UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

January 5, 2005

EA-04-221

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 SPECIAL INSPECTION REPORT 05000528/2004014, 05000529/2004014, AND 05000530/2004014; PRELIMINARY GREATER THAN GREEN FINDING

Dear Mr. Overbeck:

On August 23-27, 2004, the U.S. Nuclear Regulatory Commission (NRC) conducted the onsite portion of a special inspection at your Palo Verde Nuclear Generating Station (PVNGS). In-office inspection reviews and onsite observations of your pump testing program continued through December 8, 2004. The enclosed report documents the inspection findings which were discussed with you and members of your staff on December 9, 2004. The inspection was conducted in response to the discovery that a significant volume of containment sump safety injection suction piping was void of water. The failure to maintain this piping full could have challenged the ability of the high pressure safety injection and containment spray systems in performing their safety functions during certain design basis accident conditions. As discussed in detail in the enclosed report, because the underlying safety concern was corrected on August 4, 2004, and does not represent a current safety concern, the inspection focused on your response to this condition, your root cause and extent of condition reviews, and the identification of any generic issues related to design and operating practices that resulted in this condition.

The enclosed inspection report discusses four findings, one of which appears to have Greater than Green safety significance. As described in Section 02 of the report, this finding involved the potential failure to maintain design control of the containment sump safety injection suction piping at all three PVNGS units. Specifically, a significant portion of this piping was not consistently maintained full of water since initial operation of all three units. This finding was assessed based on the best available information, including influential assumptions, using the applicable Significance Determination Process and was preliminarily determined to be a Greater than Green finding. The basis for NRC's preliminary significance determination is described in the enclosed report. In conjunction with this finding, the NRC identified an apparent violation of 10 CFR Part 50, Appendix B, Criterion III, Design Control.

The report also describes a finding that involved the failure to perform a written safety evaluation and receive NRC approval prior to implementing changes to procedures in 1992 which involved draining, and maintaining drained, a significant segment of containment sump safety injection suction piping. In conjunction with this finding, the NRC identified an apparent violation of 10 CFR 50.59, which requires NRC approval prior to making certain changes to the facility as described in the Updated Final Safety Analysis Report.

Both apparent violations of NRC requirements are being considered for escalated enforcement action in accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions" (Enforcement Policy), NUREG-1600. The policy is available at NRC's website at www.nrc.gov/what-we-do/regulatory/enforcement.html. We note that only the apparent 10 CFR 50.59 violation, because it may have impacted the regulatory process (see Section IV.A. of the Enforcement Policy), is a candidate for assignment of a severity level and possible monetary civil penalty. However, based on its age, the potential for application of a monetary civil penalty associated with this apparent violation is still under review.

Before the NRC makes final decisions regarding the significance or enforcement actions for either of these apparent violations, you have an opportunity to present to the NRC your perspectives on the apparent violations, including the facts and assumptions used by the NRC to arrive at the findings and their significance, during a public conference. On December 21, 2004, Mr. Scott Bauer of your staff contacted Mr. Scott Schwind of my staff to inform us that Arizona Public Service Company was requesting the opportunity to meet with the NRC in a public conference. As a result, a conference has been scheduled for January 27, 2005, in the NRC's Region IV office in Arlington, Texas. The conference will be open to public observation and a meeting notice, as well as a press release, will be issued to announce it.

The NRC has received your letter, dated December 27, 2004, which provided information related to your follow-on actions to characterize the impacts of the voided condition. This information included the preliminary results of your pump testing program, associated analysis, and an assessment of the safety significance of this issue. We will review and assess this information before making a final significance determination of the degraded condition. However, in order to develop a more complete understanding of your preliminary assessment, we require additional information. As a result, in addition to the information provided in this letter, we request that you specifically address the following areas: (1) a comprehensive account of the differences between the as-found configuration of the affected systems and the test configurations, including but not limited to the differences in components, process parameters, system operation and control, power usage, indications, and environmental conditions; (2) an assessment of these differences, including the bases, relative to any final conclusions that you may reach regarding system operability and the risk significance of the voided conditions that actually existed; (3) any differences between the predicted test results and the actual test results; and (4) a more comprehensive discussion of the scaling factors used to establish the test conditions for the full scale pump tests (e.g., system resistance). We also request that you address any potential negative impacts stemming from water hammer conditions that may have resulted from system operation under the voided conditions that actually existed. We encourage you to submit this, and any other supporting documentation, to the NRC at least one week prior to the conference in an effort to make the conference more efficient and effective.

With respect to the apparent 10 CFR 50.59 violation, you should plan to address the information that would be relevant to NRC's severity level determination and civil penalty decision. This may include, for example, information regarding whether a violation occurred, information relevant to its significance, the circumstances surrounding identification, and information related to any corrective actions taken or planned. We request that you include a discussion of actions taken to address other recent performance deficiencies in implementing the requirements of 10 CFR 50.59, as documented in this and other NRC inspection reports (NRC Inspection Reports 05000528/2004006; 05000529/2004006; 05000530/2004006 and 05000528/2004013; 05000529/2004013; 05000530/2004013).

Since the NRC has not made a final determination in these matters, a Notice of Violation is not being issued for these inspection findings at this time. In addition, please be advised that the number and characterization of apparent violations described in the enclosed inspection report may change as a result of further NRC review.

In addition to the apparent violations being considered for escalated enforcement action, the NRC identified two additional findings during this inspection which also involved violations of NRC requirements. One of these was evaluated under the risk significance determination process as having very low safety significance (Green). The remaining finding, because it involved 10 CFR 50.59, was processed under the Enforcement Policy and is documented as a Severity Level IV violation. However, because of the very low safety significance of these violations and because they were entered into your corrective action program, the NRC is treating these as noncited violations (NCVs), consistent with Section VI.A of the Enforcement Policy. These NCVs are described in the subject inspection report. If you contest the violations or the significance of these NCVs, 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 the Palo Verde Nuclear Generating Station facility.

One of these two NCVs involved a failure to implement your condition reporting and operability determination procedures. This violation was determined to be Green because of the short duration in which it existed before compensatory measures were implemented. Specifically, plant engineers failed to notify the control room operators of the voided condition in a timely manner and, once notified, the impact on operability was not promptly determined. Given the close interrelationship between this finding and the two apparent violations being considered for escalated enforcement action, we request that you present your perspectives on this finding during the conference, including whether you agree that the finding constitutes a violation of NRC requirements.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document

Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Arthur T. Howell III, Director
Division of Reactor Projects

Dockets: 50-528
50-529
50-530
Licenses: NPF-41
NPF-51
NPF-74

Enclosure:
NRC Inspection Report 05000529/2004-14

cc w/enclosure:
Steve Olea
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, AZ 85007

Douglas K. Porter, Senior Counsel
Southern California Edison Company
Law Department, Generation Resources
P.O. Box 800
Rosemead, CA 91770

Chairman
Maricopa County Board of Supervisors
301 W. Jefferson, 10th Floor
Phoenix, AZ 85003

Aubrey V. Godwin, Director
Arizona Radiation Regulatory Agency
4814 South 40 Street
Phoenix, AZ 85040

M. Dwayne Carnes, Director
Regulatory Affairs/Nuclear Assurance
Palo Verde Nuclear Generating Station
Mail Station 7636
P.O. Box 52034
Phoenix, AZ 85072-2034

Hector R. Puente
Vice President, Power Generation
El Paso Electric Company
310 E. Palm Lane, Suite 310
Phoenix, AZ 85004

Jeffrey T. Weikert
Assistant General Counsel
El Paso Electric Company
Mail Location 167
123 W. Mills
El Paso, TX 79901

John W. Schumann
Los Angeles Department of Water & Power
Southern California Public Power Authority
P.O. Box 51111, Room 1255-C
Los Angeles, CA 90051-0100

John Taylor
Public Service Company of New Mexico
2401 Aztec NE, MS Z110
Albuquerque, NM 87107-4224

Cheryl Adams
Southern California Edison Company
5000 Pacific Coast Hwy. Bldg. DIN
San Clemente, CA 92672

Robert Henry
Salt River Project
6504 East Thomas Road
Scottsdale, AZ 85251

Brian Almon
Public Utility Commission
William B. Travis Building
P.O. Box 13326
1701 North Congress Avenue
Austin, TX 78701-3326

Chief, Technological Services Branch
FEMA Region IX
1111 Broadway, Suite 1200
Oakland, CA 94607-4052

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket:	50-528, 50-529, 50-530
License:	NPF-41, NPF-51, NPF-74
Report No.:	05000528/2004014, 05000529/2004014, and 05000530/2004014
Licensee:	Arizona Public Service Company
Facility:	Palo Verde Nuclear Generating Station, Units 1, 2, and 3
Location:	5951 S. Wintersburg Road Tonopah, Arizona
Dates:	August 23-27, 2004, with in-office inspection through December 8, 2004
Team Leader:	M. C. Hay, Senior Resident Inspector, Waterford 3
Inspectors:	G. B. Miller, Resident Inspector, Grand Gulf
Accompanying Personnel:	J. J. Shea, Project Manager, Office of Nuclear Reactor Regulation
Approved By:	Arthur T. Howell III, Director Division of Reactor Projects

CONTENTS

SUMMARY OF FINDINGS

IR 05000528/2004014, 05000529/2004014, 05000530/2004014, 08/23/04 - 12/08/04; Palo Verde Nuclear Generating Station, Units 1, 2, and 3; Special Inspection in response to discovery of voided containment sump safety injection recirculation piping.

The report covered a 5-day period (August 23-27, 2004) of onsite inspection, with in-office review through December 8, 2004, by a special inspection team consisting of one senior resident inspector, one resident inspector, and one specialist from the Office of Nuclear Reactor Regulation. Four findings were identified. 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-649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- TBD. The team identified an apparent violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the failure to establish measures to assure design basis information was translated into specifications, drawings, procedures, and instructions. Specifically, the licensee failed to maintain the safety injection sump suction piping full of water in accordance with the Updated Final Safety Analysis Report. This nonconformance had the potential to significantly affect the available net positive suction head described in the Updated Final Safety Analysis Report for the high pressure safety injection and containment spray pumps, since the analysis assumed the piping would be maintained full of water.

  This finding is more than minor because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely affects the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events. The finding has a potential safety significance greater than very low significance (i.e., Greater than Green) based on the results of a Significance Determination Process, Phase 3 analysis.

- Green. The team identified a noncited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," involving the failure of engineering and operations personnel to implement requirements in the station's condition reporting and operability determination procedures following identification of a degraded condition. Specifically, engineering personnel did not promptly notify operations personnel of a condition that impacted the safety function of the high pressure safety injection and containment spray systems. In addition, operations personnel did not complete an immediate assessment of operability once they were informed of the degraded condition. This finding had crosscutting aspects associated with problem identification and resolution, since engineering personnel did not forward corrective action program documents regarding the degraded condition to the control room in a timely manner and operations personnel did not complete a prompt operability assessment. This finding also involved crosscutting aspects associated human performance, since engineering and operations personnel did not adequately communicate the status of the engineering department's efforts to review the degraded condition.

This finding is more than minor because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely affects the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events. This finding has very low safety significance based on the results of a Significance Determination Process, Phase 3 analysis.

- <u>SL-IV</u>. The team identified three examples of a noncited, Severity Level IV violation of 10 CFR 50.59 requirements involving the failure to perform written safety evaluations prior to implementing changes to the facility. The first example involved a change for using manual actions in lieu of automatic actions as compensatory measures to support the safety functions of the high pressure safety injection and containment spray systems during postulated design basis loss-of-coolant accident conditions following a recirculation actuation signal. The second example involved operation of emergency core cooling systems with a 10-20 cubic foot void in the suction piping. The third example involved the failure to perform a written safety evaluation for changes involving filling the containment sump with borated water to a level above the containment sump safety injection recirculation piping. These changes were implemented in response to identifying that the safety injection system was not being maintained full of water.

  In accordance with Inspection Manual Chapter 0612, Appendix B, "Issue Disposition Screening," the team determined that traditional enforcement applied because this finding may have impacted the NRC's ability to perform its regulatory function. The severity level of this finding was assessed as having very low safety significance reflective of a Severity Level IV violation. This determination was based in part on use of the significance determination process.

- <u>AV</u>. The team identified an apparent violation of 10 CFR 50.59 requirements for the licensee's failure to perform a written safety evaluation and receive NRC approval prior to implementing changes to the facility in 1992 which involved draining, and maintaining drained, a significant segment of containment sump safety injection recirculation piping during normal plant operations. This change resulted in the failure to maintain the safety injection piping full of water in accordance with the Updated Final Safety Analysis Report. This represented an unreviewed safety question since it increased the probability of a malfunction of equipment important to safety previously evaluated in the safety analysis report.

  In accordance with Inspection Manual Chapter 0612, Appendix B, "Issue Disposition Screening," the team determined that traditional enforcement applied because this finding may have impacted the NRC's ability to perform its regulatory function. This is an apparent violation pending the results of a predecisional enforcement conference.

REPORT DETAILS

01 Background

01.1 Summary of Discovery and Response to the Voided Condition

During the week of July 12, 2004, NRC inspectors at the Waterford 3 Steam Electric Station identified that a segment of containment sump safety injection recirculation piping was inappropriately maintained in a voided condition. Engineering personnel from Waterford 3 established communications with other Combustion Engineering facilities of similar design to determine if the condition was a generic design issue. Waterford 3 contacted the Palo Verde Nuclear Generating Station (PVNGS) on July 22, 2004.

On July 28, 2004, PVNGS identified that a significant segment of containment sump safety injection recirculation piping in all three units was maintained void of water and began searching licensing basis information in an unsuccessful attempt to locate a technical basis for the voided configuration.

On the afternoon of July 29, 2004, PVNGS engineering personnel determined that the voided condition could potentially affect operability of the high pressure safety injection (HPSI) and containment spray (CS) systems and placed the condition into the corrective action program.

On the morning of July 30, 2004, operations personnel were initially informed of the voided condition. On the evening of July 30, 2004, operations personnel performed an initial operability evaluation and determined that the HPSI and CS systems were operable provided compensatory manual actions were implemented in lieu of automatic actions during system operation. **The compensatory measures involved opening the inside containment sump isolation valve following the receipt of a containment spray actuation signal in lieu of waiting for the automatic initiation of a recirculation actuation.**

On July 31, 2004, PVNGS notified the NRC of the adverse condition in accordance with 10 CFR 50.72(b)(3)(v) notification requirements. Specifically, this notification stated that the voided condition could have prevented the fulfillment of the safety function to remove residual heat and mitigate the consequences of a loss-of-coolant accident (LOCA). From August 1-4, 2004, PVNGS implemented corrective actions to fill the voided containment sump safety injection recirculation piping at all three operating units.

In accordance with NRC Management Directive 8.3, “NRC Incident Investigation Program,” the NRC determined that a special inspection was warranted on the basis of the potential safety significance of the voided condition. The special inspection charter is included as Attachment C to this report. The inspection team completed all items in the inspection scope during the on-site inspection, with the exception of reviewing the licensee’s determination of the cause of design deficiencies and determining if the licensee’s root cause analysis and corrective actions addressed the extent of condition for air voiding of safety systems. These items had not been completed by the licensee and therefore were the subject of in-office reviews by the inspectors.

In response to this degraded condition, the licensee initiated a project to perform engineering analyses and full scale pump tests in an effort to characterize the adverse impacts of the voided condition on the HPSI and CS systems.

01.2 Description of Containment Recirculation Function

Following a LOCA, water discharged from the reactor coolant system will collect on the containment floor and within the containment sump. On high containment pressure or low pressurizer pressure, a safety injection actuation signal automatically starts the high and low pressure safety injection pumps. Additionally, the CS pumps will automatically start on high containment pressure. These pumps initially draw a suction from the refueling water tank.

The low pressure safety injection and HPSI pumps supply relatively cool water to the reactor core to protect the fuel cladding. To protect the containment barrier function, the CS pumps supply water to spray headers in containment to mitigate containment pressure and temperature excursions following the LOCA. When the refueling water tank level decreases to approximately 10 percent, a recirculation actuation signal (RAS) automatically stops the low pressure safety injection pumps and transfers the HPSI and CS pumps' suction source to the containment sump.

02 Failure to Maintain Design Control of the Containment Sump Safety Injection Recirculation Piping

a. Inspection Scope

The team reviewed design documentation and analyses, the Updated Final Safety Analysis Report (UFSAR), Technical Specifications, NRC safety evaluation reports, and other relevant documentation pertaining to the licensing and design basis of the HPSI and CS systems.

b. Findings

Introduction. The team identified an apparent violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," with a safety significance potentially Greater than Green, regarding the failure to establish measures to assure design basis information was translated into specifications and procedures.

Description. As discussed in Section 01.1, following discussions with Waterford 3, PVNGS identified that a significant segment of containment sump safety injection recirculation piping was maintained in a voided condition at all three units. On July 29, 2004, Condition Report/Disposition Request (CRDR) 2726509 was initiated to document the deficiency in the corrective action program. The CRDR stated that, following a RAS, the voided condition could potentially affect the operation of the pumps due to cavitation and/or air binding and result in a water hammer event. This condition affected approximately 115 cubic feet of the containment sump recirculation suction piping between the inside containment isolation valves (SI-673 and SI-675) and the outside containment check valves (SI-205 and SI-206) (see Attachment B for details). This represented approximately 30 percent of the total volume of suction piping from the containment sump to the pumps.

Section 6.3 of the UFSAR, "Emergency Core Cooling System," states that the safety injection piping will be maintained filled with water. Additionally, Section 6.3 states that, during recirculation mode, the available net positive suction head (NPSH) for the CS and HPSI pumps is 25.8 feet and 28.8 feet, respectively. The team reviewed Calculations 13-MC-SI-017 and 13-MC-SI-018, regarding available NPSH for the HPSI and CS pumps, and noted that the available NPSH results were calculated based on the assumption that the piping would be full of water. The team also reviewed PVNGS NRC Safety Evaluation Report, Section 6.3, “Emergency Core Cooling System,” which states, “During normal operation, the ECCS lines will be maintained in a filled condition. Suitable vents are provided and administrative procedures will require that ECCS lines be returned to a filled condition following events such as maintenance that require draining of any of the lines.” The inspectors reviewed system drawings and noted that vent and fill lines were available to support maintaining the voided sump suction piping filled with water.

Based on discussions with the licensee and a review of documentation, the team determined that the licensee had not consistently maintained the containment sump recirculation piping full of water. This determination was based on the following:

- Every 18 months, during refueling outages, emergency core cooling system (ECCS) leakage testing is performed. The purpose of the test is to inspect ECCS piping outside of containment that is in contact with the recirculation sump inventory during LOCA conditions to determine the total leakage from the piping and components. This test was implemented in accordance with Surveillance Procedure 40ST-9SI09, “ECCS Systems Leak Test.” This procedure pressurizes the piping between the containment sump inboard and outboard isolation valves with demineralized water. Following the surveillance, the procedure directed draining the piping. The team noted that the instructions to drain the piping were added to the surveillance procedure during a revision in 1992. As discussed in Section 04.2 of this report, no written safety evaluation was performed, as required by 10 CFR 50.59, for this procedure change.

- Every quarter the licensee strokes the containment sump isolation valves in accordance with Surveillance Procedures 73ST-9XI03 and 73ST-9XI04, “SI Train Valves-Inservice Test.” This procedure allowed water to flow into the containment sump from the suction piping while the inboard containment sump isolation valve was open. There was no requirement to refill the piping between the containment sump isolation valves. During interviews, the team was informed that water had to be removed from the containment sumps during refueling outages. To prevent water from flowing to the containment sump during testing, the licensee revised the ECCS leakage test to intentionally drain the suction piping following test completion as previously discussed.

Based on this information, the team concluded that the licensee failed to maintain adequate control of the design of the containment sump safety injection recirculation piping. Specifically, the piping was not maintained full of water during normal plant operation in accordance with the licensing and design basis.

Analysis. This finding is considered to be a performance deficiency because the licensee failed to implement measures to maintain the design of the containment sump safety injection recirculation suction piping. In accordance with Inspection Manual Chapter 0612, Section 05.03, “Screen for Minor Issues,” the inspectors reviewed the sample minor findings in Appendix E, “Example of Minor Issues.” This performance deficiency was similar to Example 3.b, because it was a design discrepancy that occurred because of an oversight by the licensee. However, the subject deficiency met the “not minor if,” criteria in that the operation of the systems was adversely affected by the performance deficiency.

The inspectors evaluated the issue using the Significance Determination Process Phase 1 Screening Worksheet for the Initiating Events, Mitigating Systems, and Barrier Integrity cornerstones provided in Manual Chapter 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations." The screening indicated that a Phase 2 analysis was required because the performance deficiency is assumed to degrade two cornerstones. Specifically, the degradation of the HPSI system is associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely affects the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events by reducing the capability of injecting to the reactor during recirculation. The degradation of the containment spray system is associated with the barrier performance attribute of the Barrier Integrity cornerstone and adversely affects the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events by degrading the heat removal and pressure control functions for the primary containment.

The Phase 2 analysis assumed a loss of HPSI and CS pumps following a RAS. Full credit for recovery of the failed HPSI and CS systems was used even though venting of the system would likely require entry into a pump room with post-LOCA radiological conditions. Under some circumstances recovery may not be possible at all during the mission time because the pumps may become damaged beyond use. The Phase 2 analysis indicated that the significance of the finding was potentially Greater than Green. The dominate accident sequences involved a LOCA followed by a failure of the containment heat removal and high pressure recirculation functions. Based on these results, a Phase 3 analysis was conducted by a regional senior reactor analyst; however, due to uncertainties in the influential assumptions used for this analysis, the preliminary significance of this finding continues to be Greater than Green. The assumptions used in the Phase 2 and 3 analyses are documented in Attachment D to this report.

Enforcement. 10 CFR Part 50, Appendix B, Criterion III, *Design Control* requires that measures shall be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions. The UFSAR, Section 6.3, “Emergency Core Cooling System,” states that the safety injection piping will be maintained filled with water. Contrary to this, the licensee failed to establish measures to assure this design basis information for the ECCSs was translated into specifications, drawings, procedures, and instructions. Specifically, the licensee failed to maintain the safety injection piping full of water in accordance with the UFSAR. This nonconformance significantly affected the available net positive suction head described in the UFSAR for the safety injection pumps, since the analysis assumed the piping would be maintained full of water. This condition existed at all three units from initial plant operation through July 2004, at which time corrective actions were implemented to fill the voided piping. Units 1, 2, and 3 initial plant operations commenced in 1985, 1986, and 1987, respectively. Pending determination of the finding's final safety significance, this finding is identified as Apparent Violation (AV) 05000528,529,530/2004014-01, for failing to maintain design control of containment sump recirculation piping. Based on the best available information and the applicable Significance Determination Process, this issue was preliminarily determined to be a Greater than Green finding. This issue was entered into the licensee's corrective action program as CRDR 2726509.

03 Implementation of Operability Determination Program

a. Inspection Scope

The team assessed the engineering and operations departments' implementation of the operability determination process after the identification of the adverse condition involving the voided containment sump recirculation piping. This assessment was performed through interviews and a review of operator logs, operability determinations, and related documents. In addition, the team conducted an independent assessment of system operability.

b. Findings

Introduction. The team identified a Green noncited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings" for the failure to follow the condition reporting and operability determination procedures.

Description. Engineering personnel failed to implement the requirements of the condition reporting and operability determination procedures in several respects, while trying to resolve issues associated with the voided condition. Design engineering personnel failed to promptly inform the control room shift managers of a degraded condition that could adversely affect the operability of the HPSI and CS systems. On July 27, 2004, design engineers recognized that a significant segment (approximately 30 percent) of the containment sump recirculation piping was maintained void of water. After a 2-day review of design documentation, they were unable to locate a justification for the existence of the void. On the basis of interviews, it did not appear that any substantive information regarding this condition was communicated to operations personnel during the 2-day review period.

The safety injection system design engineer initiated CRDR 2726509 at 3:27 p.m. on July 29, to document that the degraded condition could cause cavitation and/or air binding of the HPSI and CS pumps and possibly a water hammer event. Administrative Procedure 90DP-0IP10, "Condition Reporting," Revision 19, Section 3.1.2, required that the originator promptly notify the shift manager of the affected unit upon the discovery of a degraded condition (i.e., loss of quality or function). The design engineer did not bring this CRDR to the attention of any of the shift managers. On July 29, the design engineering section leader was informed that a CRDR had been initiated documenting that the safety injection system was in an unanalyzed condition. Administrative Procedure 90DP-0IP10 required that the originator's leader ensure that the shift manager of the affected unit was notified of the degraded condition. The section leader took no actions to ensure operations personnel were promptly informed of the degraded condition. When interviewed by the team, the section leader stated that he did not inform operations personnel since he still believed that documentation already existed which would justify the current system configuration and demonstrate operability of HPSI and CS. He also stated that he wanted to further validate the concern before discussing it with operations personnel because of the substantial impact it would have on the operation of all three units if his assumption was incorrect. As discussed further in this report, this assumption was incorrect in that there was no existing documentation that provided a basis for the acceptability for the voided configuration. The section leader stated that his first action on the morning of July 30 was to discuss the voiding concern documented in CRDR 2726509 with operations personnel. This occurred around 7 a.m. on July 30.

Once operations had been notified of the condition, engineering began to assess operability of the HPSI and CS systems. Procedure 40DP-9OP26, "Operability Determination," specified that, "The operability determination process shall call for immediately declaring equipment inoperable when reasonable expectation of operability does not exist or mounting evidence suggests that the final analysis will conclude that the equipment cannot perform its specified safety function(s). Subsequent evaluation may restore the systems, structures, and components (SSC) to an operable status." Throughout the evaluation process on July 30 evidence was mounting that suggested that the HPSI and CS systems were inoperable. However, this was not communicated to the control room in a timely manner and no action was taken to declare the systems inoperable during this period.

Engineering's first priority on July 30 was to determine if the air void would remain in the suction piping or be displaced back into containment. Engineering concluded that the void would not migrate back to containment because of the high water velocity conditions following a RAS. This was the first indication that operability of the systems might not be justified. Engineering then focused on assessing the behavior of the air void through the containment sump safety injection recirculation piping. Based on a technical paper in the *Journal of Fluids Engineering*, they concluded that the combined total flow of the HPSI and CS pumps would result in sufficient fluid velocity to sweep the bubble intact through the horizontal section of piping and into a vertical piping section between the containment sump and the pumps. This analysis was completed at approximately 2 p.m. on July 30 and was the second indication that operability of the systems might not be justified. Engineering had yet to determine if the void would migrate intact through the vertical piping and into the pumps. In addition, the analytical method for vertical piping discussed in the *Journal of Fluids Engineering* appeared to be too complex to complete in one day. An engineer involved in analyzing this condition stated that, even if the void were to remain in the vertical piping section, there would most likely be some entrainment of air bubbles in the pipe flow. However, the flow calculations for a turbulent air-water mixture would have taken weeks to perform. This was the third indication that operability of the systems might not be justified.

The inspectors concluded that the analysis demonstrating that the air void would be swept intact through the horizontal piping toward the safety injection pumps constituted mounting evidence suggesting that the equipment could not perform its safety function, since neither outcome for the vertical piping calculation resulted in a reasonable assurance of operability. In discussions with the inspection team, the operations manager and the Units 1 and 2 shift managers stated that engineering personnel did not inform them of these in-process analysis results. Both shift managers and the operations manager stated that, if they had been aware of these conditions, then they would have declared both the HPSI and CS systems inoperable in accordance with the operability determination procedure and entered Technical Specification 3.0.3.

The team also concluded that the operability determination procedure was not followed by operations personnel. CRDR 2726509 was reviewed by all three control room operating crews the morning of July 30 after the design engineering section leader notified the operations department of the voided section of containment sump safety injection recirculation piping. The CRDR stated that the trapped air volume in the suction piping could potentially be forced into the safety injection pumps during a LOCA, causing cavitation and/or air binding of the pumps in addition to causing a water hammer event. The CRDR also identified the need to determine ECCS operability and, if necessary, develop contingency actions to reduce the likelihood of post-RAS air entrainment into the safety injection system. Despite their awareness of this condition, operations personnel did not assess and document operability of HPSI and CS systems until the end of the shift at 6:45 p.m. This delay in assessing operability was attributed to the fact that engineering did not fully communicate the status of their evaluation to operations.

In addition, the shift managers did not pursue resolution or periodic status updates of the significantly degraded condition from engineering. During interviews with the Units 1 and 2 shift managers, the following statements were made with respect to the events that transpired on July 30:

- One shift manager did not know engineering was trying to characterize the voided condition through analysis or that engineering was encountering problems demonstrating that the void would not migrate back into containment following a RAS. The shift manager was not informed that compensatory measures were being considered by engineering to provide a basis for operability. If the manager had known engineering was encountering these difficulties, then he would have declared the HPSI and CS systems inoperable and entered Technical Specification 3.0.3.

- Another shift manager stated that if he had known that engineering had identified that the void would not go back into containment following a RAS, then he would not have hesitated to declare the systems inoperable.

The analysis for the void behavior in the vertical section of piping was completed by 5 p.m., concluding that the fluid velocity would not be sufficient to draw the air void through the piping as an intact bubble. Engineering also identified the need for compensatory measures involving the use of manual operator actions in lieu of automatic actions to support the operability of the HPSI and CS systems. The compensatory measure required operators to manually open the inboard containment sump isolation valves following a LOCA but prior to the RAS in an attempt to allow the suction piping to fill with water along with the containment sump. A 10-20 cubic foot void would remain, corresponding to the volume between the outboard containment sump isolation valve and the downstream check valve. Engineering concluded that a reasonable assurance of operability existed based on the results of the vertical piping analysis and engineering judgment that the smaller void (10-20 cubic foot) would not result in an unacceptable void fraction affecting NPSH requirements for the HPSI and CS pumps.

At 6:45 p.m., on July 30, 2004, after briefing the incoming operations crew on the compensatory measure, the HPSI and CS systems were declared operable. The log entry stated that the operability determination was based on the compensatory measures that were implemented at 6:45 p.m., as well as the results of a calculation that concluded the remaining air void in the outboard section of the piping would not be entrained with the fluid flow due to low fluid velocities. When the inspection team requested a copy of this calculation, the team was informed that the log entry was in error and that this conclusion was actually based on engineering judgment. No calculation had been performed to assess the effects of air entrainment from the vertical section of voided piping. Operators did not request to review the calculation prior to concluding that the HPSI and CS pumps were operable. The team also noted that the final operability determination did not address the possibility of a water hammer event due to the voided condition even though this concern was also documented in CRDR 2726509.

The team conducted an independent assessment of operability for the HPSI and CS system with the voided condition in the suction piping. The technical paper from the *Journal of Fluids Engineering* referenced in engineering's evaluation did contain a reasonable discussion of flow regimes in horizontal piping; however, its treatment of void behavior in vertical piping was questionable. In fact, the authors stated that the flow regimes in the vertical case are "difficult to handle theoretically and probably require an extensive experimental investigation before an empirical description can be obtained." In addition, the inspectors noted that the data discussed in the paper for the vertical case was developed from experiments using gravity-driven flow through clear acrylic piping with a maximum diameter of 89 mm (3.5 in.). This did not compare closely to the plant configuration, which involves flow driven by pumps through 24-inch steel piping. The team concluded that this was insufficient technical justification for using this model to analyze the void behavior in the vertical section of pipe.

The inspectors also reviewed NUREG/CR-2792, "An Assessment of Residual Heat Removal and Containment Spray Pump Performance Under Air and Debris Ingestion Conditions," and made the following conclusions:

- For a wide range of operating flow rates, residual heat removal and CS pumps should handle volumetric air quantities up to 2 percent with negligible degradation in performance.

- For air quantities greater than 2 percent, performance degradation of pumps varies substantially depending on design and operating conditions.

- For very low flow rates (less than about 50 percent of best efficiency point), the presence of air may cause air binding in a pump.

- Small quantities of ingested air will increase the NPSH requirements for a pump. A correction factor for NPSH requirements is proposed.

- Industrial experience and the technical literature provide corroborative data to support these findings on the behavior of pumps in air/water mixtures.

NUREG/CR 2792 also stated that the performance of centrifugal pumps is known to degrade with increasing vapor or gas content in the fluid. The amount of degradation is a function of various parameters; the important ones being pump design, specific speed, flow rate, inlet pressure, and fluid properties. A general guideline commonly adhered to by the pump industry is that, for air ingestion levels less than about 2 percent by volume, degradation is not a concern at normal flow rates; for air ingestion between 2 percent and 15 percent, performance is dependent on pump design; and for air ingestion greater than 15 percent, most centrifugal pumps are fully degraded. It is also generally recognized that for NPSH values close to those required by the pump, air ingestion has a noticeable effect on performance.

In addition, the team referred to Regulatory Guide 1.82, “Water Sources for Long-Term Recirculation Cooling Following a Loss-Of-Coolant Accident,” Revision 2, to estimate the effects of the air void on available NPSH for the HPSI and CS pumps. Based on this guidance, the inspectors concluded that the potential existed for a loss of required NPSH to the pumps, resulting in degradation and/or air binding of the SI pumps.

The inspectors noted that the initial operability determination logged at 6:45 p.m. only addressed the 10-20 cubic feet voided condition that would result from the compensatory measure. No operability determination was performed to specifically address the basis for operability for the original voided condition of approximately 115 cubic feet.

Analysis. The failure to implement the condition reporting and operability determination procedures following identification of a degraded condition was a performance deficiency. This finding is more than minor because it adversely affected the equipment performance attribute of the Mitigating Systems cornerstone and the configuration control attribute of the Barrier Integrity cornerstone. Specifically, a degraded HPSI system affects the Mitigating Systems cornerstone objective associated with long-term core decay heat removal, and a degraded CS system affects the Barrier Integrity cornerstone objectives associated with containment heat removal and pressure control functions. Using Phase 1 worksheets from NRC Manual Chapter 0609, "Significance Determination Process," the team determined that a Phase 2 analysis was required since two Reactor Safety Cornerstones were affected.

The Phase 2 analysis determined that the finding potentially had more than very low safety significance; therefore, a Phase 3 analysis was completed by a regional senior reactor analyst. The finding was assumed to have existed from the time the CRDR was initiated until the final operability determination was made, or approximately one day. The Phase 3 analysis determined that the change in core damage frequency per year stemming from the voided piping was potentially Greater than Green; however, since this specific finding was assumed to exist for only one day, this finding was determined to be of very low safety significance or Green. Attachment D to this report provides additional detail regarding the Phase 2 and Phase 3 analyses.

This finding involved crosscutting aspects associated with problem identification and resolution because engineering personnel failed to ensure that corrective action program documents describing the degraded condition were forwarded to the control room in a timely manner. In addition, operations personnel did not complete a prompt operability assessment. This finding also had crosscutting aspects associated with human performance based on the lack of communications between engineering and operations personnel while evaluating the degraded condition.

Enforcement. 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," states that activities affecting quality shall be prescribed by documented procedures of a type appropriate to the circumstances and shall be accomplished in accordance with these procedures. Contrary to this, the licensee performed activities affecting quality that were not in accordance with documented procedures. Specifically:

Administrative Procedure 40DP-90P26, “Operability Determination,” Revision 12, Section 1.4 states, “Whenever it is discovered that the operability of a system, structure, or component is impacted or questioned, then the individual’s leader and the Control Room shall be immediately notified.”

Administrative Procedure 90DP-0IP10, “Condition Reporting,” Revision 19, Section 3.1.2 states, “If the condition meets either of the following criteria: (1) The condition requires immediate action to ensure the safety of the plant personnel or equipment, or (2) the condition is a nonconforming condition, or may cause a degraded condition (i.e., loss of quality or function), in a plant system, structure, or component, then the originator shall promptly notify the Shift Manager of the affected unit(s).” Section 3.2.1 states, “The originator’s leader shall ensure the Shift Manager of the affected unit(s) is notified, if required by Section 3.1.2.”

Procedure 40DP-90P26, “Operability Determination,” Section 1 required, in part, that:

(1) To continue operation while an operability determination is being made, there must be reasonable expectation that the system is operable and that the determination process will support that expectation.

(2) The process of operability determination is continuous and consists of the verification of operability by surveillance and formal determinations whenever a condition calls into question the system, structure, or component's (SSC) ability to perform its specified function.

(3) The operability determination process shall call for immediately declaring equipment inoperable when reasonable expectation of operability does not exist or mounting evidence suggests that the final analysis will conclude that the equipment cannot perform its specified safety function.

(4) Upon notification, the shift manager\STA shall perform an initial operability determination and document the results in the Unit Log. In most cases, the decision should be made immediately and must be made by the end of the shift.

Contrary to these requirements, on July 29-30, 2004: (1) engineering personnel failed to immediately inform the shift manager of the affected units after identifying that a voided condition could adversely affect the operability of the HPSI and CS pumps; (2) the licensee continued to operate the facility without a reasonable assurance of operability; (3) operations personnel did not implement a continuous operability determination process; (4) operations personnel did not declare the HPSI and CS systems inoperable even though mounting evidence suggested the final analysis would conclude equipment would not perform it's intended safety function; and (5) operations personnel did not perform an initial operability determination for the as-found conditions of the HPSI and CS systems. The failure to follow procedural guidance is considered a violation of 10 CFR Part 50, Appendix B, Criterion V. Because this finding is of very low safety significance and has been entered into the corrective action program as CRDRs 2733983 and 2734037, this violation is being treated as a noncited violation consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000528,529,530/2004014-02, Failure to Follow Procedure.

04 Implementation of 10 CFR 50.59 Evaluation Program

04.1 <u>Failure to Perform 50.59 Evaluations for Changes to the Facility Implemented Following Identification of Voided Condition</u>

<u>Introduction</u>. The team identified three examples of a violation of 10 CFR 50.59 requirements involving the failure to perform written safety evaluations prior to implementing changes to the facility.

<u>Details</u>. As discussed in Section 03, the licensee initiated CRDR 2726509 on July 29, 2004, to document that the voided condition of the containment sump safety injection recirculation piping could potentially affect the safety function of the HPSI and CS pumps during postaccident conditions following a RAS. On July 30 at 6:45 p.m., operations personnel determined that the affected systems were operable based on compensatory measures and engineering judgment. The compensatory measures required operators to manually open the inboard containment sump isolation valves (SI-673 and SI-675) following a containment spray actuation signal and prior to a RAS. The compensatory measure would allow the majority of the voided pipe to fill with sump

water, leaving a much smaller 10-20 cubic foot void. Upon a RAS, the outboard containment sump isolation valves would automatically open, the low pressure injection pumps would automatically stop, and the containment sump would then support suction requirements for the HPSI and CS pumps in the containment recirculation mode of operation. Engineering personnel determined that the remaining 10-20 cubic feet of air between the outboard containment sump isolation valves and their downstream check valves would not adversely affect the design function of the HPSI and CS pumps. No calculations were performed to support this conclusion and the licensee was unable to provide any basis for this conclusion other than engineering judgment.

The team reviewed Screening/Evaluation Log Number S-04-0204, which was initiated to assess these compensatory measures. The licensee completed the 10 CFR 50.59 screening for this change on July 31 at 6 p.m. The compensatory measures were implemented the day before, on July 30, at 6:45 p.m. Administrative Procedure 40DP-9OP26, “Operability Determinations,” Revision 12, Appendix C, Section 2, stated that a 10 CFR 50.59 Screening/Evaluation must be performed for the use of compensatory measures that are used to maintain operability. In addition, Administrative Procedure 93DP-0LC07, “10 CFR 50.59 and 72.48 Screenings and Evaluations,” Revision 7, required the performance of 10 CFR 50.59 screenings and evaluations prior to implementation of the changes that were performed. The licensee stated that the requirements of 10 CFR 50.59 were discussed prior to implementing the change; however, they determined that a 10 CFR 50.59 evaluation was not required. The decision was documented the day after the change was made. The inspection team disagreed with the licensee’s conclusion. Specifically, the team concluded that a 10 CFR 50.59 evaluation was required to be documented prior to the change.

Based on a review of NEI (Nuclear Energy Institute) 96-07, “Guidelines for 10 CFR 50.59 Evaluations,” Revision 1, which is endorsed by NRC Regulatory Guide 1.187, “Guidance for Implementation of 10 CFR 50.59, Changes, Tests, and Experiments,” the team determined that the licensee failed to adequately evaluate Question 2 on their 10 CFR 50.59 screening form. Question 2 stated, “Does the proposed activity involve a change to a procedure described in the Power Production Facility Licensing Documents that adversely affects how SSC design functions are performed or controlled? The licensee answered this question “No.” UFSAR Section 6.3.2.7 states that the two modes of operation for the HPSI and CS systems, injection and recirculation, are automatically initiated by an SAIS and a RAS, respectively. Section 4.2.1.2 of NEI 96-07 states, "For purposes of 10 CFR 50.59 screening, changes that fundamentally alter (replace) the existing means of performing or controlling design functions should be conservatively treated as adverse and screened in. Such changes include replacement of automatic action by manual action changes." Based on these statements, the team concluded that the licensee’s 10 CFR 50.59 screening inappropriately determined that a written safety evaluation was not required.

In addition, the compensatory measures did not result in complete removal of the air void in the suction piping. Following the manual actions to open the inboard containment sump isolation valves, a 10-20 cubic foot voided section of suction piping would remain between each outboard containment sump isolation valve and its respective downstream check valve (see Attachment B for details). The HPSI and CS

NPSH analyses (13-MC-SI-017, “Safety Injection System Interface Requirements Calculation,” Revision 4, and 13-MC-SI-018, “Containment Spray System Interface Requirements Calculation,” Revision 5) were both based on an assumption that suction piping would be full of water. This condition was a change to the facility as described in UFSAR, which also required a written safety evaluation.

Following implementation of the compensatory measures, the licensee determined that filling the piping from the inboard containment sump isolation valves to the downstream check valves would place the system in a safer condition and satisfy the original design basis of the systems. Operations Procedure 40OP-SI02, “Recovery from Shutdown Cooling to Normal Operating Lineup,” was revised to provide instructions for filling the piping. The licensee subsequently realized that the inboard containment sump isolation valves would not be leak tight; therefore, the decision was made to fill a portion of the containment sump to a level slightly above the suction piping. A revision to Maintenance Procedure 40OP-SI02 was implemented to provide procedural guidance to perform this activity. The licensee failed to realize that filling a portion of the containment sump was a change to the facility and therefore would require a 10 CFR 50.59 screening. Between August 1-4, the licensee completed the filling activity on all three units. During discussions with the NRC, the licensee realized that they had made changes to the facility as described in the UFSAR that should have been reviewed in accordance with 10 CFR 50.59 requirements. On August 12, the licensee completed the 10 CFR 50.59 screening of the change made to fill a portion of the containment sumps with water and determined that a 10 CFR 50.59 evaluation was not required. The inspection team disagreed with the conclusion that an evaluation was not required.

<u>Analysis</u>. The failure to implement the requirements of 10 CFR 50.59 was a performance deficiency. This finding is more than minor because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely affects the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events. In accordance with Inspection Manual Chapter 0612, Appendix B, “Issue Disposition Screening,” the team determined that traditional enforcement applied because this issue may have impacted the NRC’s ability to perform its regulatory function.

The severity level of this finding was based, in part, on the significance determination process. The examples involving replacing manual actions in lieu of automatic actions and operation with a 10-20 cubic foot void in the suction piping were assessed using the Phase 1 worksheet from Inspection Manual Chapter 0609, "Significance Determination Process." The team determined that a Phase 2 analysis was required because both the Mitigating Systems and Barrier Integrity cornerstones were potentially affected. The Phase 2 analysis determined that these findings were potentially Greater than Green; therefore, a Phase 3 analysis was completed by a regional senior reactor analyst. The Phase 3 analysis determined that these issues were of very low safety significance based on a similar analysis used in Section 03 of this report, since it only took a few days before all the compensatory measures were established. The third example involving filling the containment sump with borated water was also considered to be of very low safety significance since this change did not adversely impact the design or operation of the ECCS.

Enforcement. 10 CFR 50.59(d)(1) states that the licensee shall maintain records of changes in the facility, of changes in procedures, and of tests and experiments made pursuant to paragraph (c) of this section. These records must include a written evaluation which provides the bases for the determination that the change, test, or experiment does not require a license amendment pursuant to paragraph (c)(2) of this section. Contrary to this requirement: (1) the licensee did not perform a written evaluation prior to implementing compensatory measures involving the use of manual actions in lieu of automatic actions, as described in the UFSAR, to support the safety functions of the HPSI and CS systems; (2) the licensee did not perform a written evaluation for operation of the HPSI and CS systems with a 10-20 cubic foot void in the suction piping; and (3) the licensee did not perform a written evaluation for filling a portion of the containment sump. These represent three examples of a violation of 10 CFR 50.59 requirements and are being treated as a Severity Level IV violation. Because these examples are of very low safety significance and have been entered into the corrective action program as CRDRs 2734089 and 2729600, this violation is being treated as a noncited violation in accordance with Section VI.A of the Enforcement Policy. This violation is identified as NCV 05000528, 529, 530/2004014-03, Failure to Perform Written Safety Evaluation in Accordance with 10 CFR 50.59.

04.2 Failure to Perform 10 CFR 50.59 Evaluations for Procedural Change Involving Draining the Containment Sump Recirculation Suction Piping

Introduction. The team identified an apparent violation of 10 CFR 50.59 requirements for the failure to perform a written safety evaluation and receive NRC approval prior to implementing changes in 1992 which involved draining, and maintaining drained, a significant segment of containment sump safety injection recirculation piping during normal plant operations.

Details. The team questioned wether the voided containment sump recirculation suction piping condition had ever been identified and entered into the corrective action process or any other processes and evaluated prior to the most recent discovery of the problem in July of 2004. The licensee provided the team with documentation that a procedure revision had been implemented in 1992 in which requirements were incorporated into an ECCS leak test surveillance procedure that required draining the containment sump suction piping following the test. Specifically, Instruction Change Request 61008 was initiated to process the procedure revision for Surveillance Test Procedure SI09, “ECCS Leak Test.” The licensee inappropriately determined that draining and maintaining drained the suction piping following the leak test was not a change to the facility as described in the safety analysis report. The inspection team based this assessment on the following:

- Leaving the containment sump recirculation piping in the voided configuration adversely affected the design basis function of the HPSI and CS systems. This introduced an unreviewed safety question in that it increased the probability of occurrence of a malfunction of equipment important to safety previously evaluated in the UFSAR.

- The UFSAR, Section 6.3, “Emergency Core Cooling System,” states in part, that, the safety injection piping will be maintained filled with water.”

- The UFSAR, Section 6.3, states that the available net positive suction head for the containment spray and HPSI pumps are 25.8 feet and 28.8 feet, respectively, during recirculation mode. The HPSI and CS pumps’ net positive suction head analyses, Calculations 13-MC-SI-017 and 13-MC-SI-018, were calculated based on the assumption that the piping would be full of water.

The team determined that this procedure change request provided the licensee with an opportunity to identify that the voided condition could adversely affect the operability of the CS and HPSI pumps following a RAS. The licensee failed to adequately review design basis documentation to identify that the voided condition placed the CS and HPSI systems in an unanalyzed condition following a RAS. The team also noted that this change request identified that the ASME Section XI stroke testing performed on the containment sump isolation valves also resulted in the voided condition and the licensee failed to question the adequacy of leaving the piping in the degraded configuration.

Analysis. The failure to implement the requirements of 10 CFR 50.59 was a performance deficiency. This finding is more than minor because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely affects the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events. In accordance with Inspection Manual Chapter 0612, Appendix B, “Issue Disposition Screening,” the team determined that traditional enforcement should be applied because this issue impacted the NRC’s ability to perform its regulatory function at the time the change was made. Specifically, the team determined that the change to the facility involved draining, and maintaining drained, a significant segment of containment sump recirculation piping following surveillance activities resulted in a change that would have required NRC approval prior to implementation.

This finding was not suitable for evaluation using the significance determination process. As discussed in Section 02, the physical configuration of the plant which resulted from this finding is potentially Greater than Green.

Enforcement. This issue involved the licensee’s failure to adequately evaluate and control changes to the facility prior to March, 2001; therefore, the issue was evaluated against the 10 CFR 50.59 requirements that were in effect in 1992. 10 CFR 50.59(a)(1) states that the holder of a license authorizing operation of a production or utilization facility may: (1) make changes in the facility as described in the safety analysis report, (2) make changes in the procedures as described in the safety analysis report, and (3) conduct tests or experiments not described in the safety analysis report, without prior Commission approval, unless the proposed change, test, or experiment involves a change in the Technical Specifications incorporated in the license or an unreviewed safety question. A proposed change, test, or experiment shall be deemed to involve an unreviewed safety question: (1) if the probability of occurrence or the consequences of an accident or malfunction of equipment important to safety previously evaluated in the safety analysis report may be increased; (2) if a possibility for an accident or malfunction of a different type than any evaluated previously in the safety analysis report may be created; or (3) if the margin of safety as defined in the basis for any Technical Specification is reduced. PVNGS UFSAR, Section 6.3, "Emergency Core Cooling System," states, in part, that the safety injection piping will be maintained filled with water.

Contrary to the above, the licensee failed to perform a written safety evaluation and obtain Commission approval prior to implementing procedural changes that resulted in an unreviewed safety question. Specifically, in 1992 changes were made to Surveillance Procedure SI09, "ECCS Leak Test," which drained, and maintained drained, a significant segment of safety injection piping following ECCS leakage surveillance testing. These changes affected the available net positive suction head analysis described in the UFSAR for the safety injection pumps, which are important to safety, since the analysis assumed the piping would be maintained full of water. This represented an unreviewed safety question since it increased the probability of a malfunction of equipment important to safety previously evaluated in the safety analysis report.

This finding was also evaluated against the current 10 CFR 50.59 requirement, which states that a licensee shall obtain a license amendment pursuant to 10 CFR 50.90 prior to implementing a proposed change, test, or experiment if the change, test, or experiment would result in more than a minimal increase in the likelihood of occurrence of a malfunction of an SSC important to safety previously evaluated in the final safety analysis report. Contrary to this, the licensee implemented changes to Surveillance Procedure SI09, "ECCS Leak Test," that more than minimally increased the likelihood of occurrence of a malfunction of an SSC important to safety.

This violation of requirements is being treated as an apparent violation of 10 CFR 50.59, 05000528, 529, 530/2004014-04, Failure to Obtain Prior NRC Approval for a Change to the Facility Involving Maintaining a Significant Segment of Containment Sump Safety Injection Recirculation Piping Void of Water.

05 Evaluation of Operating Experience

a. Inspection Scope

The team performed a review of licensee evaluations and required submittals with respect to NRC generic guidance related to NPSH concerns affecting the ECCS and CS systems. Specific NRC generic guidance included:

- Generic Letter 97-04, "Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps"

- Information Notice (IN) 87-63, "Inadequate Net Positive Suction Head in Low Pressure Safety Systems"

- IN 96-55, “Inadequate Net Positive Suction Head of Emergency Core Cooling and Containment Heat Removal Pumps Under Design Basis Accident Conditions”

b. Observations

Introduction. The licensee missed a number of opportunities to identify that the voided containment sump recirculation piping could adversely affect the safety function of the ECCS and containment heat removal systems.

Description. The team reviewed the licensee's response to Generic Letter 97-04, “Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps.” The Generic Letter discussed examples in which licensees had either made changes to plant configurations and operating conditions or made errors in their NPSH calculations that could adversely affect the safety function of the ECCS system and the CS system under accident conditions. In light of these discrepancies, the Generic Letter requested that licensees review their current design basis analyses used to determine available NPSH. The letter stated that new NPSH analyses are neither requested nor required to be performed; however, new NPSH analysis may be warranted if an addressee determines that changes in plant design or procedures have occurred which may have reduced the available NPSH.

The team determined that the licensee, in developing its response to this Generic Letter, missed an opportunity to identify that changes made to the facility had adversely affected the available NPSH for the HPSI and CS pumps. Specifically, as previously discussed, in 1992 the licensee revised Surveillance Test Procedure SI09, “ECCS Leak Test,” to maintain a significant segment of containment sump safety injection recirculation piping in a voided configuration following leakage testing. Maintaining this voided configuration invalidated the analysis of NPSH initially reviewed and approved by the NRC. The original licensing and design basis assumed that the systems would be maintained in a water filled condition.

IN 96-55, “Inadequate Net Positive Suction Head of Emergency Core Cooling and Containment Heat Removal Pumps Under Design Basis Accident Conditions,” addresses the potential for insufficient NPSH for ECCS pumps and identifies concerns that licensees who credit containment overpressure to ensure adequate NPSH may not be supported by detailed containment pressure temperature analyses. The licensee initiated a CRDR to evaluate applicability of this condition to PVNGS. This evaluation concluded that the concerns identified in the IN were not applicable to PVNGS. Although the focus of IN 96-55 differed from the voided condition in the ECCS sump suction piping, it presented an opportunity to evaluate the inconsistency between their design basis and voided condition. Because the licensee’s evaluation of IN 96-55 was too narrowly focused, licensee personnel missed another opportunity to identify that the voided piping impacted the NPSH for the ECCS pumps.

IN 87-63, “Inadequate Net Positive Suction Head in Low Pressure Safety Systems,” discussed problems that could result in inadequate NPSH at the inlet to low pressure pumps following a LOCA. PVNGS performed no written evaluation of this issue.

Although IN 87-63 did not explicitly discuss conditions similar to the voided piping condition found at PVNGS, it presented another opportunity for the licensee to evaluate their ECCS configuration. The licensee missed this opportunity to identify and correct the discrepancy between the design basis and the actual configuration of their ECCS.

06 Meetings, Including Exit

On December 9, 2004, the special inspection team leader presented the inspection results to Mr. Overbeck and other members of his staff. The team leader confirmed that the inspectors were provided with information that the licensee considered to be proprietary. This information was associated with the full scale pump testing which was incomplete at the time of the exit meeting.

ATTACHMENT A

Supplemental Information

KEY POINTS OF CONTACT

Licensee Personnel

S. Bauer, Department Leader, Regulatory Affairs
P. Borchert, Director, Work Management
R. Buzard, Senior Consultant, Regulatory Affairs
D. Carnes, Director, Regulatory Affairs, Nuclear Assurance
S. Coppock, Section Leader, System Engineering
D. Fam, Department Leader, Design Engineering
D. Gregoire, 50.59 Program Manager
M. Gribsby, Unit Department Leader, Operations
R. Henry, Site Rep., SRP
J. Levine, Executive Vice President, Generation
K. Manne, Senior Attorney, PNW
D. Marks, Section Leader, Regulatory Affairs
D. Mauldin, Vice President, Engineering and Support
J. Mellody, Department Leader, Communications
G. Overbeck, Senior Vice President, Nuclear
W. Peabody, Consultant
S. Peace, Consultant, Owner Services
S. Pittalwala, Director, Project Engineering
M. Radspinner, Section Leader, System Engineering
T. Radtke, Director, Operations
J. Scott, Department Leader, Nuclear Assurance
M. Shea, Director, Maintenance
E. Shore, Site Rep., EPE
D. Smith, Plant Manager
M. Sontag, Department Leader, Nuclear Assurance
G. Sowers, Section Leader, PRA
K. Sweeney, Section Leader, System Engineering
D. Vogt, Section Leader, Operations STA
T. Weber, Section Leader, Regulatory Affairs, Licensing
D. Wheeler, Section Leader, Nuclear Assurance
M. Winsor, Director, Engineering

NRC

J. Melfi, Resident Inspector, Palo Verde Nuclear Generating Station
C. Osterholtz, Senior Resident Inspector, San Onofre Nuclear Generating Station
N. Salgado, Senior Resident Inspector, Palo Verde Nuclear Generating Station
S. Schwind, Chief, Project Branch D, Division of Reactor Projects
T. Vegel, Deputy Director, Division of Reactor Projects

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000528,529,530/ 2004014-01	AV	Failure to Maintain Design Control of Containment Sump Recirculation Piping
05000528,529,530/ 2004014-02	NCV	Failure to Follow Procedure
05000528,529,530/ 2004014-03	NCV	Failure to Perform Written Safety Evaluation in Accordance with 10 CFR 50.59 Requirements
05000528,529,530/ 2004014-04	AV	Failure to Obtain Prior NRC Approval for a Change to the Facility Involving Maintaining a Significant Segment of Containment Sump Safety Injection Recirculation Piping Void of Water

Closed

05000528,529,530/ 2004014-02	NCV	Failure to Follow Procedure
05000528,529,530/ 2004014-03	NCV	Failure to Perform Written Safety Evaluation in Accordance with 10 CFR 50.59 Requirements

LIST OF DOCUMENTS REVIEWED

Procedures:

01DP-OAP01, "Procedure Process," Revision 14

40DP-9OP26, "Operability Determination," Revision 12

40EP-9EO03, "Loss of Coolant Accident," Revision 16

40EP-9EO09, "Functional Recovery," Revision 21

40OP-9SI02, "Recovery from Shutdown Cooling to Normal Operating Lineup," Revisions 49 and 50

90DP-0IP10, "Condition Reporting," Revision 19

93DP-0LC07, “10 CFR 50.59 and 72.48 Screenings and Evaluations,” Revision 7

Analysis:

13-MC-SI-017, “Safety Injection System Interface Requirements Calculation,” Revision 4

13-MC-SI-018, “Containment Spray System Interface Requirements Calculation,” Revision 5

CRDR’s:

370221, 2726509, 2729600, 2731156, 2733983, 2734037

Miscellaneous:

10 CFR 50.59 Screening/Evaluation S-04-0204, Revision 0

10 CFR 50.59 Screening/Evaluation S-04-0207, Revision 0

Instruction Change Request 61008

NEI 96-07, “Guidelines for 10 CFR 50.59 Implementation,” Revision 1

NRC Generic Letter 96-06, “Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions”

NRC Generic Letter 97-04, Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps”

NRC Information Notice 97-78, “Crediting of Operator Actions in Place of Automatic Actions and Modifications of Operator Actions, Including Response Times”

NRC Inspection Manual Part 9900 Technical Guidance, “Operable/Operability: Ensuring the Functional Capability of a System or Component,” 1991

NUREG-0897, “Containment Emergency Sump Performance,” 1985

NUREG/CR-2792, “An Assessment of Residual Heat Removal and Containment Spray Pump Performance Under Air and Debris Conditions,” 1982

Operability Determination 2728663, Revisions 0 and Revision 1

VTD-I075-0007, “High Pressure Safety Injection Pumps Technical Manual,” Revision 0

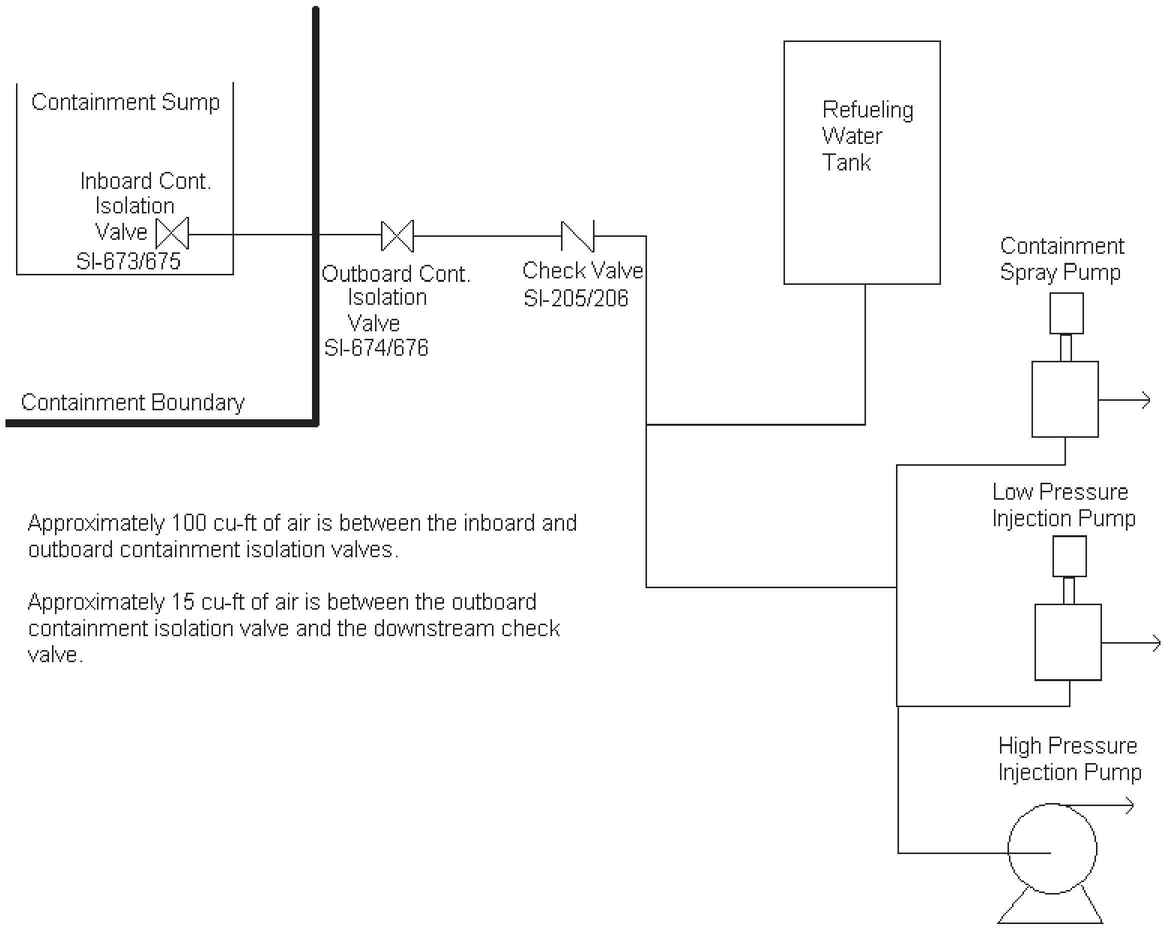
Wallis, et al, “Conditions for a Pipe to Run Full When Discharging Liquid Into a Space Filled With Gas,” *Journal of Fluids Engineering*, June 1977

LIST OF ACRONYMS

AV	apparent violation
CFR	*Code of Federal Regulations*
CRDR	condition report/disposition request
CS	containment spray
ECCS	emergency core cooling system
HPSI	High Pressure Safety Injection
IN	information notice
LOCA	loss of coolant accident
NPSH	net positive suction head
NRC	Nuclear Regulatory Commission
PVNGS	Palo Verde Nuclear Generating Station
RAS	recirculation actuation signal
SSC	structure, system, or component
UFSAR	Updated Final Safety Analysis Report

ATTACHMENT B

Figure



ATTACHMENT C

Inspection Charter

August 11, 2004

MEMORANDUM TO: Michael Hay, Senior Resident Inspector
Waterford 3 Steam Electric Station

Geoffery Miller, Resident Inspector
Grand Gulf Nuclear Power Plant

FROM: Arthur T. Howell III, Director **/RA/ CSMarschall for**
Division of Reactor Projects

SUBJECT: SPECIAL INSPECTION CHARTER TO EVALUATE PALO VERDE UNITS 1, 2, AND 3 VOIDED CONDITION DISCOVERED IN THE POST-LOCA RECIRCULATION PIPING FROM THE CONTAINMENT SUMP

In response to the discovery that during a Recirculation Actuation Signal (RAS) the trapped volume of air between the containment sump suction line isolation valves and the downstream check valve could enter the operating high pressure safety injection (HPSI) and containment spray (CS) pumps, a Special Inspection Team is being chartered. You are hereby designated as the Special Inspection Team members. Mike Hay is designated as the team leader.

A. Basis

On July 29, 2004, Palo Verde Nuclear Generating Station identified (CRDR 2726509) a pocket of air trapped between the containment sump inboard isolation motor operated valve and the containment sump check valve. This trapped air, if forced into the HPSI or CS pump suction, could result in degradation of the pumps and/or lead to a water hammer event. Technical Specifications 3.5.3 and 3.6.6 require both trains of HPSI and CS to be operable during power operations in Modes 1 through 3.

This Special Inspection Team is chartered to compare the as-found conditions to the licensing basis for the containment sump suction, determine if there are generic safety implications associated with voiding the suction piping, and review the licensee's compensatory measures following discovery of the condition.

B. Scope

The team is expected to address the following:

1. Develop a complete sequence of events related to the discovery of the voided condition and follow-up actions taken by the licensee.

2. Compare operating experience involving air voiding of emergency core cooling system suction piping to actions implemented at Palo Verde. Determine if there are any generic issues related to the design and operating practices that resulted in the voiding of the containment sump suction piping. Promptly communicate any potential generic issues to regional management.

3. Review the licensee's determination of the cause of design deficiencies and operating practices that allowed the voiding condition to exist. Independently verify key assumptions and facts. Determine if the licensee's root cause analysis and corrective actions have addressed the extent of condition for air voiding of safety systems.

4. Determine if the Technical Specifications were met for the air voided condition and following the implementation of compensatory measures.

5. Determine if the supporting analyses for the licensee's compensatory measures were made in accordance with 10 CFR 50.59.

6. Review the calculations the licensee used to evaluate the voided condition. Assess the key factors associated with the total volume of trapped air, the expected flow rates of the HPSI and CS pumps, the size and orientation of the sump suction piping, and the impact on pump operability.

7. Collect data necessary to support a risk analysis. Specifically obtain information associated with the degree to which the HPSI and CS pumps were affected, the ability to recover failed pumps, and the dominant accident sequences.

C. Guidance

Inspection Procedure 93812, "Special Inspection," provides additional guidance to be used by the Special Inspection Team. Your duties will be as described in Inspection Procedure 93812. The inspection should emphasize fact-finding in its review of the circumstances surrounding the event. It is not the responsibility of the team to examine the regulatory process. Safety concerns identified that are not directly related to the event should be reported to the Region IV office for appropriate action.

The Team will report to the site, conduct an entrance, and begin inspection no later than August 23, 2004. The inspection will include a review of the licensee's calculations associated with the transportability of the air pocket. This is not expected to be completed until following the team's initial visit. While on site, you will provide daily status briefings to Region IV management, who will coordinate with the Office of Nuclear

Reactor Regulation, to ensure that all other parties are kept informed. A report documenting the results of the inspection should be issued within 30 days of the completion of the inspection.

This Charter may be modified should the team develop significant new information that warrants review. Should you have any questions concerning this Charter, contact me at (817) 860-8248.

cc via E-mail:
B. Mallett
T. Gwynn
M. Fields
C. Marschall
D. Chamberlain
J. Clark
V. Dricks
W. Maier
N. Salgado
W. Jones
C. Paulk
J. Shea
R. Laura

ATTACHMENT D

Phase 2 and Phase 3 Risk Assessments

In accordance with MC 0612, “Power Reactor Inspection Reports,” the assumptions used in the Phases 2 and 3 analyses, as well as the dominant core damage sequences resulting from the analyses, are provided below.

Phase 2 Assumptions and Dominant Core Damage Sequences

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, "User Guidance for Determining the Significance of Reactor Inspection Findings for At-Power Situations," the inspectors evaluated the subject finding using the Risk-Informed Inspection Notebook for Palo Verde Nuclear Generating Station, Revision 1. The following assumptions were made:

- The air in the sump suction piping would be drawn into the suction of the high pressure safety injection and containment spray pumps following a recirculation actuation signal, causing them to fail via air binding or cavitation.

- Operators would be capable of recovering the pumps. The time available would be greater than 2 hours given the time after shutdown. Recovery may not have been possible in all scenarios; however, full recover credit was used as a bounding assumption.

- The condition existed for most of the life of the plant. Therefore, the exposure time window used was >30 days.

- The low pressure recirculation function remained available. The automatic operation of the containment spray and high pressure safety injection pumps would clear the air bubble from the suction piping that affects the low pressure safety injection pumps.

- Initiating event likelihoods were not affected by this performance deficiency.

- No mitigating equipment was affected by this performance deficiency prior to a recirculation actuation signal.

Table 2 of the risk-informed notebook requires that the following accident sequences be evaluated when the emergency core cooling systems are affected: SLOCA, MLOCA, LLOCA, LOPW and LONCW. Using Table 1 with an exposure time of greater than 30 days, the inspectors identified the following Initiating Event Likelihoods (IELs) for use in the estimation:

Table 2.a: Phase 2 Initiating Event Frequencies	
Accident Sequence	IEL
SLOCA	3
MLOCA	4
LLOCA	5
LOPW	3
LONCW	2

The resulting accident sequence analysis is summarized below, which indicated a finding that was potentially Greater than Green. As a result, a Phase 3 analysis was performed, as documented on pages D-3 through D-17.

Table 2.b: Phase 2 Results		
Initiating Event	Sequence	Mitigating Functions
SLOCA	1	CHR
SLOCA	2	HPR
SLOCA	4	HPSI - CHR
MLOCA	2	CHR
MLOCA	3	HPR
LLOCA	2	CHR
LLOCA	3	HPR - LPR
LOPW	3	RCPT - CHR
LOPW	4	RCPT - HPR
LONCW	3	PCS - RCPT - CHR
LONCW	4	PCD - RCPT - HPR

Phase 3 Analysis

<u>Internal Initiating Events</u>

<u>Assumptions</u>:

The results from the notebook estimation were compared with an evaluation developed using a Standardized Plant Analysis Risk (SPAR) model simulation of the failure of emergency core cooling systems upon a recirculation actuation signal, as well as an assessment of the licensee's evaluation provided by the licensee's probabilistic risk assessment staff. The SPAR runs were based on the following analyst assumptions:

b The SPAR Model, Revision 3.03, was used to assess the significance of this event. This model, including the component test and maintenance basic events, represents an appropriate tool for evaluation of the subject finding.

c NUREG/CR-5496, "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980 - 1996," contains the NRC's current best estimate of both the likelihood of each of the loss of offsite power (LOOP) classes (i.e., plant-centered, grid related, and severe weather) and their recovery probabilities.

d **The air in the sump suction piping would be drawn into the suction of the high pressure safety injection and containment spray pumps following a recirculation actuation signal causing them to fail via air binding.**

e **If operators identified the need and tripped the pumps expeditiously, recovery of the pumps would be available. The necessity to rapidly trip the pumps is accounted for under Assumption e. The time available would be greater than 2 hours given the time after shutdown. In most cases, environmental conditions would permit recovery. Some accident scenarios with initial core uncovery would result in high radiation fields. However, the vast majority would be recoverable. Procedures and training both exist for venting pumps. No specialized equipment is needed to vent the pumps.**

f The conditional probability of operators failing to properly diagnose and restore the high pressure safety injection pumps was 24%. The analyst used the SPAR-H method to calculate this probability. He assumed that the nominal diagnosis failure rate of 0.01 and the nominal action failure rate of 0.001 are multiplied by the following performance shaping factors:

, Available Time for Diagnosis: 10
, Available Time for Action: 10

The available time was assumed to be barely adequate to complete the diagnosis because the operators would have to identify the need to trip the pumps in a very short period of time in order to prevent possible damage to the pumps beyond use. If the need to trip the pumps was identified, then determining that the pumps needed to be vented was considered to be an action.

The available time to take action was also assumed to be barely adequate. The analyst assumed that, once operators shut down the pumps, it would take approximately 30 minutes to identify that venting was necessary, an additional 30 minutes would be required for metal temperatures to drop below boiling so that venting could take place, and finally 30 minutes to vent the pump given the large volume of air/steam that would need to be vented.

, Stress: 2

Stress under the conditions postulated would be high. A LOCA would be ongoing. Multiple alarms would be initiated as the four primary emergency core cooling system pumps fail during the swapover to recirculation. Additionally, operators would understand that the consequences of their actions would represent a threat to plant safety.

, Complexity for diagnosis: 1
, Complexity for action: 2

The complexity of the tasks necessary to properly diagnose this condition was determined to be nominal. The analyst noted that control board indications would show that flow was not moving forward and that operators would be required to trip the pumps. During action, however, operators would have to identify that the cause of the failure was voiding, understand that the high head pumps needed to be cooled prior to proper venting, and vent for an appropriate period of time. Therefore, the analyst determined that this action was moderately complex.

f The probability of operators failing to properly diagnose and restore the containment spray pumps was calculated to be 2.4%. The analyst used the same methods and calculations as used to determine the conditional probability of recovering the high pressure safety injection. Because containment spray is not needed as quickly as the high pressure safety injection pumps, the time available for both the action and the diagnosis steps were set to nominal (assuming that the pumps were accessible and had not catastrophically failed).

g The condition existed for the life of the plant. Therefore, an exposure time of 1 year (the reactor oversight process assessment period) was used.

h Plant equipment was assumed to have been available at their average test and maintenance frequencies.

i All accident initiators that could lead to recirculation were considered applicable.

j Although this finding is applicable to all three Palo Verde units, the performance deficiency was evaluated for a single unit only because the reactor oversight process is conducted separately on each unit.

Analysis:

Evaluation of Change in Risk

The SPAR Revision 3.03 model was modified to include updated loss of offsite power curves as published in NUREG CR-5496, as stated in Assumption b. The changes to the loss of offsite power recovery actions and other modifications to the SPAR model were documented in Table 2. This revision was incorporated into a base case update, making the revised model the baseline for this evaluation. The resulting baseline core damage frequency, CDF_{base}, was 4.04×10^{-9} /hr.

The analyst changed this modified model by setting the common cause failure to run basic event for the containment spray pumps (CSR-MDP-CF-RUN) to the recovery probability (2.4×10^{-2}). Additionally, the analyst set the basic event HPR-MOV-CF-RWT to its recovery probability of 24%. This event is the functional equivalent to failing the pumps during recirculation. However, it does not fail high pressure injection function as adjusting the failure to run probability for the pumps. The modified SPAR model was requantified with the resulting current case conditional core damage frequency, CDF_{case}, of 5.85×10^{-9} /hr.

The change in core damage frequency (ΔCDF) from the model was:

$$\begin{aligned} \Delta CDF &= CDF_{case} - CDF_{base} \\ &= 5.85 \times 10^{-9} - 4.04 \times 10^{-9} = 1.81 \times 10^{-9} \text{ /hr} \end{aligned}$$

Therefore, the total change in core damage frequency over the exposure time that was related to this finding was calculated as:

$\Delta CDF = 1.81 \times 10^{-9}$ /hr * 8760 hr/yr = 1.59×10^{-5} for a 1 year exposure time

The preliminary risk significance of this finding is presented in Table 3.a. The dominant cutsets from the internal risk model are shown in Table 3.b.

Table 2.c: Baseline Revisions to SPAR Model			
Basic Event	Title	Original	Revised
IE-LOOP	Loss of Offsite Power Initiator	5.20×10^{-6}/hr	6.32×10^{-6}/hr
EPS-DGN-FR-FTRM	Diesel Generator Fails to Run - Middle Time Frame*	3.5 hrs.	13.5 hrs.
EPS-DGN-FR-FTRL	Diesel Generator Fails to Run - Long Time Frame*	1×10^{-6} hrs.	1.2 hrs.
OEP-XHE-NOREC-ST	Operator Fails to Recover AC Power in the Short Term	5.8×10^{-1}	5.67×10^{-1}
OEP-XHE-NOREC-SL	Operator Fails to Recover AC Power before Seal LOCA	5.78×10^{-1}	6.57×10^{-1}
OEP-XHE-NOREC-BD	Operator Fails to Recover AC Power before Battery Depletion	1.1×10^{-1}	3.15×10^{-1}
OEP-XHE-NOREC-3H	Operator Fails to Recover AC Power in 3 Hours	6.5×10^{-2}	1.86×10^{-1}
RCP-MDP-LK-SEALS	RCP Seals Fail without Cooling and Injection	1.8×10^{-2}	4.09×10^{-2}
* Diesel Mission Time was increased from 2.5 to 15.2 hours in accordance with NUREG/CR-5496			

Table 3.a: Evaluation Model Results			
Model	Result	Core Damage Frequency	LERF[1]
SPAR 3.03, Revised	Baseline: Internal Risk	4.0×10^{-9}/hr	N/A
	Internal Events Risk	5.9×10^{-9}/hr	N/A
	TOTAL Internal Risk (ΔCDF)	1.6×10^{-5}	N/A
	TOTAL External Risk (ΔCDF)[2]	8.8×10^{-6}	N/A
	TOTAL Internal and External Change	**2.5×10^{-5}**	N/A

NOTE 1: None of the dominant core damage sequences analyzed were determined to be significant with respect to the large-early release frequency using Manual Chapter 0609, Appendix H.

NOTE 2: The ΔCDF from external events was estimated using the risk values from internal initiators. The methods used should be considered bounding.

Table 3.b: Top Risk Cutsets			
Initiating Event	Sequence Number	Sequence	Importance
Medium LOCA	3	HPR	1.1×10^{-9}
	4	CSR	1.1×10^{-10}
Transient	7	SRV-COOLDOWN-HPR	1.7×10^{-10}
	4	SRV-SDC-HPR	1.3×10^{-10}
	8	SRV-COOLDOWN-CSR	1.7×10^{-11}
	5	SRV-SDC-CSR	1.3×10^{-11}
Large LOCA	6	CSR	1.5×10^{-10}
	5	HPR-LPR	1.4×10^{-11}
Small LOCA	6	COOLDOWN-HPR	5.5×10^{-11}
	3	SDC-HPR	4.0×10^{-11}
	7	COOLDOWN-CSR	5.5×10^{-12}
	4	SDC-CSR	4.0×10^{-12}
Loss of Offsite Power	11	RCPSL1-OEP3H-HPR	8.3×10^{-12}
	4	RCPSL1-SDC-HPR	2.8×10^{-12}

External Initiating Events:

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, step 2.5, "Screening for the Potential Risk Contribution Due to External Initiating Events," the analyst assessed the impact of external initiators because the Phase 2 SDP result provided a Risk Significance Estimation of 7 or greater.

The analyst determined that, for the subject performance deficiency to cause an increase in plant risk from an external initiator, the initiator had to do one of three things:

(1) Cause an increase in the likelihood of an internal event affected by the performance deficiency;

(2) Affect the reliability or availability of mitigating equipment used to mitigate the initiators from the internal events evaluation; or

(3) Cause a new sequence that would result in the need for recirculation.

The analyst reviewed the major external initiators that could affect the Palo Verde site. Using the Palo Verde Individual Plant Examination of External Events (IPEEE) and the analyst's judgment and knowledge of the site, the analyst concluded that no new sequences that would require recirculation would be initiated by external events. However, increases in the likelihood of internal initiators, as well as effects on mitigating equipment were identified. The analyst evaluated each external initiator to determine its affect on the major internal events assessed by the SPAR. Each external event was then evaluated to determine if the plant response could be affected by the performance deficiency. Table 3.c provides the results of the initial screening:

Table 3.c: External Events Screening

SPAR Initiator / External Event	LONCW	LOPC	SLOCA	MLOCA	LLOCA	TRANS	LOOP
Seismic	NEG	NEG	YES	NEG	NEG	NEG	NEG
High Winds	NO	NO	NO	NO	NO	BASE	BASE
Internal Floods	IEL	IEL	NO	NO	NO	NEG	NO
External Floods	NO	NO	NO	NO	NO	NO	NO
Internal Fire	NO	YES	YES	NO	NO	BASE	NEG
External Fire	NO	NO	NO	NO	NO	NEG	NEG
Transportation	NO	NO	NO	NO	NO	NEG	NEG
Other External	NO	NO	NO	NO	NO	BASE	BASE

Notes:

1. NO / External initiator would not affect the subject internal event.
2. YES / External initiator could result in subject internal event and could affect mitigating equipment.
3. IEL / External event could result in the subject internal event but not affect mitigating equipment.
4. NEG / External initiator could result in the subject initiator, but has a frequency so low that it would have negligible change on the internal event likelihood.
5. BASE / External event could result in subject initiator, but the effect was assumed to be part of baseline risk of the plant.

Transportation Incidents, External Fires:

The analyst determined that events that were initiated and remained outside of the plant, by their nature, would not be expected to cause a plant system pipe break. Also, the likelihood of having an external event occur simultaneously with a major pipe break was considered to be negligible. Therefore, the analyst concluded that these events would only affect plant transients and losses of offsite power. However, transportation incidents and/or external fires causing plant initiators while at power are rare occurrences, compared to the likelihood of equipment and weather-related events. As a result, the change in initiating event likelihood would be very low.

The analyst reviewed the major sequences that were affected by the subject performance deficiency. For transients, the dominant failures involved stuck-open safety-relief valves. The analyst assumed that the potential for an external fire or transportation accident to induce a stuck-open valve to be negligible. Likewise, the analyst reviewed the sequence cutsets for loss of offsite power initiated sequences. These sequences involved a reactor coolant pump seal failure resulting from the loss of power. Therefore, the analyst determined that the only affect for these external events would be the increase in initiating event likelihood.

In the IPEEE, the licensee used the screening methodology suggested in Generic Letter 88-20, Supplement 4, to evaluate these events. The licensee concluded that transportation events were not significant threats for severe accident. The IPEEE was silent on external fire. However, based on the analyst's experience and judgment, the analyst determined that external fire loading surrounding the plant was insufficient to cause a loss of offsite power. Based on the licensee's methodology, their result correlates to a core damage frequency of less than 1×10^{-6}. This corroborated the analyst assumption that the increase in risk associated with the subject performance deficiency was negligible with respect to transportation events and external fires.

External Floods:

The analyst assumed that, because of the topography of the site and the nature of the desert, all external floods will drain or be quickly absorbed by the environment. Therefore, there would be no affect on the initiating event likelihoods for any initiator.

In the IPEEE, the licensee used the screening methodology suggested in Generic Letter 88-20, Supplement 4, to evaluate these events. The licensee concluded that site flooding was not a significant threat for severe accident because the effect of the probable maximum precipitation, based on Hershfield's statistics of extreme events, was less limiting than the design basis calculations from the Updated Final Safety Analysis Report. This corroborated the analyst's assumption that external flooding had no expected affect on total risk.

Internal Floods:

The analyst determined that Internal Floods have a potential to affect the initiating event frequency of loss of cooling water systems and plant transients. However, internal floods would cause a similar effect on plant mitigating equipment, with or without the performance deficiency. Additionally, there is a low frequency of the external event and the resulting low likelihood that a flood takes out all equipment to cause a complete loss of cooling water systems. The high likelihood of a transient from other causes results in a negligible change in the initiating event likelihood. However, equipment related losses of cooling water systems are quite often driven by the same piping breaks that cause an internal flooding initiator.

According to the Idaho National Engineering and Environmental Laboratory's study published in NUREG/CR-5750, "Rates of Initiating Events at U. S. Nuclear Power Plants: 1987-1995," loss of open-loop cooling water systems occur at a rate of 9.6×10^{-4} events per year. This is greater than the expected rate of piping failures large enough to cause substantial flooding in the pump areas. As a result and to bound the risk estimate, the analyst assumed that the impact of internal flooding initiated loss of nuclear or plant cooling water systems on the core damage frequency was no more than equal to the effect from internal events, regardless of whether the performance deficiency existed. The impact of these initiators is discussed under the quantification section below.

High Winds:

The analyst determined that events that were initiated and remained outside of the plant, by their nature, would not be expected to cause a plant system pipe break. Also, the likelihood of having an external event occur simultaneously with a major pipe break was considered to be negligible. Therefore, the analyst concluded that these events would only affect plant transients and losses of offsite power. The analyst reviewed the major sequences that were affected by the subject performance deficiency. For transients, the dominant failures involved stuck-open safety-relief valves. The analyst assumed that the potential for high winds to induce a stuck-open valve was negligible. Likewise, the analyst reviewed the sequence cutsets for loss of offsite power initiated sequences. These sequences involved a reactor coolant pump seal failure resulting from the loss of power. The analyst determined that high winds would not increase the likelihood of a reactor coolant pump seal failure. Therefore, the only effect for these external events would be the increase in initiating event likelihood.

The analyst also assumed that high wind events happen frequently enough that the impact of these severe weather events are already incorporated into the initiating event frequencies. Therefore, the total impact of high winds on the increase in core damage frequency related to the subject performance deficiency was evaluated as part of the internal initiating events review.

Seismic:

The analyst assumed that the normal engineering factors and resulting rigidity that were built into the Palo Verde units were sufficient to protect the plant from all but the most severe of seismic events. Given the location of Palo Verde to known faults, seismic events with a magnitude greater than the review level earthquake were expected to occur at a frequency of 3×10^{-5}/year. All Seismic Category 1 structures were built to withstand this review level earthquake, with appropriate engineering margin. Therefore, the analyst assumed that the likelihood of a seismic event causing an initiator by affecting Seismic Category 1 equipment was low and that the change in risk associated with the subject finding would be negligible. This is primarily based on the assumption that a seismic event large enough to cause a major piping rupture would most likely result in core damage. As a result, the only affect for seismic events considered by the analyst was the increase in initiating event likelihood of plant transients and loss of offsite power.

Additionally, because of the low frequency of seismic events and the low likelihood that seismic events would cause a loss of mitigating equipment, combined with the relatively high likelihood of a transient or loss of offsite power, the change in initiating event likelihood would be very low. The frequency of transients and loss of offsite power events are several orders of magnitude higher than that of severe seismic events. As a result, the analyst assumed that the increase in risk associated with the subject performance deficiency was negligible with respect to seismic events.

In the IPEEE, the licensee used the EPRI seismic margins assessment methodology to evaluate these events. The licensee concluded that the plant could respond properly to all seismic events, up to and including the review level earthquake. The EPRI method, assumes that there is a potential for the review level earthquake to cause a small-break loss of coolant accident. In reviewing the plant response to this event, the licensee determined that high-pressure recirculation was a required function for responding to this event. The analyst assumed that the EPRI evaluation was conservative and that there was a probability that the reactor coolant system would survive earthquakes larger than the review level earthquake. Therefore, the analyst assumed that a seismically induced small-break loss of coolant accident could result at a rate of 3×10^{-5}/year. The impact of this failure is discussed under the quantification section below.

Internal Fire:

The analyst evaluated the potential for internal fires to cause an initiating event that would affect the change in risk associated with the subject performance deficiency. The analyst assumed that the probability of an internal fire causing a loss of nuclear cooling water was extremely low, based on normal system separation. The analyst assumed that internal fires could not cause a medium or large-break loss of coolant accident. The analyst also assumed that the probability of an internal fire causing a loss of offsite power was extremely low, because of equipment separation inside the plant.

The analyst assumed that the probability of an internal fire resulting in a stuck-open safety-relief valve that was not recoverable, that the relief valve caused a plant transient, and that operators were unable to take the plant to cold shutdown conditions prior to recirculation was extremely low. Therefore, the effect of internal fires was considered to be negligible with respect to the dominant transient sequences. The analyst also assumed that internal fire events happen frequently enough that the impact of these events are already incorporated into the initiating event frequency for a transient. Therefore, most of the impact of internal fires on the increase in core damage frequency related to plant transients was evaluated as part of the internal initiating events review.

The analyst determined that internal fires could result in a small-break loss of coolant accident. The postulated scenario includes a control room fire that results in the evacuation of the main control room. The potential to induce a reactor coolant pump seal failure can be high in these scenarios. However, recent studies by Combustion Engineering indicate that these seals would not result in a small-break loss of coolant accident under these conditions.

The analyst assumed that an internal fire could cause the complete loss of the plant cooling water system. However, the effect of this event would be no different if it were caused by an internal fire than it would if it were initiated by equipment related problems. Therefore, the analyst determined that the only effect of these external events would be the increase in initiating event likelihood. The analyst determined that the increase in initiating event frequency was potentially large enough that the effect of the subject performance deficiency could not be ruled out. This scenario was explored further in the quantification section below.

Other External Initiators:

The analyst reviewed other external initiators to determine if they had the potential to cause one of the three effects that would cause an increase in risk related to the subject performance deficiency. The initiators review included: lightning, sand storms, extreme heat, and roof ponding. The effects of these initiators were determined, qualitatively, to either be negligible, or to already be included in the internal events initiating event frequency.

External Events Quantification:

The analyst used the assumptions made for each external event category and estimated the maximum increase in core damage frequency for each of the dominant internal event initiators. The results are documented in Table 3.d. The quantification of each bounding estimate is described below:

, Small-Break Loss of Coolant Accidents (SLOCA)

As stated above, internal fires have the potential of resulting in a small-break loss of coolant accident. However, the analyst determined that the only impact would be an increase in the likelihood of a small-break loss of coolant accident. Given that the fires reviewed would occur at a frequency lower than the expected frequency of random breaks, the analyst assumed that the increase in risk would be bounded by the change in risk associated with the subject performance deficiency quantified for internal events (9.14×10^{-7}).

As stated above the analyst assumed that the only external events that could result in an SLOCA were internal fires and seismic events.

The analyst used the SPAR model to quantify the conditional core damage probability for a small-break loss of coolant accident in a beyond-design-basis earthquake. The result was 2.64×10^{-1}. This is dominated by the loss of the high-pressure recirculation function at a rate of 24% per demand. Therefore, the assumed upper bound was estimated as follows:

3×10^{-5}/year * $2.64 \times 10^{-1} = 7.90 \times 10^{-6}$ over the exposure period.

Given that the increase resulting from internal fires is statistically independent from seismic events, the results can be added to determine that total external events contribution to SLOCAs.

$9.14 \times 10^{-7} + 7.9 \times 10^{-6} = 8.81 \times 10^{-6}$

, Medium-Break Loss of Coolant Accidents (MLOCA)

As stated above, the analyst assumed that the external events would not result in an MLOCA.

, Large-Break Loss of Coolant Accidents (LLOCA)

As stated above, the analyst assumed that the external events would not result in an LLOCA.

, Plant Transients

As stated above, many of the external initiators reviewed cause an increase in the initiating event likelihood for plant transients. Because the frequency of seismic events, internal floods, external fires, and transportation issues is so low compared to that of equipment and human error related plant transients, the impact from these external initiators is considered negligible.

High winds, internal fires, and certain other external events have occurred at such a high rate throughout the industry that the analyst believes they are well represented in the published plant transient initiating event frequencies. This resulted in the effect on risk, related to the subject performance deficiency, being fully quantified during the internal events analysis.

Therefore, the total effect of external initiators on the change in core damage frequency from plant transients related to the subject performance deficiency was determined to be negligible.

, Loss of Offsite Power

As stated above, many of the external initiators reviewed appear to cause an increase in the initiating event likelihood for a loss of offsite power. Because the frequency of seismic events, external fires, and transportation issues is so low compared to equipment and human error related loss of offsite power events, the impact from these external initiators is considered negligible.

High winds and certain other external events have occurred at such a high rate throughout the industry that the analyst believes they are well represented in the published loss of offsite power initiating event frequencies. This resulted in the effect on risk related to the subject performance deficiency being fully quantified during the internal events analysis.

Finally, the analyst assumed that internal fires were not likely to increase the probability of a loss of offsite power significantly because of the normal separation of plant equipment and because the published initiating events frequencies would include the contribution from large switchyard fires.

Therefore, the total effect of external initiators on the change in core damage frequency from loss of offsite power events related to the subject performance deficiency was determined to be negligible.

, Loss of Plant Cooling Water System

As stated above, the analyst assumed that the effect from the subject performance deficiency on a loss of plant cooling water initiating event would be an increase in the initiating event frequency from an internal flood or an internal fire affecting all system pumps. The increase in risk from internal floods is assumed to be bounded by the change in core damage frequency from the equipment related initiator (1.22×10^{-9}).

According to the Idaho National Engineering and Environmental Laboratory's study published in NUREG/CR-5750, "Rates of Initiating Events at U. S. Nuclear Power Plants: 1987-1995," loss of open-loop cooling water systems occur at a rate of 9.6×10^{-4} events per year. The analyst determined that the probability of a large oil fire causing a loss of plant cooling water system initiating event was at least an order of magnitude lower because the fire had to initiate, cause spilling of oil, and spread rapidly enough to damage system equipment, but not so rapidly that it would extinguish before causing a loss of the entire system.

Therefore, the analyst estimated that the increase in core damage frequency from an internal fire would be no greater than the internally initiated change in risk. However, because of the uncertainties in the data and to ensure that the risk is appropriately bounded, the analyst assumed that the change in core damage frequency could be as much as 10 times higher than for internally initiated events alone (1.22×10^{-8}).

Given that the increase resulting from internal fires is statistically independent from that of internal floods, the results can be added to determine the total external events contribution to SLOCAs.

$$1.22 \times 10^{-9} + 1.22 \times 10^{-8} = 1.34 \times 10^{-8}$$

, Loss of Nuclear Cooling Water System

For loss of nuclear cooling water events, the internal events contribution to the change in core damage frequency was evaluated to be 1.22 x 10^{-9}/year. As stated above, the analyst assumed that internal floods had the potential to increase the initiating event frequency by no more than that of internal events because the frequency of large piping failures tends to be smaller than the published failure rate of open loop cooling water systems. Therefore, the analyst assigned the change in core damage frequency from external events causing a loss of nuclear cooling water initiator to be equal to that of the internal events change in risk (1.22 x 10^{-9} /year). This was considered a bounding value.

Table 3.d: External Events ΔCDF Estimation

Internal Initiator	Internal ΔCDF	External ΔCDF	Cumulative External ΔCDF
SLOCA	9.14 x 10^{-7}	8.8 x 10^{-6}	8.8 x 10^{-6}
MLOCA	1.06 x 10^{-5}	-0-	8.8 x 10^{-6}
LLOCA	1.32 x 10^{-6}	-0-	8.8 x 10^{-6}
Transients	2.87 x 10^{-6}	-0-	8.8 x 10^{-6}
LOOP	1.02 x 10^{-7}	-0-	8.8 x 10^{-6}
LOPC	4.95 x 10^{-10}	1.34 x 10^{-8}	8.8 x 10^{-6}
LONCW	1.22 x 10^{-9}	1.22 x 10^{-9}	8.8 x 10^{-6}

NOTE: All ΔCDF values are unitless probabilities of the change in risk over the exposure time assumed (one year).

Risk Contribution from Large Early Release Frequency

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 7.

In PWR large, dry containments, only a subset of core damage accidents can lead to large, unmitigated releases from containment that have the potential to cause prompt fatalities prior to population evacuation. Core damage sequences of particular concern for this type of containments are intersystem loss of coolant accidents and steam generator tube ruptures. By their nature, steam generator tube ruptures and other containment bypass loss of coolant accidents do not provide water to the containment sump. Therefore, the subject finding does not impact those accident initiators.

In accordance with Manual Chapter 0609, Appendix H, "Containment Integrity SDP," the analyst determined that this was a Type A finding, because the finding affected the plant core damage frequency. The analyst evaluated both the risk-informed notebook results and the SPAR results and determined that there were no LERF potential sequences as described in Appendix H, Table 5.1, "Phase 1 Screening - Type A Findings at Full Power. Therefore, the analyst determined that the subject performance deficiency was not significant to the large-early release frequency.

Licensee's Risk Assessment

The analyst discussed the results of this analysis with the Palo Verde PRA Supervisor. The licensee's initial result was consistent with this analysis, given that the analyst's assumptions were correct. However, on December 23, 2004, the licensee provided the analyst with a draft analysis that indicated substantially different results. The new analysis took into consideration the results of a test program established and conducted by the licensee to better understand the impact of having air in the suction lines. The licensee calculated a ΔCDF of 3×10^{-6} over the one year exposure period.

The analyst noted the following key differences in assumptions used by the licensee:

19. The analyst assumed that the high-head safety injection pumps would fail following any recirculation actuation signal. The licensee stated that test results show the pumps would have continued to operate under all scenarios with the exception of SLOCAs that involve other than stuck-open relief valves.

20. The analyst assumed that the containment spray pumps would also fail following any recirculation actuation signal. The licensee stated that test results show these pumps would have continued to operate under all accident conditions.

21. The analyst assumed that following air binding, the high head pumps might be available and capable of being recovered by operator action. The licensee assumed that, once failed, the pumps would not be recoverable.

The analyst noted that these assumptions are critical to the final result of the analysis. The licensee submitted the documentation of tests and analyses supporting these assumptions on December 27, 2004. The NRC staff will review the data and discuss these critical assumptions in more detail with the licensee prior to making a final significance determination related to the subject finding.

Sensitivity

The analyst reviewed the evaluation results and determined that the total calculated risk related to the performance deficiency was dominated by the high pressure recirculation function. As such, the most critical assumptions were that both high pressure pumps failed and the recovery applied. The analyst used the SPAR model to modify these assumptions to determine the effect on the final result. Table 3.e provides the results:

Table 3.e: Internal Events Sensitivity to Assumptions			
Assumption	Change	Original ΔCDF	Revised ΔCDF
2 HPSI Pumps Fail	1 HPSI Pump Fails	1.6×10^{-5}	2.6×10^{-6}
HPSI Nonrecovery is 24%	2.4% (Nominal Time)[2]	1.6×10^{-5}	2.9×10^{-6}
HPSI Nonrecovery is 24%	HPSI Pumps are Not Recoverable[1]	1.6×10^{-5}	6.1×10^{-5}
All Pumps are Recoverable	HPSI and CS Pumps are Not Recoverable[1]	1.6×10^{-5}	8.2×10^{-5}
CS Nonrecovery is 2.4%	CS Pumps are Not Recoverable[1]	1.6×10^{-5}	8.2×10^{-5}
CS Nonrecovery is 2.4%	CS Pumps are Available at Their Nominal Rate[2]	1.6×10^{-5}	1.2×10^{-5}

NOTES:

1 - Assumes pumps are damaged beyond use
2 - Assumes pumps are available for recovery at the stated rate