a result, this item remains open.

.6 (Discussed) AV 05000346/2003016-06: Reactor Coolant System Unidentified Leakage Trend

Introduction: The NRC team examined corrective actions for a finding involving failure to follow the corrective action procedure and complete a prescribed corrective action for adverse trends in RCS unidentified leakage.

Description: This URI addressed the licensee's cancellation of a Mode 3 walkdown that was the proposed corrective action for an adverse trend in RCS unidentified leakage. Several months prior to the shutdown for the 2002 refueling outage the licensee had been examining increases in RCS leakage and as part of an extensive investigation, a walkdown of the containment while the plant was at NOP/NOT had been specified. The reason for canceling the walkdown was schedule-driven; a special Mode 3 walkdown would have delayed cooldown and entry into the lower modes required to begin refueling.

The team concluded that the root cause for this was the licensee's cultural and programmatic breakdowns. The licensee's root cause analysis report pointed to the following causal factors:

- Less than adequate safety focus;
- Less than adequate implementation of the CAP; and
- Less than adequate corrective actions.

Corrective actions for the cultural failure associated with the inadequate safety focus were addressed globally by the licensee's management and human performance improvement plan and the program compliance plan and are discussed in Section 4OA5(1)b.4.2 above. Corrective actions for the failure to properly implement the CAP were specified under CR 02-00891. These directed a complete overhaul and re-institution of the CAP. The NRC's assessment of the licensee's effectiveness in implementing the revised CAP and the specific actions noted above is discussed in Sections 4OA2 and 4OA3 of this report.

Analysis: This issue represented a the licensee performance deficiency because elimination of a key component of what was an adequate proposed corrective action rendered the proposal inadequate. Consequently, this was considered a finding because it was reflective of other corrective action deficiencies which contributed to the cavity in the reactor vessel head. This finding was of more than minor safety significance because the corrosion of the reactor head and the resulting cavity represented a significant loss of the design basis barrier integrity.

Enforcement: The licensee failed to follow the corrective action procedure and implement an effective corrective action for adverse trends in RCS unidentified leakage. Although corrective actions have now been completed, corrective actions were only one of the inputs into the final characterization and resolution of this item.

The NRC's investigation into the cause of this finding, which was referred to OI, is still ongoing. The results of that investigation will be factored into the final enforcement deliberations. As a result, this item remains open.

.7 (Discussed) AV 05000346/2003016-07: Inadequate Boric Acid Corrosion Control Program Procedure

Introduction: The NRC team examined corrective actions for the licensee's failure to have a BACC program procedure appropriate to the circumstances.

Description: The AIT follow-up inspection and the licensee's root cause report identified multiple deficiencies in the licensee's BACC program procedure which contributed to the degradation of the reactor head. As part of the licensee's program compliance plan, the BACC program procedure was completely revised and subjected to a phase 2 PRB review. The program compliance plan, the PRC review, and the revised BACC program procedure were inspected and accepted by NRC; this inspection was documented in IR 05000346-03-09;05000346-03-11.

Analysis: This issue represented a the licensee performance deficiency because the weaknesses in the procedure contributed to the failure, over a period of years, by the licensee's engineering staff to properly identify and evaluate the leaking CRDM nozzle and the expanding cavity in the reactor head. This finding is more than minor because it affected the initiating events cornerstone objective in that cracking of CRDM nozzles represented an increase in the likelihood of a LOCA. The barrier integrity cornerstone was also affected in that CRDM cracks resulted in leakage through the RCPB.

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion V, states, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings.

NG-EN-00324, "Boric Acid Corrosion Control Program," Revisions 0 through 2, were classified as a quality procedure under the licensee's procedure administrative system and were not appropriate to the circumstances in that deficiencies in the procedure contributed to the failure to detect and address corrosion of the reactor head. Although corrective actions have now been completed, corrective actions were only one of the inputs into the final characterization and resolution of this item.

The NRC's investigation into the cause of this AV, which was referred to OI, is still ongoing. The results of that investigation will be factored into the final enforcement deliberations. As a result, this item remains open.

.8 (Discussed) AV 05000346/2003016-08: Failure to Follow Boric Acid Corrosion Control Program Procedure

Introduction: The NRC team examined corrective actions for two AVs involving failure to follow the boric acid corrosion control program procedure and the corrective actions program procedure.

Description: These URIs involved failure by the licensee engineering staff to follow:

- A number of requirements of the BACC program procedure, most notably the requirement to remove all boric acid and examine the base metal underneath for signs of corrosion; and

- The guidance and examples for characterization of CRs as significant, important, routine, or non-conditions adverse to quality and, as a result, repeatedly mis-characterized the conditions on the reactor head as routine.

The team reviewed the sections of the licensee's root cause report which acknowledged these two issues, the section of the root cause report which outlined corrective actions, and the corrective action specified under CR 02-00891. To correct the failure to follow the boric acid corrosion control program procedure, the licensee developed these specific actions:

- Provide training to applicable personnel and mangers on the need to remove boric acid from components, to inspect for signs of corrosion, and to perform inspections for signs of boric acid in component internals; and

- Reinforce standards and expectations for procedure compliance and the need for work practice rigor.

These were part of the licensee's global approach to the safety culture issue as part of the management and human performance improvement plan and the program compliance plan.

In the root cause, the licensee acknowledged that CRs associated with the reactor head and other boric acid conditions were categorized as relatively low, which resulted in the use of superficial cause analysis techniques. To address this, the licensee developed two corrective actions:

- Establish and ensure that criteria for categorization of the significance of repeat equipment failures were appropriate and used by station personnel. Criteria were to be sufficient to elevate repeat problems to higher levels, which require use of more robust analyses; and

- Review existing long-standing issues for possible elevation to significant condition status, thus engaging formal root cause evaluation techniques to obtain resolution of the issues.

As part of the program compliance inspection and the corrective actions team inspection, both of these actions were verified to have been satisfactorily completed.

Analysis: This issue represented a performance deficiency because the recurrent failures, by the licensee's engineering staff, to follow the BACC program and CAP procedures resulted in the perpetuation of the CRDM nozzle leak and the development of the expanding cavity in the reactor head. This finding was of more than minor safety significance because the cavity in the reactor vessel head represented a loss of the design basis barrier integrity.

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion V states, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings.

The licensee's engineering staff failed, on multiple occasions, to adhere to both the BACC program and the CAP procedures. Although corrective actions have now been completed, corrective actions were only one of the inputs into the final characterization and resolution of this item.

The NRC's investigation into the cause of this AV, which was referred to OI, is still ongoing. The results of that investigation will be factored into the final enforcement deliberations. As a result, this item remains open.

.9 (Discussed) AV 05000346/2003016-09: Failure to Follow Corrective Action Program Procedure

This item is included as part of the discussion in Section 4OA5(1)b.4.8 above.

(2) Closure of Restart Checklist Items

.1 Restart Checklist Item 2.c: Structures, Systems, and Components Inside Containment

As part of the corrective actions resulting from the reactor vessel head degradation, the licensee established a return to service plan to identify, monitor, and control all actions necessary for the safe and reliable return to service of Davis-Besse. The plan consisted of seven building blocks designed to support safe and reliable restart of the plant and to ensure sustained performance improvements. One of the building blocks, "Containment Extent of Condition Program," was tasked with evaluating and dispositioning the extent of condition throughout the RCS and containment systems, structures, and components relative to the degradation mechanisms that occurred on the reactor vessel head.

IR 05000346/2002009 reviewed the licensee's plan for inspections, including methods, control of walkdown boundaries, resolution of obstructed examinations, and control of inspection records. Two findings of very low safety significance were identified. The first was associated with lack of acceptance criteria and the second was associated with inadequate training and certification of inspection personnel. Weaknesses were identified in the licensee's implementation of the containment inspection program.

IR 05000346/2002012 focused on evaluating corrective actions for the issues previously identified. This inspection concluded that the above issues were adequately resolved and that the inspections were effectively implemented. Three URIs associated with corrective actions for corrosion of electrical conduit, potential leakage of reactor vessel bottom head incore instrumentation penetrations, and failure to follow the procedure for Raychem™ splice removal on electrical cable were identified. Restart Checklist Item 2.c was held open pending review of these URIs.

Unresolved item 05000346/2002012-01 was discussed and closed in IR 05000346-03-23. The NRC reviewed the licensee's activities to resolve the potential leakage of reactor vessel bottom head incore instrumentation penetrations. The licensee performed chemical analysis of the deposits found on the reactor vessel sides and bottom, and in a July 30, 2003, letter to the NRC, concluded that the deposits did not result from leakage from the penetrations. Additionally, the bottom head was inspected for signs of leakage after completion of the seven day NOP/NOT leak test. This test provided reasonable assurance that the bottom head penetrations were not leaking.

Unresolved item 05000346/2002012-02 concerning corrosion of electrical conduit is discussed and closed in Section 4OA5(1)b.1.1 of this report.

Unresolved item 05000346/2002012-03 concerning removal of Raychem™ splices from electrical cable is discussed in Section 4OA3(2)b.6 and the URI is closed in Section 4OA5(1)b.1.2.

On November 18, 2003, the Davis-Besse Oversight Panel met to discuss this issue and concluded that Restart Checklist Item 2.c is closed.

.2 Restart Checklist Item 3.a: Corrective Action Program

As part of the corrective actions resulting from the reactor vessel head degradation, the licensee established a return to service plan to identify, monitor, and control all actions necessary for the safe and reliable return to service of Davis-Besse. A key element of the return to service plan was for the licensee to reestablish and reinvigorate the CAP to ensure that future conditions adverse to quality were properly identified, evaluated and corrected. The NRC performed a review of the CAP which was documented in NRC Inspection Report Nos. 50-346/02-11 and 50-346/03-09 and found the program to be acceptable. Restart Checklist item 3.a was left open following these inspections, pending completion of the CATI.

The main function of the CATI inspection, described in the report above, was to evaluate the licensee's effectiveness in correcting the deficiencies in the CAP. As noted in the previous sections of the report, the team identified numerous deficiencies still existing within the CAP. Nevertheless, the team concluded that the licensee's corrective actions were acceptable to support plant restart.

These deficiencies were discussed with the licensee during two public meetings, one on November 12, and a second on December 10, 2003. As part of these meetings, the licensee made a number of commitments to further improve the CAP as part of its Operational Improvement Plan for Cycle 14, Revision 2.

The team presented the results of this inspection to the NRC Davis-Besse Oversight Panel on February 5, 2004. The panel concluded that, based upon the licensee's improvement plans, Restart Checklist Item 3.a could be closed.

.3 <u>Restart Checklist Item 5.b</u>: Systems Readiness for Restart

As part of the corrective actions resulting from the reactor vessel head degradation, the licensee established a return to service plan to identify, monitor, and control all actions necessary for the safe and reliable return to service of Davis-Besse. One of the key elements of this return to service plan was a systematic review of a number of safety-related systems.

Concurrent with the licensee's initial evaluation of the systems, the NRC performed a SSDI as documented in IR 05000346/2002014. This inspection identified a large number of NCVs and URIs which required resolution to ensure system operability prior to restart. As part of this inspection effort, the team evaluated the adequacy of the licensee's corrective actions to address and resolve the identified deficiencies.

The team's findings and conclusions documented in this report revealed weaknesses in the licensee's implementation of corrective actions and in the engineering rigor to address and resolve identified deficiencies. Throughout the inspection, the team also made observations and reached conclusions regarding the safety significance of the identified deficiencies and ability of affected components to perform the intended design function. Concerns and issues were presented to the licensee for entry into their corrective action program and final implementation of corrective actions. The team's inspection did not reach a conclusion regarding the readiness of systems to support restart since during the team's inspection, the licensee was still in the process of returning systems to functional and operational status. Therefore, restart checklist item 5.b remains open, and will be further addressed in a separate NRC inspection report.

4OA6 Management Meetings

Exit Meeting Summary

The team presented the inspection results to Mr. L. Myers and other members of licensee management and staff at the conclusion of the inspection on September 9, 2003. The licensee acknowledged the information presented.

Per the licensee's request, on November 10, 2003, the team presented the latest inspection results, during a telephone conference, to Mr. L. Myers and other members of the licensee management and staff. The licensee acknowledged the information presented.

On January 7, 2004, the team held a telephone exit with the licensee in regard to the HPI minimum flow issue discussed in Section 4OA3(3)b.1.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
M. Bezilla, Site Vice President
B. Boles, Manager, Plant Engineering
K. Byrd, Supervisor, Design Engineering
L. Dohrmann, Manager, Performance Improvement
J. Grabnar, Manager, Design Engineering
L. Griffith, Manager, Employee Concern Program
D. Gudger, Supervisor, Regulatory Affairs
J. Hagan, Senior Vice President, FENOC
G. LeBlanc, Supervisor, Design Engineering
S. Loehlein, Manager, Nuclear Quality Assurance
W. Marini, Regulatory Interface
M. Marler, Training Manager
L. Myers, Chief Operating Officer, FENOC
K. Ostrawski, Manager, Regulatory Affairs
W. Pearce, Vice President, Oversight
J. Powers, Director, Nuclear Engineering
C. Price, Manager, Business Services
J. Rinckez, Director, Nuclear Fuel
R. Schrauder, Director, Support Services
L. Strauss, Analyst, Regulatory Affairs
J. Sturdavant, Regulatory Affairs

Nuclear Regulatory Commission
R. Gardner, Senior Project Manager, Division of Reactor Safety
J. Grobe, Chairman, Davis-Besse Oversight Panel
J. Lara, Branch Chief, Electrical Engineering Branch, Division of Reactor Safety
C. Lipa, Chief, Reactor Projects Branch 4
W. Ruland, Senior Project Manager, NRR
J. Rutkowski, Resident Inspector
S. Thomas, Senior Resident Inspector

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000346/2003010-01	VIO	Failure to Take Corrective Actions for a Previous NCV Concerning SW Discharge Path Swapover Setpoints (Section 4OA3(3)b.11)
05000346/2003010-02	VIO	Failure to Take Corrective Actions for a Previous NCV Concerning SW Pump Discharge Check Valve Acceptance Criteria (Section 4OA3(3)b.12)

Open and Closed in This Report

05000346/2003010-03	NCV	Undervoltage Time Delay Relay Setting Did Not Account For Instrument Uncertainties (Section 4OA3(2)b.1)
05000346/2003010-04	NCV	Lack of 480 Vac Class 1E Motor Thermal Overload Protection (Section 4OA3(2)b.2)
05000346/2003010-05	NCV	Failure to Perform Adequate Direct Current Contactor Testing to Ensure Minimum Voltage at Motor Operated Valves (Section 4OA3(2)b.3)
05000346/2003010-06	NCV	Failure to Verify Adequacy of Short Circuit Protection for Direct Current Circuits (Section 4OA3(2)b.4)
05000346/2003010-07	NCV	Lack of Calculations to Ensure Minimum Voltage Availability at Device Terminals (Section 4OA3(2)b.5)
05000346/2003010-08	NCV	Failure to Verify Adequacy of HPI Minimum Recirculation Line Design (Section 4OA3(3)b.1)
05000346/2003010-09	NCV	Increased Dose Consequences Due to Degraded Thermal Performance Operation of Degraded CAC (Section 4OA3(3)b.2)
05000346/2003010-10	NCV	Containment Air Cooler Air Flow Calculation Concerns (Section 4OA3(3)b.3)
05000346/2003010-11	NCV	Accumulator Sizing Calculation Errors (Section 4OA3(3)b.4)
05000346/2003010-12	NCV	Non-conservative Calculation Used in Design Analysis to Determine Required Service Water Makeup Flow to Component Cooling Water (Section 4OA3(3)b.6)
05000346/2003010-13	NCV	Calculation Concerns for Service Water Pump Room Ventilation System (Section 4OA3(3)b.7)

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED, cont

05000346/2003010-14	NCV	Inadequate Service Water System Flow Analysis (Section 4OA3(3)b.8)
05000346/2003010-15	NCV	Inadequate Flooding Protection for the Service Water System (Section 4OA3(3)b.9)
05000346/2003010-16	NCV	Inadequate Service Water System Flow Balance Testing Procedure (Section 4OA3(3)b.10)
05000346/2003010-17	NCV	Lack of Design Basis Calculations to Support Service Water Valve Single Failure Assumptions (Section 4OA3(3)b.13)
05000346/2003010-18	NCV	Auxiliary Feedwater System Calculation Issues With Main Steam Safety Valves (Section 4OA3(3)b.14)
05000346/2003010-19	NCV	Preconditioning of Auxiliary Feedwater System During Testing (Section 4OA3(3)b.15)
05000346/2003010-20	NCV	Borated Water Storage Tank Calculation Issues (Section 4OA3(3)b.18)
05000346/2003010-21	NCV	Inadequate Evaluation of Reactor Coolant Pump Casing-to-cover Stud Overstressing (Section 4OA3(3)b.19)
05000346/2003010-22	NCV	ECCS Motors Not Qualified for Service Time (Section 4OA3(3)b.21)
05000346/2003010-23	NCV	Inappropriate Application of 10 CFR 50.59 (Section 4OA3(3)b.23)
05000346/2003010-24	NCV	Failure to Perform Comprehensive Moderate Energy Line Break Analysis (Section 4OA3(3)b.24)
05000346/2003010-25	NCV	Repetitive Spacer Grid Strap Damage (Section 4OA3(4)b)
05000346/2003010-26	NCV	Process Monitoring Function for Alternative Shutdown Capability (Section 4OA3(5)b.1)
05000346/2003010-27	NCV	Supporting Functions for Alternative Shutdown Capability (Section 4OA3(5)b.2)
05000346/2003010-28	NCV	Emergency Diesel Generator Floor Drains Design Deficiency (Section 4OA3(5)b.3)

05000346/2003010-29	NCV	Failure to Provide HPI Recirculation Line (Section 4OA3(6)b.3)

Closed

05000346/2002-009-00	LER	Degradation of the High Pressure Injection Thermal Sleeves
05000346/2002012-02	URI	Potential Impact of Corrosion on the Ground Function of Electrical Conduit in Containment
05000346/2002012-03	URI	Potential Failure to Follow the Procedure for Raychem™ Splice Removal on Electrical Cables
05000346/2002014-01c	URI	Failure to Perform Comprehensive Moderate Energy Line Break Analysis
05000346/2002014-01d	URI	Lifting of Service Water Relief Valves
05000346/2002014-01e	URI	Inadequate Service Water Pump Room Temperature Analysis
05000346/2002014-01f	URI	Inadequate Service Water Pump Room Steam Line Break Analysis
05000346/2002014-01g	URI	Inadequate Cable Ampacity Analysis
05000346/2002014-01h	URI	Inadequate Flooding Protection for Service Water Pump House
05000346/2002014-01j	URI	Poor Quality Calculation for 90 Percent Undervoltage Relays
05000346/2002014-01l	URI	Inadequate Calculations for Control Room Operator Dose (GDC-19) and Offsite Dose (10 CFR Part 100) Related to High Pressure Injection (HPI) Pump Minimum Flow Values
05000346/2002014-01m	URI	Other GDC-19 and 10 CFR Part 100 Issues
05000346/2002014-01n	URI	High Pressure Injection Pump Operation Under Long Term Minimum Flow
05000346/2002014-01o	URI	Some Small Break Loss of Coolant Accident Sizes Not Analyzed
05000346/2002014-01p	URI	Inadequate Service Water System Flow Analysis

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED, cont

05000346/2002014-01q	URI	Inadequate Service Water System Thermal Analyses
05000346/2002014-01r	URI	Inadequate Ultimate Heat Sink Inventory Analysis
05000346/2002014-01s	URI	No Valid Service Water Pump Net Positive Suction Head Analysis
05000346/2002014-01t	URI	Service Water Source Temperature Analysis for Auxiliary Feedwater
05000346/2002014-01u	URI	Inadequate Short Circuit Calculations
05000346/2002014-02b	URI	Inadequate Service Water System Flow Balance Testing
05000346/2002014-03a	URI	Inappropriate Service Water Pump Curve Allowable Degradation
05000346/2002014-03b	URI	Repetitive Failures of Service Water Relief Valves
05000346/2002014-03c	URI	Non-conservative Difference in Ultimate Heat Sink Temperature Measurements
05000346/2002014-03e	URI	Non-conservative Containment Air Cooler Mechanical Stress Analysis
05000346/2002014-05	URI	Question Regarding the Definition of a Passive Failure
05000346/2002019-031	URI	Final Evaluation of Apparent Cause Evaluation for LER 05000346/2002-06-00
05000346/2003-03-00 and -01	LER	Potential Inadequate High Pressure Injection Pump Minimum Recirculation Flow Following a Small Break Loss of Coolant Accident

<u>Discussed</u>

05000346/2002-08-00 and -01	LER	Containment Air Coolers Collective Significance of Degraded Conditions
05000346/2002014-01a	NCV	Lack of a Design Basis Analysis for Containment Isolation Valve Backup Air Supplies
05000346/2002014-01b	NCV	Inadequate Blowdown Provisions for CAC Backup Air Accumulators

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED, cont

05000346/2002014-01i	NCV	Non-conservative TS Value for 90 Percent Undervoltage Relays
05000346/2002014-01k	NCV	Non-conservative Relay Setpoint Calculation for the 59 Percent Undervoltage Relays
05000346/2002014-01v	NCV	No Analytical Basis for Setpoint to Swap Service Water System Discharge Path
05000346/2002014-02a	NCV	SW Surveillance Test Did Not Use Worst Case Values
05000346/2002014-03d	NCV	Inadequate Corrective Actions Related to SW Pump Discharge Check Valve Acceptance Criteria
05000346/2002014-04	NCV	Failure to Perform TS Surveillance Requirement for HPI Pump Following Maintenance
05000346/2003016-01	AV	Reactor Operation with Pressure Boundary Leakage (URI 05000346/2002008-01)
05000346/2003016-02	AV	Reactor Vessel Head Boric Acid Deposits (URI 05000346/2002008-02)
05000346/2003016-03	AV	Containment Air Cooler Boric Acid Deposits (URI 05000346/2002008-03)
05000346/2003016-04	AV	Radiation Element Filters (URI 05000346/2002008-04)
05000346/2003016-05	AV	Service Structure Modification Delay (URI 05000346/2002008-05)
05000346/2003016-06	AV	Reactor Coolant System Unidentified Leakage Trend (URI 05000346/2002008-06)
05000346/2003016-07	AV	Inadequate Boric Acid Corrosion Control Program Procedure (URI 05000346/2002008-07)
05000346/2003016-08	AV	Failure to Follow Boric Acid Corrosion Control Program Procedure (URI 05000346/2002008-08)
05000346/2003016-09	AV	Failure to Follow Corrective Action Program Procedure (URI 05000346/2002008-09)

LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC team reviewed the documents in their entirety but rather that selected sections of portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

Bulletins

88-04; Potential Safety-Related Pump Loss; May 5, 1988

03-01; Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized-Water Reactor; June 9, 2003

Calculations

C-CSS-009.03-002; Assessment of Safety Related Structures from the Effects of Intake Structure Gantry Fall During a Tornado Event; Revision 0

C-CSS-099.20-026; Probability of Tornado Missile Damage to Davis-Besse Missile Exposed Targets; Revision 1; January 6, 2003

C-EE-002.01-010; Battery Load Profile; Revision 29; September 18, 2002

C-EE-004.01-049; 4.16 kV Bus Degraded (90 Percent Undervoltage) Relay Setpoint Relay Setting Table Bus C1; Revision 2

C-EE-004.01-049; 4.16 kV Bus Degraded (90 Percent Undervoltage) Relay Setpoint Relay Setting Table Bus D1; Revision 7

C-EE-015.03-008; Electric Transient Analysis Profile; Revisions 0 and 2

C-EE-024.01-008; Evaluation of Davis-Besse EDG Voltage Frequency Response During Design Basis LOOP/LOCA Transient Loading MPR 0200-0049-08-01; Revision 1

C-ICE-011.01-002; Service Water Flow/Pressure Indications; Revision 0

C-ICE-048.01-004; SFAS BWST Low Level Setpoint; Revision 7; April 22, 2003

C-ME-011.01-131; Service Water Relief Valve Setpoint and Capacity; Revision 0; Addendum A01

C-ME-011.01-137; Service Water Pump NPSH; Revision 0

C-ME-011.01-140; SW/CCW Makeup Line 1 HBC-35 Flow Rate; Revision 0; March 6, 2003

C-ME-011.06-007; Accumulator Sizing for Service Water Valves SW1356, SW1357 and SW1358; Revisions 0, 1, and 2

C-ME-024.02-002; Maximum Outside Temperature for EDG Operability; Revision 1; April 2, 2002

C-ME-030.01-008; Operability for Rooms 323, 324, and 325 with Loss of Normal Ventilation; Revision 0; February 4, 2003

C-ME-060.05-003; TP 850.31.01 Acceptance Criteria; Revision 0; November 13, 1986

C-ME-060.05-014; Containment Air Cooler System Fan Performance; Revision 0; September 9, 2003

C-NSA 000.00-017; PROTO-FLO Service Water System Model; December 19, 2001

C-NSA 000.00-019; GOTHIC Model Inputs for DB Primary Containment; Revision 0; February 4, 2003

C-NSA 011.01-010; Maximum Service Water Pressure to AFW System; Revision 0; April 2, 2002

C-NSA-032.02-006; ECCS Pump Room Heatup During Post LOCA; Revisions 0 and 1

C-NSA-040.01-006; TSP Volume Increase due to RCS Leakage; Revision 1; November 4, 2002

C-NSA-050.03-009; Auxiliary Feedwater Flow as a Function of Decay Heat; Revision 0

C-NSA-050.03-013; Auxiliary Feedwater System Curve; Revision 1

C-NSA-050.03-015; Auxiliary Feedwater Pump Turbine Steam Pressure Drop and Low End Pump Operation; Revisions 2 and 3

C-NSA-050.03-022; Acceptance Criteria for Auxiliary Feed Pump Quarterly Surveillance Test; Revision 2

C-NSA-050.03-023; Auxiliary Feedwater Pump Turbine Operation with Open or Broken 1½-Inch Minimum Flow Line for Modification 95-060; Revisions 0 and 1

C-NSA-059.01-019; Water Level Inside Containment Post-LOCA; Revision 2; March 28, 2003

C-NSA-060.05-008; Containment Post LOCA Response with Variable SW Temperature; Revision 3; October 20, 2001

C-NSA-060.05-010; Containment Analysis; Revision 2; February 1, 2003

E-ECS-099.16-146; Thermal Aging Effect of ECCS Room Post LOCA Temperature; Revision 0; February 26, 1992

FANP86-5024418-01 DB-1; Post-LOCA pH Analysis; Revision 1; March 19, 2003

SR-0964; Flowserve Cover Gasket Upgrade Verification for Davis-Besse Primary Coolant Pumps; Revision 1; February 3, 2003

02-113; Service Water System Design Basis Flow Analysis; Revision A

02-123; Service Water System Model Development and Benchmark; Revision B

02-124; Service Water System NPSH; Revision A

03-011; SW System Performance Following an Appendix R Event; Revision A; March 13, 2003

03-013; Service Water System Test Acceptance Criteria Correction Factors; Revision A

12501-00004; UHS Pond Thermal Performance; Revision 0

12501-M-002; LOCA and MSLB Containment Analysis with Increase of Allowable Service Water Temperature to 90 Degrees F; Revision 0; January 26, 1999

12501-M-003; ECCS Pump Room Temperatures with Initial 90 Degrees F Forebay; Revision 0; May 27, 1999

24.001; Calculated Temperature -vs.- Time in Rooms 323, 324, and 325; Revisions 1 and 3; July 24, 2003

28.003; Bechtel CAC Fan Motor; Revision 0

28.004; Containment Cooling System Pressure Drop; Revision 2; September 7, 2003

32-1171148-00; Loss of Feedwater Analysis; Revision 0

51-5023378-00; February 20, 2003

67.004; Service Water Pump Maximum Allowable Outside Air Temperature to Dissipate Entire Room Heat Load with One Ventilation Fan C99 1, 2, 3, or 4 Operable; Revision 1

67.005; Service Water Pump Room Ventilation System Capacity; Revision 4; November 20, 2002

67.007; Service Water Pump Room Ventilation System – Pressure Drop; August 30, 2002

86-5007079-00; SG Over-Pressure Protection Report; Revision 0

86-5022260-00; Determination of HPI Pump Operability During Post-LOCA Sump Recirculation For All Break Sizes And Transient Scenarios; Revision 0

86-5024418-01; DB-1 Post-LOCA pH Analysis Report; Revision 0

Condition Reports Generated as a Result of this Inspection

03-02191; Corrective Action Approval Without Supporting Documentation Finalized; March 19, 2003

03-02195; Ambiguous Description in CRA No.8 to CR 02-07646; March 19, 2003

03-02298; Failure to Generate CR for Unresolved Issues in NRC Inspection Report; March 19, 2003

03-02445; Incorrect Processing of CR 02-09928 and CR 02-0939; March 27, 2003

03-02475; Inadequate Blowdown Provisions for CAC Air Accumulators; March 28, 2003

03-02577; Appendix R Safe-Shutdown Concerns with EDG Floor Drains; April 1, 2003

03-02597; Bypassed Overload Heaters in Class 1E 480V Motors; April 2, 2003

03-02616; RFA – Bypassing Overload Heater Trips on 1E 480V Motors; April 2, 2003

03-02651; Framatome AFW Issues with MSSV; April 3, 2003

03-02654; Cable Ampacity on Containment Spray Pump Motor; April 2, 2003

03-02730; Lack of Vendor Data for High Voltage Switchgear at High Temperature; March 19, 2003

03-03184; Administrative Issues with CR 02-05640; April 25, 2003

03-03572; Lack of Coordination of Protective Devices on Bus E1 and F1; May 7, 2003

03-03891; EDG Room Heater Non-Q Yet Credited in USAR; May 19, 2003

03-03977; SW Calculations Do Not Provide Sufficient Documentation of Results; May 22, 2003

03-03979; CR 02-00891 CA-30 Operation Confidence Review Closed Out Early; May 22, 2003

03-03980; Past CAC Operability Determination Lacks Adequate Technical Justification; May 22, 2003

03-03986; Rating of the Containment Air Cooler Fan Motors; May 22, 2003

03-04010; NRC Review of SW/CCW Interface Calculation; May 22, 2003

03-04018; NRC Pointed out Discrepancy in Mode Hold Resolution for CR 02-01523; May 23, 2003

03-04035; Trending CR – Timeliness of the Evaluation of SCAQ CR 02-02943; May 22, 2003

03-04225; Response Team Communications Self-Identified During Inspection; May 28, 2003

03-04264; Non-Q Motor Loads Without Overload Heaters; May 30, 2003

03-04303; CR 03-02597 (O/L HTR Bypass) Evaluation Concerns By NRC; June 2, 2003

03-04341; Past Operability/Reportability Review of Previous CR 03-02699; dated June 3, 2003

03-04375; SR Potential Current Overloads on Load Center Breakers Feeding MCCs; June 4, 2003

03-04423; Passive Failure Assumptions; June 5, 2003

03-04435; Preliminary Davis-Besse AC System Analysis Results; June 6, 2003

03-04668; No Guidance/Criteria for a Collective Significance Review; June 13, 2003

03-04684; Isolated Occurrences of Staff Not Trained to NOP-LP-2001 Revision 4; June 13, 2003

03-05681; Inadequate Operability/Reportability Determination; July 15, 2003

03-05715; SBODG Does Not Have a Load Table; July 16, 2003

03-05739; Deficiencies in Component Evaluation for EDG Room High Temperature; July 17, 2003

03-05917; Concern Regarding Containment Spray Pump Overload Protection; July 23, 2003

03-05919; Concerns Regarding 480V Breaker Coordination for Appendix R Compliance; July 23, 2003

03-05920; Basis Not Defined for all the Appendix R DC and 120 Vac Circuits; July 23, 2003

03-06153; Timeliness of Changes to the USAR; July 31, 2003

03-06338; Discrepancies in CR 02-06773 Response; August 8, 2003

03-06375; Concerns with Motor Overload Protection for Non-Essential Service Motors; August 8, 2003

03-06383; Revise C-ME-011.06-007 Nitrogen Bottle Sizing for SW1356, SW1357 and SW1358; August 8, 2003

03-06418; Interdependencies of Calculations Associated with EDG Rating and Capacity Self-Identified In Preparation for Inspection; August 9, 2003

03-06421; Lack of Corrective Action for Cause Identification CR 02-05262 Self-Identified In Preparation for Inspection; August 9, 2003

03-06427; Lack of Corrective Action for Cause Identification CR 02-07110 Self-Identified In Preparation for Inspection; August 9, 2003

03-06428; Lack of Corrective Action for Cause Identification CR 02-09027 Self-Identified In Preparation for Inspection; August 9, 2003

03-06457; Discrepancies Between Quality and Seismic Classifications; August 11, 2003

03-06458; Invalid Information Restored to Procedure During Alteration Self-Identified In Preparation for Inspection; August 11, 2003

03-06474; Containment Spray Pump Current Values are Non-conservative; August 11, 2003

03-06475; Evaluation of Overloads on Motor Operated Valves; August 11, 2003

03-06485; Installed Equipment Size Differs From that Shown in the Calculation; August 12, 2003

03-06492; EDG Water Jacket Heat Exchanger PM Enhancement; August 12, 2003

03-06497; CATI: The NRC Team Disagrees With CR 03-03891 Resolution; August 12, 2003

03-06499; Item 0292 – 50.59 Evaluation Using NRC Pre-approved Methodologies; August 12, 2003

03-06507; Tracking CR for Actions Recommended By CR 03-04423; August 12, 2003

03-06519; Periodic Vibration Testing of LPI Pumps on Minimum Flow; August 13, 2003

03-06520; Potential Concern for Pre-Conditioning Prior to Surveillance Test; August 13, 2003

03-06524; EDG Conduit Installation for Cabinet C3615; August 2, 2003

03-06526; Adequacy of HPI Pump Minimum Flow Rate; August 13, 2003

03-06547; Potential for Supervisor/SRO Comments to Influence CR Outcome; August 13, 2003

03-06556; NRC Questions/Issues In AOV C-ME-011.06.007; August 14, 2003

03-06561; 50.59 Evaluation 02-01740 Concerns; August 14, 2003

03-06567; Accuracy of SRO Comments on 03-02597; August 14, 2003

03-06576; Auxiliary Feedwater Components Should be in GL89-13 Program; August 14, 2003

03-06578; Concern Over AFW Strainer Limiting Particle Size Report; August 14, 2003

03-06585; Inaccurate Investigation of CR 02-07547 Self-Identified In Preparation for Inspection; August 14, 2003

03-06586; Clarification to CR 02-06661; August 13, 2003

03-06588; Item 0352, LAR 96-0008 Incomplete Statements, EQ Questions; August 14, 2003

03-06656; NSA Calculations May Not Have Been Revised Properly; August 18, 2003

03-06809; Improvements to 10 CFR 50.9 Completeness and Accuracy Training; August 21, 2003

03-06837; Item 0375 – Potential Thermal Overpressurization of the SW Sys. to CACS; August 22, 2003

03-06870; NRC Unresolved Issues, Concerns with SW Pump Room HVAC 67.005; August 23, 2003

03-06901; Error Found in Flooding Calculation 15.50 Revision 1; August 25, 2003

03-06907; Quality Collective Significance Review; August 23, 2003

03-06908; Corrective Action Program Implementation Collective Significance Review; August 23, 2003

03-06909; Design Control Collective Significance Review; August 23, 2003

03-06941; Recommended SW Balance Procedural Enhancement; August 26, 2003

03-06944; Fuse Sizing for MV0106 and MV38700; August 25, 2003

03-06948; Downgrade of CR 02-06356; August 26, 2003

03-06956; 0300 – DC Voltage Drop LC – Lack of Basis for Deferring Corrective Action; August 26, 2003

03-06984; Questions on NOP-CC-2003, Engineering Changes; August 26, 2003

03-06989; ETAP Revision 2 Number was not Attained in Accordance with NOP-CC-3002; August 27, 2003

03-06990; Possible Enhancement to NOP-CC-3002 as Identified During TI-0409; August 27, 2003

03-06996; Root Cause for 02-06178 Spacer Grid Damage Needs Improvement; August 27, 2003

03-07006; Translation of Flow Balance Acceptance Criteria Should Be Formalized; August 27, 2003

03-07009; CAC Motor Sizing; August 27, 2003

03-07031; Inadequate Rollover from CR 03-02616 to CR 03-03572; August 28, 2003

03-07033; Inadequate Past Operability Evaluation for CR 03-03572; August 28, 2003

03-07035; Performance Improvement Involvement in MCTM; August 28, 2003

03-07042; UFSAR Needs to Be Clarified on Use of Safety Related Equip and Seismic; August 28, 2003

03-07047; NRC Concerns with CR Evaluations Failure to Answer the Identified Issue; August 28, 2003

03-07053; Evaluation for Operability and USAR Update Timeliness; August 28, 2003

03-07067; Observation of Proposed Service Water Relief Valve Removal EWR 01-0306; August 29, 2003

03-07069; Adequacy of Electrical DC Contactor Testing Methodology; August 29, 2003

03-07112; Collective Significance Review of Recent Operability Evaluation Revisions; August 28, 2003

03-07121; NRC Non-Cited Violation Issues; August 30, 2003

03-07124; NRC Concerns with CR Evaluations Not Including Applicable References; August 30, 2003

03-07256; Questions on Applicability of 50.59 for Manual Actions in Fire Preplans; September 2, 2003

03-07420; Restart CRs Closed Prior to All CAs Being Completed; September 6, 2003

03-07922; Thermal Overload #2 EDG Air Compressor; September 21, 2003

03-09548; New Motor Operated Valve Terminal Voltage; November 5, 2003

Condition Reports Reviewed During the Inspection

99-01109; Conversion of PCAQR 1998-0126 to Condition Report; June 28, 1999

00-00669; Potential Non-Compliance Against the ASME Code; April 1, 2000

00-00699; Steady State Leakage from Three of Four Reactor Coolant Pump Gasket Drain Lines; April 2, 2000

00-00869; Leakage at the Bolted Connection on Reactor Coolant Pump 1-1; April 10, 2000

00-01089; Relaxation of Reactor Coolant Pump Casing Studs since Refueling Outage 11; April 20, 2000

00-02033; Reactor Coolant System Flow Rate Test Acceptance Criteria Not Met; August 11, 2000

00-02304; Performance of DB-SP-04360 In Modes 1 and 2; September 21, 2000

00-02418; Zebra Mussel Particles in Service Water Lines Might Restrict Flow Through the Auxiliary Feedwater Restriction Orifices; October 6, 2000

01-00540; Dose Calculations for Post Accident Sampling System Samples Outside of Updated Safety Analysis Report 9.3.2.2.3; February 23, 2001

01-00890; Reactor Coolant System Leak Rate Data Scatter; March 28, 2001

01-01102; Letdown Diverting Valve, MU11, Is Possible Source of Reactor Coolant System Unidentified Leakage; April 20, 2001

01-01335; CAC Air Side Fouling Criteria; May 22, 2001

01-01857; RCS Leakage Anomalies; July 25, 2001

01-02019; Initial Results of Investigation into NRC Information Notice 2000-20; August 7, 2001

01-02820; Procedures Not Updated to Support Modification Implementation; October 23, 2001

01-02862; Potential Adverse Trend in Unidentified Reactor Coolant System Leakage; October 25, 2001

01-03025; Reactor Coolant System Leakage; November 12, 2001

01-03059; Minimum Voltage for AFW Valves MV0106 and MV3870; November 2001

02-00164; ASME Relief Request for the 13^{th} Refueling Outage; January 16, 2002

02-00412; DC Voltage Drop Calculation; February 8, 2002

02-00576; Small Oil Leak Discovered on Reactor Coolant Pump Motor 2-2; February 18, 2002

02-00695; Latent Issues Review (LIR) – EDG Engine Derating; February, 2002

02-00835; LIR – RCS: RCS Validation Document Contains Outdated Information; February, 2002

02-00890; Control Rod Drive Nozzle Crack Indication; February 27, 2002

02-00891; Failure to Identify Significant Degradation of the Reactor Pressure Vessel Head (Selected Corrective Actions Only); February 2002

02-01129; Valve MU66C As-found Close Stroke Time Exceeded Maximum Allowable; February 2002

02-01139; Corrosion of Containment Air Cooler 3 Flange Faces; March 8, 2002

02-01517; Containment Inspection Plan Not Fully Implemented; April 10, 2002

02-01523; Reactor Coolant Pump 1-1 and 1-2 Leakage at Gasket Drain Lines; February 16, 2002

02-01691; Inspection Plan IP-M-028 Findings; April 25, 2002

02-01915; Inspection Plan IP-M-028 (Extent of Condition) Examination Findings; May 6, 2002

02-02143; Inspection Plan IP-M-028 (Extent of Condition) Examination Findings; May 17, 2002

02-02419; Untimely Corrective Action to Address Corrective Action Program Weaknesses; June 4, 2002;

02-02584; Implementation of Corrective Action Program by Site Personnel; June 13, 2002

02-02585; Management and Supervisory Oversight and Ownership of Plant Activities; June 13, 2002

02-02658; Inadequate Ventilation for Rooms 323, 324 and 325

02-02848; Fuel Assembly Spacer Grid Impressions in Core Baffle Plates; June 27, 2002

02-02943; Containment Air Cooler Boric Acid Corrosion; July 2, 2002

02-03027; Emergency Diesel Generator Jacket Water Heat Exchanger Tubeside (CCW) Flow Rates Exceed Limits; July 8, 2002

02-03157; High Energy Line Breaks in Turbine Building Effects on AFW Pump Rooms; July 11, 2002

02-03337; Documentation Could Not be Located; July 19, 2002

02-03497; Overall Failure to Take Action to Correct Identified Deficiencies in CAP; July 27, 2002

02-03674; Recurring Trend of Untimely and Ineffective Corrective Actions; August 3, 2002

02-03668; Reactor Coolant Pump Casing-to-cover Joint Leakage; August 3, 2002

02-03673; Recurring Trend of Less Than Adequate CR Evaluations; August 3, 2002

02-03674; Recurring Trend of Untimely and Ineffective Corrective Actions; August 3 2002

02-03676; Coding and Trending; August 3, 2002

02-03960; CAC Operability; August 9, 2002

02-03963; Zebra Muscle Shells in Containment Air Cooler Cooling Coils; August 9, 2002

02-04083; LIR – EQ: 36 inch Main Steam Line Analysis; August 10, 2002

02-04146; EDG 2 Missile Shield Support Plates Have Broken and Cracked Concrete; August 11, 2002

02-04147; Missile Protection on Stacks about Six Feet Short of Completely Effective; August 11, 2002

02-04202; Oxidation on Fuses and Fuse Holders; August 12, 2003

02-04211; Performance Indicator Weakness Collective Review; August 14, 2002

02-04292; Inadequate Cause Evaluations and Corrective Actions; August 15, 2002

02-04630; LIR – Emergency Diesel Generator 1-2; August 18, 2002

02-04668; LIR – AFW-EQ Equipment Sealing; August 21, 2002

02-04673; Auxiliary Feedwater Strainers Limiting Particle Size; August 22, 2002

02-04680; No Documentation To Assure Compliance With GE SIL-44 For HFAs; August 21, 2002

02-04700; Tornado Missile Protection; August 21, 2002

02-04716; Recurring Trend of Procedural Non-Compliance; August 21, 2002

02-04740; Refer to DB-OP-01200 for Step Changes in Unidentified RCS Leakage; August 22, 2002

02-04810; LIR – AFW-W-PSL 4929A and B; August 17, 2002

02-04884; Ineffective Corrective Action Problem Resolution; August 23, 2002

02-05039; LIR – EDG System Does Not Meet IEEE-STD-387-1972 Requirements; August 26, 2002

02-05079; LIR – AFW-SFRCS High Level Isolation; August 26, 2002

02-05096; Reinspection of RCP21OUT-5-RI (Pump 220, Reactor Coolant Pump 2-1 Discharge); August 26, 2002

02-05159; Reinspection of Reactor Coolant Pump 2-1 Casing Closure Studs and Bolting; August 26, 2002

02-05165; LIR – AFW-EQ Overall Assessment; August 27, 2002

02-05262; LIR of Environmental Qualification of SW Pump Room Equipment (IR 02-14-01f); August 29, 2002

02-05296; Containment Analysis Documentation Requirements; August 30, 2002

02-05298; Limiting Containment Temperature May Not Have Been Used in System Design; August, 30, 2002

02-05300; Ensure That the Containment Spray TSP Baskets are Fully Submerged on LOCA; August 30, 2002

02-05304; TSP Design Bases; August 30, 2002

02-05322; Additional Review of the Containment is Warranted; August 30, 2002

02-05323; Clarification Required re Containment Vessel Design Pressure; August 30, 2002

02-05356; Service Water Technical Specification Instruments; September 10, 2002

02-05364; LIR – EDG Electrical Capacity C-EE-024.01-005, R8, is to Be Revised; September 3, 2002

02-05383; LIR EDG-EDG Electrical Capacity C-EE-015.03-002; August 30, 2002

02-05385; LIR – EDG Loading Table Step 1 Block Loading Inadequate; August 30, 2002

02-05390; CR Rollover Exceeds Max Default Times Without Proper Approvals; September 3, 2002

02-05446; LIR – EDG Loading Could Exceed the EDGs Electrical Capability When Paralleled; September 4, 2002

02-05459; Split CAC Motor Cables; August 6, 2002

02-05514; System Health Readiness Review (SHRR) Assessment of Testing Containment Spray Valves – Locked Closed; September 5, 2002

02-05516; LIR – SW Possible Inaccurate Consideration of Design Bases CAC Fouling Factor; September 5, 2002

02-05559; Inadequate CAP Review of Operating Experience; September 6, 2002

02-05563; Nozzle Flexibility Assumed in Calculations 65A/B is Non-conservative; September 6, 2002

02-05590; Tornado Missile Protection of Emergency Diesel Generators; September 6, 2002

02-05593; Thermal Aging Effect of Emergency Core Cooling System Room Post Loss of Coolant Accident Temperature; September 6, 2002

02-05627; LIR – 59 Percent Undervoltage Relay Logic Shown in EC128AI Is Incorrect; September 7, 2002

02-05628; LIR – 59 Percent Undervoltage Relay Logic Shown in SD-003A Is Incorrect; September 7, 2002

02-05632; LIR – Tech Spec Table 3.3-4 Trip Setpoint Tolerance Is Inadequate; September 7, 2002

02-05633; USAR Discrepancy with LOOP Timing; September 7, 2002

02-05639; Updated Safety Analysis Report Description of Limiting Strainer Size; September 10, 2002

02-05640; LIR – No Design Bases/Flow Verification Testing of SW Flow to AFW System; September 10, 2002

02-05645; Fuel Assembly NJ10KK Spacer Grid Damage; September 6, 2002

02-05691; LIR – Minimum Temperature to the AFW System SG Nozzles; September 12, 2002

02-05727; Design Capacity of Ultimate Heat Sink; September 14, 2002

02-05732; License Amendment Request 96-0008 Not Supported by Analysis; September 10, 2002

02-05738; Relief Valve Set Point Not Conservative; September 11, 2002

02-05748; Lack of Service Water and Ultimate Heat Sink Design Basis for Seismic Event and Single Active Failure; September 14, 2002

02-05749; LIR – CCW Non-Seismic Piping Over Safety Related Components; September 12, 2002

02-05784; Service Water Strainer Design Flow; September 11, 2002

02-05848; LIR – EDG High Temperature Evaluation Internal Temperature Rise for Cabinets; September 12, 2002

02-05870; LIR – EQ List of 10 CFR 50.49 Components; September 12, 2002

02-05881; Reactor Coolant Pump 2-2 Casing Closure Studs and Bolting; September 12, 2002

02-05885; No Emergency Core Cooling System Air Cooler Inspection Acceptance Criteria; September 14, 2002

02-05895; Fuel Assembly NJ10LC Spacer Grid Damage; September 13, 2002

02-05896; Fuel Assembly NJ10KL Spacer Grid Damage; September 13, 2002

02-05904; Auxiliary Feedwater Design Basis Calculations Not Located; September 14, 2002

02-05914; LIR – EDG Lube Oil Procedure Guidance; September 12, 2002

02-05922; LIR – Discrepancy in EDG Voltage and Frequency During Loading; September 12, 2002

02-05923; No Design Basis for Service Water Pump Net Positive Suction Head Available; September 16, 2002

02-05925; LIR – EDG Transient Analysis During Loading Sequence – Calculations; September 12, 2002

02-05986; Ultimate Heat Sink Water Inventory Analysis Does Not Consider All Water Losses; September 14, 2002

02-06062; LIR – EDG: Fuel Filter Inlet Operating Pressure Exceeds Vendor Limits for Change; September 14, 2002

02-06064; SSDI Item – SW Flow Balance Margins and Need for Additional Recorded Data; September 14, 2002

02-06100; SSDI Assessment Identified Incorrect Information in OJ 2000-14 (SW Valve Issue); September 14, 2002

02-06108; LIR – AFW Pumps and H2 Dilution Blower Not Evaluated for High Pressure Injection System; September 14, 2002

02-06134; Service Water Dead Leg Inspection and Cleaning; September 18, 2002

02-06160; Debris Other than Paint Chips Identified in Fuel Assemblies; September 18, 2002

02-06166; LIR – SW Flow Balance Testing of Alternate Safety Related Return Flow Paths; September 18, 2002

02-06178; Spacer Grid Damage Observed During Fuel Inspections; September 18, 2002

02-06215; Excessive Indicated Total RCS Flow Error in SP-03358; September 18, 2002

02-06275; Degraded Makeup Valve MU11 Hardware; September 19, 2002

02-06305; SSDI Item – C-EE-015.03-003, Steady-State Analysis: ELMS; September 19, 2002

02-06333; Inadequate SW Thermal Analysis; September 19, 2002

02-06337; SSDI Item – SW C-NSA-011.01-007, Revision 1 Concerns (Pump Curves); September 19, 2002

02-06341; LIR – SW: Review of Industry Experience; September 20, 2002

02-06343; Nuclear Quality Assurance Stop Work on Nuclear Fuel Movements; September 20, 2002

02-06356; Calculational Process Concerns; September 20, 2002

02-06370; SSDI Item – ECCS Pump Room Heat Load is Non-conservative; September 20, 2002

02-06384; SSDI Item – Enhancement to Calculation 50.20 Flooding of ECCS Rooms Due to a Feedwater Line Break; September 20, 2002

02-06407; SSDI Item – Instrument Uncertainty in Calibration and Surveillance of Instrumentation; September 16, 2002

02-06438; Inadequate SW Thermal Analysis; September 2002

02-06439; LIR – SW Service Water Pump Run Out; September 2002

02-06477; SSDI Item – HPI Pump Performance Not Evaluated For Expected Input Power Variations; September 2002

02-06536; LIR – RCS: PZR Vent Flow Capacity Has No Design Basis; September 2002

02-06547; Design Basis Validation – Pressurizer Vent Orifice Sizing; September 2002

02-06564; Service Water System Cleanliness for Restart; October 5, 2002

02-06677; Ineffective Corrective Action for Locked High Radiation Area Access Control; September 25, 2002

02-06701; Post-LOCA Dose from BWST with Inadvertent HP31/HP32 Failure; September 25, 2002

02-06702; Potential for Inadequate HPI Pump Minimum Recirculation Following LOCA; September 25, 2002

02-06723; LIR – NRC Concern Regarding Site’s Lubrication Program; September 26, 2002

02-06725; Sway Strut Bushing Grease Fittings; September 26, 2002

02-06737; SSDI Item – C-EE-004.01-051 Uncertainty Treatment; September 25, 2002

02-06757; LIR – EDG Potential Overload Condition; September 26, 2002

02-06767; LIR – AFW (JCO) Inputs Not Bounding; September 26, 2002

02-06773; LIR – AFW CR 95-0906 Deficiencies; September 26, 2002

02-06779; Voltage Reading Exceeded Tolerance and Evidence of Heat Damage; September 26, 2002

02-06821; LIR – AFW Pump Surveillance Testing; September 26, 2002

02-06860; Review of the Need for Relief Valves for Several Heat Exchangers; September 27, 2002

02-06861; Bearing Oil Cooler Strainer Fouling; September 27, 2002

02-06885; Reactor Coolant System Flow Uncertainty May Be Higher than Assumed; September 27, 2002

02-06893; Effect of Room 105, and 115 Temp Increase; September 24, 2002

02-06951; LIR – EDG Engine Derating; September 27, 2002

02-06986; Relay Testing; September 26, 2002

02-06996; HPI Flow Test Acceptance Criteria Versus T.S. 4.5.2.H; September 27, 2002

02-07110; Unqualified Splice in MOV; October 1, 2002

02-07148; LIR CCW – Lack Of Functional Testing Of Letdown Cooler And RCP Interlocks; October 1, 2002

02-07153; LIR – EDG Appendix R Load Calculation; October 1, 2002

02-07159; Lack of Valve Position Alarm; October 1, 2002

02-07188; Non-conservative Assumptions in 67.005, Service Water Ventilation Capacity; October 1, 2002

02-07236; LIR – AFW SG Accident Pressure versus AFW Pump Flow; October 1, 2002

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LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agency-wide Document Access and Management System
AIT	Augmented Inspection Team
AFW	Auxiliary Feedwater
ASME	American Society of Mechanical Engineers
AV	Apparent Violation
BACC	Boric Acid Corrosion Control
BWST	Borated Water Storage Tank
B&W	Babcock and Wilcox
CAC	Containment Air Cooler
CARB	Corrective Action Review Board
CAP	Corrective Action Program
CATI	Corrective Action Team Inspection
CCW	Component Cooling Water
CFR	Code of Federal Regulations
CR	Condition Report
CRDM	Control Rod Drive Mechanism
CS	Containment Spray
DC	Direct Current
DHR	Decay Heat Removal
EAB	Engineering Assessment Board
ECCS	Emergency Core Cooling System
ECR	Engineering Change Request
EDG	Emergency Diesel Generator
EPRI	Electric Power Research Institute
EQ	Environmental Qualification
ESF	Engineered Safety Feature
ETAP	Electric Transient Analysis Profile
FENOC	FirstEnergy Nuclear Operating Company
FIN	Finding
GDC	General Design Criteria
GL	Generic Letter
GPM	Gallons per Minute
HPI	High Pressure Injection
HPR	High Pressure Recirculation
IMC	Inspection Manual Chapter
IN	Information Notice
IR	Inspection Report
ISI	In-service Inspection
IST	In-service Testing
KSI	Kilo (1000) Pounds per Square Inch
kV	Kilo Volt (1000 volts)
LAR	License Amendment Request
lb/ft^3	Pounds per Cubic Foot
LER	Licensee Event Report
LIR	Latent Issues Review
LOCA	Loss of Coolant Accident

LIST OF ACRONYMS USED, cont'd.

LOOP	Loss of Offsite Power
LPI	Low Pressure Injection
MRB	Management Review Board
MSSV	Main Steam Safety Valve
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NOBP	Nuclear Operations Business Practice
NOP/NOT	Normal Operating Pressure and Normal Operating Temperature
NPSH	Net Positive Suction Head
NQA	Nuclear Quality Assessment
NRC	United States Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
OI	Office of Investigations
PARS	Publicly Available Records
PI	Performance Indicator
PORV	Power Operated Relief Valve
PRA	Probabilistic Risk Assessment
PRC	Project Review Committee
PSIG	Pounds Per Square Inch Gauge
RCPB	Reactor Coolant Pressure Boundary
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RFO	Refueling Outage
RSRB	Restart Station Review Board
SCAQ	Significant Condition Adverse to Quality
SDP	Significance Determination Process
SG	Steam Generator
SHA	System Health Assurance
SRA	Senior Reactor Analyst
SRB	Station Review Board
SSC	Structures, Systems, Components
SSDI	Safety System Design and Performance Capability Inspection
SW	Service Water
the Code	ASME Boiler and Nuclear Pressure Vessel Code
TPCS	Transient without Power Conversion System
TS	Technical Specifications
TSP	Tri-Sodium Phosphate
UHS	Ultimate Heat Sink
URI	Unresolved Item
USAR	Updated Safety Analysis Report
V	Volts
Vac	Volts (alternating current)
Vdc	Volts (direct current)
VIO	Violation
WO	Work Order
°F	Degrees Fahrenheit