UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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ARLINGTON, TEXAS 76011-4005

November 5, 2004

Gregg R. Overbeck, Senior Vice
President, Nuclear
Arizona Public Service Company
P.O. Box 52034
Phoenix, AZ 85072-2034

SUBJECT: PALO VERDE NUCLEAR GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000528/2004004, 05000529/2004004, AND 05000530/2004004

Dear Mr. Overbeck:

On September 30, 2004, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Palo Verde Nuclear Generating Station, Units 1, 2, and 3, facility. The enclosed integrated report documents the inspection findings, which were discussed on October 21, 2004, with you and other members of your staff.

The inspection examined activities conducted under your licenses as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your licenses. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents four NRC identified and two self-revealing findings of very low safety significance (Green). These findings were determined to involve violations of NRC requirements; however, because of the very low safety significance and because they were entered into your corrective action program, the NRC is treating these findings as noncited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. A licensee-identified violation, which was determined to be of very low safety significance, is listed in Section 4OA7 of this report. If you contest these noncited violations, you should 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, U.S. Nuclear Regulatory Commission Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington DC 20555-0001; and the NRC Resident Inspector at Palo Verde Nuclear Generating Station, Units 1, 2, and 3, facility.

In accordance with 10 CFR 2.390 of the NRC's “Rules of Practice,” a copy of this letter, its enclosure, and your response (if any) will be made 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).

Sincerely,

/RA/

Troy W. Pruett, Chief
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Dockets: 50-528
50-529
50-530
Licenses: NPF-41
NPF-51
NPF-74

Enclosure:
NRC Inspection Report 05000528/2004004, 05000529/2004004, and 05000530/2004004
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MPShannon	JAClark	LJSmith	TWPruett	
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U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Dockets:	50-528, 50-529, 50-530
Licenses:	NPF-41, NPF-51, NPF-74
Report:	05000528/2004004, 050000529/2004004 and 05000530/2004004
Licensee:	Arizona Public Service Company
Facility:	Palo Verde Nuclear Generating Station, Units 1, 2, and 3
Location:	5951 S. Wintersburg Tonopah, Arizona
Dates:	July 1 through September 30, 2004
Inspectors:	R. Azua, Project Engineer R. Bywater, Senior Reactor Analyst L. Ellershaw, Senior Reactor Inspector G. Johnston, Senior Operations Engineer D. Loveless, Senior Reactor Analyst T. McConnell, Reactor Inspector W. McNeill, Reactor Inspector J. Melfi, Resident Inspector C. Paulk, Senior Project Engineer N. Salgado, Senior Resident Inspector G. Warnick, Resident Inspector
Approved By:	Troy W. Pruett, Chief, Project Branch D Division of Reactor Projects

CONTENTS

SUMMARY OF FINDINGS

IR 05000528/2004004, 05000529/2004004; 05000530/2004004; 7/01/04 - 9/30/04; Palo Verde Nuclear Generating Station, Units 1, 2, and 3; Integrated Resident and Regional Report; Heat Sink Performance, Post-Maintenance Test, Event Followup, and Other Activities.

This report covered a 3-month period of inspection by resident inspectors and inspection staff from the regional office   The inspection identified six findings. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using 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's 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, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A self-revealing noncited violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” was identified for the failure to implement a modification. The modification should have removed a pipe support associated with a high pressure safety injection system drain line. The failure to remove the pipe support, combined with high vibrations, resulted in a reactor coolant system pressure boundary leak from a cracked socket weld upstream of high pressure safety injection header drain Valve 1-P-SIA-V056. The issue was entered into the licensee’s corrective action program as Condition Report/Disposition Request 2669474.

  The finding is greater than minor since it is associated with the equipment performance and design control attributes of the initiating events cornerstone and affects the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions. Using the Phase 1 worksheet in Manual Chapter 0609, "Significance Determination Process," this finding is determined to have very low safety significance because assuming worst case degradation, the leak would not have exceeded the Technical Specification limit for identified reactor coolant system leakage and mitigating systems were not affected (Section 4OA5).

Cornerstone: Mitigating Systems

- Green. A noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” was identified for the failure to promptly correct a condition adverse to quality associated with the lubrication of reach rods on safety-related manual valves. The issue involved problem identification and resolution crosscutting aspects associated with untimely prioritization of work necessary to correct degraded equipment conditions. This issue was entered into the licensee’s corrective action program as Condition Report/Disposition Request 2328588.

The finding was greater than minor safety significance because if left uncorrected, it could become a more significant safety concern in that the failure to perform maintenance on reach rod assemblies could result in an inability to operate safety-related manual valves. This finding is associated with the equipment performance attribute of the mitigating systems cornerstone and affects the cornerstone objective of ensuring the reliability of systems that respond to initiating events. Using the Phase 1 worksheet in Manual Chapter 0609, "Significance Determination Process," the finding is determined to have very low safety significance because it only affected the mitigating systems cornerstone and there was not a loss of safety function (Section 1R12).

- Green. A noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," was identified for the failure to correct a significant condition adverse to quality. The adverse condition involved failed resistors in the power supply to the turbine driven auxiliary feedwater pump governor control circuits in Units 2 and 3 that had transportability to Unit 1. The finding involved problem identification and resolution crosscutting aspects associated with engineering personnel not performing an adequate extent of condition review. The finding also involved human performance crosscutting aspects associated with engineering and maintenance personnel not communicating correct technical information. This issue was entered into the licensee's corrective action program as Condition Report/Disposition Request 2746954.

  The finding was greater than minor because if left uncorrected, it could have become a more significant safety concern in that the Unit 1 turbine driven auxiliary feedwater pump could have experienced an unnecessary failure. This finding is associated with the equipment performance attribute of the mitigating systems cornerstone and affects the cornerstone objective of ensuring the reliability of systems that respond to initiating events. Using the Phase 1 worksheet in Manual Chapter 0609, "Significance Determination Process," the finding is determined to have very low safety significance because it only affected the mitigating systems cornerstone and did not result in an actual loss of safety function for the auxiliary feedwater system (Section 1R19).

- Green. A self-revealing noncited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified for an inadequate procedure which resulted in an unexpected reactor coolant system level anomaly during the Unit 1 reactor coolant system draindown to hot midloop conditions. Specifically, Procedure 40OP-9ZZ16, "RCS Drain Operations," did not provide reduced drain rates or increased hold points when only the reactor head vent was utilized to support draining evolutions. This issue was entered into the licensee's corrective action program as Condition Report/Disposition Request 2695262.

  The finding was greater than minor because it is associated with the equipment performance attribute of the mitigating systems cornerstone and affects the cornerstone objective of ensuring the reliability of systems that respond to initiating events. The inadequate procedure resulted in an actual unexpected indicated level transient while the reactor coolant system was being drained in reduced inventory conditions. Using Manual Chapter 0609, Appendix G, "Shutdown Operations Significance Determination Process," this finding is determined to have very low safety significance because the event did not constitute a loss of control and did not represent a finding requiring quantitative assessment. The finding did not increase the likelihood of loss or cause a degradation in the ability to restore decay heat removal, reactor coolant system inventory, offsite power, alternate core cooling, or containment (Section 4OA3).

- Green. A noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” was identified for the failure to assure that significant conditions adverse to quality were promptly identified and corrected. Specifically, maintenance personnel failed to promptly identify that retaining ring slots were not adequately sized to allow the use of the standard lock pins, contributing to the damage to the steam generator nozzle dam diaphragms. Subsequent to the identification, maintenance personnel failed to correct the condition by not implementing the actions recommended by plant engineers. The finding involved problem identification and resolution crosscutting aspects associated with engineering personnel not performing an adequate extent of condition review. That is, this finding was the direct result of licensee personnel's failure to promptly identify and correct a condition adverse to quality. This issue was entered into the licensee’s corrective action program as Condition Report/Discrepancy Requests 2686201 and 2686271.

  This finding was greater than minor because it is associated with the mitigating systems cornerstone and affects reactor coolant system boundary performance. Specifically, the plant operated for an extended period in reduced inventory as a result of not correcting the incompatibility between the nozzle dams and the locking ring. Using Manual Chapter 0609, “Significance Determination Process,” this finding is determined to have very low safety significance because the senior reactor analysts’ Phase 2 and 3 analyses determined that the increase in core damage frequency was approximately 3 $X10^{-7}$ (Section 4OA5).

- Green. The inspectors identified a noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” for the failure to promptly correct the lack of an adequate routine inspection and maintenance program for essential spray pond system piping and components. The finding has been entered into the licensee’s corrective action program as Condition Report/Disposition Request 2732683. The finding had problem identification and resolution crosscutting aspects associated with engineering personnel not entering deficiencies into their licensee commitment tracking system and not generating a condition report/disposition request.

  This finding is greater than minor because it affected the reactor safety mitigating systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. If left uncorrected the finding could become a more significant safety concern in that inspections of spray pond piping was not performed as committed to in the licensee's Generic Letter 89-13 response. The finding is of very low safety significance because the issue constituted a qualification deficiency that did not result in a loss of function per Generic Letter 91-18, "Information to Licensees Regarding NRC Inspection Manual Section on Resolution of Degraded and Nonconforming Conditions," Revision 1 (Section 4OA5).

B. Licensee-Identified Violations

A violation of very low safety significance which was identified by the licensee has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program (Section 4OA7).

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at essentially full power for the entire inspection period.

Unit 2 operated at full power until July 14, 2004, when the unit experienced a generator loss of field trip and reactor trip during an electrical storm. Following evaluation of the event and impacted systems, a reactor startup was completed; and the unit was returned to essentially full power on July 18, 2004, where it remained for the duration of the inspection period.

Unit 3 operated at essentially full power for the entire inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

Partial System Walkdowns. The inspectors (1) walked down portions of the three below listed risk important systems and reviewed plant procedures and documents to verify that critical portions of the selected systems were correctly aligned; and (2) compared deficiencies identified during the walk down to the licensee's corrective action program to ensure problems were being identified and corrected.

- July 12, 2004, Unit 3, low pressure safety injection system, Train A
- September 7, 2004, Unit 2, low pressure safety injection system, Train B
- September 9, 2004, Unit 1, low pressure safety injection system, Train B

The inspectors completed three samples.

Complete Walkdown. The inspectors (1) reviewed plant procedures, drawings, the Updated Final Safety Analysis Report, Technical Specifications, and vendor manuals to determine the correct alignment of the system; (2) reviewed outstanding design issues, operator work arounds, and corrective action program documents to determine if open issues affected the functionality of the system; and (3) verified that the licensee was identifying and resolving equipment alignment problems.

On July 22, 2004, the inspectors performed a complete system walkdown of accessible portions of the emergency diesel generators (EDGs) on all three units. The inspectors also performed an assessment of the commercial grade dedication of repaired circuit cards and the rework to fiber optic cards associated with the EDG.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

Routine Inspection. The inspectors walked down the six below listed plant areas to assess the material condition of active and passive fire protection features, their operational lineup, and their operational effectiveness. The inspectors (1) verified that transient combustibles and hot work activities were controlled in accordance with plant procedures; (2) observed the condition of fire detection devices to verify they remained functional; (3) observed fire suppression systems to verify they remained functional; (4) verified that fire extinguishers and hose stations were provided at their designated locations and that they were in a satisfactory condition; (5) verified that passive fire protection features (electrical raceway barriers, fire doors, fire dampers, steel fire proofing, penetration seals, and oil collection systems) were in a satisfactory material condition; (6) verified that adequate compensatory measures were established for degraded or inoperable fire protection features; and (7) reviewed the corrective action program to determine if the licensee identified and corrected fire protection problems.

- July 7, 2004, Unit 3, main steam support structure 80-foot, 100-foot, 120-foot, and 140-foot elevations
- July 19, 2004, Unit 1, auxiliary building 100-foot, 120-foot, and 140-foot elevations
- July 19, 2004, Unit 2, control building 74-foot, 100-foot, 120-foot, 140-foot, and 160-foot elevations
- July 19, 2004, Unit 3, control building 74-foot, 100-foot, 120-foot, 140-foot, and 160-foot elevation
- July 27, 2004, Unit 1, auxiliary building 40-foot, 52-foot, 70-foot, and 88-foot elevations
- August 4, 2004, Unit 3, auxiliary building 40-foot, 52-foot, 70-foot, and 88-foot elevations

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

Annual External Flooding. The inspectors (1) reviewed the Updated Safety Analysis Report, the flooding analysis, and plant procedures to assess seasonal susceptibilities involving external flooding; (2) reviewed the corrective action program to determine if the licensee identified and corrected flooding problems; (3) inspected underground bunkers/manholes to verify the adequacy of (a) sump pumps, (b) level alarm circuits, (c) cable splices subject to submergence, and (d) drainage for bunkers/manholes; (4) verified that operator actions for coping with flooding can reasonably achieve the desired outcomes; and (5) walked down safety-related areas to verify the adequacy of: (a) equipment seals located below the floodline, (b) floor and wall penetration seals, (c) watertight door seals, (d) common drain lines and sumps, (e) sump pumps, level alarms, and control circuits, and (f) temporary or removable flood barriers.

The inspectors completed one sample.

Semi-annual Internal Flooding. The inspectors (1) reviewed the Updated Safety Analysis Report, the flooding analysis, and plant procedures to assess seasonal susceptibilities involving internal flooding; (2) reviewed the corrective action program to determine if the licensee identified and corrected flooding problems; (3) inspected underground areas/bunkers/manholes to verify the adequacy of (a) sump pumps, (b) level alarm circuits, (c) cable splices subject to submergence, and (d) drainage for bunkers/manholes; (4) verified that operator actions for coping with flooding can reasonably achieve the desired outcomes.

- August 16, 2004, Unit 1, control building, all elevations.
- August 18, 2004, Unit 2, control building, all elevations.
- August 18, 2004, Unit 3, control building, all elevations.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

a. Inspection Scope

Biennial Heat Sink Performance (71111.07B)

From August 16-20, 2004, the inspectors performed the biennial heat sink performance inspection. The inspectors selected four safety-related heat exchangers for this inspection, including the essential cooling water heat exchangers, diesel generator jacket cooling water heat exchangers, diesel generator lube oil heat exchangers, and diesel generator turbocharger aftercoolers.

The inspectors reviewed test, inspection, licensing, design and vendor documents and verified that (1) testing, inspection/maintenance and biotic fouling controls were adequate to ensure proper heat transfer; (2) acceptance criteria properly considered the differences between test/inspection conditions and design basis requirements; (3) acceptance criteria were consistent with accepted industry practices and testing accounted for instrument uncertainties, either implicitly or explicitly; (4) the frequency of testing or inspection was adequate to detect degradation prior to loss of acceptable heat removal capabilities; (5) as-found test/inspection results were appropriately evaluated and findings were properly dispositioned; and (6) the ultimate heat sink and subcomponents demonstrated adequate performance.

The inspectors reviewed 12 essential spray pond system-related condition reports and verified that heat exchanger problems were properly documented, dispositioned, and corrected. In addition, the inspectors reviewed 14 work orders (WOs).

b. Findings

A noncited violation (NCV) for the failure to promptly correct the lack of an adequate routine inspection and maintenance program for the essential spray pond system piping and components was identified in Section 4OA5 of this report.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope

The inspectors observed testing and training of senior reactor operators and reactor operators to identify deficiencies and discrepancies in the training, to assess operator performance, and to assess the evaluator's critique. The simulator scenario observed was SES-0-09-0-02, "RRS Malfunction, Loss of Vacuum, ESD Inside Containment without Containment Spray (CTPC-2)." Additionally, the inspectors compared simulator board configurations with actual control room board configurations for consistency.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed the three below listed maintenance activities to (1) verify the appropriate handling of structure, system, and component (SSC) performance or condition problems; (2) verify the appropriate handling of degraded SSCs functional performance; (3) evaluate the role of work practices and common cause problems; and (4) evaluate the handling of SSCs issues reviewed under the requirements of the Maintenance Rule, 10 CFR Part 50, Appendix B, and Technical Specifications.

- Relay failures for EDG 1A (Unit 1) as documented in Condition Report/Discrepancy Report (CRDR) 2705929 and EDG 1A (Unit 3) as documented in CRDR 2719200

- Valve open position indication failure in high pressure safety injection header discharge isolation Valve SIA-HV-698 as documented in CRDR 2713743 (Unit 2)

- Preventive maintenance implementation for reach rods associated with safety-related manual valves (Units 1, 2, and 3)

The inspectors completed three samples.

b. Findings

Introduction. A Green noncited violation was identified for the failure to promptly correct a condition adverse to quality associated with reach rods on safety-related manual valves.

Description. During plant tours, the inspectors identified numerous reach rods and knuckles to manual valves in the safety-injection system that were not appropriately lubricated. The inspectors determined that some of these valves were required to be operated per abnormal operating procedures for plant events (i.e., loss of spent fuel pool, midloop operations). The inspectors' review determined that these valves had not been lubricated for approximately 10 years.

In October 1995 the licensee changed the preventive maintenance (PM) schedule for lubrication of reach rods for safety-related valves from a 5-year cycle to lubrication on an as-needed basis since reach rod performance issues were not an observed trend. In February 2000 the licensee initiated CRDR 115430 in response to industry information involving inadequate lubrication of reach rods to assess applicability. On October 10, 2000, the Nuclear Assurance Department initiated CRDR 2328588 due to an apparent increasing trend in reach rod deficiencies. The evaluation associated with CRDR 2328588 determined that a 3-year PM frequency was needed in response to the adverse trend. However, the licensee did not implement corrective actions even though it had been at least six years since the last PM was performed on the safety-related valves that were used to respond to plant events.

In June 2002 the Nuclear Assurance Department closure review of CRDR 2328588 identified that the 2000 industry experience review was incomplete in that four safety-related valves in each unit were omitted from the PM program. In February 2003 the licensee corrected this oversight by placing these valves in the PM program with a once per 3-year frequency. However, corrective actions were untimely in that eight years had elapsed when the first of these valves were lubricated on February 3, 2003. Preventive maintenance for the last valve was not completed until October 2004 which is approximately 10 years since the PM was last performed.

Analysis. The failure to correct a condition adverse to quality in a timely manner was determined to be greater than minor because if left uncorrected, it could become a more significant safety concern in that safety-related manual valves could fail when required to be operated per abnormal operating procedures for plant events. This finding is associated with the equipment performance attribute of the mitigating systems cornerstone and affects the cornerstone objective of ensuring the reliability of systems that respond to initiating events. Using the Phase 1 worksheet in Manual Chapter 0609, “Significance Determination Process,” the finding is determined to have very low safety significance because it only affected the mitigating systems cornerstone and there were no actual valve failures. The finding involved problem identification and resolution cross-cutting aspects associated with untimely prioritization of work necessary to correct degraded equipment conditions.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” requires, in part, that conditions adverse to quality be promptly identified and corrected. Contrary to the above, the licensee did not implement prompt corrective actions in response to their discovery of inadequately lubricated reach rods on safety-related manual valves. Because the finding is of very low safety significance and has been entered into the corrective action program as CRDR 2328588, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000528; 05000529; 05000530/2004004-01, “Untimely Lubrication of Reach Rods for Safety-Related Manual Valves.”

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

a. Inspection Scope

Risk Assessment and Management of Risk. The inspectors reviewed the assessment activities listed below to verify (1) performance of risk assessments when required by 10 CFR 50.65 (a)(4) and licensee procedures prior to changes in plant configuration for maintenance activities and plant operations; (2) the accuracy, adequacy, and completeness of the information considered in the risk assessment; (3) that the licensee recognizes, and/or enters as applicable, the appropriate licensee-established risk category according to the risk assessment results and licensee procedures; and (4) the licensee identified and corrected problems related to maintenance risk assessments.

- August 18, 2004, Unit 2, scheduled online outage for EDG, essential chilled water, essential cooling water, essential spray pond, and containment spray systems Train B.

- September 15, 2004, Unit 1, scheduled online outage for EDG, essential chilled water, essential cooling water, essential spray pond, and containment spray systems Train B.

The inspectors completed two samples.

Emergent Work Control. The inspectors (1) verified that the licensee performed actions to minimize the probability of initiating events and maintained the functional capability of mitigating systems and barrier integrity systems; (2) verified that emergent work-related activities such as troubleshooting, work planning/scheduling, establishing plant conditions, aligning equipment, tagging, temporary modifications, and equipment restoration did not place the plant in an unacceptable configuration; and (3) reviewed the corrective action program to determine if the licensee identified and corrected risk assessment and emergent work control problems for the below listed activities:

- August 5, 2004, Unit 3, evaluated licensee's assessment of flow noise near the low pressure safety injection Pump A while the pump was being used to circulate water through the refueling water tank.

- August 6, 2004, Unit 1, evaluated licensee's troubleshooting and restoration of core operating limit supervisory system Channel B after an intermittent alarm was received.

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Nonroutine Plant Evolutions and Events (71111.14 and 71153)

a. Inspection Scope

The inspectors (1) reviewed operator logs, plant computer data, and/or strip charts for the below listed evolution to evaluate operator performance in coping with nonroutine events and transients; (2) verified that operator response was in accordance with the response required by plant procedures and training; and (3) verified that the licensee identified and implemented appropriate corrective actions associated with personnel performance problems that occurred during the nonroutine evolutions sampled.

- On July 14, 2004, during an electrical storm, Unit 2 received a generator loss of field trip and large load reject/reactor power cutback. Approximately 10 seconds later, the reactor tripped on a core protection calculator generated low departure from nucleate boiling ratio trip. This Unit 2 event was documented in CRDR 2721635.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors (1) reviewed plants status documents such as operator shift logs, emergent work documentation, deferred modifications, and standing orders to determine if an operability evaluation was warranted for degraded components; (2) referred to the Updated Final Safety Analysis Report and design basis documents to review the technical adequacy of licensee operability evaluations; (3) evaluated compensatory measures associated with operability evaluations; (4) determined degraded component impact on any Technical Specifications; (5) used the significance determination process to evaluate the risk significance of degraded or inoperable equipment; and (6) verified that the licensee has identified and implemented appropriate corrective actions associated with degraded components.

- July 17, 2004, Units 1, 2, and 3, operability determination for selected Rotork valve operators subject to 10 CFR Part 21 as documented in Operability Determination 278.

- September 10, 2004, Units 1, 2, and 3, operability evaluation for apparent error in safety analysis for a steam generator tube rupture coincident with a loss-of-offsite power documented in CRDR 2736275.

- September 11, 2004, Units 1, 2, and 3, operability evaluation for not bypassing the thermal overloads for the spray pond pump room exhaust fan documented in CRDRs 2736244 and 2736478.

- September 23, 2004, Units 1, 2, and 3, operability determination for fire detector base resistor differences as documented in Operability Determination 283.

- September 29, 2004, Unit 2, reviewed operability assessment and Technical Specification 3.6.3 compliance for containment isolation Valve SGB-UV-221 failure as documented in CRDRs 2740832 and 2741070.

The inspectors completed five samples.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

Selected Operator Workarounds. The inspectors reviewed the below listed operator workaround to (1) determine if the functional capability of the system or human reliability in responding to an initiating event is affected; (2) evaluate the effect of the operator workaround on the operator's ability to implement abnormal or emergency operating procedures; and (3) verify that the licensee has identified and implemented appropriate corrective actions associated with operator workarounds.

- August 10 and 12, 2004, Unit 1, reactor coolant Pump 1B oil lift pump handswitch is functional.

The inspectors completed one sample.

Cumulative Review of the Effects of Operator Workarounds. The inspectors reviewed the cumulative effects of operator workarounds to determine (1) the reliability, availability, and potential for misoperation of a system; (2) if multiple mitigating systems could be affected; (3) the ability of operators to respond in a correct and timely manner to plant transients and accidents; and (4) if the licensee has identified and implemented appropriate corrective actions associated with operator workarounds.

- August 10 and 12, 2004, Unit 1 operator challenges - routine and conditional
- August 10 and 12, 2004, Unit 2 operator challenges - routine and conditional
- August 10 and 12, 2004, Unit 3 operator challenges - routine and conditional

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors selected the postmaintenance test activities for the below listed risk significant systems or components. For each item, the inspectors (1) reviewed the applicable licensing basis and/or design-basis documents to determine the safety functions; (2) evaluated the safety functions that may have been affected by the maintenance activity; and (3) reviewed the test procedure to ensure it adequately tested the safety function that may have been affected. The inspectors either witnessed or reviewed test data to verify that acceptance criteria were met, plant impacts were evaluated, test equipment was calibrated, procedures were followed, jumpers were properly controlled, the test data results were complete and accurate, the test equipment was removed, the system was properly realigned, and deficiencies during testing were documented. The inspectors also reviewed the corrective action program to determine if the licensee identified and corrected problems related to postmaintenance testing.

- July 27, 2004, Unit 3, observation of alternate supply Breaker 3ENANS06A to the Unit 3 13.8 SO6 bus installation per WO 2391149

- August 12, 2004, Unit 1, observation of position indication stroke on atmospheric dump Valve 185, per WO 2724960

- August 24, 2004, Unit 2, observation of troubleshooting on EDG 2A excitation bridge voltage monitoring per WO 2729077

- August 20, 2004, Unit 1, observation of turbine driven auxiliary feedwater (TDAFW) power supply resistor replacement per WO 2732276

The inspectors completed four samples.

b. Findings

Introduction. A Green noncited violation was identified for the failure to correct a significant condition adverse to quality in a timely manner. The adverse condition involved a failed resistor in the power supply to the TDAFW pump governor control circuits in Units 2 and 3 that had transportability to Unit 1.

Description. On May 14, 2004, Unit 2 received an alarm alerting operators to a failure within the TDAFW governor control panel. Investigation by the licensee determined that a voltage dropping resistor associated with the power supply to the governor failed. The resistor had been in-service for approximately 6 months prior to failure. The resistor is normally replaced every 18 months as a preventive maintenance activity. This issue was entered into the licensee's corrective action program as CRDR 2709451.

On July 5, 2004, Unit 3 operators received a similar alarm on the TDAFW pump governor control panel. The Unit 3 TDAFW pump governor power supply resistor failed after approximately 15 months of in-service time. This equipment failure was entered into the licensee's corrective action program as CRDR 2720228 due to the potential repeat maintenance rule functional failure implications. The licensee's initial documentation review identified that the Units 2 and 3 TDAFW pump governor power supply resistors were manufactured at approximately the same time and was potentially a contributing cause of failure. Due to a miscommunication with maintenance and engineering personnel, the TDAFW System Engineer initially determined that the resistor for the Unit 1 TDAFW pump governor power supply was manufactured on a different date, and therefore, was not affected by the problems identified on Units 2 and 3. On August 18, 2004, further investigation revealed that the resistor for the Unit 1 TDAFW pump governor power supply was manufactured during the same period as the resistors for Units 2 and 3. Due to the potential for common cause failure, the licensee initiated WO 2732276 to replace the resistor for the Unit 1 TDAFW pump governor power supply on August 20, 2004.

Analysis. The failure to promptly identify and correct the adverse condition was determined to be greater than minor because if left uncorrected, it could have become a more significant safety concern in that the Unit 1 turbine driven auxiliary feedwater pump could have experienced an unnecessary failure. This finding is associated with the equipment performance attribute of the mitigating systems cornerstone and affects the cornerstone objective of ensuring the reliability of systems that respond to initiating events. The failure of the power supply resistor would have affected the reliability of the auxiliary feedwater (AFW) system. Using the Phase 1 worksheet in Manual Chapter 0609, “Significance Determination Process,” the finding is determined to have very low safety significance because it only affected the mitigating systems cornerstone and did not result in an actual loss of safety function. The finding involved problem identification and resolution crosscutting aspects associated with engineering personnel not performing an adequate extent of condition review. The finding also involved human performance crosscutting aspects associated with engineering and maintenance personnel not communicating correct technical information.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” requires in part, that conditions adverse to quality be promptly identified and corrected. Contrary to the above, the licensee did not identify and correct an equipment condition adverse to quality in a timely manner. Specifically, the licensee failed to properly assess the extent of condition of the power supply resistor failures in Units 2 and 3, and the potential impact to Unit 1 AFW pump operability. Because the finding is of very low safety significance and has been entered into the corrective action program as CRDR 2746954, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000528; 05000529; 05000530/2004004-02, “Turbine Driven Auxiliary Feedwater Pump Governor Power Supply Resistor Failures.”

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the Updated Final Safety Analysis Report, procedure requirements, and Technical Specifications to ensure that the four below listed surveillance activities demonstrated that the SSCs tested were capable of performing their intended safety functions. The inspectors either witnessed or reviewed test data to verify that the following significant surveillance test attributes were adequate: (1) preconditioning; (2) evaluation of testing impact on the plant; (3) acceptance criteria; (4) test equipment; (5) procedural adherence; (6) jumper/lifted lead controls; (7) test data; (8) testing frequency and method demonstrated Technical Specification operability; (9) test equipment removal; (10) restoration of plant systems; (11) fulfillment of ASME Code requirements; (12) updating of performance indicator data; (13) engineering evaluations, root causes, and bases for returning tested SSCs not meeting the test acceptance criteria were correct; (14) reference setting data; and (15) annunciator and alarm setpoints. The inspectors also verified that the licensee identified and implemented any needed corrective actions associated with the surveillance testing.

- On September 2, 2004, Unit 2, performance of Procedure 73ST-9SI11, “Low Pressure Safety Injection Pumps Miniflow - Inservice Test,” Revision 15

- On September 5, 2004, Unit 1, performance of Procedure 73ST-9SI11, “Low Pressure Safety Injection Pumps Miniflow - Inservice Test,” Revision 15

- September 21, 2004, Unit 3, performance of Procedure 73ST-9CT01-3, “Condensate Transfer System - Inservice Test,” Revision 7

- September 24, 2004, Unit 3, performance of Procedure 40ST-9DG01, “Diesel Generator A Test,” Revision 21

The inspectors completed four samples.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the Updated Final Safety Analysis Report, plant drawings, procedure requirements, and Technical Specifications to ensure that the temporary modification listed below was properly implemented. The inspectors (1) verified that the modification did not have an affect on system operability/availability; (2) verified that the installation was consistent with the modification documents; (3) ensured that the post-installation test results were satisfactory and that the impact of the temporary modification on permanently installed SSCs were supported by the test; (4) verified that the modifications were identified on control room drawings and that appropriate identification tags were placed on the affected drawings; (5) verified that appropriate safety evaluations were completed; and (6) examined drawings, procedures, and operations logs for temporary modifications that have not been so designated. The inspectors verified that the licensee identified and implemented any needed corrective actions associated with temporary modifications.

- September 3, 2004, Unit 1, Temporary Modification 2733669, “Installation of Jumpers to Disable Heated Junction Thermocouple 2 on the ‘B’ QSPDS”

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

For the below listed drill and simulator-based training evolutions contributing to drill/exercise performance and emergency response organization performance indicators, the inspectors (1) observed the training evolution to identify any weaknesses and deficiencies in classification, notification, and protective action requirements development activities; (2) compared the identified weaknesses and deficiencies against licensee identified findings to determine whether the licensee is properly identifying failures; and (3) determined whether licensee performance is in accordance with the guidance and acceptance criteria of NEI 99-02, “Regulatory Assessment Indicator Guidelines,” Revision 2, documents.

- August 20, 2004, observation of an unannounced emergency preparedness drill to evaluate emergency response organization performance in responding to an off-hours call.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Mitigating Systems Cornerstone

a. Inspection Scope

The inspectors verified the accuracy of the performance indicator data reported and used the performance indicator definitions and guidance contained in NEI 99-2, “Regulatory Assessment Indicator Guideline,” Revision 2, to verify the basis in reporting for each data element.

- safety system functional failures (Units 1, 2, and 3)

The inspectors reviewed licensee event reports (LERs) for all three units from July 2003 through May 2004 to verify the accuracy and completeness of data associated with the safety system functional failures performance indicator.

- AFW system unavailability (Units 1, 2, and 3)

The inspectors reviewed unit logs and maintenance rule unavailability tracking database and Technical Specification component condition records from June 2003 through May 2004 to verify the accuracy and completeness of the unavailability data used to calculate the AFW system unavailability for all three units.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review

a. Inspection Scope

The inspectors reviewed a selection of CRDRs written during this period to determine if the licensee was entering conditions adverse to quality into the corrective action program at an appropriate threshold; the CRDRs were appropriately categorized and dispositioned in accordance with the licensee's procedures; and in the case of conditions significantly adverse to quality, the licensee's root cause determination and extent of condition evaluation were accurate and of sufficient depth to prevent recurrence of the condition.

b. Findings

No findings of significance were identified.

.2 Cross-References to PI&R Findings Documented Elsewhere

Section 1R12 describes a finding that involved untimely prioritization of work necessary to correct degraded equipment conditions.

Sections 1R19 and 4OA5 describe findings that involved inadequate extent of condition reviews.

Section 4OA5 describes a finding that involved engineering personnel not entering deficiencies into their licensee commitment tracking system and not generating a condition report/disposition request.

4OA3 Event Followup (71153)

.1 (Closed) LER 05000528/2004001-00: "Reactor Shutdown Due to Reactor Coolant System Pressure Boundary Leakage"

This LER is related to an apparent violation identified in NRC Inspection Report 05000528; 05000529; 05000530/2004002 which involved the discovery on

February 3, 2004, of a RCS pressure boundary leak from a socket weld upstream of 1-inch high pressure safety injection header Drain Valve 1-P-SIA-V056. A detailed discussion of this event, including enforcement aspects, is described in Section 4OA5. This LER is closed.

.2 (Closed) LER 05000529/2003002-00: "Engineered Safety Feature Actuation Unit 2 EDG Actuation"

On November 21, 2003, while testing the gas turbine generators (GTG) per a newly implemented Procedure 40TI-9GT01, "GTG Isochronous Test," Revision 0B, a valid engineered safety feature actuation signal occurred. The inspectors reviewed CRDR 2654236 and its significant root cause investigation. The licensee concluded that a faulty Relay 4S provided an "engine not running" signal. This relay is in the nonemergency portion of the EDG control system. When the bus was de-energized, this shifted the EDG control system to emergency mode. While in emergency mode, the Relay 4S is bypassed and the output breaker automatically closed to restore power to the vital bus. A procedural change to the GTG test procedure was made to ensure the EDG is in emergency mode while it is the only source of power to the bus. No new findings were identified in the inspectors' review. This LER is closed.

.3 (Closed) LER 05000528; 05000529; 05000530/2003004-00: "Cracks in Contact Block of Main Control Room Handswitches Resulted in Inoperable Equipment"

The discussion of this event is described in Section 4OA5 as an Unresolved Item (URI) 05000528; 05000529; 05000530/2003004-02. This LER is closed.

.4 (Closed) LER 05000530/2003001-01: "Main Steam Safety Valve As-Found Lift Pressures Outside of Technical Specification Limits"

The licensee submitted this LER supplement in response to an NRC identified minor violation documented in Inspection Report 05000528; 05000529; 0500030/2004006. The violation was a result of the team's determination that problem identification was inadequate based on the licensee's failure to identify that inaccurate information was provided to the NRC in the submittal of LER 05000530/2003001-00. The supplement to this LER corrected inaccurate information that related to the cause of the event. No new findings were identified in the inspectors' review. This LER is closed.

.5 (Closed) LER 05000530/2004001-00: "RCS Pressure Boundary Leakage Caused by Degraded Alloy 600 Components"

On February 29, 2004, engineering personnel, while performing a required boric acid walkdown, discovered a small quantity of boric acid on the pressurizer heater sleeve associated with Heater A03. Upon discovery, the licensee entered Limiting Condition for Operation 3.4.14, Condition B, at 5:21 a.m. on February 29, 2004. The licensee exited the limiting condition for operation at 6:08 a.m. on March 1 when the unit was brought to Mode 5, cold shutdown. Although a nondestructive examination was not performed for this heater sleeve, the licensee attributed this pressure boundary leak to primary water stress corrosion cracking of the Alloy 600 material comprising the sleeve. This conclusion was based on previous licensee inspections and industry experience with pressure boundary leakage from similar penetrations. The leaking sleeve was repaired with a mechanical nozzle seal assembly clamp, a device previously approved by the NRC staff for this application. Additional corrective actions included the scheduled replacement of all pressurizer heater sleeves with heater sleeves manufactured with Alloy 690 material during the October 2004 refueling outage. Based on previous experience with similar pressurizer heater sleeve pressure boundary leaks, the senior reactor analyst concluded that the leakage existed greater than 36 hours prior to the unit entering Mode 5. This finding is greater than minor since it is associated with the RCS performance attribute of the barrier integrity cornerstone and affects the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases. This finding had very low safety significance based on the very minor amount of boric acid residue identified (indicative of only trace amounts of through-wall leakage), no visible degradation of the pressurizer vessel, and a degradation mechanism for these pressurizer heater sleeve leaks not being capable of exceeding the Technical Specification limit for identified RCS leakage over the course of an operating cycle as described in the Phase 1 Significance Determination Process worksheet of NRC Manual Chapter 0609, Appendix A. This licensee-identified finding involved a violation of TS 3.4.14, Condition B. The enforcement aspects of the violation are discussed in Section 4OA7. This LER is closed.

.6 Reactor Coolant System (RCS) Level Deviation (Unit 1)

Introduction. A Green self-revealing noncited violation was identified for an inadequate procedure which resulted in an unexpected RCS level deviation during the Unit 1 RCS draindown to midloop conditions.

Description. On April 6, 2004, the licensee implemented Procedure 40OP-9ZZ16, “RCS Drain Operations,” Revision 40, to reduce RCS inventory to establish midloop conditions. During this draindown evolution, at a level of approximately 107.73 feet, an unexpected 1.71 foot sudden increase in reactor level indication occurred. In response to this event, the licensee secured the draindown and raised RCS level to exit reduced inventory.

During RCS draindown evolutions, the dynamics of the reactor water level indicating system are such that the actual level is greater than indicated level with the reactor vessel head installed. This level difference is caused by the increase in the static head difference between the water columns in the pressurizer/surge line and the reactor. This static head difference is equal to the pressure drop across the reactor head vent line orifice, and is what produces the lag between pressurizer level and reactor level during a draindown. This manometer effect created by the static head difference was more severe on April 6, 2004, since the two heated junction thermal-couples (HJTCs) had not been opened to provide increased venting capability. The reactor head vent line orifice provides a 0.028 square inch vent path and each HJTC provides a 0.25 square inch vent path.

The licensee’s CRDR 2695262 analysis postulated that the April 6, 2004, level anomaly occurred because the hydraulic line pressure balance was upset when level was sufficiently low enough to make a direction change from the horizontal portion of the pressurizer surge line into the vertical portion of the pressurizer surge line at approximately 107 feet 9 inches. This resulted in a sudden equalization of the static head difference between the reactor vessel and pressurizer which caused the level anomaly. The licensee calculated that the 1.71 foot indicated level change correlated to a 2.6 inch decrease in actual reactor water level.

Corrective actions in response to this level anomaly included incorporation of additional hold points into Procedure 40OP-9ZZ16 and a reduced drain rate to provide controlled equalization of the static head difference during draindown evolutions. The drain rate allowed by Procedure 40OP-9ZZ16 was 135 gallons per minute (gpm), but was usually maintained at 90 gpm or less. The 135 gpm was based on the maximum allowed drain rate associated with the chemical volume and control system and did not account for the reduced vent capability of only the reactor head orifice. With only the reactor head orifice vent path, the drain rate should have been reduced to minimize the static head difference between the water columns in the pressurizer/surge line and the reactor.

Analysis. The finding was greater than minor because it is associated with the equipment performance attribute of the mitigating systems cornerstone and affects the cornerstone objective of ensuring the reliability of systems that respond to initiating events. The inadequate procedure resulted in an actual unexpected indicated level transient while the reactor coolant system was being drained in reduced inventory conditions. Using Manual Chapter 0609, Appendix G, "Shutdown Operations Significance Determination Process," this finding is determined to have very low safety significance because the event did not constitute a loss of control and did not represent a finding requiring quantitative assessment. The finding did not increase the likelihood of loss or cause a degradation in the ability to restore decay heat removal, reactor coolant system inventory, offsite power, alternate core cooling, or containment.

Enforcement. 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings” requires, 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. Contrary to the above, Procedure 40OP-9ZZ16, “RCS Drain Operations,” Revision 40, was inadequate in that it did not provide reduced drain rates or increased hold points when only the reactor head vent was utilized to support draining evolutions. Because the finding is of very low safety significance and has been entered into the corrective action program as CRDR 2695262, this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy:
NCV 05000528/2004004-03, “Reactor Water Level Anomaly While in Reduced Inventory.”

.7 Air Voids in Sections of Recirculation Sump Piping

a. Inspection Scope

Evaluated plant conditions, equipment performance, and licensee actions related to air voiding in sections of the recirculation sump piping (Units 1, 2 and 3).

b. Findings

A special inspection was performed to review the licensee's response to the deficient condition and assess the associated safety implications. The results will be documented in NRC Special Inspection Report 05000528; 05000529; 05000530/2004014.

4OA4 Crosscutting Aspects of Findings

Section 1R19 describes a finding where engineering and maintenance personnel did not communicate correct technical information when performing an extent of condition review.

4OA5 Other Activities

a. (Closed) Apparent Violation (AV) 05000529/2004009-02, "Failure to Promptly Identify and Correct a Condition Adverse to Quality"

Introduction. A violation with very low safety significance (Green) was identified for the failure to promptly identify and correct a condition adverse to quality.

Description. During a special inspection to review the circumstances surrounding a steam generator tube leak in Unit 2, the team identified a violation for the failure to promptly identify that the locking ring slots for the steam generator nozzle dams were not adequately sized to allow the use of the standard lock pins, contributing to the damage to the diaphragms (NRC Report 05000529/2004009, Section 3.4). The significance of the violation was to be determined.

Analysis

Brief Description of Issue

On February 24, 2004, during the installation of the Steam Generator 22 hot leg nozzle dam, maintenance personnel experienced difficulties inserting the lock pins. Maintenance personnel noted that more force was needed to insert the pins than was used for the installation of the other nozzle dams.

After the installation of the hot leg nozzle dam in Steam Generator 22, operators received a Steam Generator 22 hot leg nozzle dam pressure high alarm. The alarm remained after maintenance personnel adjusted the appropriate pressure regulator. Maintenance personnel performed a pressure drop test and determined that the dry seal was leaking instrument air into the annulus area resulting in the high pressure alarm. These activities were occurring approximately 7 hours after entering reduced inventory.

The nozzle dam was qualified for approximately 22 psid across the passive seal. If there was a loss of shutdown cooling during a station blackout (worst-case scenario), there could be up to 50 psid across the nozzle dam. Because the nozzle dams had been qualified to approximately 22 psid across the passive seal, licensee engineers determined not to use the nozzle dam on the passive seal alone. Therefore, the licensee engineers decided to be conservative and replace the diaphragm.

After the installation of the second diaphragm, the maintenance personnel noted that it too had an air leak. This was noted after being in reduced inventory for approximately 30 hours.

Maintenance personnel stated that significant force had been required to install the replacement diaphragm. Plant engineering personnel had identified the need to use a set of “shaved” pins for the installation of the replacement diaphragm. However, maintenance personnel installing the replacement did not use the “shaved” pins.

These “shaved” pins were approximately 0.120 inches thinner at the end where the pin entered the locking ring slots reducing any interference fit concerns. The “shaved” pins were available to be installed, but maintenance personnel decided that it would take too long to replace the standard pins and they did not understand the need for the “shaved” pins. Therefore, the maintenance personnel proceeded with the standard pins.

Subsequently, another replacement diaphragm was obtained and was successfully installed with the “shaved” pins. The operators refilled the primary and exited reduced inventory after approximately 44 hours in reduced inventory operations.

Statement of Performance Deficiency

Licensee personnel failed to promptly identify that retaining ring slots were not adequately sized to allow the use of the standard lock pins, contributing to damage of the diaphragms. Subsequent to the identification, licensee personnel failed to correct the condition by not implementing the actions recommended by plant engineers. This failure significantly increased the amount of time that the plant was in reduced inventory operations and resulted in the need for an additional drain to midloop.

Significance Determination Basis

1. Phase 1 Screening Logic, Results, and Assumptions

In accordance with Manual Chapter 0612, Appendix B, “Issue Disposition Screening,” the inspectors determined that the issue was more than minor because it is associated with the mitigating systems cornerstone and affects RCS boundary performance. Specifically, the plant operated for an extended period in reduced inventory as a result of not correcting the incompatibility between the nozzle dams and the locking ring.

In accordance with Manual Chapter 0609, Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations,” the inspectors conducted a significance determination process (SDP) Phase 1 screening and determined that the finding needed to be evaluated in accordance with Manual Chapter 0609, Appendix G, “Shutdown Operations Significance Determination Process,” because it is a finding that is assumed to degrade the safety of a shutdown reactor.

The inspectors used Checklist 3, “PWR Cold Shutdown and Refueling Operation - RCS Open and Refueling Cavity Level < 23',” from Manual Chapter 0609, Appendix G, Attachment 1, “Shutdown Operations SDP Phase 1 Operational Checklists for both PWRs and BWRs.” A Phase 2 estimation was required because the finding represented a degradation of the licensee’s ability to recover decay heat removal should it be lost.

2. Phase 2 Estimation for Internal Events

In accordance with Manual Chapter 0609, Appendix G, Attachment 2, Step 4.2, the senior reactor analyst characterized the risk of entering and remaining in a second midloop as a condition finding. The analyst determined that all initiators were affected because the condition caused by the finding could affect the plant response in any of the sequences covered by the Plant Operating State (POS) 2 templates. As directed by Step 4.4.2, Table 5 was used to obtain the appropriate initiating event likelihoods (IELs). Given that the additional time in reduced inventory operations (exposure time) was less than 3 days, the IEL for loss of level control was found to be 2, the IEL for loss of inventory was found to be 4, the IEL for losses of offsite power was found to be 3, and the IEL for loss of the operating train of residual heat removal (RHR) system was found to be 3.

The following assumptions were made:

- Two high head safety injection pumps were available for injection to the core.

- Three positive displacement pumps were available, each pump had a 44 gpm flow rate. At the time of this condition, the decay heat rate in the core was high enough that two charging pumps were not able to makeup enough water to match the boil off rate should boiling occur.

- The condition existed between 80 and 160 hours after shutdown. Therefore, the time to boil was 17 minutes, the time to core uncovery was 45 minutes, and the time to core damage was estimated as 5 hours.

- Primary containment remained intact throughout the exposure time.

  Refueling water storage tank makeup would always have been successful because, at 755,000 gallons, the tank contained enough inventory to makeup to the RCS for well over 24 hours.

Based on these assumptions, the mitigating system credit provided for each of the top events is documented in Table 1.

Table 1: Phase 2 Mitigation Credits		
Top Event	**Credit**	**Limiting Credit Explanation**
FEED	4	Operator credit of 4 given in accordance with Appendix G. Equipment available provided a credit equal to or greater than that of the operator failure probability.
RHR-R	3	Operator credit of 3 was given for ability to vent and restart the operating RHR train.
RWSTMU	Success	As assumed, makeup was not needed for well over 24 hours.
EAC	3	Multi-train system was available for automatic start and load during the condition.
GRAVITY	3	Operator credit of 3 for establishing gravity feed after RCS boiling initiates.
LEAK-STOP	3	Operator credit of 3 for identifying and isolating the leak utilizing existing plant valves.
RHR-S	0	Sufficient time did not exist to recovery RHR before boiling started (17 minutes assumed).
RLOOP4	1	Assumed in Appendix G Templates
RLOOP18	2	Assumed in Appendix G Templates

Manual Chapter 0609, Appendix G, required that all initiating event scenarios be evaluated for this condition, given the plant operating state when the performance deficiency impacted the plant. However, because of the assumed success of the refueling water storage tank makeup function, scenarios with refueling water storage tank makeup were not included. The analyst identified and quantified the remaining core damage sequences from the templates.

Using the counting rule worksheet, this finding was estimated to have low to moderate safety significance (White). However, the templates do not clearly assess the increase in risk caused by the draining to midloop and the additional time spent in reduced inventory conditions. The analyst determined that the IEL for a loss of level control used in the templates was not reflective of the IEL that related to this performance deficiency. Therefore, a Phase 3 analysis was conducted.

3. Phase 3 Analysis

Internal Initiating Events

Assumptions:

A. The IEL for a loss of RHR system caused by a failure of operators to maintain level while the plant is in midloop operations is 9.4×10^{-6} per hour as documented in Table 2-1, "Industry-wide Initiating Event Frequencies Based on NUREG/CR-6144," of the Palo Verde 1, 2, and 3 Low Power and Shutdown Operation Standardized Plant Analysis Risk Model.

B. The likelihood for a loss of RHR system caused by operators overdraining the RCS during a drain to midloop is 9.8×10^{-3} per demand as documented in Table 2-1, "Industry-wide Initiating Event Frequencies Based on NUREG/CR-6144," of the Palo Verde 1, 2, and 3 Low Power and Shutdown Operation Standardized Plant Analysis Risk Model.

C. The air ingestion that took place in the RHR system during the extended midloop, as discussed in the inspection report, was not caused by the performance deficiency related to the nozzle dams. Therefore, in accordance with Manual Chapter 0609, Appendix A, Section III, "Concurrent Multiple Equipment or Functional Degradations," a separate inspection finding was written to address the potential risk associated with loss of the operating train of RHR. This was documented in NRC Inspection Report 05000529/2004009.

D. Refueling water storage tank makeup would always have been successful because, at 755,000 gallons, the tank contained enough inventory to makeup to the RCS for well over 24 hours.

E. Any two of the three charging pumps have the capacity (44 gpm each) to makeup for boil off in the vessel.

F. Either high pressure safety injection pump can be used for makeup. The suction of these pumps would be unaffected by any air accumulation in the RHR system.

G. The analyst determined that it was 3.6 times more likely that operators will overdrain the vessel during the first drain down to midloop than during subsequent drain downs, using data from NUREG/CR-6144, Volume 2, Part 1A, “Analysis of Core Damage Frequency from Internal Events During Mid-Loop Operations.”

H. The analyst determined that the probability of operators failing to inject via available sources following a loss of the operating train of RHR system and prior to core damage was on the order of 1×10^{-4}. (Reference: MC 0609, Appendix G, Phase 2, Worksheet 2, “SDP for a PWR Plant - Loss of Level Control in POS 2, RCS Vented.”)

I. The exposure time for this evaluation was the 44 hours that the plant was in reduced inventory operations. Additionally, the nominal time in midloop for placing a nozzle dam was taken as 7.75 hours. (Reference: Table 2-2, “Summary of Palo Verde 1, 2, & 3 SPAR LP/SD Model Initiating Event Frequencies,” note a, of the Palo Verde 1, 2, and 3 Low Power and Shutdown Operation Standardized Plant Analysis Risk Model).

Analysis

<u>IEL</u>

The analyst determined that the increased likelihood of a loss of RHR, as a result of this finding, could be determined by quantifying the following two factors:

- The likelihood of a loss of level control during the second drain down of the RCS that was the direct result of the performance deficiency.

- The likelihood of a loss of level control during the extended time at midloop that was the direct result of the performance deficiency.

Both these initiations were probabilities per demand or exposure period and are statistically independent of one another. Therefore, the analyst added the values to obtain an IEL of 3×10^{-3}/event. This value was approximately an order of magnitude smaller than the IEL from Manual Chapter 0609, Appendix G. The predominant difference is the assumption that a second drain to midloop is less likely to progress to a loss of RHR than is a first drain.

<u>RCS Injection Before Core Damage</u>

The analyst determined that both high head injection pumps and two charging pumps were available for injection throughout the reduced inventory operations. This resulted in the high head injection system, a multi-train system with failure rate estimated at 1×10^{-3} for it’s mission time, and the charging system, a single-train system (two pumps are required for success) with a failure rate estimated at 1×10^{-2} for its mission time, being available. Therefore, the estimated failure rate of all injection equipment is 1×10^{-5} for its mission time.

In accordance with Assumption H, the probability of operators failing to inject via available sources following a loss of the operating train of RHR system and prior to core damage is on the order of 1×10^{-4}.

The total probability that RCS injection fails to function is the sum of the failure probabilities for equipment and operator actions (i.e., 1×10^{-4}).

Borated Water Makeup Before Core Damage

As stated in the assumptions, refueling water storage tank makeup would always have been successful because, at 755,000 gallons, the tank contained enough inventory to makeup to the RCS for well over 24 hours. Therefore, Sequence 1 of Appendix G, Phase 2, Worksheet 2, "SDP for a PWR Plant - Loss of Level Control in POS 2, RCS Vented," was not evaluated.

The analyst determined that the only sequence that needed to be quantified was Sequence 2 of Worksheet 2. This sequence involved a loss of level control and a failure to inject to the vessel. The sequence was quantified at 3×10^{-7} core damage frequency over the exposure time.

This result indicated that the finding was of very low safety significance.

External Initiating Events

The plant specific SDP worksheets do not currently include initiating events related to fire, flooding, severe weather, seismic, or other external initiators. In accordance with Manual Chapter 0609, Appendix A, Attachment 1, Step 2.5, "Screening for the Potential Risk Contribution Due to External Initiating Events," experience with using the site specific risk informed inspection notebooks has indicated that accounting for external initiators could result in increasing the risk significance attributed to an inspection finding by as much as one order of magnitude. The analyst determined that an evaluation of external risk was required because the result of the Phase 2 provided a risk significance estimation of greater than or equal to 1×10^{-7}.

The analyst determined that in order for the risk associated with an external initiator to increase as a result of the subject finding, the initiator would have to result in a loss of level control during the 36.5 additional hours that the plant was in reduced inventory operations. Palo Verde Individual Plant Examination for External Events identified two event types that resulted in the majority of risk from external initiators: internal fires and seismic events. The analyst determined through quantitative evaluation that the initiating event frequencies for external initiators that could result in a loss of RHR were small enough that the combined core damage frequency would be negligible.

Potential Risk Contribution to Large Early Release Frequency (LERF)

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, Step 2.6, "Screening for the Potential Risk Contribution Due to LERF," the analyst assessed the impact of large early release frequency because the Phase 2 SDP result provided a risk significance estimation of greater than or equal to 1 x 10^{-7}.

The analyst determined that this issue represented a Type A finding. As such, the procedures in Manual Chapter 0609, Appendix H, Section 5.2, "Approach for Assessing Type A Findings During Shutdown," were used to evaluate the potential risk associated with this finding.

The finding occurred during POS 2, TW-E. As such, a Phase 2 assessment was completed. Resident inspectors determined that the containment had been "intact" and was required to be closed during midloop operations by licensee administrative procedures. The only applicable core damage sequence for internal events was Sequence 2 of Draft Appendix G, Phase 2, Worksheet 2, "SDP for a Westinghouse 4-Loop Plant - Loss of Level Control in POS 2."

Table 5.4, "Phase 2 Assessment Factors - Type A Findings at Shutdown," states that accident sequences in POS 2E screen out for pressurized water reactor large dry containments, provided that containment closure can be established within the time to boil. The licensee's procedures required the containment to be intact during midloop conditions, therefore, this issue screens out as not significant to LERF.

Enforcement. This issue was previously identified as a violation of Criterion XVI of Appendix B to 10 CFR Part 50. Because the risk analysis determined the significance to be very low, this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000529/2004004-04,"Failure to Promptly Identify and Correct a Condition Adverse to Quality." The licensee entered this issue into the corrective action program as CRDRs 2686201 and 2686271.

.2 Temporary Instruction (TI) 2515/154, "Spent Fuel Material Control and Accounting at Nuclear Power Plants"

The inspectors collected the data specified in Phases I and II of the TI. The data was forwarded to the individuals identified in the TI, for consolidation and assessment.

.3 TI 2515/159 Review of Generic Letter 89-13: "Service Water System Problems Affecting Safety-Related Equipment"

Per TI 2515/159, this report section is an approved one time deviation from the NRC's normal report format specified in NRC Manual Chapter 0612, "Power Reactor Inspection Reports," dated January 14, 2004.

The purpose of this inspection is to help the NRC evaluate licensee activities associated with historical operating experience and NRC generic communications. Generic Letter 89-13 was selected as the focus for TI 2515/159 because service water systems have a dominant role in plant risk profiles and the recommendations made in Generic Letter 89-13 are important to plant safety. At the Palo Verde Nuclear Generating Station, the station service water system is referred to as the essential spray pond system. The TI requires the inspectors to verify that licensees continue to properly implement programs and commitments associated with the generic letter. The NRC will assess the need for future regulatory actions based on the results of these inspections.

The inspectors evaluated the following five topical areas:

a. <u>The Effectiveness of Generic Letter 89-13 in Communicating Information</u>

Generic Letter 89-13 was clear in communicating information about service water system problems, both in the initial letter and the supplement. The inspectors found no problems with ambiguity in the generic letter's guidance or the licensee's interpretation of the guidance.

b. <u>Licensee Actions that are Being Implemented for the Five Recommended Actions of Generic Letter 89-13</u>

<u>Recommendation 1: For Open-Cycle Service Water Systems, Implement and Maintain an Ongoing Program of Surveillance and Control Techniques to Significantly Reduce the Incidence of Flow Blockage Problems as a Result of Biofouling</u>

The inspectors found that the licensee continued to properly implement this recommendation. The inspectors reviewed the licensee's response to Generic Letter 89-13 and the operational history of the essential spray pond system for the past two operating cycles. The inspectors also reviewed the implementation of the periodic inspection program to detect flow blockages from biofouling. The inspectors further reviewed related LERs CRDR forms, maintenance work requests, and heat exchanger test results.

<u>Recommendation 2: Implement a Test Program for the Heat Transfer Capability of all Safety-Related Heat Exchangers Cooled by the Service Water System</u>

The licensee continues to meet this recommendation. During every refueling outage, the licensee currently implements thermal performance testing for the essential cooling water heat exchangers which are cooled by the essential spray pond system.

In performing this testing, the licensee aligns the essential cooling water system to the spent fuel pool heat exchangers, in order to achieve the maximum possible load on the essential cooling water heat exchanger. From this alignment, the licensee establishes a heat balance across the essential cooling water heat exchanger using Procedure 70TI-9EW01, "Thermal Performance Testing of Essential Cooling Water Heat Exchangers," Revision 4, to record information for the test. The licensee uses Procedure 73DP-9ZZ10, "Guidelines for Heat Exchanger Thermal Performance Analysis," Revision 4, to calculate the performance of heat exchangers. The inspectors reviewed the results of these tests and calculations for all six essential cooling water heat exchangers from the most recent refueling outages.

The EDG cooling heat exchangers (jacket cooling water heat exchangers, lube oil heat exchangers, turbocharger aftercoolers, and fuel oil return line cooler) are also cooled by the essential spray pond system. The licensee's inspection of these other heat exchangers consists of visual inspections which are performed on both trains of diesel generators during each refueling outage. The inspectors verified that the inspections provide reasonable assurance that the diesel generator cooling heat exchangers are maintained continuously operable when required.

Recommendation 3: Ensure by Establishing a Routine Inspection and Maintenance Program for Open-Cycle Service Water System Piping and Components that Corrosion, Erosion, Protective Coating Failure, Silting, and Biofouling Cannot Degrade the Performance of the Safety-Related Systems Supplied by Service Water

The licensee had not adequately met this recommendation. The inspectors evaluated the licensee's (1) response to Generic Letter 89-13; (2) response to a Notice of Deviation identified in NRC Inspection Report 055000528; 05000529; 05000530/1993017; and (3) implementation of a routine inspection and maintenance program for open-cycle service water system piping and components.

Failure to Promptly Correct the Lack of an Adequate Routine Inspection and Maintenance Program, a Condition Adverse to Quality

Introduction. The inspectors identified a Green NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the failure to promptly correct the lack of an adequate routine inspection and maintenance program for the essential spray pond system piping and components. The finding had crosscutting aspects associated with problem identification and resolution. Specifically, corrective actions were not initiated because the licensee failed to enter the deficiencies into their licensee commitment tracking system and did not generate a CRDR.

Description. Generic Letter 89-13 was written because a number of national events called into question compliance of service water systems to requirements designed to ensure the systems would perform their safety function. The NRC requested that licensees either complete the recommended actions to address the specific areas of concern or develop equally effective actions to assure that latent failures do not remain unidentified. Specifically, the NRC recommended that licensees implement a routine inspection and maintenance program that assures that corrosion, erosion, protective coating failure, silting, and biofouling cannot degrade the performance of the safety-related systems supplied by the service water (essential spray pond) system or develop an equally effective alternative.

The licensee informed the NRC by letter dated July 1, 1991, that the Generic Letter 89-13 actions to which they had committed were implemented. In June 1993 the NRC performed an inspection to evaluate the licensee's implementation of these commitments. In that inspection (NRC Inspection Report 05000528; 0500029; 05000530/1993017) the inspectors identified a Notice of Deviation for, in part, the failure to include the inspection of service water (essential spray pond system) piping in regular preventive maintenance program tasks.

The licensee provided a response to the NRC's Notice of Deviation in a letter dated September 3, 1993. In a followup letter dated December 29, 1995, (Letter 102-03576), the licensee notified the NRC of their intent to revise their 1993 response to the Notice of Deviation. In this letter, the licensee stated, “The revised response will include a plan to develop maintenance tasks that periodically inspect service water system piping. . . . Video camera inspections on a portion of the spray pond piping in Units 1 and 3 will be conducted during Refueling Outages 1R4 and 3R4, respectively. Engineering will evaluate the inspection results from all three units (Unit 2 has already been inspected and evaluated as satisfactory) and recommend the scope and frequency of spray pond system piping inspections to be included in the preventive maintenance program by June 30, 1994.”

During this current inspection, the inspectors identified that the licensee had not submitted a revised response to the Generic Letter 89-13 commitments and, as of the close of the inspection, had not developed an alternative equally effective essential spray pond piping inspection and maintenance program.

Specifically, the licensee had developed revised guidance, which they incorporated into Revisions 1 and 2 of the Nuclear Administrative and Technical Manual, 73DP-0ZZ04, “Service Water Reliability Program.” Section 3.4, “Piping Inspections,” of Manual 73DP-0ZZ04 states the following:

> “Portions of Units 1, 2, and 3 spray pond piping have been visually inspected using a remote camera/pipe crawler. The planned inspections of spray pond piping are intended to be performed during scheduled refueling and maintenance outages.”
>
> “Based upon completed piping inspections, the GL 89-13 Program Manager shall determine a scope and periodicity for future piping inspections in all three Units.”
>
> “The GL 89-13 Program Manager shall generate Work Requests for the intended inspections prior to the establishment of final outage work scope for a particular unit refuel outage. . . .”

The inspectors found this guidance to not be equally effective for the following reasons:

- The revised response described in Manual 73DP-0ZZ04 did not provide a methodology for developing maintenance tasks that would periodically inspect service water (essential spray pond) system piping. Therefore, the scope and periodicity of the piping inspections were not included in a preventive maintenance program.

- The licensee had no documentation to show that service water piping inspections had occurred between September 1998 and March 2003.

- Work orders issued before September 1998 and after March 2003, simply stated “inspect” or “perform TV inspection” or “perform boroscope inspection,” without any guidance in terms of scope, extent of inspection, or acceptance criteria.

- The inspectors determined that the licensee's inspections prior to September 1998 and after March 2003 had only evaluated the condition of the coating on the inside diameter of the piping. The licensee had not inspected the piping with respect to the other generic letter specified parameters, such as corrosion, erosion, silting, and biofouling.

Analysis. The inspectors identified a finding associated with the failure to promptly correct the lack of an adequate routine inspection and maintenance program for the essential spray pond system piping and components. This finding was more than minor because it affected the reactor safety mitigating systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences as described in NRC Manual Chapter 0612, Appendix B. Both the EDGs and the essential cooling water systems respond to initiating events and they are cooled by the essential spray pond system.

The finding is of very low safety significance because the risk significant function was not impacted, so the issue constitutes a nonconforming condition that has been shown not to impact the operability of safety-related equipment. This finding has crosscutting aspects in the area of problem identification and resolution because the licensee failed to implement corrective actions to address a condition adverse to quality identified by the NRC in 1993. In addition, the licensee failed to fulfill a commitment to implement a program that adequately addressed recommendations in Generic Letter 89-13.

Enforcement. Criterion XVI of 10 CFR Part 50, Appendix B, requires, in part, that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. Contrary to the above, the licensee failed to assure a condition adverse to quality was corrected. Specifically, the licensee did not promptly correct the lack of an adequate routine inspection and maintenance program for the essential spray pond system piping and components. Because this finding is of very low safety significance and has been entered into the licensee's corrective action program as CRDR 2732683, this finding is being treated as a NCV consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000528; 05000529; 05000530/2004004-05, "Ineffective Corrective Actions to Address an Inadequate Service Water Piping Inspection Program"

Recommendation 4: Verify that the Service Water System will Perform its Intended Function in Accordance with the Design Basis for the Plant

The licensee continued to meet this recommendation. The inspectors reviewed the design basis of the spray pond and the essential spray systems. This effort included review of the safety analysis report, safety evaluation report, drawings, calculations, Technical Specifications, design basis manual, procedures, and training documents of the two systems. Inspectors also reviewed the acceptance criteria found in procedures and the system health report. To assure that the licensee was maintaining the design basis, inspectors reviewed corrective action documents, corrective maintenance, and modifications. The inspectors also reviewed documents associated with subsystems that are designed to minimize silting and biofouling. The licensee took credit for its pre-operational testing, so the inspectors reviewed the heat balancing of essential cooling water system performed during preoperational testing. The licensee performed a engineering review of the design in response to Generic Letter 89-13 which the inspectors reviewed as well.

The inspectors performed a walkdown of the spray pond and the essential spray systems to verify the material condition of the system. The inspectors evaluated equipment lubrication, efficiency tags, and general equipment condition.

Recommendation 5: Verify that Maintenance Practices, Operating and Emergency Procedures, and Training that Involves the Service Water System are Adequate to Ensure that Safety-Related Equipment Cooled by the Service Water System Will Function as Intended and that the Operators of this Equipment Will Perform Effectively

The licensee continued to meet this recommendation. The inspectors reviewed the licensee's response to Generic Letter 89-13 and the maintenance history of the service water system for the past two operating cycles to determine if recurring equipment problems existed. The inspectors also reviewed the maintenance procedures for technical adequacy. Finally, the inspectors reviewed the service water system training program and procedures, and training records of maintenance personnel identified in work orders to have worked on the service water system. The inspectors verified the proper alignment of valves in the systems by review of procedures and during the system walkdown.

c. Effective Programmatic Maintenance of the Actions in Response to Generic Letter 89-13

As noted in Recommendation 3 above, the licensee had not consistently maintained proper programmatic controls over their Generic Letter 89-13 program.

d. As applicable, Noteworthy Service Water System Operational History that Supports Inspection Results.

The licensee has not experienced significant operational problems associated with service water issues.

e. Effectiveness Assessment of Licensee's Program Procedure(s) on Related Service Water System Operating Experience

The inspectors reviewed the licensee's operating experience program and associated procedures. The inspectors reviewed service water related condition reports to ensure that the licensee did not experience plant problems due to known issues already identified by industry operating experience and NRC generic communications. No problems were identified.

.4 (Closed) URI 05000528; 05000529; 05000530/2003004-02, "Root Cause and Safety Significance for Cracked Control Room Switches"

NRC Inspection Report 05000528, 05000529, 05000530/2003004-02 described a condition where several control room switch contact blocks were cracked. This condition potentially affected switches among all three units. This URI was opened to assess the safety significance and root cause evaluation for these cracked switch contact blocks.

The licensee's root cause analysis determined that the failure was related to the original installation of the switch possibly combined with aging of the components. The licensee's corrective action was to (1) replace cracked switches on all units, with Unit 3 schedule for completion in October 2004; and (2) revise generic work instructions to caution not to overstress new switches during installation. The inspectors reviewed the licensee's root cause analysis and did not identify any finding of significance. This URI is closed.

.5 (Closed) Apparent Violation (AV) 05000528/2004002-03, "Failure to Remove Pipe Support Leads to RCS Pressure Boundary Leak"

Introduction. A self-revealing Green noncited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was identified for the failure to implement a modification. The modification should have removed a pipe support associated with a high pressure safety injection system drain line. Failure to remove the pipe support, combined with high vibrations, resulted in a reactor coolant system pressure boundary leak from a cracked socket weld upstream of high pressure safety injection header drain Valve 1-P-SIA-V056

Description. The AV identified in NRC Inspection Report 05000528; 05000529; 05000530/2004002 involved the discovery on February 3, 2004, of a RCS pressure boundary leak from a socket weld upstream of 1-inch high pressure safety injection header Drain Valve 1-P-SIA-V056. The inspectors concluded that a violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," had occurred. The violation involved the licensee's failure to implement a modification that should have removed a pipe support associated with the high pressure safety injection drain line. Failure to remove the pipe support resulted in the socket weld remaining susceptible to high cycle fatigue failure.

The licensee discovered this condition while the unit was operating at nearly full power. During a planned containment entry to perform other work, licensee personnel identified an approximately 1-2 drops/second leak from the upstream socket weld of Valve 1-P-SIA-V056. Upon contacting the control room, operations staff entered Technical Specification Limiting Condition for Operation 3.4.14 and initiated a plant shutdown and cooldown. The licensee later repaired the socket weld and restored the pipe supports to their proper configuration. The finding was assumed to have increased the likelihood of an initiating event, specifically, a loss-of-coolant accident. The significance of this finding had not been determined at the conclusion of the inspection.

Analysis. The senior reactor analyst reviewed this finding and determined that it was of very low safety significance (Green). The factors (assumptions used in the significance determination process, Manual Chapter 0609, Appendix A causing the finding to be of very low safety significance are described below:

The analyst reviewed LER 05000528/2004001-00 and the licensee's root cause evaluation documented in CRDR 2669474. The analyst also reviewed the licensee's procedure for monitoring and responding to RCS leakage as documented in Procedure 40ST-9RC02, "ERFADS (Preferred) Calculation of RCS Water Inventory," Revision 25.

Based on interviews with staff who identified the leak, only a very small amount of leakage was present at the time of discovery; and based on the lack of boric acid crystals and small amount of water present on the floor beneath the valve, the leak likely initiated just prior to the discovery. The licensee performed a destructive examination and metallurgical analysis of the socket weld to identify the crack extent and its cause. The examination showed no evidence of an initial weld flaw that could have caused the crack. The crack appeared to have been caused by cyclic fatigue and not due to inadequate material properties nor stress corrosion cracking. The licensee performed a fracture mechanics analysis based on the as-found crack dimensions, piping and weld configuration, materials, and vibration, and determined the critical flaw size (the size of the crack at which point it becomes unstable and can fail the joint completely). With an as-found dimension of 21.4° of the weld circumference, the critical flaw size (with a safety factor of three) was determined to be 191° of circumference. The time expected to reach the critical flaw dimension was 305 days. The licensee also performed an analysis of leakage rates versus flaw sizes. The licensee estimated that the leakage rate would have reached approximately 0.2 gpm after approximately 275 days. The leakage would continue to increase continuously to approximately 5 gpm at the time of failure. The analyst conferred with experts in fatigue analysis and materials engineering from the Office of Nuclear Reactor Regulation, and these experts informed the analyst that this result appeared reasonable.

The analyst reviewed the licensee's RCS inventory monitoring procedure and confirmed that it required actions for investigation of potential sources of RCS leakage when unidentified leakage rates were determined to exceed an alert level of 0.12 gpm. Technical Specification 3.4.14 required this leakage rate be determined every 72 hours. In practice, RCS leakage rate determinations were performed more frequently. Technical Specification 3.4.14 also required the unit be shutdown if unidentified leakage exceeded 1 gpm.

The analyst concluded that, if the leak had not been discovered and repaired in February 2004 the leakage rate would likely not have reached detectable levels using the RCS leakage detection systems prior to the start of the April 2004 refueling outage. However, due to the high-traffic location of the valve and work planned to be performed in its vicinity, it was highly likely the leak would have been discovered during the refueling outage during the licensee's boric acid walkdown inspections. However, even if the unit had been restarted without discovering and repairing the flaw, the analyst concluded that the increasing leakage rate would have reached a detectable quantity and exceeded the alert level requiring investigation, shutdown, and repair, prior to the flaw propagating to critical size. Therefore, assuming worst case degradation, this finding would not have resulted in exceeding the Technical Specification limit for RCS identified leakage (10 gpm). Consistent with the Significance Determination Process Phase 1 worksheet in Manual Chapter 0609, Appendix A, this finding is, therefore, of very low safety significance (Green).

Enforcement: Because this failure to comply with 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” is of very low safety significance and has been entered in the licensee’s corrective action program as CRDR 2669474, this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000528/2004004-06, "Failure to Remove Pipe Support Leads to RCS Pressure Boundary Leak."

4OA6 Meetings, Including Exit

The regional engineering inspectors presented the inspection results to Mr. Craig Seaman, Director, Nuclear Fuel Management, and other members of licensee management on August 20, 2004. Licensee management acknowledged the inspection findings. Licensee management acknowledged the inspection findings.

The resident inspectors presented the inspection results of the integrated inspection to Mr. G. Overbeck, Senior Vice-President, Nuclear, and other members of the licensee's management staff at the conclusion of the inspection on October 21, 2004. Licensee management acknowledged the inspection findings.

The inspectors noted that while proprietary information was reviewed, none would be included in this report.

4OA7 Licensee-Identified Violations

The following violation of very low significance (Green) was identified by the licensee and is a violation of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as a NCV.

> Technical Specification Limiting Condition for Operation 3.4.14 requires that RCS pressure boundary leakage shall be limited to no pressure boundary leakage. Condition B requires, for the existence of pressure boundary leakage, that the plant be in Mode 5 within 36 hours. Contrary to this, the licensee was in violation of Technical Specification Limiting Condition for Operation 3.4.14, Condition B, since a pressure boundary leakage on a pressurizer heater sleeve associated with Heater A03 existed greater than 36 hours prior to the unit entering Mode 5. This finding was documented in CRDR 2687292 and LER 05000530/2004001-00.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

S. Bauer, Department Leader, Regulatory Affairs
P. Borchert, Director, Work Management
S. Coppock, Department Leader, System Engineering
A. Davé, Senior Engineer
M. Grigsby, Unit Department Leader, Operations
J. Hughey, Senior Engineer, Systems Engineering
D. Marks, Section Leader, Regulatory Affairs
M. McGhee, Unit Department Leader, Operations
G. Overbeck, Senior Vice President, Nuclear Operations
S. Peace, Consultant, Owners Services
S. Pittalwala, Director, Project Engineering
D. Mauldin, Vice President, Engineering and Support
M. Radsprinner, Section Leader, Systems Engineering
T. Radtke, Director, Operations
F. Riedel, Director, Nuclear Training Department
C. Seaman, Director, Nuclear Fuel Management
K. Schrader, Section Leader, Design Engineering
M. Shea, Director, Maintenance
D. Smith, Plant Manager, Production
M. Sontag, Department Leader, Nuclear Assurance
D. Straka, Senior Consultant, Regulatory Affairs
K. Sweeney, Section Leader, Steam Generator Project Group
J. Taylor, Department Leader, Operations Support
T. Weber, Section Leader, Regulatory Affairs
D. Wheeler, Section Leader, Nuclear Assurance Department
M. Winsor, Director, Engineering

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000528; 05000529; 05000530/2004004-01	NCV	Untimely Lubrication of Reach Rods for Safety-Related Manual Valves (Section 1R12)
05000528; 05000529; 05000530/2004004-02	NCV	Turbine Driven Auxiliary Feedwater Pump Governor Power Supply Resistor Failures (Section 1R19)
05000528; 05000529; 05000530/2004004-03	NCV	Reactor Level Anomaly while in Reduced Inventory (Section 4OA3)
05000528; 05000529; 05000530/2004004-04	NCV	Failure to Promptly Identify and Correct a Condition Adverse to Quality (Section 4OA5)

05000528; 05000529; 05000530/2004004-05	NCV	Ineffective Corrective Actions to Address an Inadequate Service Water Piping Inspection Program (Section 4OA5)
05000528; 05000529; 05000530/2004004-06	NCV	Failure to Remove Pipe Support Leads to RCS Pressure Boundary Leak (Section 4OA5)

Closed

05000530/2003001-01	LER	Main Steam Safety Valve As-Found Lift Pressures Outside of Technical Specification Limits (Section 4OA3)
05000529/2003002-00	LER	Engineered Safety Feature Actuation Unit 2 EDG Actuation (Section 4OA3)
05000528; 05000529; 05000530/2003004-00	LER	Cracks in Contact Block of Main Control Room Handswitches Resulted in Inoperable Equipment (Section 4OA3)
05000528/2004001-00	LER	Reactor Shutdown Due to RCS Pressure Boundary Leakage (Section 4OA3)
05000528; 05000529; 05000530/2003004-02	URI	Root Cause and Safety Significance for Cracked Control Room Switches (Section 4OA5)
05000530/2004001-00	LER	RCS Pressure Boundary Leakage Caused by Degraded Alloy 600 Components (Section 4OA3)
05000528/2004002-03	AV	Failure to Remove Pipe Support Leads to RCS Pressure Boundary Leak (Section 4OA5)
05000529/2004009-02	AV	Failure to Promptly Identify and Correct a Condition Adverse to Quality (Section 4OA5)

LIST OF DOCUMENTS REVIEWED

In addition to the documents called out in the inspection report, the following documents were selected and reviewed by the inspectors to accomplish the objectives and scope of the inspection and to support any findings:

Section 1R04: Equipment Alignment

Drawings

01-E-DGB-009, “Elementary Diagram Diesel Generator System Instrumentation and Alarms,” Revision 4

01-M-DGP-001, “P&I Diagram Diesel Generator System,” Sheet 1, Revision 44
01-M-DGP-001, “P&I Diagram Control Air Diesel Generator System,” Sheet 2, Revision 44
01-M-DGP-001, “P&I Diagram Lube Oil Diesel Generator System,” Sheet 3, Revision 44
01-M-DGP-001, “P&I Diagram Jacket Water Diesel Generator System,” Sheet 4, Revision 44
01-M-DGP-001, “P&I Diagram Fuel Oil Diesel Generator System,” Sheet 7, Revision 44
13-J-03K-097, “Diesel Generator A or B Fuel Oil Day Tk Lvl Control,” Revision 5
01-M-SIP-001, “P&I Diagram Safety Injection and Shutdown Cooling System,” Revision 28
02-M-SIP-001, “P&I Diagram Safety Injection and Shutdown Cooling System,” Revision 24
03-M-SIP-001, “P&I Diagram Safety Injection and Shutdown Cooling System.” Revision 21
02-M-CHP-002, “P&I Diagram Chemical and Volume Control System,” Revision 39
03-M-CHP-002, “P&I Diagram Chemical and Volume Control System.” Revision 37

Work Maintenance Order

WM 2689302

CRDR

2722846

Section 1R05: Fire Protection

Procedure

14DP-0FP33, “Control of Transient Combustibles,” Revision 11

CRDRs

2723103, 2723278, and 2724956

Drawings

03-E-ZCL-007, “Main Steam Support Structure Lighting & Communication Plans at El. 81' thru and 110'-3",” Revision 2

03-E-ZCL-008, “Main Steam Support Structure Lighting & Communication Plans at El. 120'-0", 132'-0", and 140'-0",” Sheet 1, Revision 2
03-E-ZCL-008, “Main Steam Support Structure Lighting & Communication Plans at El. 148'-0" and 166'-11",” Sheet 2, Revision 2

Section 1R06: Flood Protection Measures

Drawings

01-M-OWP-003, “Oily Waste and Non-Radioactive Waste System (Control Building),” Revision 6
02-M-OWP-003, “Oily Waste and Non-Radioactive Waste System (Control Building),” Revision 4

03-M-OWP-003, “Oily Waste and Non-Radioactive Waste System (Control Building),” Revision 3

Section 1R12: Maintenance Effectiveness

Procedures

02DP-0ZZ01, “Verification of Plant Activities,” Revision 6
12DP-0MC46, “Receipt Inspection,” Appendix A, Revision 2
60DP-0QQ17, “Conduct of Nuclear Assurance Evaluations,” Revision 14
77DP-0WG01, “Electronics Rework Facility Functional Test Guidelines,” Revision 1
77DP-0AC01, “Electronics Rework Facility Functional Test Control,” Revision 1
80DP-0DC01, “Reverse Engineering and Manufacturing Process,” Revision 2

Drawings

01-E-DGB-007, “Diesel Generator System Diesel Engines Control,” Revision 7
13-MO18-00141, “EDG Control Schematic (Starting Sequence Control),” Revision 22
13-MO18-00142, “EDG Control Schematic (Starting Sequence Control),” Revision 23
13-MO18-00143, “EDG Control Schematic (Starting Sequence Control),” Revision 17
13-MO18-00144, “EDG Control Schematic (Starting Sequence Control),” Revision 11
13-MO18-00153, “EDG Control Schematic (Starting Sequence Control),” Revision 16
13-MO18-00702, “Fiber Optic Power Supply Board SPS 145-10,” Revision 2
13-MO18-01232, “EDG Control Schematic (Starting Sequence Control),” Revision 1

Miscellaneous

Functional Test FTA-100, “Technipower Power Supply,” Revision 2
Functional Test FTA-112, “CE PPS Bistable Comparator Card,” Revision 2.2
Functional Test FTA-401, “MSFIS Replacement Board,” Revision 1.2
Engineering Document Change (EDC) 2001-00201, “Replace Fiber Optic Boards with New Design”
Quality Receiving Checklist 0516-02, “Receiver Signal Conditioner for EDG”
Quality Receiving Checklist 0519-02, “Transmitter Signal Conditioner for EDG”
Nuclear Assurance Evaluation Reports ER 01-0220, ER 01-0255, ER 01-0453, ER 02-0265, ER 03-0079, and ER 04-0158
218265, “Design Input Requirements Checklist,” Revision 1
MEE-01168, “Commercial Grade Item Type Evaluation for Printed Circuit Boards,” Revision 2
MEE-01024, “Commercial Grade Item Type Evaluation for Integrated Circuits,” Revision 2
MEE-01080, “Commercial Grade Item Type Evaluation for Power Supply Modules,” Revision 1
Pending Change Package 2369438, “Develop Inspection Plans for Fiber Optic Cards Manufactured per DMWO 218265,” dated March 6, 2001
Preventative maintenance basis Documents 248707 and 248709

CRDRs

2722998, 2395840, 2405543, and 2405526,

Work Orders

2556988, 2590651, 2492915, and DMWO 218265

Section 1R13: Risk Assessments and Work Control

Procedure

30DP-9MT03, “Assessment and Management of Risk When Performing Maintenance in Modes 1-4,” Revision 8

Section 1R14: NonRoutine Events

Miscellaneous

Operator Logs
DFWO 2735428
DIWO 2735417

Drawings

13-SI-106-H-007, “Pipe Support Assembly,” Revision 5
13-SI-106-H-009, “Pipe Support Assembly,” Revision 2
13-SI-106-H-011, “Pipe Support Assembly,” Revision 2

Section 1R15: Operability Evaluations

CRDRs

2721573, 2722278, 2736375, 2736478, and 2741069

Miscellaneous

Operability Determination 259
Calculation 13-MC-ZA-023, “Aux Building HELB Analysis,” Revision 2

Procedures

40EP-9EO01, “Standard Post Trip Actions,” Revision 11
40EP-9EO03, “Loss of Coolant Accident,” Revision 15
40EP-9EO05, “Excess Steam Demand,” Revision 14
40EP-9EO09, “Functional Recovery,” Revision 20

Drawings

01-M-GAP-001, “Service Gas System (N_2 and H_2 Supply),” Revision 15
01-M-HPP-001, “Containment Hydrogen Control,” Revision 16
02-M-HPP-001, “Containment Hydrogen Control,” Revision 18
03-M-HPP-001, “Containment Hydrogen Control,” Revision 11

Section 1R16: Operator Workarounds

Computer printout of operator workarounds, burdens, and challenges dated August 10 and 12, 2004

Section 1R19: Postmaintenance Testing

Drawing
Portec Inc.,Drawing Number 072-12201-710, “Bridge Schematic,” Revision C

Section 1R22: Surveillance Testing

Drawing

03-M-CTP-001, “Condensate Storage and Transfer System,” Revision 15

Section 1EP6: Drill Evaluation

CRDR

2733268

Section 4OA2: Identification and Resolution of Problems

CRDRs

2521361, 2569898, 2721804, 2732786, 2735052, 2735329, 2735332, 2735671, 2735943, 2736244, and 2736275

Procedures

39MT-9ZZ02, “PM or EQ Inspection of the GL 89-10 Limitorque SMB/SB Motor Operated Valve Actuators,” Revision 14
39MT-9ZZ03, “PM/EQPM Inspection of the Limitorque SMC Valve Motor Operators,” Revision 7

90DP-0IP10, “Condition Reporting,” Revision 18

Work Order/Instruction

DFWO 2489994
DI 2490060

Safety Evaluations

S-02-0179, Revision 0

Section 4OA5: Other Activities

Procedure

40TI-9GT01, “GTG Isochronous Test,” Revision 0B

CRDR

2654236

Section: 1R07 and 4OA5

Calculations

73DP-9ZZ10, “Guidelines for Heat Exchanger Thermal Performance Analysis.” Revision 4
70TI-9EW01, “Thermal Performance Testing of Essential Cooling Water Heat Exchangers,” Revision 4

Inspection Records for Diesel Generator Heat Exchangers

Unit 1 Diesel Generators 1A and 1B, April 20, 2004
Unit 3 Diesel Generators 3A and 3B, April 14, 2003
Unit 2 Diesel Generators 2A and 2B, October 28, 2003

CRDRs

2428176, 2490694, 2577160, 2651121, 2653867, 2655779, 2699739, 2732683, 2720437, and 2732345

Procedures

40OP-9SP03, “Spray Pond Chemical Addition System Train A,” Revision 16
40OP-9SPO4, “Spray Pond Chemical Addition System Train B,” Revision 15
40OP-9SP05, “Essential Spray Pond Filter Operations Train A,” Revision 13
40OP-9SPO6, “Essential Spray Pond Filter Operations Train B,” Revision 13
40OP-9SP01, “Essential Spray Pond (SP) Train A,” Revision 31

40OP-9SP02, “Essential Spray Pond (SP) Train B,” Revision 28
40DP-9OP06, “Operations Department Repetitive Task Program,” Revision 74
70DP-9SP01, “Spray Pond Piping Integrity Verification,” Revision 1
73ST-9SP01, “Essential Spray Pond Pumps - Inservice Test,” Revision 20
41ST-1SP02, “Essential Spray Pond Pump Inservice Performance Test,” Revision 11
74CH-9SP01, “Essential Spray Pond System Corrosion Monitoring,” Revision 4
74DP-9CY04, “Systems Chemistry Specifications,” Revision 27
73DP-0ZZ04, “Service Water Reliability Program,” Revision 2
41AL-1RK2A, “Panel B02A Alarm Response,” Revision 43
42AL-1RK2A, “Panel B02A Alarm Response,” Revision 47
43AL-1RK2A, “Panel B02A Alarm Response,” Revision 45
65DP-0QQ01, “Industry Operating Experience,” Revision 6

73DP-9ZZ10, “Guidelines for Heat Exchanger Thermal Performance Analysis,” Revision 4
70TI-9EW01, “Thermal Performance Testing of Essential Cooling Water Heat Exchangers,” Revision 4

Work Orders

2651343, 2639607, 587370, 601500, 613238, 658517, 724838, 749118, 768238, 794288, 822536, 851172, and 895502

Maintenance Training Records

LP Number: NMD20C000102, “Pump Theory,” June 6, 2003
LP Number: NMD20C000202, “Centrifugal Pumps,” June 6, 2003
LP Number: NMD20C000302, “Positive Displacement Pumps,” June 6, 2003
LP Number: NMB48C000103, “Valve Inspection, Disassembly, and Rework,” September 9, 2003
LP Number: NMB48C000203, “Valve Refurbishment,” September 9, 2003
LP Number: NMZ48P000101, “Practical Exercise” (for valves), September 9, 2003
LP Number: NMB48C000303, “Valve Packing,” September 9, 2003
LP Number: NMB48C000403, “Valve Rework Verification,” September 9, 2003
LP Number: NMD40C000100, “Heat Exchanger Construction and Operation,” May 24, 2002
LP Number: NMD40C000200, “Heat Exchanger Inspection and Cleaning,” May 24, 2002
LP Number: NMD40C000300, “Heat Exchanger Tube Maintenance,” May 24, 2002

Piping and Instrumentation Drawings

Unit 1 P&ID 01-M-SPP-001, “Essential Spray Pond System,” Sheets 1, 2, and 3, Revision 5
Unit 2 P&ID 02-M-SPP-001, “Essential Spray Pond System,” Sheets 1, 2, and 3, Revision 36
Unit 3 P&ID 03-M-SPP-001, “Essential Spray Pond System,” Sheets 1, 2, and 3, Revision 33
Unit 2 P&ID 02-P-SPF-701, “Essential Spray Pond System,” Revision 0
Unit 2 P&ID 02-P-ZA-061, ”Essential Spray Pond System Isometric,” Revision 0
Unit 2 P&ID 02-P-ZA-926, “Essential Spray Pond System Isometric,” Revision 1
Unit 2 P&ID 02-P-ZA-925, “Essential Spray Pond System Isometric,” Revision 0
Unit 2 P&ID 02-P ZA-927, “Essential Spray Pond System Isometric,” Revision 0
Unit 2 P&ID 02-P-ZA-928, “Essential Spray Pond System Isometric,” Revision 0
Unit 2 P&ID 02-P-SPF201, “Essential Spray Pond System,” Revision 0

Miscellaneous

Unit 1 PSB Test Schedule for 73ST-9ZZ20
NKASYC0127, “Emergency Diesel Generator Lesson Plan,” Revision 0
NKASYC107, “Essential Cooling Water System Lesson Plan,” Revision 0
NKASYC106, “Essential Spray Pond System Lesson Plan,” Revision 0
Letter 102-03576-WOS/ASK/DAK, “Revised Response to Notice of Deviation 05500028; 0500029; 0500030/9317002,” December 29, 1995
Design Basis Manual, “Essential Spray Pond System,” Revision 13

LIST OF ACRONYMS

AFW	auxiliary feedwater
AV	apparent violation
CFR	*Code of Federal Regulations*
CRDR	condition report/discrepancy request
EDG	emergency diesel generator
GTG	gas turbine generators
HJTC	heated junction thermocouple
IELs	initiating event likelihoods
LER	licensee event report
LERF	large early release frequency
NCV	noncited violation
POS	plant operating state
RCS	reactor coolant system
RHR	residual heat removal
SDP	significance determination process
SSC	structure, system, and component
TDAFW	turbine driven auxiliary feedwater
TI	temporary instruction
URI	unresolved item
WO	work order