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

July 24, 2006

James M. Levine, Executive Vice
President, Generation
Arizona Public Service Company
P.O. Box 52034
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SUBJECT: PALO VERDE NUCLEAR GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000528/2006003, 05000529/2006003, AND 05000530/2006003

Dear Mr. Levine:

On June 30, 2006, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Palo Verde Nuclear Generating Station, Units 1, 2, and 3 facility. The enclosed integrated report documents the inspection findings, which were discussed on June 23, 2006, with you and other members of your staff.

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

The report documents four NRC identified findings and five self-revealing findings. Eight of these findings were evaluated under the risk significance determination process as having very low safety significance (Green). One finding and one example of a finding were not suitable for evaluation under the significance determination process; however, they were determined to be of very low safety significance (Green) by NRC management review. 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 findings as noncited violations consistent with Section VI.A of the NRC Enforcement Policy. One licensee identified violation, which was determined to be of very low safety significance, is listed in Section 4OA7 of this report. If you contest these noncited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington DC 20555-0001; and the NRC Resident Inspector at Palo Verde Nuclear Generating Station, Units 1, 2, and 3, facility.

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

Sincerely,

/RA/

Troy W. Pruett, Chief
Project Branch D
Division of Reactor Projects

Dockets: 50-528
50-529
50-530

Licenses: NPF-41
NPF-51
NPF-74

Enclosure:
NRC Inspection Report 05000528/2006003, 05000529/2006003, and 05000530/2006003
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Dockets:	50-528, 50-529, 50-530
Licenses:	NPF-41, NPF-51, NPF-74
Report:	05000528/2006003, 050000529/2006003, 05000530/2006003
Licensee:	Arizona Public Service Company
Facility:	Palo Verde Nuclear Generating Station, Units 1, 2, and 3
Location:	5951 S. Wintersburg Road Tonopah, Arizona
Dates:	April 1 through June 30, 2006
Inspectors:	R. Azua, Reactor Inspector, Engineering Branch 1 B. Baca, Health Physicist, Plant Support Branch P. Benvenuto, Resident Inspector L. Carson II, Senior Health Physicist, Plant Support Branch P. Elkmann, Emergency Preparedness Inspector L. Ellershaw, PE, Consultant G. George, Reactor Inspector, Engineering Branch 1 J. Melfi, Resident Inspector E. Owen, Reactor Inspector, Engineering Branch 1 C. Paulk, Senior Reactor Inspector, Engineering Branch 1 N. Salgado, Senior Reactor Analyst, Headquarters W. Sifre, Reactor Inspector, Engineering Branch 1 M. Snell, Reactor Inspector, Region I R. Telson, Reactor Systems Engineer, Headquarters D. Melendez-Colon, Reactor Inspector, Region III G. Warnick, Senior Resident Inspector G. Werner, Senior Project Engineer, Project Branch D
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Enclosure

CONTENTS

SUMMARY OF FINDINGS

IR 05000528/2006003, 05000529/2006003, 05000530/2006003; 04/01/06 - 06/30/06; Palo Verde Nuclear Generating Station, Units 1, 2, and 3; Int. Res. and Reg. Report; Flood Pro. Meas., Main. Risk Assess. and Emer. Work Cont., Op. Per. During Nonroutine Evo. and Events, Refuel. and Other Out. Act., Sur. Test., Event Follow-up.

This report covered a 3-month period of inspection by three resident inspectors, five reactor inspectors, two health physicists, one emergency preparedness inspector, one reactor systems engineer, one senior project engineer, one senior reactor engineer, one senior reactor inspector, one consultant, and one senior reactor analyst. The inspection identified nine noncited violations. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management's review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A self-revealing noncited violation of Technical Specification 5.4.1.a was identified for the failure of maintenance personnel to follow procedures. Specifically, on April 2, 2006, maintenance personnel failed to follow Procedure 73ST-9DG02, "Class 1E Diesel Generator and Integrated Safeguards Test, Train B," by installing a jumper on the incorrect relay while testing the overcurrent trip. This resulted in an emergency diesel generator trip and de-energization of safety-related Bus PBB-S04. This issue was entered into the licensee's corrective action program as Condition Report/Disposition Request 2880952.

  The finding is greater than minor because it is associated with the human performance cornerstone attribute of the initiating events cornerstone and affects the associated cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Using the Manual Chapter 0609, "Significance Determination Process," Appendix G, "Shutdown Operations Significance Determination Process," Checklist 2, the finding is determined to have very low safety significance because the finding did not result in non-compliance with low temperature over pressure protection Technical Specifications, nor did it degrade the ability of containment to remain intact following an accident. Additionally, the finding did not degrade the licensee's ability to terminate a leak path, add reactor coolant system inventory, recover decay heat removal once it is lost, or establish an alternate core cooling path. Lastly, the finding did not increase the likelihood of a loss of reactor coolant system inventory, decay heat removal, or offsite power. The cause of the finding is related to the crosscutting element of human performance in that maintenance personnel did not follow procedures due to self-imposed schedule pressures (Section 1R14).

- Green. A self-revealing noncited violation of Technical Specification 5.4.1.a was identified for the failure of operations personnel to follow procedures. Specifically, between April 7 and April 12, 2006, operations personnel did not follow Procedure 40OP-9PC06, "Fuel Pool Clean Up and Transfer," Revision 37, Appendix AU, resulting in Valve PCN-V119, "Cleanup Header Return to the Fuel Canal," being improperly aligned. This resulted in an inadvertent transfer of approximately 1200 gallons of spent fuel pool water to the transfer canal and a spill of contaminated water onto the 120 foot and 100 foot elevations of the fuel building. This issue was entered into the licensee's corrective action program as Condition Report/Disposition Request 2884054.

  The finding is greater than minor because it is associated with the configuration control and human performance cornerstone attributes of the initiating events cornerstone and affects the associated cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. This finding cannot be evaluated by the significance determination process because Manual Chapter 0609, "Significance Determination Process," Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," and Appendix G, "Shutdown Operations Significance Determination Process," do not apply to the spent fuel pool. This finding is determined to be of very low safety significance by NRC management review because radiation shielding was provided by the spent fuel pool water level, the spent fuel pool cooling and fuel building ventilation systems were available, and there were multiple sources of makeup water. The cause of the finding is related to the crosscutting element of human performance in that operations personnel did not follow procedures due to poor human error prevention techniques (Section 1R14).

- Green. A self-revealing noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," was identified for the failure of licensee personnel to preclude repetition of a significant condition adverse to quality. Specifically, on April 17, 2006, and for the second time in two years, a submersible vehicle was suctioned into a system providing cooling to nuclear fuel, rendering the system inoperable. Following the April 11, 2004, event, the licensee's corrective actions concentrated on a lack of instructions and a lack of communications with the control room. While it was recognized that the event was transportable to other systems, and that the consequences could have been more severe, the corrective actions were limited in scope and were not adequate to preclude repetition. This issue was entered into the licensee's corrective action program as Condition Report/Disposition Request 2885213.

  The finding is greater than minor because it is associated with the configuration control and human performance cornerstone attributes of the initiating events cornerstone and affects the associated cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Using the Manual Chapter 0609, "Significance Determination Process," Appendix G, "Shutdown Operations Significance Determination Process," Checklist 4, the finding is determined to have very low safety significance because the finding did not increase the likelihood of a loss of reactor coolant system inventory. Additionally, the finding did not degrade the licensee's ability to terminate a leak path or add reactor coolant system inventory, neither did it degrade the licensee's ability to recover decay heat removal once it is lost. The cause of the finding is related to the crosscutting element of problem identification and resolution in that licensee personnel did not implement corrective actions to preclude repetition of a significant condition adverse to quality. Additionally, the cause of the finding is related to the crosscutting element of human performance in that licensee personnel did not stop movement of the submersible upon becoming disoriented (Section 1R14).

- Green. A self-revealing noncited violation of Technical Specification 5.4.1.a was identified for the failure of operations personnel to follow procedure. Specifically, on May 6, 2006, operations personnel failed to achieve a current of approximately zero amperes through Breaker NAN-S03A prior to opening the offsite supply breaker to Bus PBA-S03 as required by Procedure 40OP-9GT01, "Gas Turbine Generator Isochronous Test." This resulted in the loss of power to safety-related Bus PBA-S03 and an actuation of emergency diesel generator Train A. This issue was entered into the licensee's corrective action program as Condition Report/Disposition Request 2891404.

  The finding is greater than minor because it is associated with the human performance cornerstone attribute of the initiating events cornerstone and affects the associated cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Using the Manual Chapter 0609, "Significance Determination Process," Appendix G, "Shutdown Operations Significance Determination Process," Checklist 2, the finding is determined to have very low safety significance because the finding did not result in non-compliance with low temperature over pressure protection Technical Specifications, nor did it degrade the ability of containment to remain intact following an accident. Additionally, the finding did not degrade the licensee's ability to terminate a leak path, add reactor coolant system inventory, recover decay heat removal once it is lost, or establish an alternate core cooling path. Lastly, the finding did not increase the likelihood of a loss of reactor coolant system inventory, decay heat removal, or offsite power. The cause of the finding is related to the crosscutting element of human performance in that poor attention to detail by operations personnel resulted in the loss of power to a safety bus (Section 1R14).

Cornerstone: Mitigating Systems

- Green. The inspectors identified a noncited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the failure of operations personnel to verify or check the adequacy of the design of drain hose manifold boxes. Specifically, between 1997 and June 16, 2006, operations personnel failed to verify or check the adequacy of design of drain hose manifold boxes when the decision was made to leave the boxes permanently attached to the emergency core cooling system pump vents. The failure to evaluate the drain hose manifold boxes resulted in the degradation of the Unit 2 low pressure safety injection Train A pump room level switch, and the failure of the Unit 1 containment spray Train B pump room level switch. On June 16, 2006, the drain hose manifold boxes were removed from the emergency core cooling system pump rooms in all three units. This issue was entered into the licensee's corrective action program as Condition Report/Disposition Request 2903515.

The finding is greater than minor because it is associated with the design control cornerstone attribute of the mitigating systems cornerstone and affects the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because the condition only affected the mitigating systems cornerstone, and using the flooding criteria, would not cause a plant trip or any of the initiating events used by Phase 2, and would not degrade two or more trains of a multi-train safety system. The cause of the finding is related to the crosscutting element of problem identification and resolution in that operations personnel failed to adequately evaluate the impact of degraded level switches on the ability to detect and respond to an emergency core cooling system pump room flooding event (Section 1R06).

- Green. The inspectors identified two examples of a noncited violation of Technical Specification 5.4.1.a for the failure of engineering personnel to follow procedures. On April 17, 2006, engineering personnel failed to follow Procedure 81DP-0DC13, "Deficiency Work Order," resulting in shutdown cooling Train B being declared operable without fully addressing a potential degraded condition associated with the potential for missing parts from a submersible remaining in plant systems. On May 10, 2006, engineering personnel did not perform evaluations and dispositions required by Procedure 81DP-0DC13 to justify a degraded condition for continued use of a pipe support associated with shutdown cooling line Train A. These issues were entered into the licensee's corrective action program as Condition Report/Disposition Requests 2902258 and 2892737.

The finding is greater than minor because it would become a more significant concern if left uncorrected in that Technical Specification required structures, systems, and components (SSCs) may not be operable as required for applicable plant conditions. The performance deficiency associated with this finding was representative of a broader concern related to how the licensee ensures the operability of SSCs required to comply with Technical Specifications. Specifically, the licensee's programs and processes for assessing degraded conditions have not been implemented with the rigor and thoroughness necessary to ensure compliance with regulatory requirements. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because the condition only affected the mitigating systems cornerstone and did not represent an actual loss of safety function. The cause of the finding is related to the crosscutting element of human performance in that engineering personnel did not follow procedures, resulting in the failure to perform required evaluations and dispositions for deficient conditions (Sections 1R13 and 1R20).

- Green. The inspectors identified three examples of a Green noncited violation of Technical Specification 3.0.4 for the failure of operations personnel to ensure the operability of required equipment prior to entry into a mode or other specified condition in the limiting condition for operations applicability. Specifically, on March 20, 2006, Mode 4 was entered with reactor coolant system pressure at 386 psia and only one operable train of containment spray. Unaware that any Technical Specification requirements were violated, operations personnel lowered reactor coolant system pressure below 385 psia and controlled pressure at this level as they proceeded towards Mode 3. A short time later, on March 20, 2006, the control room supervisor incorrectly concluded that both trains of containment spray were operable and raised reactor coolant system pressure above 385 psia. On March 20, 2006, the class pressurizer heater Train B supply circuit breaker tripped due to a grounded condition on Heater A05, rendering the equipment inoperable. This equipment condition was not recognized by operations personnel until March 22. As a result of the equipment condition, on March 21, 2006, Unit 1 changed from Mode 4 to Mode 3 without two trains of pressurizer heaters operable. This issue was entered into the licensee's corrective action program as Condition Report/Disposition Requests 2877648, 2877591, and 2878030.

  The finding is greater than minor because it is associated with the configuration control cornerstone attribute of the mitigating systems cornerstone and affects the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. For the examples of this finding related to the containment spray system, a Phase 2 analysis was required since they impacted both the mitigating systems and barrier integrity cornerstones as determined by the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet. Using the Phase 2 Worksheets associated with loss of coolant accidents, the finding is determined to have very low safety significance since all remaining mitigation capability was available. The example of this finding related to pressurizer heaters cannot be evaluated by the significance determination process because Manual Chapter 0609, "Significance Determination Process," Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," and Appendix G, "Shutdown Operations Significance Determination Process," do not consider the pressurizer heaters as a risk significant function as defined in the risk informed notebook. This finding is determined to be of very low safety significance by NRC management review. The cause of the finding is related to the crosscutting element of human performance in that operations personnel did not follow procedures and apply the necessary rigor and questioning attitude to requirements and associated decisions because of self-imposed schedule pressures (Section 1R20).

- Green. The inspectors identified a noncited violation of Technical Specification 5.4.1.a for the failure of operations personnel to follow Procedure 73ST-9SI03, Leak Test of SI/RCS Pressure Isolation Valves, which resulted in declaring both trains of low pressure safety injection inoperable. Specifically, on May 10, 2006, operations personnel inappropriately allowed safety-injection header pressure to exceed 1850 pisg, which rendered the associated low pressure safety injection pumps inoperable. This issue was entered into the licensee's corrective action program as Condition Report/Disposition Request 2892697.

The finding is greater than minor because it is associated with the human performance cornerstone attribute of the mitigating systems cornerstone and affects the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because the condition only affected the mitigating systems cornerstone and did not represent an actual loss of safety function. The cause of the finding is related to the crosscutting element of human performance in that operations personnel did not follow procedures and apply the necessary rigor and questioning attitude to requirements and associated decisions because of self-imposed schedule pressures (Section 1R22).

- Green. A self-revealing noncited violation of Technical Specification 3.8.7, "Inverters - Operating," was identified for the failure to maintain two operable trains of inverters. On October 20, 2005, Inverter 1EPNBN12 failed. The licensee's evaluation determined that procurement engineering personnel did not identify the lack of oil in the output filter capacitors for the inverter. The capacitors were installed in the inverter between October 1999 and October 20, 2005. This issue was entered into the licensee's corrective action program as Condition Report/Disposition Request 2845317.

  The finding is greater than minor because it is associated with the equipment performance cornerstone attribute of the mitigating systems cornerstone and affects the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because the condition only affected the mitigating systems cornerstone and did not represent an actual loss of safety function (Section 4OA3).

B. Licensee-Identified Violation

A violation of very low safety significance which was identified by the licensee has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. This violation and its corrective actions are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 remained shutdown during the entire quarter in order to develop and install a permanent plant modification to correct the vibration issue on shutdown cooling (SDC) suction isolation Valve 1JS1AUV0651. At the end of the inspection period, Unit 1 was in Mode 3, making preparations to return to power operations.

Unit 2 operated at essentially full power until April 4, 2006, when power was reduced to 90 percent for maintenance on a heater drain pump. Power remained at 90 percent until April 10 when the unit was shutdown to perform repairs to the turbine driven auxiliary feedwater pump steam supply warm-up line isolation Valve SGA-V0138A. Following repairs, the unit returned to essentially full power on April 13, 2006, and remained there for the duration of the inspection period.

Unit 3 was shutdown for the twelfth refueling outage on April 1, 2006. The outage was completed and the unit returned to essentially full power on May 12, 2006, and remained there for the duration of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

Readiness For Seasonal Susceptibilities

The inspectors completed a review of the licensee's readiness of seasonal susceptibilities involving extreme high temperatures. The inspectors: (1) reviewed plant procedures, the Updated Final Safety Analysis Report (UFSAR), and Technical Specifications (TS) to ensure that operator actions defined in adverse weather procedures maintained the readiness of essential systems; (2) walked down portions of the three systems listed below to ensure that adverse weather protection features (heat tracing, space heaters, weatherized enclosures, temporary chillers, etc...) were sufficient to support operability, including the ability to perform safe shutdown functions; (3) evaluated operator staffing levels to ensure the licensee could maintain the readiness of essential systems required by plant procedures; and (4) reviewed the corrective action program (CAP) to determine if the licensee identified and corrected problems related to adverse weather conditions.

- May 16, 2006, Unit 2, spray pond (SP) system Trains A and B
- May 16, 2006, Unit 3, SP system Trains A and B

- May 16, 2006, Unit 3, essential cooling water (EW) system Trains A and B

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R02 Evaluation of Changes, Tests, or Experiments (71111.02)

a. Inspection Scope

The procedure requires a minimum sample size of 5 evaluations and 10 screenings. The team reviewed 7 licensee-performed safety evaluations to verify that the licensee had appropriately considered the conditions under which the licensee may make changes to the facility or procedures or conduct tests or experiments without prior NRC approval. The team also reviewed 14 licensee-performed screenings and applicability determinations, in which a full evaluation had been excluded. The team did so to ensure consistency with the requirements of 10 CFR 50.59, "Changes, Tests, and Experiments," in the exclusion of a full evaluation.

The team reviewed changes made to the UFSAR and permanent plant modifications to determine if the requirements of 10 CFR 50.59 were properly implemented.

The inspectors reviewed a sample of two corrective action documents associated with safety evaluations, written by licensee personnel, to determine whether licensee personnel properly identified and subsequently resolved problems or deficiencies.

Documents reviewed by the inspectors are listed in the attachment.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

Partial Walkdown

The inspectors: (1) walked down portions of the four below listed risk important systems and reviewed plant procedures and documents to verify that critical portions of the selected systems were correctly aligned; and (2) compared deficiencies identified during the walk down to the licensee's UFSAR and CAP to ensure problems were being identified and corrected.

- April 5, 2006, Unit 3, low pressure safety injection (LPSI), containment spray (CS), and high pressure safety injection (HPSI) Train B while Train A was in service for reduced inventory

- April 14, 2006, Unit 2, SP Train A during emergency diesel generator (EDG) Train B scheduled maintenance

- April 21, 2006, Unit 2, LPSI and HPSI Train B while Train A was out of service for testing

- May 25, 2006, Unit 3, EDG Train A during EDG Train B maintenance outage

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed four samples.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

Quarterly Inspection

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

- April 12, 2006, Unit 3, containment building, all elevations

- April 20, 2006, Unit 3, control building, all elevations

- April 21, 2006, Unit 2, control building, all elevations

- April 25, 2006, Unit 1, containment building, all elevations
- May 18, 2006, Unit 1, containment building, 80 foot and 100 foot elevations

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed five samples.

Annual Inspection

On June 1, 2006, the inspectors observed a fire brigade drill to evaluate the readiness of licensee personnel to prevent and fight fires, including the following aspects: (1) the number of personnel assigned to the fire brigade, (2) use of protective clothing, (3) use of breathing apparatuses, (4) use of fire procedures and declarations of emergency action levels, (5) command of the fire brigade, (6) implementation of pre-fire strategies and briefs, (7) access routes to the fire and the timeliness of the fire brigade response, (8) establishment of communications, (9) effectiveness of radio communications, (10) placement and use of fire hoses, (11) entry into the fire area, (12) use of fire fighting equipment, (13) searches for fire victims and fire propagation, (14) smoke removal, (15) use of pre-fire plans, (16) adherence to the drill scenario, (17) performance of the post-drill critique, and (18) restoration from the fire drill.

- June 1, 2006, Unit 2, simulated fire in the turbine building, non-class switchgear

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

Semi-annual Internal Flooding

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

- June 6-8, 2006, Units 1, 2, and 3, emergency core cooling system (ECCS) pump rooms

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed one sample.

b. Findings

Introduction. The inspectors identified a Green noncited (NCV) of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the failure of the licensee to verify or check the adequacy of the design of drain hose manifold boxes.

Description. On May 19, 2005, the Unit 1 CS pump Train B, room flooding level switch failed its functional test. UFSAR Section 7.6.1.1.3.3, "Auxiliary Building ESF Pump Room Level Monitoring," specified that this safety grade level instrumentation, mounted in the engineered safety feature sumps, is used to alert the control room of a pipe break in an ECCS room (including CS, HPSI, and LPSI). A high level alarm on 3.6 inches of water actuates the respective Class 1E alarm in the control room. Since the ECCS room level switches are only discussed in the UFSAR, and not in the TS, no TS limiting conditions for operations (LCO) entries were required due to the functional failure. The licensee initiated Work Mechanism (WM) 2800950 to repair the failed level switch.

On February 14, 2006, the Unit 2 LPSI Train A, pump room level switch was identified in a rusted and damp condition, although it passed its functional test. The licensee initiated WM 2869114 to correct the as-found condition. The WM was evaluated by operations personnel and no degraded or nonconforming condition was identified since the level switch performed its safety function during the test.

On April 12, 2006, the licensee initiated Condition Report/Disposition Request (CRDR) 2884056 to evaluate the impact of the degraded high water level switches when it was recognized that installation of the drain hose manifold boxes were contributing to the level switch degradation. The evaluation concluded that there was no impact on operations since there was a backup non-class ECCS pump room level alarm in the control room and the operators would notice a decrease in reactor coolant water level, indicative of possible flooding. However, operations personnel failed to consider that the backup non-class level alarm is not designed to work after a design basis pipe break. Additionally, operations personnel failed to address other sources of flooding, such as fire water or the refueling water tank. Further, the auxiliary building flooding calculation assumed that the worst case pipe break in the CS Train B pump room will not cause water level to reach more than 17.55 feet. The calculation assumed an operator response time of 30 minutes. With the CS Train B room flooding level switch not performing its design function of alerting the control room to a pipe break, it is possible that the operators may not recognize and isolate the flood in 30 minutes.

The inspectors observed that drain hose manifold boxes were installed to direct water from the ECCS pump vents to the sumps during pump venting. Initially, the drain hose manifold boxes were used as a tool to aid in system venting and draining operations during outage periods. However sometime between 1997 and 2000, the drain hose manifold boxes were left permanently attached to the pump vents without an evaluation for temporary or permanent installation, and their effect on the level switches. Consequently, the continued, frequent venting of the pumps, and draining of the water directly on top of the level switches, corroded these components.

The licensee's review of WM 2800950, WM 2869114, and evaluation under CRDR 2884056 failed to identify that a nonconforming condition existed, in that the drain hose manifold boxes installed in the plant were not evaluated for either temporary or permanent installation, and were adversely affecting the design basis function of the ECCS room level switches. Upon identification of the nonconforming condition by the inspectors, the licensee initiated CRDR 2903515 and notified the Unit 1, 2, and 3 control rooms. On June 16, 2006, the drain hose manifold boxes were removed from the ECCS rooms in all three units.

<u>Analysis</u>. The performance deficiency associated with this finding involved the failure of operations personnel to verify the adequacy of plant design. The finding is greater than minor because it is associated with the design control cornerstone attribute of the mitigating systems cornerstone and affects the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because the condition only affected the mitigating systems cornerstone, and using the flooding criteria, would not cause a plant trip or any of the initiating events used by Phase 2, and would not degrade two or more trains of a multi-train safety system. The cause of the finding is related to the crosscutting element of problem identification and resolution in that operations personnel failed to adequately evaluate the impact of degraded level switches on operations' ability to detect and respond to an ECCS pump room flooding event.

<u>Enforcement</u>. 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program. Contrary to the above, from approximately 1997 to June 16, 2006, operations personnel failed to verify or check the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program. Specifically, operations personnel failed to verify or check the adequacy of design of drain hose manifold boxes when the decision was made to leave them permanently attached to the pump vents. The permanent installation of the boxes adversely affected the design basis function of the ECCS room

level switches. Additionally, the failure to evaluate the drain hose manifold boxes resulted in the degradation of the Unit 2 LPSI Train A pump room level switch, and the failure of the Unit 1 CS Train B pump room level switch. On June 16, 2006, the drain hose manifold boxes were removed from the ECCS rooms in all three units. Because the finding is of very low safety significance and has been entered into the licensee's CAP as CRDR 2903515, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000528/2006003-01, "Failed Unit 1 CS Train B Pump Room Flood Level Switch Due to Nonconforming Drain Hose Manifold Boxes."

1R07 Heat Sink Performance (71111.07)

a. Inspection Scope

The inspectors reviewed licensee programs, verified performance against industry standards, and reviewed critical operating parameters and maintenance records for the heat exchangers associated with Unit 3 EDG Train A. The inspectors verified that: (1) performance tests were satisfactorily conducted for heat exchangers/heat sinks and reviewed for problems or errors; (2) the licensee utilized the periodic maintenance method outlined in Electric Power Research Institute (EPRI) NP-7552, "Heat Exchanger Performance Monitoring Guidelines;" (3) the licensee properly utilized biofouling controls; (4) the licensee's heat exchanger inspections adequately assessed the state of cleanliness of their tubes, and (5) the heat exchanger was correctly categorized under the Maintenance Rule.

- April 18, 2006, Unit 3, EDG Train A jacket water heat exchanger per Work Order (WO) 2805523
- April 18, 2006, Unit 3, EDG Train A intercooler heat exchanger per WO 2805525
- April 18, 2006, Unit 3, EDG Train A lube oil heat exchanger per WO 2805528

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

Inspection Procedure 71111.08 requires four samples, as identified in Sections 02.01, 02.02, 02.03, and 02.04.

02.01 Performance of Nondestructive Examination Activities Other Than Steam Generator Tube Inspections, Pressurized Water Reactor Vessel Upper Head Penetration Inspections, Boric Acid Corrosion Control

a. Inspection Scope

The inspection procedure requires the review of nondestructive examination activities consisting of two or three different types (i.e., volumetric, surface, or visual). The inspectors observed the performance of ultrasonic examinations (volumetric) on one reactor pressure vessel upper head penetration nozzle and two SDC line welds, and reviewed radiographic examinations (volumetric) on five pressurizer spray line welds. The inspectors also observed the performance of eddy current examinations (combination volumetric and surface) on three reactor pressure vessel upper head penetration nozzles. In addition, the inspectors observed two magnetic particle examinations (surface) on component supports and three visual (VT-3) examinations performed on component supports, as well. The table below identifies the above examinations which were conducted using four methods and three different examination types.

System/ Component	Identity	Examination Type	Examination Method
Safety Injection	Pipe to Elbow Weld 21-14	Volumetric	Ultrasonic
Safety Injection	Pipe to Elbow Weld 21-15	Volumetric	Ultrasonic
Component Support	Component Support SG-5-H-1	Surface	Magnetic Particle
Component Support	Component Support SG-2-H-1	Surface	Magnetic Particle
Component Support	Component Support SG-5-H-1	Visual	Visual (VT-3)
Component Support	Component Support SG-2-H-2	Visual	Visual (VT-3)
Component Support	Component Support SG-5-H-3	Visual	Visual (VT-3)
Pressurizer	Pressurizer Spray Line Welds 219337-2, -4, -5, -7, and -10	Volumetric	Radiography
Reactor Vessel Upper Head	Control Element Drive Mechanism Nozzle 14, 30, and 37	Volumetric	Ultrasonic
		Combination volumetric and surface	Eddy Current

For each of the observed nondestructive examination activities, the inspectors verified that the examinations were performed in accordance with the specific site procedures and the applicable American Society of Mechanical Engineers Boiler and Pressure Vessel (ASME) Code requirements.

During review of each examination, the inspectors verified that appropriate nondestructive examination procedures were used, examinations and conditions were as specified in the procedure, and test instrumentation or equipment was properly calibrated and within the allowable calibration period. The inspectors also verified the nondestructive examination certifications of the personnel who performed the above volumetric, surface, and visual examinations. Finally, the inspectors observed that indications identified during the ultrasonic, radiographic, visual, and eddy current examinations were dispositioned in accordance with the ASME qualified nondestructive examination procedures used to perform the examinations.

The inspection procedure requires review of one or two examinations with recordable indications that were accepted for continued service to ensure that the disposition was made in accordance with the ASME Code. The inspectors were informed that no indications exceeding ASME Code allowables were known to be in service.

The inspection procedure further requires verification of one to three welds on Class 1 or 2 pressure boundary piping to ensure that the welding process and welding examinations were performed in accordance with the ASME Code. The inspectors verified through record review and observation that welding performed on a safety injection system vent valve, both in the shop and in the field, was performed in accordance with Sections IX and XI of the 1995 Edition of the ASME Code. This included review of welding material issue slips to establish that the appropriate welding materials had been used and verification that the welding procedure specification (WPS-8MN-GTAW/SMAW, Revision 13) had been properly qualified.

The inspectors completed the one sample required by Section 02.01.

b. <u>Findings</u>

No findings of significance were identified.

02.02 <u>Reactor Vessel Upper Head Penetration Inspection Activities</u>

a. <u>Inspection Scope</u>

The inspection requirements for this section parallel the inspection requirement steps in Section 02.01. The inspectors observed the nondestructive examinations on several reactor vessel upper head penetrations identified in the table.

Additionally, the nondestructive examination procedures used to perform the above examinations were reviewed to assure that they were consistent with ASME Code requirements, and the equipment and calibration requirements were appropriately identified and demonstrated. The inspectors also observed and reviewed the eddy current and ultrasonic examination data analyses process used on reactor vessel upper head penetration Nozzles 7, 10, 21, 22, 24, 30, 79, 84, 85, 87, and 92. The nondestructive examination records were also reviewed to verify that 100 percent of the required inspection coverage was achieved on the observed penetration nozzles.

The inspectors also observed the bare metal visual inspection of approximately 100 percent of the penetration nozzles, performed in accordance with NRC Order EA-03-009, "Issuance of Order Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors," and reviewed the licensee's procedure and inspection report.

The inspectors verified that the nondestructive activities were performed in accordance with the requirements of NRC Order EA-03-009.

The nondestructive examinations performed during the NRC inspection did not reveal any defects. Indications were dispositioned in accordance with the licensee's qualified procedures and in accordance with ASME Code acceptance criteria parameters.

The inspectors determined through discussions with licensee personnel that welding repairs have not been performed on upper head penetrations.

The inspectors completed the one sample required by Section 02.02.

b. Findings

No findings of significance were identified.

02.03 Boric Acid Corrosion Control Inspection Activities (Pressurized Water Reactors)

a. Inspection Scope

The inspectors evaluated the implementation of the licensee's boric acid corrosion control program for monitoring degradation of those systems that could be deleteriously affected by boric acid corrosion.

The inspection procedure requires review of a sample of boric acid corrosion control walkdown visual examination activities through either direct observation or record review. The inspectors reviewed the documentation associated with the licensee's boric acid corrosion control walkdown, as specified in Procedure 70TI-9ZCO1, "Boric Acid Corrosion Prevention Program," Revision 5. Samples of documented visual inspection records of inspection walkdowns performed on components and equipment during April 2006 were reviewed by the inspectors.

Additionally, the inspectors performed independent observations of piping containing boric acid during walkdowns of the containment building and the auxiliary building.

The inspection procedure requires verification that visual inspections emphasize locations where boric acid leaks can cause degradation of safety significant components. The inspectors verified through direct observation and program/record review that the licensee's boric acid corrosion control inspection efforts are directed towards locations where boric acid leaks can cause degradation of safety-related components.

The inspection procedure requires both a review of one to three engineering evaluations performed for boric acid leaks found on reactor coolant system (RCS) piping and components, and one to three corrective actions performed for identified boric acid leaks. There were no applicable CRDRs generated since the last inspection period that required formal engineering evaluations, (e.g., that resulted in a separate design or structural engineering analysis to determine continued operability). The inspectors reviewed CRDRs (see Attachment), documenting minor valve packing leaks on valves in the safety injection system. The planned corrective actions were adequate in each case.

The inspectors completed the one sample required by Section 02.03.

b. Findings

No findings of significance were identified.

02.04 Steam Generator Tube Inspection Activities

a. Inspection Scope

The inspection procedure specified performance of an assessment of in situ screening criteria to assure consistency between assumed nondestructive examination flaw sizing accuracy and data from the EPRI examination technique specification sheets. It further specified assessment of appropriateness of tubes selected for in situ pressure testing, observation of in situ pressure testing, and review of in situ pressure test results.

At the time of this inspection, no conditions had been identified that warranted in situ pressure testing. The inspectors did, however, review the licensee's report, "PVNGS Steam Generator Degradation Assessment Report," dated March 2000, with Appendix update for 3R12 dated April 4, 2006, and compared the in situ test screening parameters to the guidelines contained in the EPRI document, "In Situ Pressure Test Guidelines," Revision 2. This review determined that the remaining screening parameters were consistent with the EPRI guidelines.

In addition, the inspectors reviewed both the licensee site-validated and qualified acquisition and analysis technique sheets used during this refueling outage and the qualifying EPRI examination technique specification sheets to verify that the essential variables regarding flaw sizing accuracy, tubing, equipment, technique, and analysis had been identified and qualified through demonstration. The inspector-reviewed acquisition and analysis technique sheets are identified in the Attachment.

The inspection procedure specified comparing the estimated size and number of tube flaws detected during the current outage against the previous outage operational assessment predictions to assess the licensee's prediction capability. The inspectors compared the previous outage operational assessment predictions contained in the "Unit 3 Cycle 11 Operational Assessment for Palo Verde End-of-Cycle 11, 2004," with the flaws identified, thus far, during the current steam generator tube inspection effort. Compared to the projected damage mechanisms identified by the licensee, the number of identified indications fell within the range of prediction and were actually much lower than predictions. No new damage mechanisms had been identified during this inspection.

The inspection procedure specified confirmation that the steam generator tube eddy current test scope and expansion criteria meet TS requirements, EPRI guidelines, and commitments made to the NRC. The inspectors evaluated the recommended steam generator tube eddy current test scope established by TS requirements and the Palo Verde Nuclear Generating Station degradation assessment report. The inspectors compared the recommended test scope to the actual test scope and found that the licensee had accounted for all known flaws and had, as a minimum, established a test scope that met technical specification requirements, EPRI guidelines, and commitments made to the NRC. The scope of the licensee's eddy current examinations of tubes in both steam generators included:

- A full length or straight section bobbin examination of 100 percent of inservice tubes,
- Rotating pancake coil exams (+Point) of 100 percent of hot leg top-of-tubesheet locations (+2", - 14")
- Rotating pancake coil exams (+Point) of 20 percent of cold leg top-of-tubesheet locations (+2", -14"),
- Rotating pancake coil exams (+Point) of 100 percent of rows 1-5 U-bend locations,
- Rotating pancake coil exams (+Point) of 20 percent of rows 6-18 U-bend locations, and
- Rotating pancake coil exams (+Point) of approximately 3096 special interest locations

The inspection procedure specified, if new degradation mechanisms were identified, verification that the licensee fully enveloped the problem in its analysis of extended conditions including operating concerns and had taken appropriate corrective actions before plant startup. To date, the eddy current test results had not identified any new degradation mechanisms.

The inspection procedure requires confirmation that the licensee inspected all areas of potential degradation, especially areas that were known to represent potential eddy current test challenges (e.g., top-of-tubesheet, tube support plates, and U-bends). The inspectors confirmed that all known areas of potential degradation were included in the scope of inspection and were being inspected.

The inspection procedure further requires verification that repair processes being used were approved in the TS. At the time of this inspection, it was estimated that a total of approximately 20 tubes in Steam Generator 31 would be plugged and approximately 80 tubes in Steam Generator 32 would be plugged. The inspectors verified that the mechanical expansion plugging process to be used was an NRC-approved repair process. A second mechanical expansion plugging process had been NRC-approved but was not expected to be used.

The inspection procedure also requires confirmation of adherence to the TS plugging limit, unless alternate repair criteria have been approved. The inspection procedure further requires determination whether depth sizing repair criteria were being applied for indications other than wear or axial primary water stress corrosion cracking in dented tube support plate intersections. The inspectors determined that the TS plugging limits were being adhered to (i.e., 40 percent maximum through-wall indication).

If steam generator leakage greater than 3 gallons per day was identified during operations or during post shutdown visual inspections of the tubesheet face, the inspection procedure requires verification that the licensee had identified a reasonable cause based on inspection results and that corrective actions were taken or planned to address the cause for the leakage. The inspectors did not conduct any assessment because this condition did not exist.

The inspection procedure requires confirmation that the eddy current test probes and equipment were qualified for the expected types of tube degradation and an assessment of the site-specific qualification of one or more techniques. The inspectors observed portions of eddy current tests performed on the tubes in Steam Generators 31 and 32. During these examinations, the inspectors verified that: (1) the probes appropriate for identifying the expected types of indications were being used, (2) probe position location verification was performed, (3) calibration requirements were adhered, and (4) probe travel speed was in accordance with procedural requirements. The inspectors performed a review of site-specific qualifications of the techniques being used. These are identified in the Attachment.

If loose parts or foreign material on the secondary side were identified, the inspection procedure specified confirmation that the licensee had taken or planned appropriate repairs of affected steam generator tubes and that they inspected the secondary side to either remove the accessible foreign objects or perform an evaluation of the potential effects of inaccessible object migration and tube fretting damage. At the time of this inspection, the licensee had identified two possible loose parts in each steam generator. Foreign object search and retrieval had not yet been implemented during this inspection but was scheduled. Evaluations had determined that the possible loose parts had not created wear conditions.

Finally, the inspection procedure specified review of one to five samples of eddy current test data if questions arose regarding the adequacy of eddy current test data analyses. The inspectors did not identify any results where eddy current test data analyses adequacy was questionable.

The inspectors completed the one sample required by Section 02.04.

b. Findings

No findings of significance were identified.

02.05 Identification and Resolution of Problems

a. Inspection scope.

The inspection procedure requires review of a sample of problems associated with inservice inspections documented by the licensee in the corrective action program for appropriateness of the corrective actions.

The inspectors reviewed three CRDRs, which dealt with inservice inspection activities and found that the corrective actions were appropriate. From this review the inspectors concluded that the licensee had an appropriate threshold for entering issues into the corrective action program and has procedures that direct a root cause evaluation when necessary. The licensee also had an effective program for applying industry operating experience.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope

The inspectors observed testing and training of senior reactor operators and reactor operators to identify deficiencies and discrepancies in the training, to assess operator performance, and to assess the evaluator's critique. The training scenario on May 25, 2006, involved a series of five events including (1) RCS Leak, (2) Inadvertent Closure of Nuclear Cooling Containment Isolation valve, (3) Loss of Plant Cooling Water/Reactor Trip, (4) Standard Post Trip Actions/Loss of Coolant Accident, and (5) Functional Recovery Plan (loss of HPSI).

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

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

- April 8, 2006, Unit 2, auxiliary feedwater pump turbine steam supply Valve 2JSGAUV0138A stroke time failure documented in CRDR 2883052

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

Risk Assessment and Management of Risk

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

- April 21, 2006, Unit 2, swapping of protected trains to complete unfinished surveillances and corrective maintenance for HPSI pump Train A during a Train B work week

- May 15, 2006, Unit 2, evaluation of the risk management action levels during a Train B outage of EDG, EW, essential chilled water, and SP

- June 17, 2006, Units 1, risk assessment and management during east bus outage while Unit 1 was in a short notice outage

- June 30, 2006, Unit 1, 2, and 3, assessment of engineering evaluation and operability determination for de-sludging of the SP

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed four samples.

Emergent Work Control

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

- April 7, 2006, Unit 2, corrective maintenance of Valve GS-HV-05, "Main Steam Supply to Gland Steam Regulator"
- April 18, 2006, Unit 1, while the licensee was using a remote controlled submersible camera to assist with defueling operations, the submersible was drawn into the SDC suction line, causing the licensee to declare the SDC Train B inoperable
- May 18, 2006, Unit 2, evaluation of the risk management action levels during removal of EW Train A and associated SSCs following discovery of excessive EDG Train B intake air temperature indicative of intercooler heat exchanger fouling
- June 13, 2006, Unit 1, risk assessment and management during a loss of power to Bus PBA-S03
- June 14, 2006, Unit 1, EDG Train A sequencer taken out of service for troubleshooting, to identify the cause of recurring lock-ups
- June 23, 2006, Units 1, 2, and 3, risk assessment and management during evaluation and disposition of degraded condition on the EDG exhaust fans

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed six samples.

b. Findings

Introduction. The inspectors identified two examples of a Green NCV of TS 5.4.1.a for the failure of engineering personnel to follow Procedure 81DP-0DC13, "Deficiency Work Order." Specifically, engineering personnel failed to follow procedures resulting in the Unit 1 SDC Train B being declared operable without fully addressing a potential degraded condition. The second example is documented in Section 1R20.1.

Description. On April 17, 2006, during refueling operations in Unit 1, a technician that was driving a submersible camera became disoriented, and allowed the submersible to drift inside the reactor vessel and become lodged in SDC Train B as documented in Section 1R14.3, NCV 05000528/2006003-05, "Failure to Preclude a Significant Condition Adverse to Quality." On May 1, the licensee was able to retrieve the submersible by disassembling SDC suction isolation Valve SIB-UV-652. After inspecting the submersible, it was determined that there were several parts missing. The missing parts included a plastic skid shaped as a sleigh, which weighed approximately 180 grams, and measured approximately 0.25 inches in thickness, 6 inches in width, and 12 inches in length. Two sets of counter weights. Each set normally included a threaded stud, approximately 3 inches long, approximately 8 metal weights, shaped as washers that are held together by the stud to a center piece that is common to both sets of counter weights, and six screws that attach the counter weight and the skid to the submersible. The counter weight weighed a total of 540 grams, and the screws 1 gram each.

Engineering personnel implemented their retrieval plan by inspecting different portions of the SDC system. Through video inspections the licensee found the skid at the suction of the SDC Train B pump. The licensee opened the suction of the pump and removed the skid, which was broken into two pieces. By reconstruction, and by weighing the skid, the licensee demonstrated that the entire skid was recovered. Additional inspections found more pieces of the submersible in the SDC warm-up line. By disassembling Valve SIB-UV-690, the licensee was able to retrieve the six screws and one set of counter weights, which included one threaded stud with all its associated weights (approximately 8), and the common center piece. The inspectors questioned the licensee concerning the missing pieces and the impact on the operability of the system. Engineering personnel stated that the inspections would continue until all pieces were recovered and the impact on the system evaluated.

After completing video inspections of most of the system, engineering personnel installed a strainer at the suction of the SDC pump and ran the pump for approximately 90 minutes. Only a small plastic washer that was missing from one of the six small screws was found. The licensee assumed that the other set of counter weights had probably been removed before the submersible was placed in the water. The inspectors challenged this assumption since they lacked definitive evidence that the parts were not still in the system. The licensee stated that thorough inspections would be conducted, including inspections of the reactor vessel, to obtain reasonable assurance that the missing counter weights were not on the submersible prior to the event, and consequently, not in the system. Further, an evaluation detailing the inspections and assumptions to justify that all missing parts were accounted for would be documented before declaring the system operable.

The licensee documented the event in CRDR 2885213 and wrote TSCCR 2885240 to ensure the CRDR would be closed before declaring the system operable. Additionally, CRDR 2885213 had Deficiency Work Order 2890926 as a closure restraint. Deficiency Work Order 2890926 was written to address the missing parts from the submersible. On June 13, 2006, the inspectors questioned the licensee concerning the evaluation of any possible missing parts and their impact on system operability. While trying to produce the evaluation, the licensee discovered that SDC Train B had been declared operable on June 4, 2006, without performing the required evaluation. CRDR 2885213 had been closed even though Deficiency Work Order 2890926 was still being developed.

On June 13, 2006, engineering personnel documented the evaluation, but it did not provide reasonable assurance that there were no additional missing parts. Specifically, the licensee's evaluation did not address whether missing parts remained in uninspected portions of the SDC or reactor coolant systems. After the inspectors questioned the evaluation, engineering personnel provided an acceptable response to provide a reasonable level of confidence that no other submersible missing parts remained in the system.

Analysis. The performance deficiency associated with this finding involved the failure of engineering personnel to perform required evaluations and dispositions for deficient conditions to ensure operability of SSCs required to comply with TS. The finding is greater than minor because it would become a more significant concern if left uncorrected in that TS required SSCs may not be operable as required for applicable plant conditions. The performance deficiency associated with this finding was representative of a broader concern related to how the licensee ensures the operability of SSCs required to comply with TS. Specifically, the licensee's programs and processes for assessing degraded conditions have not been implemented with the rigor and thoroughness necessary to ensure compliance with regulatory requirements (Similar examples include: Auxiliary feedwater (AFW) resistors and emergency diesel generator sequencer issues documented in NRC Inspection Report 2006-008, resistance temperature detector, level instrumentation, and operability determination issues documented in NRC Inspection Report 2005-005, and usable tank volume and operability issues documented in NRC Inspection Report 2005-012). Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because the condition only affected the mitigating systems cornerstone and did not represent an actual loss of safety function. The cause of the finding is related to the crosscutting element of human performance in that engineering personnel did not follow procedures for performing evaluations and dispositions for deficient conditions.

Enforcement. TS 5.4.1.a requires that written procedures be established, implemented, and maintained covering the activities specified in Regulatory Guide 1.33, Appendix A, "Typical Procedures for Pressurized Water Reactors and Boiling Water Reactors," of Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operations)," dated February 1978. Regulatory Guide 1.33, Appendix A, Item 1(c), requires procedures for Equipment Control. Procedure 81DP-0DC13, "Deficiency Work Order," Revision 18, Step 3.4.1.7, stated that, "Prior to an SSC being declared operable or returned to service, the disposition of associated ENG DFWO's shall be complete and given a Final Disposition or revised to a Conditional Release." Contrary to the above, on June 4, 2006, engineering personnel closed a CRDR with restraining mechanisms still open. Specifically, engineering personnel closed CRDR 2885213, with DFWO 2890926 still open, resulting in SDC Train B being declared operable without fully addressing a potential degraded condition. Engineering personnel completed the required evaluation on June 13, 2006. Because this violation is of very low safety significance and has been entered into the CAP as CRDR 2902258, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000528; 05000530/2006003-02, "Failure to Evaluate Degraded Conditions to Ensure Equipment Operability."

1R14 Operator Performance During Nonroutine Evolutions and Events (71111.14, 71153)

a. Inspection Scope

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

- On April 2, 2006, Unit 2 experienced a loss of power actuation of EDG Train B due to a maintenance personnel error during testing. This event was documented in CRDR 2880952.

- On April 10, 2006, Unit 2 performed a TS required shutdown to complete repairs to the turbine driven auxiliary feedwater pump steam supply warm-up line isolation Valve SGA-V0138A. Inspectors observed the unit shutdown from the control room. This event was documented in CRDR 2883283.

- On April 12, 2006, Unit 3, an operator observed water leaking from the 140 foot to the 120 foot elevation of the fuel building. Upon investigation it was determined that the leakage was coming through the winch assembly for the new fuel elevator. During defueling, the pool cooling (PC) cleanup pump had been inappropriately aligned to both the spent fuel pool (SFP) and the fuel transfer canal. This caused the pump to raise level in the fuel transfer canal higher than in the SFP, until it began overflowing through the winch assembly. After securing the PC cleanup pump the leakage stopped. This event was documented in CRDR 2884054.

- On April 18, 2006, the licensee was in the process of removing the upper guide structure from the reactor vessel and was using a remote controlled submersible camera to check the lift, movement, and placement of the upper guide structure. After the upper guide structure was placed on its stand, the submersible was moved inadvertently over the reactor vessel. SDC Train B was in service and the submersible was drawn into the hot leg and then into the SDC line. The licensee was able to retrieve the submersible after defueling on May 1, 2006. This event was documented in CRDR 2885213.

- On May 6, 2006, Unit 3 experienced a valid actuation of EDG Train A due to an undervoltage condition on safety-related Bus PBA-S03. This loss of power occurred during performance of Procedure 40OP-9GT01, "Gas Turbine Generator Isochronous Test." During this test, voltage on safety-related Bus PBA-S03 dropped below the degraded voltage relay setpoint, resulting in isolation of the bus and an actuation of EDG Train A. All equipment loaded onto the bus as designed. This event was documented in CRDR 2891404.

- On May 30, 2006, Unit 1, the EDG Train A sequencer failed during the cooldown period of the diesel, after completing a scheduled surveillance of the EDG. The failure caused a loss of power to the safety-related Bus PBA-S03, forcing the licensee to enter their abnormal procedure for degraded electrical conditions. Operations personnel de-energized the EDG Train A sequencer to restore power to safety-related Bus PBA-S03. This event was documented in CRDR 2899375.

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed six samples.

b. Findings

.1 Emergency Diesel Generator Trip During Testing

Introduction. A Green self-revealing NCV of TS 5.4.1.a was identified for the failure of maintenance personnel to follow procedures, resulting in an EDG trip and de-energization of safety-related Bus PBB-S04.

Description. On April 2, 2006, during refueling Outage 3R12, maintenance personnel were conducting a test of Unit 3, EDG Train B, in accordance with Procedure 73ST-9DG02, Section 8.6. Section 8.6 had operations personnel start the EDG in "emergency mode" by opening the normal supply breaker to safety-related Bus PBB-S04, and simulated a safety injection actuation signal and a containment isolation actuation signal. Further, Section 8.6, demonstrated that "test mode" trips were bypassed when the EDG was operating in "emergency mode." One of the trips being tested was the overcurrent trip, which is simulated by installing a jumper across the overcurrent relay while the EDG is running. Before beginning the test, the licensee conducted a pre-brief in the control room with the reactor operator (RO), auxiliary operators, test coordinator, and test engineer involved in the testing. However, the two electricians that were installing the jumper to simulate the overcurrent trip were not present.

After the pre-brief was completed, the EDG was started in "emergency mode" and all the steps were performed as required until it was time to simulate the overcurrent trip. Because the electricians were not at the pre-brief, the test engineer decided to read the procedure and direct the electricians verbally through the steps to install the jumper and simulate the overcurrent trip. The electrician installing the jumper did not read the procedure but rather listened to the instructions by the test engineer. The electrician acknowledged the instructions, but installed the jumper on the incorrect relay. The jumper was installed on the differential current relay instead of the overcurrent relay, resulting in a trip of the EDG, and a loss of power to safety-related Bus PBB-S04. The differential current relay is an "emergency mode" trip of the EDG. In response to the condition, operations personnel entered abnormal operating Procedure 40AO-9ZZ12, "Degraded Electrical Power," Revision 29. EDG Train B was reset and it automatically started to restore power to the safety-related Bus PBB-S04. All the equipment responded as designed.

The licensee's investigation and personnel statements revealed several causes for the error. They included the absence of the electricians at the pre-brief, inadequate briefing of the electricians by the test engineer prior to commencing work, inadequate or lack of peer verification, actual or perceived time pressures due to delays of the test, and poor communications between the electricians and the test engineer during the test.

Analysis. The performance deficiency associated with this finding involved the failure of maintenance personnel to follow procedures resulting in an EDG trip and de-energization of the safety-related Bus PBB-S04. The finding is greater than minor because it is associated with the human performance cornerstone attribute of the initiating events cornerstone and affects the associated cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Using the Manual Chapter 0609, "Significance Determination Process," Appendix G, "Shutdown Operations Significance Determination Process," Checklist 2, the finding is determined to have very low safety significance because the finding did not result in non-compliance with low temperature over pressure protection TSs, nor did it degrade the ability of containment to remain intact following an accident. Additionally, the finding did not degrade the licensee's ability to terminate a leak path, add RCS inventory, recover decay heat removal once it is lost, or establish an alternate core cooling path. Lastly, the finding did not increase the likelihood of a loss of RCS inventory, decay heat removal, or offsite power. The cause of the finding is related to the crosscutting element of human performance in that maintenance personnel did not follow procedures due to self-imposed schedule pressures, resulting in an EDG trip and de-energization of a safety-related bus.

Enforcement. TS 5.4.1.a requires that written procedures be established, implemented, and maintained covering the activities specified in Regulatory Guide 1.33, Appendix A, February 1978. Regulatory Guide 1.33, Appendix A, Item 8.b.(1)(q) requires procedures for Emergency Power Tests. Procedure 73ST-9DG02, "Class 1E Diesel Generator and

Integrated Safeguards Test, Train B," Revision 12, required a test of the overcurrent trip by installing a jumper across the overcurrent relay. Contrary to the above, on April 2, 2006, maintenance personnel failed to follow Procedure 73ST-9DG02, by installing a jumper on the incorrect relay, while testing the overcurrent trip. This resulted in an EDG trip and de-energization of safety-related Bus PBB-S04. Because this violation is of very low safety significance and has been entered into the CAP as CRDR 2880952, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000530/2006003-03, "Emergency Diesel Trip During Testing."

.2 Spent Fuel Pool Drain Down and Spill in the Fuel Building

Introduction. A Green self-revealing NCV of Technical Specification 5.4.1.a was identified for the failure of operations personnel to follow procedures, which resulted in an inadvertent transfer of SFP water to the transfer canal and a spill onto the 120 foot and 100 foot elevations of the fuel building.

Description. On April 12, 2006, after completing defueling activities for refueling Outage 3R12, refueling personnel installed the gate between the SFP and the fuel transfer canal. Shortly after, an operator noticed a spill of water on the 120 foot and the 100 foot elevations of the Unit 3 fuel building. Further investigation identified that SFP level was low at 137 feet 7 inches, but the fuel transfer canal level was high at 139 feet. Operations personnel immediately secured PC cleanup pump Train B. The leakage stopped shortly thereafter, and levels equalized between the SFP and transfer canal.

Subsequent investigation by the licensee found that Valve PCN-V119, "Cleanup Header Return to the Fuel Canal," was improperly aligned. Valve PCN-V119 should have been closed, with the PC cleanup pump Train B taking a suction out of the SFP and discharging via Valve PCN-V080, "Spent Fuel Pool Cleanup Header Return Isolation," to the SFP only. Contrary to this, PCN-V119 and PCN-V080 were both open. This resulted in PC cleanup pump Train B taking a suction out of the SFP and discharging to both the fuel transfer canal and the SFP, resulting in a transfer of inventory from the SFP to the fuel transfer canal. These valves were manipulated on April 7, 2006, when the licensee filled the fuel transfer canal using PC cleanup pump Train B in a normal line-up per Procedure 40OP-9PC06, "Fuel Pool Cleanup and Transfer," Revision 37, Appendix AU. On April 9, 2006, operations personnel used Procedure 40OP-9PC06 to place PC cleanup pump Train B in a normal line-up. Subsequent investigation by the licensee determined that PCN-V119 should have been closed during the April 9 evolution. Since the gate between the fuel transfer canal and the SFP was open between April 7 and April 12, there were no differences in level and the improper alignment was not detected.

As a result of the improper alignment, an estimated 1200 gallons of SFP inventory was pumped directly into the fuel transfer canal. When the water level in the fuel transfer canal increased to 139 feet, water entered the new fuel elevator winch assembly pit. From there, the water leaked through conduits and resulted in slightly contaminated SFP water spilling into the fuel building. Radiation protection (RP) found contamination consistent with the presence of SFP water on the 120 foot elevation, 100 foot elevation, and in the pit that contains the new fuel elevator winch assembly. All of the water was collected and the contamination cleaned. The licensee concluded that the most probable cause was that the auxiliary operators checked Valve PCN-V119 in the wrong position. Similar events occurred between April 24, 2003, and April 23, 2005, when valves associated with the SFP were inappropriately positioned, resulting in a loss of SFP inventory. The events were documented in NCVs 05000528; 05000529; 05000530/2004003-09 and 05000528/2005003-04.

Analysis. The performance deficiency associated with this finding involved operations personnel not following procedures. The finding is greater than minor because it is associated with the configuration control and human performance cornerstone attributes of the initiating events cornerstone and affects the associated cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. This finding cannot be evaluated by the significance determination process because Manual Chapter 0609, "Significance Determination Process," Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," and Appendix G, "Shutdown Operations Significance Determination Process," do not apply to the SFP. This finding is determined to be of very low safety significance by NRC management review because radiation shielding was provided by the SFP water level, the SFP cooling and fuel building ventilation systems were available, and there were multiple sources of makeup water. The cause of the finding is related to the crosscutting element of human performance in that operations personnel did not follow procedures.

Enforcement. TS 5.4.1.a requires that written procedures be established, implemented, and maintained covering the activities specified in Regulatory Guide 1.33, Appendix A, February 1978. Regulatory Guide 1.33, Appendix A, Section 3.h, requires procedures for operating the fuel storage pool purification and cooling system.
Procedure 40OP-9PC06, "Fuel Pool Cleanup and Transfer," Revision 37, provided a required valve line up to operate the PC clean up system. Contrary to the above, between April 7 and April 12, 2006, operations personnel failed to properly implement Procedure 40OP-9PC06 for operating the PC cleanup system, resulting in Valve PCN-V119, "Cleanup Header Return to the Fuel Canal," being improperly aligned. This resulted in an inadvertent transfer of SFP water to the transfer canal and a spill of contaminated water onto the 120 foot and 100 foot elevations of the fuel building. Because the finding is of very low safety significance and has been entered into the licensee's CAP as CRDR 2884054, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000530/2006003-04, "Failure to Follow Procedures Resulted in Spent Fuel Pool Drain Down and Spill in the Fuel Building."

.3 Failure to Preclude a Significant Condition Adverse to Quality

Introduction. A Green self-revealing NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," was identified for the failure of licensee personnel to preclude repetition of a significant condition adverse to quality. Specifically, for the second time in two years a submersible vehicle was suctioned into a system providing cooling to the nuclear fuel.

Description. On April 17, 2006, during refueling operations in Unit 1, licensee personnel were moving the upper guide structure from the reactor vessel to the stand. A technician was assisting these efforts with a submersible camera. While trying to drive the submersible away from the upper guide structure and into the other side of the refueling cavity, the technician became disoriented as to the location of the submersible and allowed it to drift inside the reactor vessel. Once inside the vessel, the submersible was drawn into the RCS hot leg and became lodged in the Train B SDC suction line.

The licensee declared SDC Train B inoperable, and placed SDC Train A in service to continue providing cooling to the fuel. The operators only saw a slight decrease in SDC flow from approximately 4100 gpm to 4000 gpm for a few minutes before placing SDC Train A in operation. Licensee personnel performed several unsuccessful attempts to retrieve the submersible by pulling its electrical power cable. On April 19, the licensee decided to delay retrieval of the submersible until after full core off-load. After ensuring the submersible's tether was secure and out of the way, the nuclear fuel was removed from the core. Fuel movement was completed on April 23. On May 1, the licensee was able to retrieve the submersible by disassembling SDC suction isolation Valve SIB-UV-652. After inspecting the submersible, it was determined that there were several parts missing. At that point, the licensee initiated a comprehensive inspection plan to locate and retrieve the missing parts. All of the parts believed to be missing were retrieved on May 18. Other potential missing parts were evaluated per DFWO 2890926 on June 13, 2006. No other plant equipment was damaged and adequate cooling to the fuel was always maintained (See Section 1R13).

This was the second time that a submersible vehicle was suctioned into a system providing cooling to the nuclear fuel. Specifically, on April 11, 2004, while the licensee was testing this same submersible in preparation for a scheduled inspection of the reactor vessel, the submersible was drawn into the SFP cooling pump combined suction. In this event it was determined that the operator of the submersible did not have written instructions or operation's permission to perform the test. The event was documented in CRDR 2697384 and NRC NCV 05000528/2004003-08, "Failure to Have Instructions for Testing a Submersible in the Unit 1 SFP." The licensee's corrective actions concentrated on the lack of instructions for the test and the lack of communications with the control room. While it was recognized that the event was transportable to other systems, and that the consequences could have been more severe, the corrective actions were limited in scope and were not adequate to preclude repetition.

Analysis. The performance deficiency associated with this finding was the failure of licensee personnel to correct and preclude repetition of a significant condition adverse to quality. The finding is greater than minor because it is associated with the configuration control and human performance cornerstone attributes of the initiating events cornerstone and affects the associated cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Using the Manual Chapter 0609, "Significance Determination Process," Appendix G, "Shutdown Operations Significance Determination Process," Checklist 4, the finding is determined to have very low safety significance because the finding did not increase the likelihood of a loss of RCS inventory. Additionally, the finding did not degrade the licensee's ability to terminate a leak path or add RCS inventory, neither did it degrade the licensee's ability to recover decay heat removal once it is lost. The cause of the finding is related to the crosscutting element of problem identification and resolution in that RP personnel did not implement corrective actions to preclude repetition of a significant condition adverse to quality. Additionally, the cause of the finding is related to the crosscutting element of human performance in that RP personnel lacked a questioning attitude and did not stop movement of the submersible upon becoming disoriented.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," requires, in part, that in the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective actions taken to preclude repetition. Contrary to the above, the licensee failed to preclude repetition of a significant condition adverse to quality. Specifically, on April 17, 2006, for the second time in two years, a submersible vehicle was suctioned into a system providing cooling to the nuclear fuel, rendering the system inoperable. Following the April 11, 2004, event, the licensee's corrective actions concentrated on the lack of instructions and a lack of communications with the control room. While it was recognized that the event was transportable to other systems, and that the consequences could have been more severe, the corrective actions were limited in scope and were not adequate to preclude repetition. Because the finding is of very low safety significance and has been entered into the licensee's CAP as CRDR 2885213, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000528/2006003-05, "Failure to Preclude a Significant Condition Adverse to Quality."

.4 Loss of Power to Safety-Related Bus

Introduction. A Green self-revealing NCV of TS 5.4.1.a was identified for the failure of operations personnel to follow procedures, resulting in a loss of power to safety-related Bus PBA-S03 and an automatic EDG start.

Description. On May 6, 2006, Unit 3 operations personnel conducted a test of the station blackout gas turbine generators (GTG) in accordance with Procedure 40OP-9GT01, "Gas Turbine Generator Isochronous Test," Revision 1. Operations personnel participating in the test included control room operators, auxiliary operators, and water reclamation facility operators. The test included steps to start the GTG, connect it to Bus PBA-S03, and place it in parallel operation with offsite power. Subsequently, the test directed the removal of offsite power so that the GTG provided power to Bus PBA-S03. This test demonstrates that the GTG can supply uninterrupted power to safety-related Bus PBA-S03.

Procedure 40OP-9GT01, Step 4.8, directed that operations personnel observe the actual current load on Bus PBA-S03 using the local ampere meter on the safety-related bus feeder breaker in preparations for the load transfer. Operators used the value to calculate the required power that the GTG must provide to supply all of the loads on safety-related Bus PBA-S03. Since the safety-related bus operates at 4.16 kV and the GTG supplies power at 13.8 kV, operators calculated the equivalent current that the

GTG must provide. After reading 220 amperes at the local Bus PBA-S03 ampere meter, operators calculated that the GTG needed to provide 66 amperes to supply all of the loads on Bus PBA-S03. Water reclamation facility operators then connected the GTG in parallel with offsite power to Bus PBA-S03, and transferred the calculated load from offsite power to the GTG. The GTG was controlling in 'droop' mode for load sharing, which will cause the generator to vary voltage to maintain required electrical current. Before disconnecting offsite power, Procedure 40OP-9GT01, Step 4.10.3, directed the auxiliary operators to confirm that offsite power was not supplying any power to Bus PBA-S03. Step 4.10.3 was performed by an auxiliary operator by observing the local offsite power supply ampere meter located at Breaker NAN-S03A. The local ampere meter at Breaker NAN-S03A has a selector switch, which is normally in the off position. The auxiliary operator arrived at Breaker NAN-S03A to perform Step 4.10.3, observed that current indicated zero on the local ampere meter, and informed the control room operator. Understanding that electrical conditions were properly established, in that all of the load was carried by the GTG, the control room operator opened Breaker NAN-S03A to disconnect offsite power from Bus PBA-S03 and initiate the GTG load test. Unexpectedly, voltage on Bus PBA-S03 dropped below the degraded voltage relay setpoint, resulting in loss of power to the bus and an actuation of EDG Train A.

The inspectors reviewed the current trends from plant computers following the event and identified that the actual current load on Bus PBA-S03 was 250 amperes, implying that the GTG should have supplied approximately 75 amperes versus 66 amperes. As a result of this error in determining actual load, and the resulting failure to establish proper electrical conditions, a portion of the load was still being supplied from offsite power. Furthermore, the local ampere meter at Breaker NAN-S03A should have indicated current flow greater than zero since the offsite source was still supplying power. Since the GTG was in 'droop' mode, a decrease in voltage supplied by the GTG occurred when Breaker NAN-S03A was opened as the GTG attempted to rapidly assume the additional load. This transient caused the voltage on safety-related Bus PBA-S03 to decline below the degraded voltage setpoints of 3.745 kV for greater than the time delay of 31.8 seconds. As a result, the degraded voltage relays isolated safety-related Bus PBA-S03 from the GTG, which resulted in the actuation of EDG Train A.

The licensee determined that the local ampere meter at safety-related Bus PBA-S03 was not calibrated properly, which resulted in the lower than actual current reading. The licensee initiated WO 2900554 to calibrate this meter on June 6, 2006. Further, the licensee's investigation determined that the auxiliary operator failed to select one of the phases using the selector switch on the local ampere meter at Breaker NAN-S03A to determine the actual current value which would have identified that test conditions had not been properly established.

<u>Analysis</u>. The performance deficiency associated with this finding involved the failure of operations personnel to follow procedure, resulting in a loss of power to safety-related Bus PBA-S03 and an automatic EDG start. The finding is greater than minor because it is associated with the human performance cornerstone attribute of the initiating events cornerstone and affects the associated cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during

shutdown as well as power operations. Using the Manual Chapter 0609, "Significance Determination Process," Appendix G, "Shutdown Operations Significance Determination Process," Checklist 2, the finding is determined to have very low safety significance because the finding did not result in non-compliance with low temperature over pressure protection TSs, nor did it degrade the ability of containment to remain intact following an accident. Additionally, the finding did not degrade the licensee's ability to terminate a leak path, add RCS inventory, recover decay heat removal once it is lost, or establish an alternate core cooling path. Lastly, the finding did not increase the likelihood of a loss of RCS inventory, decay heat removal, or offsite power. The cause of the finding is related to the crosscutting element of human performance in that in that poor attention to detail by operations personnel resulted in the loss of power to a safety bus.

Enforcement. Technical Specification 5.4.1.a requires that written procedures be established, implemented, and maintained covering the activities specified in Regulatory Guide 1.33, Appendix A, February 1978. Regulatory Guide 1.33, Appendix A, Item 8.b.(1)(q) requires procedures for Emergency Power Tests. Procedure 40OP-9GT01, "Gas Turbine Generator Isochronous Test," Revision 1, demonstrated that the GTGs can provide emergency power to the safety-related buses under station blackout conditions. Procedure 40OP-9GT01, Section 4.10.3, required that operations personnel achieve a current of approximately zero amperes through Breaker NAN-S03A prior to opening the offsite supply breaker to Bus PBA-S03. Contrary to the above, on May 6, 2006, operations personnel failed to achieve a current of approximately zero amperes through Breaker NAN-S03A prior to opening the offsite supply breaker to Bus PBA-S03, which resulted in the loss of power to a safety-related bus and automatic EDG actuation. Because this violation is of very low safety significance and has been entered into the CAP as CRDR 2891404, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000530/2006003-06, "Failure to Follow GTG Surveillance Procedure Causes Loss of Power to Safety-Related Bus."

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors: (1) reviewed plant status documents such as operator shift logs, emergent work documentation, deferred modifications, and night orders to determine if an operability evaluation was warranted for degraded components; (2) referred to the UFSAR and design basis documents to review the technical adequacy of licensee operability evaluations; (3) evaluated compensatory measures associated with operability evaluations; (4) determined degraded component impact on any TSs; (5) used the Significance Determination Process to evaluate the risk significance of degraded or inoperable equipment; and (6) verified that the licensee has identified and implemented appropriate corrective actions associated with degraded components.

- April 11, 2006, Unit 2, boric acid leakage from safety injection Tank 1A outlet Valve SIAV634, as documented in CRDR 2831339

- April 13, 2006, Unit 1, EDG Train A, air bank pressure Switch B non-conformance due to lack of a pressure test during the qualification process

- April 14, 2006, Unit 3, incorrect type of flange gasket installed in the SP Train B piping annubar connection

- April 21, 2006, Unit 3, review of deficient primary disconnect assembly for EDG output Breaker 3EPBAS03B as documented in DFWO 2886468

- April 24, 2006, Unit 3, through wall leakage on reactor drain tank, as documented in DFWO 2813864

- May 19, 2006, Unit 3, LPSI pump Train B, high concentration of lead in the upper motor bearing

- May 19, 2006, Unit 2, observation of excessive EDG Train B intake air temperature during May 17 monthly surveillance run, indicative of excessive intercooler heat exchanger fouling documented in CRDR 2896661

- May 22, 2006, Unit 3, evaluation of transportability and potential operability impact of heat exchanger fouling to Unit 3 EDGs as documented in CRDR 2897266

- May 24, 2006, Unit 2, evaluation of CRDR 2860763 for lower than expected thermal margin data for EW heat exchanger Train B

- June 5, 2006, Unit 1, evaluation of anomalous indication identified on fuel Assembly P1R518 guide tube as documented in CRDR 2900375

- June 9, 2006, Units 1, 2, and 3, excess grease in battery room essential exhaust fan motors, as documented in CRDR 2901186

- June 9, 2006, Unit 1, source range monitor channels degraded condition due to spikes in the signal due to electrical noise

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed twelve samples.

b. Findings

No findings of significance were identified (See Section 4OA3.11).

1R17 Permanent Plant Modifications (71111.17B)

a. Inspection Scope

The procedure requires the review of a minimum of five permanent plant modifications. The inspectors reviewed five permanent plant modification packages and associated documentation, including safety evaluation screenings, safety evaluations, and calculations to verify that they were performed in accordance with plant procedures. The inspectors also reviewed the procedures governing plant modifications to evaluate the effectiveness of the programs for implementing modifications to risk-significant systems, structures, and components, such that these changes did not adversely affect the design and licensing basis of the facility.

The inspectors interviewed the cognizant design and system engineers for the identified modifications as to their understanding of the modification packages.

The inspectors evaluated the effectiveness of the licensee's corrective action process to identify and correct problems concerning the performance of permanent plant modifications. In this effort, the inspectors reviewed two corrective action documents and the subsequent corrective actions pertaining to licensee-identified problems and errors in the performance of permanent plant modifications.

The primary focus of this inspection effort was the modification package to relocate the shutdown cooling isolation valve (SI-651) to reduce the magnitude of vibration on the shutdown cooling line. The inspectors reviewed the analyses, calculations, proposed post-modification testing, and the requirements for returning the system to operation.

b. Issues and Findings

No findings of significance were identified. The inspectors found that the licensee's engineers had adequately addressed engineering requirements and had developed a modification that could reduce the vibrations. While a root cause was not definitively identified, the inspectors found that licensee personnel had done extensive assessment and investigation to identify several contributing causes and develop corrective actions to significantly reduce the vibrations. The inspectors noted that the initial vibration levels were lower than the levels allowed by the ASME code by an order of magnitude.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

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

- May 2, 2006, Unit 3, EDG Train B testing after scheduled maintenance during refueling Outage 3R12 in accordance with WO 2628326
- May 17, 2006, Unit 2, retest of EDG Train B output Breaker 2EPPBBS04B per WO 2895648
- April 7-8, 2006, Unit 2, retests of AFW steam warm-up Valve SGA-138A per WOs 2881061, 2882624, and 2883563
- April 28, 2006, Unit 3, retest of the spent fuel handling machine after refurbishment of the sprag brake in accordance with WO 2883588
- June 1, 2006, Unit 1, retest of SDC suction isolation Valve 1JS1AUV0651 per DFWO 2882666
- June 21, 2006, Unit 1, retest of the EDG Train A sequencer after troubleshooting and repairs to eliminate the recurring lock-ups

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20)

a. Inspection Scope

For the Unit 3 Refueling Outage 3R12 and Unit 1 Short Notice Outage, the inspectors reviewed the following risk significant refueling items or outage activities to verify defense in depth commensurate with the outage risk control plan, compliance with the TSs, and adherence to commitments in response to Generic Letter 88-17, "Loss of Decay Heat Removal:" (1) the risk control plan; (2) tagging/clearance activities; (3) RCS instrumentation; (4) electrical power; (5) decay heat removal; (6) SFP cooling; (7) inventory control; (8) reactivity control; (9) containment closure; (10) reduced inventory or mid-loop conditions; (11) refueling activities; (12) heatup and coldown activities; (13) restart activities; and (14) licensee identification and implementation of appropriate corrective actions associated with refueling and outage activities. The inspectors' containment inspections included observations of the containment sump for damage and debris; and supports, braces, and snubbers for evidence of excessive stress, water hammer, or aging.

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed two samples.

b. Findings

.1 Failure to Revise Engineering Deficiency Work Order

Introduction. The inspectors identified an additional example of the Green NCV of TS 5.4.1.a for the failure of engineering personnel to follow procedures, documented in Section 1R13. Specifically, engineering personnel failed to perform required evaluations and dispositions to justify a degraded condition for continued use (operability) of SDC Train A due to a pipe support being out of service.

Description. On December 16, 2004, during the engineering review of plant systems and structures for the Unit 1 power uprate and steam generator replacement, a discrepancy was discovered in a reactor coolant pipe support analysis. Specifically, pipe Support 01-RC-051-H-005 was failing analytically when the frictional force due to thermal pipe movement was added. Further investigation of the existing support calculations indicated that the support was never evaluated for these frictional forces. The discrepancy was determined to be applicable to all three units.

The Unit 3 piping system, was found to meet all applicable code requirements with much reduced margins, despite the analytical failures identified. Consequently, pipe Support 03-RC-051-H-005 was evaluated as degraded, but operable, and scheduled for repair during refueling Outage 3R12 in the Spring of 2006. A DFWO was developed to provide an engineering disposition to restore the system to a condition which conforms to the documented design condition per Procedure 81DP-0DC13, "Deficiency Work Order," Revision 18. DFWO 2772650 was issued per Procedure 81DP-0DC13, and categorized as a "Repair Disposition" per Step 3.2.3, to alter the existing support in lieu of restoration to the fully qualified condition. The DFWO also analyzed the resultant condition to confirm it would continue to perform its function as defined in the design and current licensing basis. The supports in Units 1 and 2 were corrected during their associated steam generator replacement outages.

On May 10, 2006, the inspectors performed a review of the Unit 3 TSCCR to evaluate operability of equipment and systems required for an upcoming Mode 4 entry. The inspectors also reviewed all corrective and preventive maintenance that the licensee planned to defer beyond refueling Outage 3R12. During the review, the inspectors identified that WO 2822090, related to the DFWO 2772650 repair disposition, was approved for deferral to a future outage. The reason for the deferral was related to complications identified with the planned repair. Specifically, the planned repair resulted in load increases that exceeded code allowable values. The licensee concluded that an alternate repair method was a better option due to the design issues associated with the friction load. However, the discovery of the oversight was too late to perform a redesign of the pipe support and place the product order within the time frame of the scheduled outage. Engineering personnel recognized the need to revise DFWO 2772650 to provide a "Use-As-Is Disposition" conditional release per Procedure 81DP-0DC13, Step 3.2.4, to justify a deviation from the current licensing basis and accept the as-found condition until the final disposition could be implemented during a future outage. However, as a result of deficiencies with the work control and outage planning processes, the licensee failed to redisposition the DFWO and recognize the condition as a barrier to Mode 4 entry.

Once the oversight was identified by the NRC, engineering personnel performed the necessary evaluation and disposition as required by Procedure 81DP-0DC13 to support Mode 4 entry. Additionally, the licensee initiated CRDR 2892737 to evaluate and correct the deficiencies with the work control and planning processes that failed to identify the engineering oversight.

The performance deficiency associated with this finding was representative of a broader concern related to how the licensee ensures the operability of SSCs required to comply with TS. Specifically, the licensee's programs and processes for assessing degraded conditions have not been implemented with the rigor and thoroughness necessary to ensure compliance with regulatory requirements (Similar examples include: AFW resistors and emergency diesel generator sequencer issues documented in NRC Inspection Report 2006-008, resistance temperature detector, level instrumentation, and operability determination issues documented in NRC Inspection Report 2005-005, and usable tank volume and operability issues documented in NRC Inspection Report 2005-012).

Analysis. The performance deficiency associated with this finding involved the failure of engineering personnel to perform required evaluations and dispositions for deficient conditions to ensure operability of SSCs required to comply with TSs. The finding is greater than minor because it would become a more significant event if left uncorrected in that TS required SSCs may not be operable as required for applicable plant conditions. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because the condition only affected the mitigating systems cornerstone and did not represent an actual loss of safety function. The cause of the finding is related to the crosscutting element of human performance in that engineering personnel did not follow procedure, resulting in the failure to perform required evaluations and dispositions for deficient conditions.

Enforcement. TS 5.4.1.a requires that written procedures be established, implemented, and maintained covering the activities specified in Regulatory Guide 1.33, Appendix A, February 1978. Regulatory Guide 1.33, Appendix A, Item 1(c), requires procedures for Equipment Control. Procedure 81DP-0DC13, "Deficiency Work Order," Revision 18, Step 3.4.1.7, stated that, "Prior to an SSC being declared operable or returned to service, the disposition of associated ENG DFWO's shall be complete and given a Final Disposition or revised to a Conditional Release." Contrary to the above, on May 10, 2006, engineering personnel failed to revise DFWO 2772650 to a conditional release as required for Mode 4 entry. Specifically, engineering personnel deferred repairs to pipe Support 03-RC-051-H-005, related to the DFWO 2772650 repair disposition, without revising the DFWO to provide a "Use-As-Is Disposition" conditional release to accept the as-found condition until the final disposition could be implemented during a future outage. Because this violation is of very low safety significance and has been entered into the CAP as CRDR 2892737, this violation is being treated as an NCV, and represents an additional example of NCV 05000528; 05000530/2006003-02, "Failure to Evaluate Degraded Conditions to Ensure Equipment Operability," documented in Section 1R13.

.2 Three Examples of a Technical Specification 3.0.4 Violation

Introduction. The inspectors identified three examples of a Green NCV of TS LCO 3.0.4 for the failure of operations personnel to ensure the operability of required equipment prior to entry into a mode or other specified condition in the LCO applicability.

Description. On March 20, 2006, Unit 1 was in Mode 5 and in the process of being returned to Mode 1 following a short notice outage per Procedure 40OP-9ZZ24, "SNOW Outage," Revision 23. SDC was in operation and lined up to Train B with RCS temperature below 210°F. During SDC Train B operations, Valve SIBHV0689 was closed rendering CS inoperable.

TS 3.6.6 requires two trains of the CS system to be operable in Mode 4 when reactor coolant system pressure is greater than or equal to 385 psia. Mode 4, "Hot Shutdown," conditions exist when core reactivity is less than 0.99 and cold leg temperature is between 210 and 350°F. Procedure 40OP-9ZZ24, Step 9.55, required that operations personnel ensure that RCS pressure is being maintained less than 385 psia before RCS temperature exceeds 210°F. Step 9.55 also reiterated the requirements of TS 3.6.6. The control room supervisor (CRS) failed to ensure compliance with Procedure 40OP-9ZZ24, Step 9.55, since the RO was maintaining an RCS pressure band between 345 and 415 psia. The Mode 5 to Mode 4 checklist was completed at 0400 per Procedure 40OP-9ZZ11, "Mode Change Checklist," Revision 66. Mode 4 was entered at 0445 with RCS pressure at 386 psia, which was in the inappropriate band used by the RO and greater than the pressure allowed by TSs and Procedure 40OP-9ZZ24. Unaware that any TS requirements were violated, operations personnel continued with preparations to return to Mode 1 throughout the remainder of the night shift. At approximately 0630 hours, the night shift turned over operation of Unit 1 to the day shift crew. At approximately 0645 hours, operations personnel lowered RCS pressure below 385 psia and controlled pressure at this level as they continued to implement Procedure 40OP-9ZZ24. On March 21, 2006, the licensee identified through plant data review that RCS pressure had exceeded 385 psia following entry into Mode 4 with CS Train B inoperable. This violation of TS 3.6.6 and 3.0.4 was entered into the CAP as CRDR 2877648.

On March 20, 2006, at the beginning of day shift, the CRS directed operations personnel to perform Procedure 40OP-9ZZ24, Step 9.63, which included direction to remove the operating SDC Train from service per Procedure 40OP-9SI02, "Recovery From Shutdown Cooling to its Normal Operating Lineup," Revision 64, and applicable sections of Procedure 40ST-9SI13, "LPSI and CS System Alignment Verification," Revision 9. Following the order to perform Step 9.63, the CRS proceeded to Step 9.66, which stated that RCS pressure could continue to be raised to approximately 400 psia only when both trains of CS are operable. To determine CS operability, the CRS (1) reviewed the unit logs for inoperable equipment; (2) reviewed the TSCCR for potential impacts to the CS system; and (3) questioned the shift technical advisor on whether he knew if both trains of CS were operable. The CRS failed to take the time to perform an adequate review of CS system operability through (1) consulting with the shift manager or any other licensed operators regarding the operational status of the CS system; (2) reviewing TS bases for the applicable TS requirements; and (3) understanding procedural requirements prior to proceeding to the next procedure step. Furthermore, the CRS and shift technical advisor failed to recognize the impact of SDC operations on CS operability and that Step 9.63 should have been completed prior to proceeding on to Step 9.66. Consequently, at 0905 hours, the CRS incorrectly concluded that both trains of CS were operable and performed Step 9.66 to raise pressurizer pressure above 385 psia.

Operations personnel continued with preparations to return to Mode 1 since they were unaware that any TS had been violated. At 1109 hours, SDC Train B was removed from service per Procedure 40OP-9SI02. At approximately 1530 hours, operations personnel were performing a section of Procedure 40ST-9SI13 as directed by Procedure 40OP-9ZZ24, Step 9.63, and realized that CS Train B was inoperable. The TS violations were identified at approximately 1600. RCS temperature was 338°F and pressure was 1750 psia. At approximately 1630 hours, operations management directed RCS pressure to be lowered to restore compliance with TS 3.6.6. At 1915 hours, operations personnel initiated depressurization of the RCS and pressurizer cooldown. At 2030 hours, upon completion of Procedure 40ST-9SI13, operations personnel restored CS Train B to operable and exited TS 3.6.6. With both trains of CS operable and in compliance with TS 3.6.6, operations personnel secured the RCS cooldown and depressurization with RCS temperature at 328 degrees and pressure at 1550 psia. Operations personnel transitioned back to Procedure 40OP-9ZZ24 to return to Mode 1 as soon as TS compliance was restored. This TS violation was entered into the CAP as CRDR 2877591.

On March 20, 2006, at approximately 0230 hours, operations personnel were working with electrical maintenance to conduct a retest of a non-class pressurizer heater bank per WM 2877281. The retest resulted in a locked-in condition of the pressurizer trouble alarm. At 0249 hours, Alarm RCYS1005, "PZR BACKUP HTRS 5 ELEC PROT TRIP," came into alarm, but was not announced or recognized by operations personnel. Subsequently, four rounds performed by three different area operators failed to identify that the "86" lock-out relay for the class pressurizer heater Train B supply circuit breaker had tripped, rendering the equipment inoperable. Procedure 40DP-9OP05, "Control Room Database Instructions," Revision 56, required a daily alarm review to identify and correct abnormalities. However, two night shift alarm reviews failed to identify the tripped condition of the breaker. An additional alarm review was performed on March 22, 2006, at the request of the unit department leader which identified the pressurizer backup heater alarm condition. The alarm response actions were performed when operations personnel recognized the alarm condition. The unit entered TS 3.4.9, "Pressurizer," since the tripped breaker condition would prevent operation of the Train B pressurizer heaters. Unit 1 changed from Mode 4 to Mode 3 on March 21, 2006, at 0117 hours with only the Train A pressurizer heaters operable in violation of TS 3.0.4. The licensee determined that the tripped breaker condition was caused by a ground on pressurizer backup Heater A05. On March 24, 2006, a temporary modification was successfully installed to isolate backup Heater A05 and connect backup Heater B04 in its place to restore operability and exit TS LCO 3.4.9. This TS violation was entered into the CAP as CRDR 2878030.

These three events were evaluated by the licensee as one significant root cause investigation. The investigation determined that the root cause for the three events was that operational fundamentals were not consistently applied for controlling and monitoring plant parameters to ensure compliance with license conditions. Operating crew weaknesses associated with the root cause included inappropriate assumptions, shortcuts taken, ineffective communications, and inadequate monitoring of plant and equipment conditions. Furthermore, the investigation determined that the quality of routine operational tasks that support monitoring and controlling plant parameters was not always maintained during periods of high activity. For example, the investigation observed that the night and day shift CRSs were focused on the schedule, and inappropriately assumed that tasks had been carried out as directed. The actions identified to prevent recurrence were to reinforce operations fundamentals to improve individual and team performance in the monitoring and control of the power plant. The inspectors noted that similar past significant events also identified that the root causes were related to operations personnel not meeting standards and expectations with respect to operations fundamental (See Sections 1R20.1 and 4OA2.2).

The follow-up of these events and review of the significant root cause investigation performed by the inspectors determined that the licensee failed to address the underlying causes of the poor human performance in applying operations fundamentals. Specifically, the situation (i.e. the oversight of the exceptionally high amount of control room activity during the unit restart), and self-imposed schedule pressures where the completion of an assigned task was valued more than the method in which the task was completed, were not so much related to individual performance, but a broader cultural problem.

Analysis. The performance deficiency associated with this finding involved the failure of operations personnel to adequately implement procedures to ensure the operability of equipment required to comply with TSs to take the unit from shutdown to power operating conditions. The finding is greater than minor because it is associated with the configuration control cornerstone attribute of the mitigating systems cornerstone and affects the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

For the examples of this finding related to the containment spray system, a Phase 2 analysis was required since they impacted both the mitigating systems and barrier integrity cornerstones as determined by the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet. Using the Phase 2 Worksheets associated with loss of coolant accidents, the finding is determined to have very low safety significance since all remaining mitigation capability was available.

The example of this finding related to pressurizer heaters cannot be evaluated by the significance determination process because Manual Chapter 0609, "Significance Determination Process," Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," and Appendix G, "Shutdown Operations Significance Determination Process," do not consider the pressurizer heaters as a risk significant function as defined in the risk informed notebook. This finding is determined to be of very low safety significance by NRC management review.

The cause of the finding is related to the crosscutting element of human performance in that operations personnel did not follow procedures and apply the necessary rigor and questioning attitude to requirements and associated decisions due to self-imposed schedule pressures during periods of high control room activity.

Enforcement. TS 3.0.4 requires when an LCO is not met, entry into a mode or other specified condition in the applicability shall not be made. TS 3.6.6 requires two trains of the CS system to be operable in Mode 4 when pressurizer pressure is greater than or equal to 385 psia. TS 3.4.9 requires an operable pressurizer with two groups of operable pressurizer heaters in Mode 3. Contrary to the above, twice on March 20, 2006, and once on March 21, 2006, operations personnel entered a mode or other specified condition in the applicability when LCOs were not met. Specifically, on March 20, 2006, Mode 4 was entered on two occasions with RCS pressure above 385 psia and only one operable train of CS. On March 20, 2006, the Train B pressurizer heater supply circuit breaker tripped due to a grounded condition on Heater A05, rendering the equipment inoperable. This equipment condition was not recognized by operations personnel until identified on March 22. As a result of the equipment condition, on March 21, 2006, Unit 1 changed from Mode 4 to Mode 3 with only the Train A pressurizer heater operable.

Because the finding is of very low safety significance and has been entered into the licensee's CAP as CRDRs 2877648, 2877591, and 2878030, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000528/2006003-07, "Three Examples of a Technical Specification 3.0.4 Violation."

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the UFSAR, procedure requirements, and TSs to ensure that the ten below listed surveillance activities demonstrated that the SSCs tested were capable of performing their intended safety functions. The inspectors either witnessed or reviewed test data to verify that the following significant surveillance test attributes were adequate: (1) preconditioning; (2) evaluation of testing impact on the plant;

(3) acceptance criteria; (4) test equipment; (5) procedures; (6) jumper/lifted lead controls; (7) test data; (8) testing frequency and method to demonstrate TS operability; (9) test equipment removal; (10) restoration of plant systems; (11) fulfillment of ASME Code requirements; (12) updating of performance indicator data; (13) engineering evaluations, root causes, and bases for returning tested SSCs not meeting the test acceptance criteria were correct; (14) reference setting data; and (15) annunciators and alarms setpoints. The inspectors also verified that the licensee identified and implemented any needed corrective actions associated with the surveillance testing.

- April 11, 2006, Unit 3, local leak rate testing of containment Penetration 41 per Procedure 73ST-9CL01, "Containment Leakage Type 'B' and 'C' Testing," Revision 28, Section 8.19
- April 14, Unit 3, Procedure 73ST-9DG02, "Class 1E Diesel Generator and Integrated Safeguards Test, Train B," Revision 12
- April 18, 2006, Unit 3, hydrogen monitoring system leak rate test between Penetrations 36 and 38 per Procedure 73ST-9HP03, "Hydrogen Monitoring Subsystem Leakage Testing," Revision 4, Section 8.2
- April 20, 2006, Unit 3, local leak rate testing of containment Penetration 78 per Procedure 73ST-9CL07, "Containment Ventilation Purge Isolation Valves - Penetration 78 and 79," Revision 17
- April 27, 2006, Unit 3, Procedure 73ST-9XI33, "HPSI Pump and Check Valve Full Flow Test," Revision 39
- May 1, Unit 3, Procedure 73ST-9DG01, "Class 1E Diesel Generator and Integrated Safeguards Test, Train A," Revision 10
- May 8, 2006, Unit 3, Procedure 73ST-9SG05, "ADV Nitrogen Accumulator Drop Test," Revision 23
- May 10, 2006, Unit 3, Procedure 73ST-9SI03, "Leak Test of SI/RCS Pressure Isolation Valves," Revision 36
- May 19, 2006, Unit 2, Procedure 73ST-9SP01, "Essential Spray Pond Pumps - Inservice Test," Revision 23
- June 2, 2006, Unit 1, surveillance of departure from nucleate boiling ratio margin monitors per Procedure 40ST-9ZZM1, "Operation Mode 1 Surveillance Logs," Appendix I, Revision 38

The inspectors completed ten samples.

b. Findings

Introduction. The inspectors identified a Green NCV of TS 5.4.1.a for the failure of operations personnel to follow procedures which resulted in declaring both trains of LPSI inoperable.

Description. On May 10, 2006, night shift operations personnel were performing various sections of Procedure 73ST-9SI03, "Leak Test of SI/RCS Pressure Isolation Valves," Revision 36. The night shift crew completed the test through Step 8.6.6, which utilized a HPSI pump to pressurize a portion of the safety injection header to leak check the safety injection tank outlet and safety injection header check valves. Since the header was pressurized greater than 1000 psig, actuation of the alarm associated with annunciator Window 2B09B, "SI CHK VLV LEAK PRESS HI," was expected and locked-in. Section 8.6 included a caution that stated, "Header pressure greater than 1850 pisg on SIP319 through SIP349 makes the associated LPSI pumps inoperable." As a barrier, Step 8.6.1, created an audible alarm for pressure Instruments SIP319 through SIP349 to alert the operator prior to exceeding 1850 psig in the associated injection line.

The night shift RO turned over, with the test in-progress at Step 8.6.7, to the day shift RO. The turnover included a discussion of annunciator Window 2B09B, why the associated alarm was locked-in, and that alarm response Procedure 40AL-9RK2B, "Panel B02B Alarm Responses," Revision 50, would be used at the end of the test to reset the alarm. The day shift RO misunderstood that all alarms would be addressed upon completion of the entire test procedure, rather than during the restoration portions of each individual section in which the alarm was actuated, as described in the procedure.

The day shift RO, who was assuming the role of the test leader, failed to review previously performed portions of Procedure 73ST-9SI03, including: Section 5.0, "Limitations and Precautions," which stated, in part, that operating the LPSI injection motor-operated valves against a pressure differential of greater than 1850 psid may damage the valve actuators and that all available indications be monitored during testing to ensure that LPSI discharge piping upstream of the LPSI injection valves is not being pressurized. Section 6.0, "Personnel Indoctrination," which explained that the test leader directs and coordinates test personnel in the plant, ensures test personnel understand the objective of the test and their responsibilities, and ensures limitations and precautions of the test procedure and TSs are observed; Section 7.0, "Prerequisites," which required that Sections 5.0 and 6.0 have been read and understood by all test personnel; and Section 8.6 which included the caution that warned test personnel of the potential impacts to LPSI train operability. Additionally, no pre-job brief was held with the day shift operations personnel prior to continuing on with the test procedure since there were people stationed in the field. The licensee's investigation stated that these failures to adhere to standards and expectations, and procedure requirements, were a result of the exceptionally high amount of activity that was occurring during the testing period.

The pressure in the section of piping associated with the test increased above 1750 psig at approximately 0820 hours, when Procedure 73ST-9SI03, Step 8.6.8, was performed to isolate the boundaries to initiate the leak test. The pressure increase was a result of unexpected backleakage from the RCS through boundary check valves which warmed up the water in the trapped section. The audible alarm created in Step 8.6.1 was acknowledged by operations personnel, however, due to the high level of control room activity and background noise in the control room, the alarm was not announced or recognized. The RO did recognize that the pressure had increased above the HPSI pump discharge pressure, and concluded through discussions with the shift manager, that the only way pressure could be greater than the HPSI pump was if the RCS boundary check valves were leaking. As a result of the unexpected backleakage, the pressure continued to increase to a RCS system pressure of 2250 psig. However, the RO failed to recognize this as an abnormal condition due to his prior misunderstanding of when the alarms would be addressed and failure to review previously performed portions of Procedure 73ST-9SI03. Consequently, the RO proceeded to Step 8.6.10 to restore from the test and stop the HPSI pump. At approximately 0930 hours, the control room supervisor identified the abnormal condition through observation of Instruments SIP319 through SIP349, and directed appropriate actions per alarm response Procedure 40AL-9RK2B. Operations personnel appropriately determined that both LPSI trains were inoperable, entered TS 3.0.3, and took action to reduce pressure to less than 1850 psig and restore operability.

The licensee's investigation concluded that there was reasonable assurance that the LPSI injection valves did not experience a differential pressure high enough to cause pressure locking, and that the LPSI trains remained operable, and consequently, no TS 3.0.3 entry was required. This conclusion was based on data collected during the performance of other portions of Procedure 73ST-9SI03, since no leakage was observed through two of the three check valves between the LPSI injection valves and the reactor coolant system.

The investigation identified that the causes of the event were related to individual performance errors and a lack of a clear understanding of the procedures in progress and expected alarms. The licensee also determined that, since the event was related to personal error, it was not likely that the condition existed in other locations, components, procedures, documents, or situations. Contrarily, the follow-up of the event and review of the apparent cause evaluation performed by the inspectors determined that the licensee failed to address the underlying causes of the poor human performance. Specifically, the situation (i.e., the oversight of the exceptionally high amount of control room activity during the testing period), and self-imposed schedule pressures where the completion of an assigned task was valued more than the method in which the task was completed, were not so much related to individual performance, but a broader cultural problem. (See Sections 1R20.2 and 4OA2.2)

Analysis. The performance deficiency associated with this finding involved the failure of operations personnel to follow procedures which resulted in declaring both trains of LPSI inoperable. The finding is greater than minor because it is associated with the human performance cornerstone attribute of the mitigating systems cornerstone and affects the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because the condition only affected the mitigating systems cornerstone and did not represent an actual loss of safety function. The cause of the finding is related to the crosscutting element of human performance in that operations personnel did not follow procedures and apply the necessary rigor and questioning attitude to requirements and associated decisions due to self-imposed schedule pressures.

Enforcement. TS 5.4.1.a requires that written procedures be established, implemented, and maintained covering the activities specified in Regulatory Guide 1.33, Appendix A, February 1978. Regulatory Guide 1.33, Appendix A, Section 8, requires procedures for performing surveillance tests. Section 5.0 of Procedure 73ST-9SI03, "Leak Test of SI/RCS Pressure Isolation Valves," Revision 36, required that operations personnel monitor all available indications during testing to ensure that LPSI discharge piping upstream of the LPSI injection valves is not pressurized. Contrary to the above, on May 10, 2006, operations personnel failed to provide adequate monitoring to ensure the LPSI discharge piping upstream of the LPSI injection valves was not pressurized. Specifically, operations personnel did not maintain safety injection header pressure less than 1850 pisg, which rendered the associated LPSI pumps inoperable. Upon recognition of the abnormal condition by the control room supervisor, operations personnel took action to reduce pressure to less than 1850 psig and restore operability. Because the finding is of very low safety significance and has been entered into the licensee's CAP as CRDR 2892697, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000530/2006003-08, “Failure to Follow Procedures Resulted in Declaring Both Trains of Low Pressure Safety Injection Inoperable.”

Cornerstone: Emergency Preparedness

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope

The inspector performed in-office reviews of Revisions 34 and 35 to the Palo Verde Nuclear Generating Station Emergency Plan, submitted February 17 and March 17, 2006, respectively. These revisions:

- Revised emergency action levels in accordance with NRC Bulletin 2005-002, “Emergency Preparedness and Response Actions for Security-Based Events”

- Added emergency action level indicators for tornados and flooding affecting the licensee’s protected area

- Revised fire and explosion emergency action level descriptions to language used in emergency plan implementing procedures

- Expanded descriptions of the site radio, telephone, and fiber optic communications systems

- Revised commitments for performing drills and exercises in accordance with NRC Bulletin 2005-002

- Updated the emergency planning zone population survey

- Added two sirens to the description of the offsite siren system, and relocated one siren on emergency planning zone diagrams

- Updated licensee and offsite agency titles, the name of the licensee's primary offsite medical facility, and the names of offsite care and reception centers

These revisions were compared to their previous revisions, to the criteria of NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," Revision 1, to NEI 99-01, "Methodology for Development of Emergency Action Levels," Revision 2, and to the requirements of 10 CFR 50.47(b) and 50.54(q) to determine if the licensee adequately implemented 10 CFR 50.54(q). This review was not documented in a Safety Evaluation Report and did not constitute approval of licensee changes, therefore, these changes are subject to future inspection.

The inspector completed two samples during this inspection.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

a. Inspection Scope

This area was inspected to assess the licensee's performance in implementing physical and administrative controls for airborne radioactivity areas, radiation areas, high radiation areas, and worker adherence to these controls. The inspector used the requirements in 10 CFR Part 20, the TS, and the licensee's procedures required by TS as criteria for determining compliance. During the inspection, the inspector interviewed the radiation protection manager, radiation protection supervisors, and radiation workers. The inspector performed independent radiation dose rate measurements and reviewed the following items:

- Performance indicator events and associated documentation packages reported by the licensee in the Occupational Radiation Safety Cornerstone

- Controls (surveys, posting, and barricades) of containment, radwaste, and auxiliary building radiation, high radiation, and potential airborne radioactivity areas

- Radiation exposure permits, procedures, engineering controls, and air sampler locations

- Conformity of electronic personal dosimeter alarm set points with survey indications and plant policy; workers' knowledge of required actions when their electronic personnel dosimeter noticeably malfunctions or alarms

- Barrier integrity and performance of engineering controls in Containment and auxiliary building airborne radioactivity areas

- Adequacy of the licensee's internal dose assessment for any actual internal exposure greater than 50 millirem committed effective dose equivalent

- Physical and programmatic controls for highly activated or contaminated materials (non-fuel) stored within spent fuel and other storage pools

- Corrective action documents related to access controls

- Licensee actions in cases of repetitive deficiencies or significant individual deficiencies

- Radiation exposure permit briefings and worker instructions

- Adequacy of radiological controls, such as, required surveys, RP job coverage, and contamination controls during job performance

- Dosimetry placement in high radiation work areas with significant dose rate gradients

- Changes in licensee procedural controls of high dose rate - high radiation areas and very high radiation areas

- Controls for special areas that have the potential to become very high radiation areas during certain plant operations

- Posting and locking of entrances to all accessible high dose rate - high radiation areas and very high radiation areas

- Radiation worker and RP technician performance with respect to RP work requirements

The inspector completed 20 of the required 21 samples.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope

The inspector assessed licensee performance with respect to maintaining individual and collective radiation exposures as low as is reasonably achievable (ALARA). The inspector used the requirements in 10 CFR Part 20 and the licensee's procedures required by TS as criteria for determining compliance. The inspector interviewed licensee personnel and reviewed:

- Five (to ten) outage and on-line maintenance work activities scheduled during the inspection period and associated work activity exposure estimates, which were likely to result in the highest personnel collective exposures
- Site-specific ALARA procedures
- ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements
- Interfaces between operations, RP, maintenance, maintenance planning, scheduling and engineering groups
- Integration of ALARA requirements into work procedure and radiation work permit (or radiation exposure permit) documents
- Shielding requests and dose/benefit analyses
- Dose rate reduction activities in work planning
- Method for adjusting exposure estimates, or re-planning work, when unexpected changes in scope or emergent work were encountered
- Use of engineering controls to achieve dose reductions and dose reduction benefits afforded by shielding
- Workers use of the low dose waiting areas
- First-line job supervisors' contribution to ensuring work activities are conducted in a dose efficient manner
- Radiation worker and RP technician performance during work activities in radiation areas, airborne radioactivity areas, or high radiation areas

The inspector completed 7 of the required 15 samples and 6 of the optional samples.

b. Findings

No findings of significance were identified.

3. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151)

a. Inspection Scope

Cornerstone: Occupational Radiation Safety

- Occupational Exposure Control Effectiveness

The inspector reviewed licensee documents from January 1 through March 31, 2006. The review included corrective action documentation that identified occurrences in locked high radiation areas (as defined in the licensee's TS), very high radiation areas (as defined in 10 CFR 20.1003), and unplanned personnel exposures (as defined in NEI 99-02). Additional records reviewed included ALARA records and whole body counts of selected individual exposures. The inspector interviewed licensee personnel that were accountable for collecting and evaluating the performance indicator data. In addition, the inspector toured plant areas to verify that high radiation, locked high radiation, and very high radiation areas were properly controlled. Performance indicator definitions and guidance contained in NEI 99-02, "Regulatory Assessment Indicator Guideline," Revision 4, were used to verify the basis in reporting for each data element.

The inspector completed the required sample (1) in this cornerstone.

Cornerstone: Public Radiation Safety

- Radiological Effluent Technical Specification/Offsite Dose Calculation Manual Radiological Effluent Occurrences

The inspector reviewed licensee documents from January 1 through March 31, 2006. Licensee records reviewed included corrective action documentation that identified occurrences for liquid or gaseous effluent releases that exceeded performance indicator thresholds and those reported to the NRC. The inspector interviewed licensee personnel that were accountable for collecting and evaluating the performance indicator data. PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Indicator Guideline," Revision 4, were used to verify the basis in reporting for each data element.

The inspector completed the required sample (1) in this cornerstone.

Cornerstone: Mitigating Systems

The inspectors sampled licensee submittals for the one performance indicator listed below for the period from June 2004 through April 2006, for Units 1, 2, and 3. The definitions and guidance of Nuclear Energy Institute 99-02, "Regulatory Assessment Indicator Guideline," Revision 4, were used to verify the licensee's basis for reporting each data element in order to verify the accuracy of PI data reported during the assessment period. The inspectors reviewed licensee event reports, out-of-service logs, operating logs, and the maintenance rule database as part of the assessment. Licensee PI data were also reviewed against the requirements of Procedure 93DP-0LC09, "Data Collection and Submittal Using INPO's Consolidated Data Entry System," Revision 4

- Safety System Functional Failures (Units 1, 2, and 3)

Documents reviewed by the inspectors are listed in the attachment.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

The inspectors performed a daily screening of items entered into the licensee's CAP. This assessment was accomplished by reviewing daily summary reports for CRDRs and WMs, and attending corrective action review and work control meetings. The inspectors: (1) verified that equipment, human performance, and program issues were being identified by the licensee at an appropriate threshold and that the issues were entered into the CAP; (2) verified that corrective actions were commensurate with the significance of the issue; and (3) identified conditions that might warrant additional follow-up through other baseline inspection procedures.

.2 Semiannual Trend Review

a. Inspection Scope

The inspectors completed a semi-annual trend review of repetitive or closely related issues that were documented in NRC inspection reports to identify trends that might indicate the existence of more safety significant issues. The inspectors review consisted of the 6 month period of January 1 to June 30, 2006. When warranted, some of the samples expanded beyond those dates to fully assess the issue. The inspectors also reviewed CAP items associated with human performance issues. The inspectors compared and contrasted their results with the results contained in the licensee's quarterly trend reports. Corrective actions associated with a sample of the issues identified in the licensee's trend report were reviewed for adequacy. Documents reviewed by the inspectors are listed in the attachment.

b. Assessment and Observations

The inspectors reviewed a series of recent human performance events that occurred during the last six months. They included three examples of a violation of TS 3.0.4, documented in NCV 05000528/2006003-07, an EDG trip during integrated safeguards testing, documented in NCV 05000530/2006003-03, and a failure of operations personnel to follow procedures which resulted in declaring both trains of LPSI inoperable, documented in NCV 05000530/2006003-08.

The inspectors reviewed the investigation report for CRDRs 2877591, 2877648 and 2878030, for the three TS 3.0.4 violations, which occurred on March 20, 2006. The inspectors noted that the licensee identified one root cause and three contributing causes for the events:

Root Cause #1: "Operational Fundamentals were not consistently applied for controlling and monitoring plant parameters to ensure compliance with license conditions." Further, the report stated that, "assumptions were made and shortcuts were taken."

Contributing Cause #1: "The quality of routine operational tasks that support monitoring and controlling plant parameters is not always maintained during periods of high activity." The inspectors found this to be a repeating theme across other human performance events. The report also stated that, "...during outages less thorough performance of monitoring, challenging, and questioning occurs."

Contributing Cause #2: "The Mode Change Checklist is not human factored to clearly distinguish the requirement to remain below 385 psia until both trains of CS can be determined to be operable."

Contributing Cause #3: "The class back up pressurizer heater hand switch green light intensity was not distinguishable when in '86' lockout."

The inspectors noted that the immediate corrective actions involved relieving the crew from shift duties and coaching of the individuals involved. Additionally, most of the lower priority corrective actions to prevent recurrence involved changing procedures, with the exception of an action to reinforce operations fundamentals and the replacement of the hand switch green light in the control room. The inspectors observed that while the report presented evidence of a potential concern with schedule pressures during periods of high activity in the control room, there were no corrective actions specifically targeted at this issue. Further evidence of this potential concern is presented in Appendix B of the licensee's report, which contains a Human Performance Analysis that lists the causes for the event, including:

- Additional staffing requested for the short notice outage but not received
- Both night and day shift control room supervisors focused on schedule
- Poor communication verification, inadequate pre-job brief, inadequate oversight, and inadequate peer checking

The inspectors also reviewed CRDR 2880952, which documented the Unit 3 EDG trip during integrated safeguards testing during refueling Outage 3R12. Personnel statements indicated that, "There was a self-imposed time pressure to get testing done as soon as possible to avoid having to work Monday night." However, the CRDR evaluation indicated that the individual was coached, the CRDR should be assigned a trend code of procedure non-adherence, and that the event was not transportable. When the inspectors inquired into the personnel statements, the licensee indicated that this was an isolated event due to a personal situation of the individual. The inspectors noted that the potential concern of either perceived, or self-imposed schedule pressures during periods of high activity was not mentioned in the evaluation, nor was the CRDR trended for this concern.

The inspectors also reviewed CRDR 2892697, which described the failure of operations personnel to follow procedures which resulted in declaring both trains of LPSI inoperable. Similar to the previous examples, the licensee identified the root cause of this event as the failure of an individual to follow procedures and the same corrective actions of individual disqualification and procedure changes were taken. However, the first statement in the root cause evaluation stated, "The activity level in the control room was exceptionally high." The evaluation further stated, "Since this event is related to a personnel error, it is not likely that it exists in other locations, components, procedures, documents, or situations."

The inspectors observed that while these CRDRs seem to have a common repeating theme of perceived or self-imposed schedule pressures during periods of high activity, neither the root causes, or the corrective actions captured this concern. The inspectors decided to expand the trend review to human performance events that resulted in violations since 2003. The inspectors expanded the sample to include two examples from 2005, two examples from 2004, and two from 2003. The examples are listed below:

- CRDR 2825485, for the failure to follow procedures which resulted in an automatic reactor trip and main steam isolation signal due to a high steam generator water level (NCV 05000528/2005004-02)

- CRDR 2777901, for a mode change violation with a safety injection valve not in its required position (LER 05000528/2005002-00)

- CRDR 2707290, for a TS violation while in Mode 3 while performing simultaneous evolutions that affected RCS inventory (FIN 05000528/2004003-05)

- CRDR 2704331, for failing to correct a degraded refueling machine equipment condition that could have impacted the ability to safely handle fuel (NCV 05000528/2004003-04)

- CRDR 2657316, for a violation of TS 3.0.4 for entering Mode 3 without two operable motor driven auxiliary feedwater pumps (NCV 05000529/2004002-05)

- CRDR 2654704, for performing core alterations with less than the required number of startup range monitors (NCV 05000529/2004005-07)

All of these examples represented human performance deficiencies during periods of high activity in the control room. However, with only one exception, high activity or schedule pressures were not identified as a contributing factor. The only exception, was CRDR 2707290, which documented a loss of letdown during performance of Procedure 40ST-9CH04 and atmospheric dump valve testing, which resulted in a pressurizer level increase above TS limits. The CRDR evaluation stated: "Effective command and control, and oversight, would have identified too many potentially counter productive activities ongoing at the same time and taken action to limit activity levels and establish activity priorities and communication requirements." But in all of these events, the corrective actions were similar and focused on the coaching of the individuals or procedure changes. None of the corrective actions addressed the repeating theme that the inspectors observed, of a potential perceived or self-imposed schedule pressure during periods of high activity, which result in human performance errors.

During the Performance Improvement Plan (PIP) review, documented in Section 4OA2.3, the inspectors noted several licensee assessments that identified a culture where production was valued more than the method in which the task was completed. Condition Report Action Item (CRAI) 2830460 was initiated to evaluate and disposition feedback from procedure use and adherence training. Observation 2 indicated that, "The single most common statement provided during the training was associated with schedule impact. Overwhelmingly, employees stated that schedule impact was most often the reason they could not meet the expectations for procedure use." The streaming analysis for the PIP indicated that personnel, "Value production over compliance," that "Reward for performance has fostered a get'er done attitude vs a get'er done RIGHT attitude," and that conservative decision making was impacted by a production mentality. Additionally, an outside consultant completed an operations assessment of corrective actions contained in CRDR 2729600 on May 11, 2005. The assessment noted that a directive management style and decision making approach has led to the development of perceptions by some personnel that production concerns for maintaining SSC operability are taking precedence over nuclear safety. The inspectors noted that the licensee had implemented actions to improve the management interactions with operations staff.

The inspectors noted that the licensee had changed the employee incentive plan to include human performance and that they had focused corrective actions on improving standards and expectations across the site. However, the inspectors did not identify specific corrective actions to address a concern associated with personnel not following procedures or making mistakes due to a self-imposed production/schedule pressure.

The inspectors concluding observations are that:

- Perceived or self-imposed schedule pressures during periods of high activity have resulted in human performance errors. All of the events reviewed by the inspectors were periods of high activity in the control room, resulting in errors by personnel.
- There is a disconnect between the schedule pressure concerns that employees and event follow-up have identified, and what is being documented in the corrective action program.

In response to the inspectors' observations, the licensee initiated CRDR 2905535 on June 23, 2006, to review operational events occurring at high activity times and whether they are related to self imposed schedule pressures. As of July 7, 2006, CRDR 2905535 was still in the evaluate stage.

.3 Crosscutting Issue Follow-up Inspections

Between June 5-8, 2006, the inspectors performed a review of selected portions of the PIP, Integrated Improvement Plan (IIP), and the Operations Department Plan. The inspectors conducted several interviews of personnel involved in the development or oversight of the IIP. The inspectors also assessed the development of the PIP and IIP, reviewed a sample of items which were statused as closed in the Operations Department Plan and the Human Performance Focus Area of the PIP, and assessed performance metrics and measures for human performance and operations. The inspectors determined that while a root cause analysis of the underlying issues was not completed, the IIP included appropriate elements to address the human performance and problem identification and resolution substantive crosscutting areas. The inspectors also concluded that implementation of the PIP, departmental improvement plans, and performance metrics needed improvement.

Structure of IIP and PIP

The IIP is a combination of the Business Plan, PIP, Departmental Improvement Plans, and the employee incentive program. For this review, the inspectors primarily focused on the PIP and Departmental Improvement Plans.

The licensee used a streaming analysis to develop the key focus areas within the PIP. Inputs into the streaming analysis were limited to 18 source documents. The documents included NRC assessment letters, external assessment reports, significant CRDRs, the Synergy Safety Culture report, and the INPO assessment report. The inspectors selected three documents (Root Cause Expert Panel Assessment Report, the Palo Verde Performance Assessment Report - CRDR 2827487, and the Notaro Assessment Report - CRDR 2817300) to determine if the licensee had appropriately considered the findings and recommendations in the streaming analysis. The inspectors determined that the license had appropriately factored the issues documented in the reports into the streaming analysis.

The inspectors evaluated the results of the streaming analysis and determined that the licensee had appropriately binned the issues into 18 areas. Of these 18 areas, the licensee selected 5 Focus Areas (Accountability, Corrective Actions, Human Performance, Leadership, and Standards) as the foundation for the PIP. The inspectors determined that the selection of the 5 Focus Areas for the PIP was appropriate. The inspectors also noted that the licensee was addressing performance issues in several of the other bins.

Personnel from the Performance Improvement Group indicated that prior to development of the PIP, additional activities were being implemented to address performance concerns. These actions were included in the Integrated Improvement Schedule and not restated within the PIP. The inspectors requested that the licensee demonstrate how each of the items developed as part of the streaming analysis were included in the integrated schedule or the PIP. The licensee was not able to provide documentation to demonstrate how each of the concerns was captured by the PIP.

Page 1 of the PIP indicates that Part 2, "Tactical Actions to Improve Performance," is a living document. The inspectors noted that the PIP was approved in October 2005, and that Part 2 of the PIP had not been revised to reflect changes in Focus Area Owners and revisions to action steps. Section 6.5, "Action Plan Revisions," indicated that action plans may need to be modified to address emergent issues or to improve effectiveness. The inspectors were not able to identify any action plans that had been revised to improve effectiveness. The licensee indicated that the integrated improvement schedule more accurately tracked the status of action plans and action plan items, and acknowledged that the PIP had not been revised.

Section 6.9 "Leadership Review Team," indicated that the Leadership Review Team (LRT) evaluates performance on a periodic basis to ensure adequacy of PIP implementation. The inspectors were not able to identify instances where the LRT had performed a periodic assessment of the closure of individual action steps. Additionally, the inspectors were not able to identify instances where the responsible Focus Area Owner or Quality Assurance organization had performed an assessment to verify the adequacy of closed action steps. The Performance Improvement Group acknowledged that the quality of close-out reviews was lacking and that measures were being implemented to strengthen expectations for close-out reviews.

The inspectors attended a PIP Progress Review Meeting on June 7, 2006. The meeting was attended by senior management and personnel knowledgeable of the issues to be discussed. The inspectors determined that the meeting was effective in ensuring milestones within the IIP were being met.

The inspectors noted that the effectiveness reviews were listed as Priority 4 CRAIs. The licensee indicated that the effectiveness reviews had been changed to a higher priority. Nevertheless, the PIP had not been revised to reflect the current priority for the reviews.

<u>Closure of PIP Steps</u>

The inspectors selected the Human Performance Focus Area to evaluate the licensee's PIP processes. Numerous discrepancies were noted.

1. The Focus Area Owner listed in the PIP was incorrect.

2. The completion date for the Focus Area was listed as "TBD."

3. The new Focus Area Owner indicated that actions in other Focus Areas were also needed to improve human performance. However, no cross reference to the other areas existed. Additionally, the Human Performance Focus Area Owner did not approve or review completed steps in other Focus Areas.

4. Step 4.1.2.2 was statused as closed; however, the closing CRAI had not been approved. The closure basis indicated that one or more departments for each of the 13 items in the standards and expectations book had been identified; however, the concept statement indicated there were 15 standards and expectations.

5. Step 4.1.2.5 was statused as closed on January 30, 2006; however, there was no indication that an acceptance review had been completed. The closure basis indicated that the human performance simulator is in progress for implementation by March 15, 2006; however, as of June 8, 2006, the simulator was still being developed.

6. Step 4.1.5.1 was statused as closed on March 3, 2006. The step required the development of human performance indicators and action plans for negative trends or less than top quartile performance. The inspectors noted that the licensee was still developing guidance for performance indicators. Therefore, in many cases the responsible owner was not knowledgeable of criteria for the indicator, the basis for thresholds, the status of newly developed action plans, if any, and the data used to support the indicator.

   Several human performance indicators were either yellow or red. No formal guidance had been developed on when to initiate an action plan. Licensee personnel indicated that any red indicator or any indicator that had been yellow for 2 months required an action plan. However, the inspectors were not provided any action plans for indicators that meet the above criteria.

The human performance site clock reset and departmental clock reset indicators were not effectively implemented. The licensee issued new criteria for site clock reset events in January 2006. As of April 30, 2006, there had been 3 site reset events (unplanned mode change, emergency diesel generator trip, and submersible in the RCS hotleg). With minimal review, the inspectors noted that several reset events had not been included in the indicator results (two additional unplanned mode changes, and an entry into a short duration TS for auxiliary feedwater). The licensee concluded that each of the events should have reset the site clock and that an additional review would be performed to ensure the indicator was accurately monitoring performance. The licensee implemented the departmental reset clock in June 2006. The inspectors discussed the departmental clock reset criteria with the operations manager on June 7, 2006. The operations manager was unaware of the new departmental clock reset criteria.

7. Step 4.1.5.2 and 4.2.2.1 indicated a charter would be developed for prevent event review boards and a decision making model would be developed for conservative decision making. The licensee decided to develop site-wide policies; however, the steps were not revised to reflect the change in direction.

8. Step 4.2.4.1 was closed on April 28, 2006. The closure basis indicated action had been taken for creation and implementation of a computer based training module. The concept statement indicated the item could be closed when the training had been implemented. The inspectors noted that the item was closed even though the target audience was not defined, the training had just been initiated, and there was no expected completion date for the training.

<u>Operations Department Plan</u>

The inspectors reviewed the operations department plan to evaluate the integration to the IIP. The Performance Improvement Group indicated that all department plans were to be revised to ensure that the 5 Focus Areas described in the PIP were addressed. The Performance Improvement Group indicated that as of June 8, 2006, the Engineering Department Plan was the only plan that had been revised and approved. The operations manager was unaware that the Operations Department Plan needed to be revised.

The inspectors discussed selected topics from the Operations Department Plan with the operations manager. The "Shift Managers Role in Site Leadership" topic was statused as complete. The action was to establish models of excellence for documents where the shift manager interfaces with the site. The operations manager was not able to define what a "model of excellence" constituted or what the differences were between the low and high performance level.

The inspectors reviewed the performance indicator for the topic, "Operability Determination Implementation." The licensee had developed an indicator using

3 components (individual age, average age, and the quality of operability determinations). The operations manager was not able to explain the standards used to evaluate the quality of an operability determination.

.4 Cross-References to Problem Identification and Resolution Findings Documented Elsewhere

Section 1R06 describes a finding that involved the failure of operations personnel to verify or check the adequacy of the design of drain hose manifold boxes, that were installed in the plant and adversely affected the design basis function of the emergency core cooling system room level switches.

Section 1R14 describes a finding that involved the failure of licensee personnel to preclude repetition of a significant condition adverse to quality.

4OA3 Event Follow-up (71153)

a. Inspection Scope

.1 (Closed) Licensee Event Report (LER) 05000529/2003001-01, "Reactor Trip with Loss of Forced Circulation Due to Failed Pressurizer Main Spray Valve"

This LER is a supplement to LER 05000529/2003001-00, which was closed in NRC Inspection Report 05000528; 05000529; 05000530/2004006. This supplement provided the root cause of the spray valve failure and added one corrective action for this failure. The inspectors reviewed this LER and no additional findings were identified. This LER is closed.

.2 (Closed) Licensee Event Report (LER) 05000528/2003002-01, "Manual Reactor Trip Due to Degraded Main Condenser Tube Plug"

This LER is a supplement to LER 05000528/2003002-00, which was closed in NRC Inspection Report 05000528; 05000529; 05000530/2003003. This supplement provided additional information on the root cause of the condenser plug failure. The inspectors reviewed this LER and no additional findings were identified. This LER is closed.

.3 (Closed) Licensee Event Report (LER) 05000530/2004002-01, "Main Turbine Control System Malfunction Results in Automatic Reactor Trip on Low DNBR"

This LER is a supplement to LER 05000530/2004002-00, which was closed in NRC Inspection Report 05000528; 05000529; 05000530/2005004. This supplement provided additional information on the root cause of the reactor trip. The inspectors reviewed this LER and no findings were identified. This LER is closed.

.4 (Closed) LER 05000529;05000530/2004003-00, "Actuation of Unit 2 and 3 Emergency Diesel Generators"

On December 31, 2004, a Salt River Project employee performing maintenance at the Westwing switchyard in Phoenix, de-energized the incorrect relay, opening switchyard Breakers PL-922 and PL-925. The error caused startup Transformer NAN-X01 at the Palo Verde switchyard, to be de-energized and the actuation of two EDGs, one in Unit 2 and one in Unit 3. All systems responded as expected and there was no damage to any plant equipment. The LER was reviewed by the inspectors and no findings of significance were identified and no violations of NRC requirements occurred. The licensee documented the problem in CRDR 2764549. This LER is closed.

.5 (Closed) LER 05000528/2006001-00, "Containment Spray Inoperable in Mode 4 With RCS Pressure Greater Than 385 psia"

This issue was dispositioned as NCV 05000528/2006003-07, "Three Examples of a Technical Specification 3.0.4 Violation." The inspectors reviewed the LER and identified no additional concerns. This LER is closed.

.6 (Closed) LER 05000528/2006002-00, "Mode 3 Entry Without the Required Number of Pressurizer Heater Groups Operable"

This issue was dispositioned as NCV 05000528/2006003-07, "Three Examples of a Technical Specification 3.0.4 Violation." The inspectors reviewed the LER and identified no additional concerns. This LER is closed.

.7 (Closed) LER 05000528/2005006-01, "TS Required Reactor Shutdown on EDG A Failure to Start During Post Maintenance Testing"

This LER is a supplement to LER 05000528/2005006-00, which was closed in NRC Inspection Report 05000528; 05000529; 05000530/2006008. This supplement provided additional information on the root cause of the EDG governor failure. The inspectors reviewed this LER and no additional findings were identified. This LER is closed.

.8 (Closed) LER 05000529/2005001-00, "Reactor Head Vent Axial Indications Caused by Degraded Alloy 600 Component"

On April 23, 2005, licensee engineering personnel performing in-service examinations of the Unit 2 reactor vessel head vent penetration discovered two axial indications in the reactor vessel head vent penetration. Operations personnel entered TS 3.4.103, and made an 8 hour notification to the NRC, for a non-conforming condition of the RCS. The licensee determined that the indications were the result of primary water stress corrosion cracking. The licensee removed the flaws by machining the vessel head vent, and verified their removal by eddy current examination. The licensee also evaluated the remaining wall thickness and determined that the remaining wall thickness was adequate. The LER was reviewed by the inspectors and no findings of significance were identified and no violations of NRC requirements occurred. The licensee documented the problem in CRDR 2764549. This LER is closed.

.9 (Closed) LER 05000530/2006003-00, "Loss of Power to One Class Bus During Testing Due to Human Error"

This issue was dispositioned as NCV 05000530/2006003- 03, "Emergency Diesel Trip During Testing." The inspectors reviewed the LER and identified no additional concerns. This LER is closed.

.10 (Closed) LERs 05000528/2005008-00 and 05000528/2005008-01, "Inverter Failure - Technical Specification Violation - Unit 1"

a. Inspection Scope

The inspectors reviewed this LER and CRDR 2845317 to assess the cause, analysis and corrective actions for this event.

b. Findings

Introduction. A Green self-revealing NCV of TS 3.8.7, "Inverters - Operating," was identified for the failure of procurement engineering personnel to identify the lack of oil in the output filter capacitors for Inverter 1EPNBN12 which resulted in its failure.

Description. On October 20, 2005, Unit 1 was de-fueled when Inverter 1EPNBN12 failed resulting in the actuations of the following Train B signals: containment purge isolation, fuel building essential ventilation, and control room essential filtration. Since the core was de-fueled and no irradiated fuel movement was in progress, no TS entries were required.

The licensee determined that the direct cause of the inverter failure was internal shorts on the output filter capacitors as a result of a lack of "Dielektrol -VI Fluid" (oil). The licensee determined that eight of the 15 capacitors had never been filled with oil due to a manufacturing process error. Two root causes were identified by the licensee's investigation: 1) the procurement process allowed material classification upgrades without assigning a new part number, and 2) an impact review did not consider capacitors that were issued to the field, but not yet installed in the plant. The procurement process only addressed the impact to warehouse stock and installed equipment. Consequently, as a result of a reclassification of various capacitors in August 1997, eight capacitors that had been issued to the shop in October 1995 with a quality classification of safety related low risk significant, were later returned to the warehouse and accepted with a quality classification of safety related commercial grade without receiving the appropriate requalification/dedication. The requalification inspection for the capacitors has an acceptance criterion for weight, which would have identified the underweight condition as a result of the lack of oil. In October 1999, the eight capacitors were reissued to the field and installed in Inverter 1EPNBN12.

Following the inverter failure and identification of the degraded capacitors, the licensee performed inspections of the inverters in all three units and did not identify similar conditions. Additionally, Procedure 87DP-0MC09, "Item Procurement Specification (IPS) Requirements," was revised to address the root causes.

The inverter normal and post accident loads are essentially the same, therefore; engineering concluded that Inverter 1EPNBN12 was capable of performing its function up until the time of failure. However, the equipment failure analysis concluded that operability with the lack of oil could not be justified, and as such, did not meet the requirements of TS 3.8.7 for the period between October 1999 and October 20, 2005.

Analysis. The performance deficiency associated with this finding involved procurement engineering personnel's failure to identify the lack of oil in the output filter capacitors for Inverter 1EPNBN12 which resulted in its failure. The finding is greater than minor because it is associated with the equipment performance cornerstone attribute of the mitigating systems cornerstone and affects the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because the condition only affected the mitigating systems cornerstone and did not represent an actual loss of safety function.

Enforcement. TS 3.8.7 requires Train A and B inverters to be operable in Modes 1, 2, 3, and 4. With one train inoperable, the affected inverter must be restored within 24 hours. If the inverter is not restored to operable within the allowed time, then actions are required to place the unit in Mode 3 within six hours and Mode 5 within 36 hours. Contrary to the above, between October 1999 and October 20, 2005, the licensee did not maintain two operable trains of inverters during Mode 1-4 operation. Because the finding is of very low safety significance and has been entered into the licensee's CAP as CRDR 2845317, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000528/2006003-09, "Inoperable Inverter Due to Degraded Capacitors."

.11 Fouling of Heat Exchangers Cooled by Spray Pond System

a. Inspection Scope

The inspectors evaluated plant conditions, equipment performance, and licensee actions related to chemistry control of SP, and fouling of heat exchangers cooled by SP system.

b. Findings

A special inspection was performed to evaluate the effect of SP chemistry on heat exchanger fouling. The results will be documented in NRC Special Inspection Report 05000528, 05000529, and 05000530/2006011.

4OA5 Other Activities

.1 Implementation of Temporary Instruction (TI) 2515/165 - Operational Readiness of Offsite Power and Impact on Plant Risk

a. Inspection Scope

The objective of TI 2515/165, "Operational Readiness of Offsite Power and Impact on Plant Risk," is to gather information to support the assessment of nuclear power plant operational readiness of offsite power systems and impact on plant risk. During this inspection, the inspectors interviewed licensee personnel, reviewed licensee procedures, and gathered information for further evaluation by the Office of Nuclear Reactor Regulation.

b. Findings

No findings of significance were identified.

.2 INPO Report Review

a. Inspection Scope

The inspectors reviewed the INPO assessment dated July 2005.

b. Findings

No findings of significance were identified.

.3 Unit 3 Event - Report of Onsite Tritium Contamination Threatening Groundwater

a. Inspection Scope

This inspection was conducted to review an event involving an onsite release of tritium that had the potential to cause the Environmental Protection Agency (EPA) drinking water standard for tritium (20,000 pCi/L) to be exceeded in a groundwater aquifer. On March 7, 2006, the NRC initiated an event follow-up inspection to assess the licensee's gaseous and liquid radioactive waste effluent processing systems and program. The onsite portion of the inspection was conducted March 7 - 8, 2006, with additional in-office inspection to ascertain that the radioactive effluent program, and systems were properly maintained. The inspector used the requirements in 10 CFR Part 20; 10 CFR Part 50, Appendices A and I; the Offsite Dose Calculation Manual; and the licensee's procedures required by TS as criteria for determining compliance. The inspector interviewed licensee personnel and reviewed:

- The most current radiological effluent release reports, changes to radiation monitor setpoint calculation methodology, anomalous sampling results, effluent radiological occurrence performance indicator incidents, special reports, audits, self-assessments, and corrective action reports performed since the last effluents program and environmental monitoring inspection in February 2005.
- Gaseous and liquid release system component configurations
- Routine processing, sample collection, sample analysis, and release of radioactive liquid and gaseous effluent; and radioactive liquid and gaseous effluent release permits and dose projections to members of the public
- Abnormal releases
- Changes made by the licensee to the Offsite Dose Calculation Manual, the liquid or gaseous radioactive waste system design, procedures, or operation since the last inspection
- Counting room instrumentation calibration and quality control
- Interlaboratory comparison program results
- NRC independent laboratory analysis of spilt samples for tritium and gamma radioactive isotopes

b. Assessment and Observations

No findings of significance were identified. The inspector reviewed an event in which the licensee found tritium in an underground Unit 3 pipe tunnel that had the potential to cause the EPA drinking water standard for tritium to be exceeded in a groundwater aquifer.

On March 1, 2006, a water sample collected by the licensee from a test hole located within the licensee's Unit 3 Protected Area identified tritium levels of 71,400 pCi/L. On March 2, 2006, the licensee notified the Arizona Department of Environmental Quality that tritium had been found onsite that had the potential to cause the EPA drinking water standard for tritium to be exceeded in a groundwater aquifer. On March 2, 2006, as required by 10 CFR 50.72(b)(2)(xi), the licensee notified the NRC of the event.

The licensee had been investigating the source of water leakage in the same area since February 15, 2006. From interviews with licensee staff, the inspector determined that water had leaked into an underground pipe tunnel located within the Protected Area of Units 2 and 3. From a review of the corrective action documents, the inspector noted that the licensee had identified a similar situation in 1998. Test holes were drilled inside the Protected Area near all three Units' power blocks and SPs in an effort to find the source of the tritiated water and the extent of the contamination. However, only water samples from the Unit 3 test hole contained tritium that were greater than the EPA levels.

As part of the follow-up to the onsite elevated tritium levels, an NRC inspector obtained a split water sample from the Unit 3 test hole for the NRC's independent analysis on March 3, 2006. The NRC's independent laboratory analyzed the spilt sample for tritium and gamma radioactive isotopes, and the results were consistent with the 71,400 pCi/L value obtained by the licensee. The inspector also obtained groundwater well split samples at locations outside the Protected Area for analysis by the NRC's laboratory. No detectable activity was measured. All NRC sample results were consistent with the licensee's results.

The inspector's review of the licensee's actions determined that: (1) the tritiated water at elevated levels was confined onsite; (2) no elevated levels have been found in wells located outside the protected area; and (3) there was no evidence of an offsite release of the radioactive water.

In May 2006, the licensee contracted an environmental consultant to determine the apparent cause and source of elevated tritium levels in the test holes. According to the consultant's report, tritiated water was found in Units 2 and 3 subsurface soils, but only Unit-3 had tritium levels were above the EPA action level. The report concluded that most of the elevated tritium contamination onsite stemmed from past operational practices during boric acid concentrator system (evaporator system) releases, rain deposition and washdown of roof drains, and other operational events. Prior to the mid-1990s, the licensee allowed evaporator system batch releases to occur during rainy weather days. During those releases, entrained gaseous tritiated vapors were condensed by rain, and the resulting water runoff on the site was absorbed into the ground and ran into the storm drain system. As of June 8, 2006, the licensee had not identified a system pipe break or tank leak, but they had to leak test a Unit 3 pipe that connects the reactor water makeup tank to the auxiliary feedwater system. The licensee and the contractor did not believe that the piping between the reactor water makeup tank and auxiliary feedwater system was the likely source of tritium contamination underground. Because, the contractor reported that: (1) a leak from this pipe would not cause the same contamination levels at the other two Units, and (2) the condition of other underground pipes that were recently tested showed no leakage. The report indicated that groundwater aquifers under the Palo Verde site were not impacted by these tritium releases due to the geological hydrology of the soil layers onsite. Tritiated water onsite has been localized in the upper sand and clay layers of the subsurface soil surrounding the piping systems. Consequently, the tritiated water in the upper subsurface is unable to penetrate, migrate, or infiltrate the low permeable compacted clay soils that separate the groundwater aquifers from the upper subsurface contamination onsite. However, the licensee was continuing to investigate and assess plant storm drain runoff and system leakage, and develop a monitoring, remedial action, and mitigation strategy.

The inspector concluded that this issue did not represent a noncompliance of the PVNGS effluents program. This issue has been entered into the licensee's corrective action program as CRDRs 2869959 and 2874033, entered into the licensee's 10 CFR 50.75(g) decommissioning records program, and reported to the NRC pursuant to 10 CFR 50.72(b)(2).

4OA6 Meetings, Including Exit

On April 20, 2006, the engineering inspectors presented the results of the inservice inspection review to Mr. J. Levine, Vice President of Generation, and other members of licensee management. Licensee management acknowledged the inspection findings.

On April 21, 2006, the RP inspector presented the access controls inspection results to Mr. J. Levine, Executive Vice-President of Generation, and other members of his staff who acknowledged the findings.

On May 18, 2006, the emergency preparedness inspector conducted a telephonic exit meeting to present the inspection results to Mr. E. O'Neil, Department Leader, Emergency Preparedness, who acknowledged the findings.

On June 8, 2006, the RP inspector presented the tritium inspection results to Mr. S. Bauer, and other members of his staff who acknowledged the findings.

On June 9, 2006, the lead engineering inspector presented the results of the inspection of safety evaluations and permanent plant modifications to Mr. J. Levine, Executive Vice President, Generation, and other members of licensee management. The licensee's management acknowledged the findings presented.

On June 23, 2006, the resident inspectors presented the resident inspection results to Mr. J. Levine, Executive Vice President, Generation, and other members of the licensee's management staff at the conclusion of the inspection. The licensee acknowledged the findings presented.

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

4OA7 Licensee-Identified Violations

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

- TS 5.7.1 requires that high radiation areas greater than 100 millirem per hour but less than 1,000 millirem per hour have their entrance controlled by a radiation exposure permit and that personnel are made aware of the dose rate levels. On April 13, 2006, a radiation worker inspecting and removing snubbers was challenged by a RP technician as to his purpose in a particular high radiation area. The radiation worker was not authorized to be in that particular area and had not been briefed on the associated dose rates. The worker stepped into the area while inspecting a near-by snubber. This event is described in CRDR 2884237. This finding is of very low significance because: (1) it did not involve an ALARA finding, (2) there was no personnel overexposure, (3) there was no substantial potential for personnel overexposure, and (4) the finding did not compromise the licensee's ability to assess dose. The finding also had a crosscutting aspect related to human performance, in that, the radiation worker did not obtain authorization or an associated radiological briefing for the high radiation area entered, which directly resulted in the finding.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

G. Andrews, Department Leader, System Engineering
S. Bauer, Department Leader, Regulatory Affairs
P. Borchert, Director, Operations
J. Boyer, Principal Environmental Scientist
R. Buzard, Senior Consultant, Regulatory Affairs
D. Carnes, Director, Nuclear Assurance
P. Carpenter, Unit Department Leader, Operations
C. Churchman, Director, Engineering
D. Coxon, Unit Department Leader, Operations
C. Eubanks, Vice President, Nuclear Operations
M. Fladagar, Department Leader, Radiological Services, Radiation Protection
J. Gaffney, Director, Radiation Protection
T. Gober, Section Leader, Radiation Protection Decontamination, Radiation Protection
T. Gray, Department Leader, Radiation Protection Technical Services, Radiation Protection
D. Gregoire, Project Manager, Safety Evaluations
M. Grissom, Section Leader, Valve Services Engineering
D. Hanson, Steam Generator System Engineer
D. Hautala, Senior Compliance Engineer
J. Hesser, Director, Emergency Services
J. Hughey, Senior Engineer, Systems Engineering
M. Karbasian, Department Leader, Design Mechanical Engineering
H. Lesan, Environmental Section Leader
J. Levine, Executive Vice President, Generation-Nuclear
D. Mauldin, Vice President, Engineering
J. McDonnell, Department Leader, Radiation Protection Operations, Radiation Protection
M. McGhee, Unit Department Leader, Operations
S. McKinney, Department Leader, Operations Support
W. McMurry, Senior Technical Advisor, Radiation Protection Technical Services, Radiation Protection
M. Melton, Section Leader, Inservice Inspection
E. O'Neil, Department Leader, Emergency Preparedness
S. Pittalwala, Director, Project Engineering
C. Podgurski, Section Leader, Dosimetry/Technology, Radiation Protection
J. Proctor, Section Leader, Regulatory Affairs - Compliance
M. Radsprinner, Section Leader, System Engineering
T. Radtke, General Manager, Emergency Services and Support
F. Riedel, Director, Nuclear Training Department
J. Scott, Section Leader, Nuclear Assurance
C. Seaman, General Manager, Regulatory Affairs and Performance Improvement
M. Shea, Director, Maintenance
D. Straka, Senior Consultant, Regulatory Affairs
K. Sweeney, Steam Generator Section Leader
M. Wagner, Section Leader, ALARA Planning, Radiation Protection
T. Weber, Section Leader, Regulatory Affairs

Others
L. Davis, NDE Level III Examiner, Lambert MacGill Thomas, Inc.
M. Baughn, PCI Energy Services

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000528/2006003-01	NCV	Failed Unit 1 CS Train B Pump Room Flood Level Switch Due to Nonconforming Drain Hose Manifold Boxes (Section 1R06)
05000528; 05000530/2006003-02	NCV	Failure to Evaluate Degraded Conditions to Ensure Equipment Operability (Sections 1R13 and 1R20)
05000530/2006003-03	NCV	Emergency Diesel Trip During Testing (Section 1R14)
05000530/2006003-04	NCV	Failure to Follow Procedures Resulting in Spent Fuel Pool Drain Down and Spill in the Fuel Building (Section 1R14)
05000528/2006003-05	NCV	Failure to Preclude a Significant Condition Adverse to Quality (Section 1R14)
05000530/2006003-06	NCV	Failure to Follow GTG Surveillance Procedure Causes Loss of Power to Safety-Related Bus (Section 1R14)
05000528/2006003-07	NCV	Three Examples of a Technical Specification 3.0.4 Violation (Section 1R20)
05000530/2006003-08	NCV	Failure to Follow Procedures Resulted in Declaring Both Trains of Low Pressure Safety Injection Inoperable (Section 1R22)
05000528/2006003-09	NCV	Inoperable Inverter Due to Degraded Capacitors (Section 4OA3)

Closed

05000529/2003001-01	LER	Reactor Trip with Loss of Forced Circulation Due to Failed Pressurizer Main Spray Valve (Section 4OA3.1)
05000528/2003002-01	LER	Manual Reactor Trip Due to Degraded Main Condenser Tube Plug (Section 4OA3.2)
05000530/2004002-01	LER	Main Turbine Control System Malfunction Results in Automatic Reactor Trip on Low DNBR (Section 4OA3.3)
05000529;05000530/ 2004003-00	LER	Actuation of Unit 2 and 3 Emergency Diesel Generators (Section 4OA3.4)
05000528/2006001-00	LER	Containment Spray Inoperable in Mode 4 With RCS Pressure Greater Than 385 psia (Section 4OA3.5)

05000528/2006002-00	LER	Mode 3 Entry Without the Required Number of Pressurizer Heater Groups Operable (Section 4OA3.6)
05000528/2005006-01	LER	TS Required Reactor Shutdown on EDG A Failure to Start During Post Maintenance Testing (Section 4OA3.7)
05000529/2005001-00	LER	Reactor Head Vent Axial Indications Caused by Degraded Alloy 600 Component (Section 4OA3.8)
05000530/2006003-00	LER	Loss of Power to One Class Bus During Testing Due to Human Error (Section 4OA3.9)
05000528/2005008-00	LER	Inverter Failure - Technical Specification Violation - Unit 1 (Section 4OA3.10)
05000528/2005008-01	LER	Inverter Failure - Technical Specification Violation - Unit 1 (Section 4OA3.10)

Discussed

None

LIST OF DOCUMENTS REVIEWED

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

Section 1R01: Adverse Weather Protection

Procedures

Number	Title	Revision
40OP-9ZZ19	Hot Weather Protection	0
43AL-3RK2A	Panel B02A Alarm Responses	48

CRDRs

2830372 2861962 2816567 2799440

Miscellaneous

Palo Verde IPEEE, page 5-16 thru 5-18, Revision 1

1R02 - Evaluations of Changes, Tests, and Experiments

Applicability Evaluations

13-JC-CH-0206
40OP-9AF01
40OP-9DF01
40OP-9HC01
40OP-9RC01
40OP-9SF08

Condition Reports/Disposition Requests

2900857
2900622

Miscellaneous

NUMBER	TITLE	REVISION / DATE
87DP-0MC06	Substitution Evaluation for CEDM and RSPT Cables	0
IEEE 1202-1991	Flame Testing of Cables for Use in Industrial and Commercial Occupancies	March 21, 1981
LDCR 99-F057	UFSAR Change to CEDM Cable requirement	December 1999
MEE 03842	Trisodium Phosphate Evaluation Determination	0
MEE-03793	Substitution Evaluation for Relief Valves	0

Safety Evaluations

E-04-0021	E-04-0008	E-04-0016	S-06-0246
E-06-0005	E-04-0009	S-06-0009	

Safety Evaluation Screenings

S-05-0474	S-05-0541	S-06-0086	S-06-0132
S-05-0477	S-06-0085	S-06-0123	S-06-0181

Section 1R04: Equipment Alignment

Procedures

Number	Title	Revision
40OP-9DG01	Emergency Diesel Generator A	43
40DP-9OP06	Operations Department Repetitive Task Program	83

Drawings

Number	Title	Revision
02-M-SIP-001	P&I Diagram Safety Injection & SDC System	30
02-M-EWP-001	P&I Diagram Essential Cooling Water System	25
02-M-ECP-001	P&I Diagram Essential Chilled Water System	28
13-J-03K-019	Essential Cooling Water Surge Tank	8
13-JC-EW-0200	Evaluation of the Adequacy of ECWS Surge Tank Level Setpoints	3
01-P-ZYA-061	Essential Spray Pond Sections & Details	
B-35317	Arrangement Drawing of ESPS Pump	
01-M-SPP-001	P&I Diagram Essential Spray Pond System	37
01-M-SPP-002	P&I Diagram Essential Spray Pond System	12
03-M-SIP-001	P&I Diagram Safety Injection and Shutdown Cooling System	26
03-M-SIP-002	P&I Diagram Safety Injection and Shutdown Cooling System	22
02-M-SIP-001	P&I Diagram Safety Injection and Shutdown Cooling System	31
02-M-SIP-002	P&I Diagram Safety Injection and Shutdown Cooling System	21

Miscellaneous

Palo Verde Nuclear Generating Station Design Basis Manual, - EQ System, Revision 17

Site Work Management Systems component data sheet - 2JEWNLSHL0098**IBISSW Surge Tk B LVL SW HI/LO

Technical Document, 81TD-0EE10, "Essential Spray Pond System Design Bases Manual," Revision 15

13-MC-SP-306, "MINET Hydraulic Analysis of SP System"

13-MC-SP-307, "SP/EW System Thermal Performance Design Bases Analysis"

13-CC-SP-015, "Spray Pond Walls and Slab"

Section 1R05: Fire Protection

Drawings

Number	Title	Revision
13-A-ZYD-029	Fire Protection Control Building Floor Plan at Elevation 74'-0" - Level A	Sheet 1 of 7, Revision 23
13-A-ZYD-029	Fire Protection Control Building Floor Plan at Elevation 100'-0" - Level 1	Sheet 2 of 7, Revision 23
13-A-ZYD-029	Fire Protection Control Building Floor Plan at Elevation 120'-0" - Level 2	Sheet 3 of 7, Revision 23
13-A-ZYD-029	Fire Protection Control Building Floor Plan at Elevation 140'-0" - Level 3	Sheet 4 of 7, Revision 23
13-A-ZYD-029	Fire Protection Control Building Floor Plan at Elevation 160'-0" - Level 4	Sheet 5 of 7, Revision 23

Miscellaneous

Pre-Fire Strategies Manual, Revision 16

Section 1R06: Flood Protection Measures

Procedures

Number	Title	Revision
40AL-9RK2D	Panel B02D Alarm Responses	5
73DP-9XI01	Pump and Valve Inservice Testing Program - Component Tables	18
81DP-0DC17	Temporary Modification Control	16
88DP-4EQ04	Equipment Qualification Impact Assessment	6

Drawings

Number	Title	Revision
13-J-ZAF-002	Instrument Location Plan Auxiliary Building EL. 40'-0" Level D ZADD	11
13-J-ZZS-062	Leak Detection Drain Q-Class Level Switch Installation Detail	3

13-P-OOE-003	Plumbing Details," Sheet 1 of 2	8
13-P-ZAE-200	Auxiliary Building Level D Plumbing Plan Between EL. 40'-0" & 51'-6	13
D131850-01	Magnetrol Installation Dimensions for Model FLS Flood Level Switch	3

CRDRs

2884056 2903515 2903116

Work Orders

2706316 2708303 2755357 2775796 2775819 2775820 2800950 2869114

Miscellaneous

1JRDBLSH0148, "Containment Spray Pumproom B Level Switch - HI Component Data Sheet"

13-MC-ZA-0805, "Auxiliary Building Flooding," Revision 6

Palo Verde Nuclear Generating Station Design Basis Manual, - SI System, Revision 23

Palo Verde UFSAR Section 6.3, "Emergency Core Cooling System," Revision 12

Palo Verde UFSAR Section 7.6, "All Other Instrumentation Systems Required for Safety," Revision 11

Repetitive Maintenance, Task 015674

TSCCR

3001007

Section 1R08: Inservice Inspection Activities

Procedures

Number	Title	Revision
73TI-9ZZ80	ASME Sec XI Appendix VIII Examination of Austenitic Piping	4
81DP-9RC01	PVNGS Steam Generator Degradation Management Program	4
73TI-0ZZ13	Radiographic Examination	12
73TI-9ZZ18	Visual Examination of Support Components	9
73TI-9ZZ05	Dry Magnetic Particle	11

73TI-9ZZ78	ICI Nozzles Partial Penetration Weld	6
73TI-9RC09	Bare Metal Visual Examination of Reactor Vessel Upper Head	0
70TI-9ZC01	Boric Acid Corrosion Prevention Program	5
73TI-9ZZ78	Visual Examination for Leakage	6
WPS 8MN-GTAW/SMAW	Tungsten Inert Gas Welding - Austenitic Stainless Steel	13
WDI-UT-013	Intraspect UT Evaluation Guidelines	10
WDI-ET-004	Intraspect ET Evaluation Guidelines	10

ISI Inspection Reports

VT-06-003	ICI Nozzles Partial Pen Weld
VT-06-004	CEDM Nozzles/Head Vent
RT-06-061	Pressurizer Spray Line Weld 219337-2
RT-06-064	Pressurizer Spray Line Weld 219337-7
RT-06-062	Pressurizer Spray Line Weld 219337-10
RT-06-059	Pressurizer Spray Line Weld 219337-5
RT-06-060	Pressurizer Spray Line Weld 219337-4
UT-06-027	Safety Injection Pipe to Elbow Weld 21-15
UT-06-026	Safety Injection Pipe to Elbow Weld 21-14
MT-06-012	Support SG-2-H-1
MT-06-013	Support SG-5-H-1
VT-06-132	Support SG-5-H-3
VT-06-131	Support SG-5-H-2
VT-06-130	Support SG-5-H-1
RT-06-007	Report of Valve Body Weld PSV-200

Work Orders

2843168 2865575 2816444 2592792

CRDRs

2600546 2829998 2885972 2886281 2886287 2843168 2642817

Arizona Public Service (APS) Examination Technique Specification Sheets (ETSS), Acquisitions Technique Sheets (ACTS), and Analysis Technique Sheets (ANTS)

APS ACTS	APS ANTS	EPRI ETSS
B1-A-70 R5	B1-A-70 R16 B2-A-70 R21 B3-A-70 R15	96004.1 R9, 96007.1 R10, and 96008.1 R13
R2-A-70 R6	R2-A-70 R11	96910.1 R9, 21409.1 R4, 21410.1 R4, 20510.1 R4, 20511.1 R7, and 96703.1 R16
R3-A-70 R1	R3-A-70 R3	96910.1 R9, 21409.1 R4, 21410.1 R4, 20510.1 R4, 20511.1 R7, and 96703.1 R16
R5-A-70 R4	R5-A-70 R10	99997.1 R9 and 96511.2 R15
R6-A-70 R7	R6-A-70 R9	96910.1 R9, 21409.1 R4, 21410.1 R4, 20510.1 R4, 20511.1 R7, and 96703.1 R16

Miscellaneous

Number	Title/Description	Rev/Date
WCAP-16208-P	NDE Inspection Length for CE SG Tubesheet Region - Explosive Expansion	1
Procedure Qualification Record 063	PQR for WPS-8MN-GTAW/SMAW	3
Generic Letter 88-05	Boric Acid Corrosion Control of Carbon Steel Reactor Pressure Boundary Components in PWR Plants	March 17, 1988
EPRI Appendix H	Examination Technique Specification Sheets (ETSS)	2
N/A	EPRI PWR Steam Generator Examination Guidelines	6
NEI 97-06	Steam Generator Program Guidelines	2

Section 1R11: Licensed Operator Requalification Program

Miscellaneous

Scenario SES-0-09-E-04, "RCS leak, Loss of NC to Containment, Loss of PW, LOCA with No HPSI FRP (MVAC-2)"

LOCT Weekly Schedule Cycle NLR06-03 Week 1, Starting: 05/23/2006

Section 1R12: Maintenance Effectiveness

CRDRs

2881083 2881956 2882959 2883052

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures

Number	Title	Revision
70DP-0RA01	Shutdown Risk Assessments	12
70DP-0RA03	Probabilistic Risk Assessment Model Control	2
30DP-9MT03	Assessment and Management of Risk When Performing Maintenance in Modes 1-4	7
70DP-0RA05	Assessment and Management of Risk When Performing Maintenance in Modes 1 and 2	1

CRDRs

2899375 2881083 2881956 2882959 2883052 2850999

Work Order

2870395

Miscellaneous

Scheduler's evaluation for PV Unit 2, EOOS print out
June 13, 2006, Scheduler's Evaluation for PV Unit 1, EOOS print out
April 7, 2006, Scheduler's Evaluation for PV Unit 2, EOOS print out
Schedulers evaluation for Unit 1, Shutdown risk assesment with pressurizer manway on
Work week plan for January 9 - January 12, 2006

Section 1R14: Operator Performance

Procedures

Number	Title	Revision
40EP-9EO01	Standard Post Trip Actions	13
40OP-9NA03	13.8 kV Electrical System (NA)	19
40OP-9ZZ05	Power Operations	111
40OP-9ZZ07	Plant Shutdown Mode 1 to Mode 3	27
40OP-9PC02	Filling and Draining the Refueling Pool Using the CS, LPSI and HPSI Pumps	31
40OP-9PC06	Fuel Pool Cleanup and Transfer	37
40AO-9ZZ12	Degraded Electrical Power	29
40OP-9SA02	De-energization of BOP ESFAS	19

CRDRs

2881083 2881956 2883283

Drawings

Number	Title	Revision
01-P-SIF-105	Containment Building Isometric Safety Injection System Shutdown Cooling Lines	19
01-P-SIF-108	Containment Building Isometric Safety Injection System Shutdown Cooling Lines Refuel Wtr Supply & Return	0
01-P-SIF-202	Auxillary Building Isometric Safety Injection System ESF Pump Suction Lines-Train B	2

Miscellaneous

Unit 2 operator logs
Unit 3 operator logs
RP surveys 3-06-01178, 3-06-01179, 3-06-01188

Section 1R15: Operability Evaluations

Procedures

Number	Title	Revision
40DP-9OP26	Operability Determination and Functional Assessment	16

90DP-01P10	Condition Reporting	16
40DP-90P26	Operability Determination	14
36ST-9SE13	Excore Startup Channel and Boron Dilution Alarm System Response	21

Drawings

03-M-ECP-001	P&I Diagram Essential Chilled Water System	22

CRDRs

2860763	2896661	2897266	2897810	2898237	2898120	2883927	2882958
2896417	2879324	2689482	2879324	2813750	2901815	2901432	2901186

Work Orders

2831329	2883936	2886469	2896333	2749052	2864614

Miscellaneous

10 CFR 50.59 Screening S-06-0177, "Conditional Repair Disposition to Allow Repair of the Bus Side A Phase Primary Disconnect Assembly in 3EPBAS03B Using RTV-103," Revision 0

VTD-J127-0016, "Joy Manufacturing Company Fan Maintenance and Storage Instructions," Revision 0

VTD-J127-0018, "Joy Technologies Axivane Fan Installation and Maintenance Manual," Revision 2

VTD-R165-0016, "Lubrication of Anti-Friction Bearings in Reliance Electric Motors," Revision 2

Calculation 13-EC-PK-0204, "Hydrogen Generation Calculation for Class 1E Station Batteries - GNB Model NCN-33," Revision 1

PM Basis documents for Essential and Non-Essential Battery Room Exhaust Fans

PI Data for Unit 1 Ex-Core Nuclear Instrumentation: 3/24/06, 3/28/06, 4/1/06, 6/6/06-6/10/06

Unit 1 Operator Logs: 3/24/06, 3/28/06, 4/1/06, 6/6/06-6/10/06

Unit Night Orders, Dated June 15 and June 23, 2006

Westinghouse Letter, "Westinghouse Recommendation Regarding Fuel Assembly P1R518," Dated June 14, 2006

EDC 2006-00270

Design Input Requirements Checklist for DFWO 2813864

Calculation 13-MC-CH-0239

1R17B - Permanent Plant Modifications

Calculations

NUMBER	TITLE	REVISION
13-CC-ZC-0165	Pipe Whip Restraint Codes	6
13-MC-SI-0309	Emergency Sump Screen Blockage	5
13-MC-SI-0326	Containment Building Flooding by SI System	6

Condition Reports/Disposition Requests

2900861
2901114

Miscellaneous

NUMBER	TITLE	REVISION / DATE
	Gap Measurements for Core Support Barrel - Before and After Inspections	May 8 & 31, 2006
D2006-0010	Limitorque SMB-3 for SI-651 Inside the Bioshield (Supplement to EQCF D2006-002)	May 26, 2006
D2006-002	Limitorque SMB-3 for SI-651 Inside the Bioshield	May 16, 2006
MEE-02534	Allow Unlimited Mixing of MOVLL with Nebula EP Grease in Valve Actuators Located in Any Section of the Plant	8

Modification Packages

NUMBER	TITLE	REVISION
2593803	"B" Containment Building Atmosphere Monitor	0
2625501	Cooling Fans on Radiation Monitors XJSQNRU006	0

Modification Packages

NUMBER	TITLE	REVISION
2717767	Relocation of Reactor Head Orifice	0
2774514	Replace Dropping Resistor R17 in Turbine Driven Auxiliary Feedwater Pump Governor	0
2883666	SI Valve 651 Relocation	0

Section 1R19: Postmaintenance Testing

Procedures

Number	Title	Revision
73DP-9XI01	Pump and Valve Inservice Testing Program - Component Tables	18
78OP-9FX03	Spent Fuel Handling Machine	33
40OP-9ZZ16	RCS Drain Operations	55
40OP-9SI01	Shutdown Cooling Initiation	37
40OP-9PB01	4.16 kV Class 1E Power (PB)	21

CRDRs

2899672 2894792

Work Orders

2794258 2801464 2810534 2785109 2894751 2855488m 2900941

Miscellaneous

01-J-ZZS-0220, "Engineering Document Change for Motor Operated Valve Technical Data Files Drawings", Revision 05

13-JC-ZZ-221, "Engineering Document Change for Motor Operated Valve Technical Data Files Drawings," Revision 05

Test Data for Full Stroke Closed Test of 1SI651 on 5/31/06

50.59 S-06-0235, 'DFWO 2882666 - Conditional Release,' Revision 0
01-J -ZZI-04, "Engineering Document Change for Controlled Motor Operator Data Base," Revision 23

01-JC-ZZ-223, "Engineering Document Change for 89-10 Program Motor Operated Valve Adjusted Setpoint Calculation," Revision 03

13-JC-MO-204, “Engineering Document Change for Calculation 89-10 Program Valve Spring Pack, Maximum Displacement Calculation,” Revision 09

13-JC-ZZ-201, “Engineering Document Change for MOV Thrust, Torque, and Actuator Sizing Calculation,” Revision 14

13-MS-B07, “Engineering Study MOVs” Palo Verde Nuclear Generating Station Design Basis Manual, - SI System, Revision 23

Test Data for Full Stroke Closed Test of 1SI651 on 6/9/06

Section 1R20: Refueling and Other Outage Activities

Procedures

Number	Title	Revision
40OP-9ZZ20	Reduced Inventory Operations	7
40OP-9ZZ16	RCS Drain Operations	54
78OP-9FX01	Refueling Machine Operations	28
40DP-9OP05	Control Room Data Sheet Instructions	56
40OP-9ZZ11	Mode Change Checklist	66
40AL-9RK4A	Panel B04A Alarm Responses	18
73DP-9XI01	Pump and Valve Inservice Testing Program - Component Tables	18
39MT-9ZZ32	Motor Operated Valve Diagnostic Testing	6

Drawings

03-M-SIP-001	P&I Diagram Safety Injection and Shutdown Cooling System
03-M-SIP-002	P&I Diagram Safety Injection and Shutdown Cooling System

CRDRs

2882657	2883107	2883138	2883360	2893768	2894741

Work Orders

2882651	2808603	2591292	2591316

Permits

121791	122763	123120	123125	124402	124994	125598	126471

Miscellaneous

Refueling Outage 3R12 Scope Change Requests
Technical Specification Component Condition Record Report
Significant CRDR Evaluation Review for CRDR 2877591 Performed by NAD
Alarm Typeout from March 22, 2006

Section 1R22: Surveillance Testing

Procedures

Number	Title	Revision
40ST-9ZZM1	Operation Mode 1 Surveillance Logs	38

CRDRs

2884026 2891552 2891679

Work Orders

02728478

Miscellaneous

PVNGS UFSAR

Licensing Document Change Request, Log No 01-F018, CPC Replacement

M.J. Reid, "Resolution of EER 91-RX-10, CPCS Operability Guidelines," APS Memo 162-04771-PFC/LCH, July 19, 1991

John J. Valerio, "CPC Deviation Limits," APS Memo 162-08195-PFC/JJV, December 19, 1997

CPC System Design Basis Manual

CRAI 2885508

Section 2OS1: Access Control to Radiologically Significant Areas (71121.01)

Procedures

Number	Title	Revision
13CN-211	Installation Specification for Temporary Shielding	9
30DP-9MP03	System Cleanliness and Foreign Material Exclusion Controls	4
40OP-9ZZ16	RCS Drain Operations	54
60DP-0QQ19	Internal Audits, Revision	14
73TI-0ZZ13	Radiographic Examination	12

75DP-0RP01	Radiation Protection Program Overview	6
75DP-0RP02	Radioactive Contamination Control	7
75DP-0RP03	ALARA Program Review	2
75DP-0RP04	Radiological Reports	7
75DP-9RP01	Radiation Exposure and Access Control	6
75RP-0RP01	Radiological Posting and Labeling	20
75RP-9ME27	High Noise Area EPDs	1
75RP-9ME28	Automated Radiological Access Control Software (ARACS)	1
75RP-9OP02	Control of High Radiation Areas, Locked High Radiation Areas and Very High Radiation Areas	17
75RP-9RP02	Radiation Exposure Permits	18
75RP-9RP05	Contamination Dose Evaluation	5
75RP-9RP07	Radiological Surveys and Air Sampling	11
75RP-9RP10	Conduct of Radiation Protection Operations	16
75RP-9RP16	Special Dosimetry	11
90DP-0IP10	Condition Reporting	25

CRDR

2839231 2843429 2847991 2848061 2850459 2851646 2871198 2873296

2878799 2880588 2884054 2884237

Radiation Exposure Permit

1-1365 A	Inspection and Maintenance of Reactor Drain Tank (RDT)
1-3501 F	Radiation Protection Tours, Inspections and Routine Surveys
1-8022 A	Refueling and Associated Work
3-1365 C	Inspection and Maintenance of Reactor Drain Tank (RDT)
3-3002 G	Reactor Destack and Restack
3-3006 G	Incore Instrumentation and Heated Junction Thermal Couple Maintenance
3-3015 G	Refuel Cavity Decontamination

3-3045 C	Reactor Vessel Head Penetration Inspections
3-3306 G	Primary Side Steam Generator Maintenance
3-3502 H	Valve, Flange, and Pump Maintenance and Inspection (< 8" Diameter)
3-3507 H	Remove, Install, Inspect, Test, and Modify Snubbers
3-3521 B	Large Bore SI System Valve and Flange Intrusive Disassembly, Inspection, and Repair ≥ 8" Diameter
9-1017 B	Radiography (All RCAs and Protected Area)

Miscellaneous

Radiation Contamination Control Event #021
U3R12 Radiation Protection Containment Turnover Log
U3R12 Radiation Protection Outage Manager's Log

Section 2OS2: ALARA Planning and Controls (71121.02)

Procedures

Number	Title	Revision
75DP-0RP01	Radiation Protection Program Overview	6
75DP-0RP03	ALARA Program Review	2
75DP-0RP04	Radiological Reports	7
75DP-0RP06	ALARA Committee	4
75DP-9RP01	Radiation Exposure and Access Control	6
75RP-9ME28	Automated Radiological Access Control Software (ARACS)	1
75RP-9RP02	Radiation Exposure Permits	18

CRDRs

2834976 2873296

Radiation Exposure Permits

1-8022 A	Refueling and Associated Work
3-1365 C	Inspection and Maintenance of Reactor Drain Tank (RDT)
3-3002 G	Reactor Destack and Restack
3-3006 G	Incore Instrumentation and Heated Junction Thermal Couple Maintenance
3-3015 G	Refuel Cavity Decontamination
3-3045 C	Reactor Vessel Head Penetration Inspections

3-3306 G	Primary Side Steam Generator Maintenance
3-3502 H	Valve, Flange, and Pump Maintenance and Inspection (< 8" Diameter)
3-3507 H	Remove, Install, Inspect, Test, and Modify Snubbers
3-3521 B	Large Bore SI System Valve and Flange Intrusive Disassembly, Inspection, and Repair $\geq$ 8" Diameter

Temporary Shielding Packages

3-06-004/A-40-19, 3-06-005/A-40-20, 3-06-020/C-100-39, 3-06-023/C-100-15, 3-06-024/C-100-03, 3-06-025/C-100-04, 3-06-026/C-100-05, 3-06-035/C-100-38, 3-06-041/C-100-02, 3-06-043/C-100-09, 3-06-044/C-108-01, 3-06-052/C-140-19, 3-06-054/C-114-05, 3-06-056/C-153-01

Miscellaneous

ALARA Committee Meeting - U3R12 Goal Planning REP Estimates Revision
WinRRACS Live Time Reports - Radiation Exposure Permit Cumulative Dose Reports

Section 4OA1: Performance Indicator (PI) Verification (71151)

Procedures

Number	Title	Revision
75RP-0LC01	Performance Indicator Occupational Radiation Safety Cornerstone	1
75RP-0LC02	Performance Indicator Public Radiation Safety Cornerstone	

Miscellaneous

1st Quarter 2006 Performance Indicator Data Input Sheets
2004 Annual Radioactive Effluent Release Report

Section 4OA2: Identification and Resolution of Problems (71152)

Procedures

Number	Title	Revision
90DP-0IP10	Condition Reporting	28

Miscellaneous

Palo Verde Operations 2006 Improvement Plan

Site Integrated Performance Improvement Schedule

Independent Review of Performance at Palo Verde dated February 28, 2005

Performance Improvement Plan

Performance Improvement Plan Streaming Analysis

Palo Verde Performance Improvement Plan Rollout Plan dated May 10, 2006, Revision 6, 2006-2020 Palo Verde Business Plan

Human Performance-Continuous Learning Health Report, April 2006

Human Performance-Continuous Learning Health Report, May 2006

Performance Improvement Department Performance Indicators, April 2006

Palo Verde Nuclear Generating Station Monthly Trend Report, April 2006

Operations Assessment of Corrective Actions Contained in CRDR 2729600, May 11, 2005

PG-126 Palo Verde Human Performance Policy Guide, Revision 0

Root Cause Expert panel - Observations on Significant Investigation Process & RCEP Self-Assessment, March 2, 2005

CRDRs

2878030	2877648	2825485	2777901	2707290	2704331	2657316
2654704						

CRAIs

2837074	2837280	2830256	2837279	2837258	2837097	2830257
2837103	2837082	2837083	2880597	2837278	2828405	2830257
2830460						

Section 4OA3: Event Follow-up (71153)

Number	Title	Revision
74CH-9XC50	Operation of the Gamma Spectrometry	13
74CH-9XC73	Environmental Tritium	3
74CH-9ZZ69	Operation of the Liquid Scintillation Systems	14
74DP-9CY08	Radiological Monitoring Program	14
74OP-9SC02	Sampling Instructions for Auxiliary Systems	23
74RM-0EN02	Radiological Environmental Air Sampling	18
74RM-0EN03	Radiological Environmental Sampling	23
74RM-0EN10	Weekly Radiological Environmental Sample Collection Verification	12

74RM-9EF20	Gaseous Radioactive Release Permits and Offsite Dose Assessment	13
74RM-9EF23	Secondary System Liquid Discharge	
75RP-9RP09	Release of Vehicles, Equipment, and Material from Radiological Controlled Areas	23

<u>CRDRs</u>

3-8-0028 3-8-0029 3-8-0056 2862819 2866038 2866065 286593 2874033

2845317

<u>Audits and Assessments</u>
Radiation Safety Audit 2004-013

<u>Miscellaneous</u>
Annual Radiological Environmental Operating Report - 2004
Annual Radiological Environmental Operating Report - 2005
Palo Verde Nuclear Generating Station Offsite Dose Calculation Manual, Revision 19
Palo Verde Aquifer Protection Permit: No. P-3507-100388, Revision 1
Updated Final Safety Analysis Report, Chapters 2 and 11
3rd Quarter 2004 Environmental Cross-Check Results
4th Quarter 2004 Environmental Cross-Check Results
Special Report: Notification of Discharge of Non-Hazardous Materials, March 10, 2006
Special Report: Tritium Evaluation 30 Day Follow-up Report, May, 31, 2006
2004 Annual Effluents Report
2005 Annual Effluents Report

LIST OF ACRONYMS

AFW	auxiliary feedwater
ALARA	as low as is reasonably achievable
ASME	American Society of Mechanical Engineers
CAP	corrective action program
CFR	*Code of Federal Regulations*
CRDR	condition report/disposition requests
CRS	control room supervisor
CS	containment spray
ECCS	emergency core cooling system
EDG	emergency diesel generator
EPA	environmental protection agency
EPRI	Electric Power Research Institute
EW	essential cooling water
GTG	gas turbine generator
HPSI	high pressure safety injection
IIP	integrated improvement plan
INPO	Institute of Nuclear Power Operations
LCO	Limiting Condition for Operation
LER	licensee event report
LPSI	low pressure safety injection
LRT	leadership review team
NCV	noncited violation
NEI	nuclear energy institute
NRC	Nuclear Regulatory Commission
PC	pool cooling
PI	performance indicator
PIP	performance improvement plan
PVNGS	Palo Verde Nuclear Generating Station
QSPDS	qualified safety parameter display system
RCS	reactor coolant system
RO	reactor operator
RP	radiation protection
SDC	shutdown cooling
SFP	spent fuel pool
SP	spray pond system
SSC	structure, system, and component
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
WM	work mechanism
WO	work order