UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
612 EAST LAMAR BLVD, SUITE 400
ARLINGTON, TEXAS 76011-4125

May 4, 2009

Ross T. Ridenoure,
Senior Vice President and
Chief Nuclear Officer
Southern California Edison Company
San Onofre Nuclear Generating
Station
P.O. Box 128
San Clemente, CA 92674-012

Subject: SAN ONOFRE NUCLEAR GENERATING STATION – NRC INTEGRATED INSPECTION REPORT 05000361/2009002 and 05000362/2009002

Dear Mr. Ridenoure:

On March 24, 2009, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your San Onofre Nuclear Generating Station, Units 2 and 3 facility. The enclosed integrated inspection report documents the inspection findings, which were discussed on April 1, 2009, with Mr. A. Hochevar, and other members of your staff.

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

This report documents four NRC identified and three self-revealing findings of very low safety significance (Green). All of these findings were determined to involve violations of NRC requirements. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as non-cited violations, consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest the violations or the significance of the non-cited 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, D.C. 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 612 E. Lamar Blvd, Suite 400, Arlington, Texas, 76011-4125; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the San Onofre Nuclear Generating Station, Units 2 and 3 facility. In addition, if you disagree with the characterization of any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region IV, and the NRC Resident Inspector at the San Onofre Nuclear Generating Station, Units 2 and 3 facility. The information you provide will be considered in accordance with Inspection Manual Chapter 0305.

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

Michael C. Hay, Chief
Project Branch D
Division of Reactor Projects

Docket Nos. 50-361
50-362

License Nos. NPF-10 NPF-15

Enclosure:

NRC Inspection Report 05000361/2009002 and 05000362/2009002
w/Attachment: Supplemental Information

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SUNSI Rev Compl.	☒ Yes ☐ No	ADAMS	☒ Yes ☐ No	Reviewer Initials	MH
Publicly Avail	☒ Yes ☐ No	Sensitive	☐ Yes ☒ No	Sens. Type Initials	MH

RIV:RI:DRP	SRI:DRP/D	C:DRS/PSB2	C:DRS/PSBI	C:DRS/EBI
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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	50-361, 50-362
License:	NPF-10, NPF-15
Report:	05000361/2009002 and 05000362/2009002
Licensee:	Southern California Edison Co. (SCE)
Facility:	San Onofre Nuclear Generating Station, Units 2 and 3
Location:	5000 S. Pacific Coast Hwy San Clemente, California
Dates:	January 1 through March 24, 2009
Inspectors:	P.J. Elkman, Senior Emergency Preparedness Inspector C.C. Osterholtz, Senior Operations Engineer, Region IV J.P. Reynoso, Resident Inspector, Project Branch D, DRP T.C. Steadham, Resident Inspector, Region III G.G. Warnick, Senior Resident Inspector, Project Branch D, DRP
Approved By:	Michael C. Hay, Chief, Project Branch D Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000361/2009002, 05000362/2009002; 01/01/2009 – 03/24/2009; San Onofre Nuclear Generating Station, Units 2 and 3, Integrated Resident and Regional Report; Maint. Effect.; Oper. Eval.; Plant Mod.; Postmaint. Test.; Ident. and Res. of Problems; Event Follow-up.

The report covered a 3-month period of inspection by resident inspectors and announced baseline inspections by regional based inspectors. Seven Green non-cited violations of significance were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. NRC-Identified Findings and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. The inspectors identified a non-cited violation of Technical Specification 5.5.1.1 for the failure of operations personnel to follow procedures for performing reactivity manipulations. Specifically, a procedure modification performed to Procedure SO23-3-2.19.2, "Control Element Assembly Exercise and Troubleshooting," was inaccurate and incomplete to appropriately control reactivity manipulations, and thus, an adequate procedure was not in hand as required by Procedure SO123-O-A1, "Conduct of Operations," to appropriately control the control element assembly manipulations by a licensed operator. This finding was entered into the licensee's corrective action program as Nuclear Notification 200339686.

  The finding is greater than minor because it is associated with procedure quality attribute of the Initiating Events Cornerstone and affects the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Using 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, degrade the ability to terminate a leak path, or degrade the ability to recover decay heat removal. This finding has crosscutting aspect in the area human performance associated with work control because the licensee did not appropriately plan a work activity [H.3.(a)] (Section 1R19).

- Green. The inspectors identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," for the failure of engineering personnel to properly perform an evaluation of reactor coolant pump vapor seal boric acid accumulation caused by a clogged vapor seal drain line, in accordance with boric acid corrosion control program procedures. Specifically, engineering personnel failed to follow the requirements of Procedures SO23-XV-85 and SO23-XV-8.15 to properly evaluate the impact of boric acid leakage to reactor coolant system pressure boundary components. This finding was entered into the licensee's corrective action program as Nuclear Notification 200258836.

The finding is greater than minor because if left uncorrected, excessive boric acid buildup would have a potential to lead to a more significant safety concern. The finding is associated with the Initiating Events Cornerstone. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheets, the finding is determined to have very low safety significance because the finding would not result in exceeding the technical specification limit for reactor coolant system leakage and would not have affected other mitigation systems resulting in a total loss of their safety function. The finding has a crosscutting aspect in the area of human performance associated with decision-making because engineering personnel did not use conservative assumptions to identify possible unintended consequences associated with the identified boric acid accumulation [H.1.(b)] (Section 4OA2).

- Green. A self-revealing non-cited violation of Technical Specification 5.5.1.1 was identified for the failure of operations personnel to follow procedures to place Ion Exchanger ME074 in service which resulted in an interruption of letdown flow and diversion of approximately 160 gallons of reactor coolant to the radiological waste system. This finding was entered into the licensee's corrective action program as Nuclear Notification 200319240.

  The finding is greater than minor because it is associated with the configuration control attribute of the Initiating Events Cornerstone and affects the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheets, the finding is determined to have very low safety significance because the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. The finding has a crosscutting aspect in the area of human performance associated with work practices because the licensee did not properly use human error prevention techniques [H.4(a)] (Section 4OA3).

Cornerstone: Mitigating Systems

- Green. A self-revealing non-cited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," was identified for the failure of maintenance personnel to follow maintenance order instructions to fully remove fuses to establish conditions necessary to perform valve testing on the auxiliary feedwater system. Instead of removing the fuse entirely from the fuse holder, maintenance personnel only removed one side of the fuse and left the other side inserted. This inappropriate maintenance practice caused plastic deformation on the associated side of the fuse holder, which impacted the design configuration of the auxiliary feedwater control system, and its ability to perform its required design function under all design basis accident conditions. This finding was entered into the licensee's corrective action program as Nuclear Notification 200253911.

  The finding is greater than minor because it is associated with the configuration control attribute of the Mitigating Systems Cornerstone and affects the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors evaluated the issue using the Significance Determination Process (SDP) Phase 1 Screening Worksheet for the Initiating Events, Mitigating Systems, and Barriers Cornerstones provided in Manual Chapter 0609, Attachment 4, "Phase 1 – Initial Screening and Characterization of Findings." The inspectors determined that this finding represented a loss of the system safety function for the ability to provide secondary heat removal during a station blackout. This required that a Phase 2 estimation be completed. Because the Phase 2 assumptions significantly overestimated the risk related to this finding, the senior reactor analyst conducted a Phase 3 evaluation to provide a best-estimate risk assessment. The analyst calculated that a total ΔCDF of 4.4×10^{-7}, therefore this finding is of very low risk significance (Green). The finding has a crosscutting aspect in the area of human performance associated with work practices because maintenance personnel did not comply with expectations regarding procedural compliance to follow the procedure as written without deviating from its intent [H.4(b)] (Section 1R12).

- Green. The inspectors identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," for the failure of operations and engineering personnel to follow procedures and adequately evaluate degraded conditions to support operability decision-making. Specifically, operations and engineering personnel failed to adequately evaluate the operability of the Unit 2 component cooling water system Train B, when a tube leak was identified, and subsequently, when the tube exhibited a degrading trend. This finding was entered into the licensee's corrective action program as Nuclear Notification 200289984.

  The finding is greater than minor because the degraded component cooling water heat exchanger is associated with the equipment performance 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 Worksheets, the finding is determined to have very low safety significance because the finding did not result in a loss of safety function of component cooling water Train B for greater than the technical specification allowed outage time. The finding has a crosscutting aspect in the area of human performance associated with decision-making because the licensee did not review past operability decisions to verify the validity of the underlying assumptions [H.1(b)] (Section 1R15).

- Green. The inspectors identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," for the failure of maintenance personnel to properly install and inspect scaffolding in safety-related areas in accordance with written procedural requirements. Four instances were found where the minimum separation distance between a scaffold and safety-related components was less than the minimum allowed by procedure and an approved engineering evaluation to justify the deviation was not performed. The licensee evaluated the scaffolds and modified them as necessary. This finding was entered into the licensee's corrective action program as Nuclear Notification 200356209.

The finding is greater than minor because if left uncorrected, it would have the potential to lead to a more significant safety concern. The inspectors concluded this finding was associated with the Mitigation Systems Cornerstone. Using the Manual Chapter 0609, “Significance Determination Process,” Phase 1 Worksheets, the finding is determined to have very low safety significance because the finding did not affect both trains of any single mitigating system or represent an actual loss of a safety function. This finding has a crosscutting aspect in the area of human performance associated with work practices because the licensee did not utilize appropriate human performance techniques to ensure that scaffold construction was performed safely [H.4(a)] (Section 1R18).

Cornerstone: Barrier Integrity

- Green. A self-revealing non-cited violation of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures and Drawings,” was identified for the failure of work control and maintenance personnel to follow the procedure requirements for work on a reactor coolant system pressure retaining component. Specifically, work control and maintenance personnel did not use work documents and procedures to reassemble the vent valve for the control element drive mechanism associated with control element Assembly 22, which resulted in a reactor coolant system leak during the fill and vent process. This finding was entered into the licensee’s corrective action program as Nuclear Notification 200323460.

  The finding is greater than minor because it is associated with the reactor coolant system equipment and barrier performance attribute of the Barrier Integrity Cornerstone and affects the associated cornerstone objective to provide reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Using Manual Chapter 0609, “Significance Determination Process,” Appendix G, “Shutdown Operations Significance Determination Process,” Checklist 4, the finding was of very low safety significance because it did not increase the likelihood of a loss of reactor coolant system inventory by more than two feet when not in a mid loop operation. This finding has a crosscutting aspect in the area of human performance associated with work control because the licensee did not appropriately coordinate work activities by incorporating actions to address the impact of work on different job activities [H.3(b)] (Section 4OA3).

B. Licensee-Identified Violations

None

REPORT DETAILS

Summary of Plant Status

Unit 2 was shutdown at the beginning of the inspection period for mid-cycle Outage U2M15. The unit was started up on February 17, 2009, and reached essentially full power on February 20. The unit was at essentially full power for the remainder of the inspection period.

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

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignments (71111.04)

Partial Walkdowns

a. Inspection Scope

The inspectors performed partial system walkdowns of the following risk-significant systems:

- January 27, 2009, Unit 2, containment spray Pump MP012 Train A backup to shutdown cooling system
- January 28, 2009, Unit 2, shutdown cooling system Train B
- February 3, 2009, Unit 2, emergency diesel generator Train A while Train B was out of service for maintenance

The inspectors selected these systems based on their risk significance relative to the reactor safety cornerstones at the time they were inspected. The inspectors attempted to identify any discrepancies that could affect the function of the system, and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, Updated Final Safety Analysis Report, technical specification requirements, administrative technical specifications, outstanding work orders, condition reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the corrective action program with the appropriate significance characterization. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of three partial system walkdown samples as defined by Inspection Procedure 71111.04-05.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

Quarterly Fire Inspection Tours

a. Inspection Scope

The inspectors conducted fire protection walkdowns that were focused on availability, accessibility, and the condition of firefighting equipment in the following risk-significant plant areas:

- February 3, 2009, Unit 3, emergency diesel Generators 3G002 and 3G003 Rooms A and B

- February 3, 2009, Unit 2, emergency diesel Generators 2G002 and 2G003 Rooms A and B

- February 17, 2009, Unit 2, containment Elevations 63 foot, 45 foot, and 30 foot during mid-cycle Outage U2M15

- February 25, 2009, Unit 2, safety equipment building Rooms 2 through 5, and Room 15

The inspectors reviewed areas to assess if licensee personnel had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant; effectively maintained fire detection and suppression capability; maintained passive fire protection features in good material condition; and had implemented adequate compensatory measures for out of service, degraded or inoperable fire protection equipment, systems, or features, in accordance with the licensee's fire plan. The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant's Individual Plant Examination of External Events with later additional insights, their potential to affect equipment that could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. Using the documents listed in the attachment, the inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed, that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's corrective action program. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of four quarterly fire-protection inspection samples as defined by Inspection Procedure 71111.05-05.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope

On February 26, 2009, the inspectors observed a crew of licensed operators in the plant's simulator to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- Licensed operator performance
- Crew's clarity and formality of communications
- Crew's ability to take timely actions in the conservative direction
- Crew's prioritization, interpretation, and verification of annunciator alarms
- Crew's correct use and implementation of abnormal and emergency procedures
- Control board manipulations
- Oversight and direction from supervisors
- Crew's ability to identify and implement appropriate technical specification actions and emergency plan actions and notifications

The inspectors compared the crew's performance in these areas to pre-established operator action expectations and successful critical task completion requirements. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one quarterly licensed-operator requalification program sample as defined in Inspection Procedure 71111.11.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors evaluated degraded performance issues involving the following risk significant systems:

- January 8, 2009, Unit 3, auxiliary feedwater Pump P140 failure due to improperly installed fuse
- March 19 through March 27, 2009, Unit 3, auxiliary feedwater exceeded performance criteria

The inspectors reviewed events such as where ineffective equipment maintenance has resulted in valid or invalid automatic actuations of engineered safeguards systems and independently verified the licensee's actions to address system performance or condition problems in terms of the following:

- Implementing appropriate work practices
- Identifying and addressing common cause failures
- Scoping of systems in accordance with 10 CFR 50.65(b)
- Characterizing system reliability issues for performance
- Charging unavailability for performance
- Trending key parameters for condition monitoring
- Ensuring proper classification in accordance with 10 CFR 50.65(a)(1) or (a)(2)
- Verifying appropriate performance criteria for structures, systems, and components classified as having an adequate demonstration of performance through preventive maintenance, as described in 10 CFR 50.65(a)(2), or as requiring the establishment of appropriate and adequate goals and corrective actions for systems classified as not having adequate performance, as described in 10 CFR 50.65(a)(1)

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the corrective action program with the appropriate significance characterization. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of two quarterly maintenance effectiveness samples as defined in Inspection Procedure 71111.12-05.

b. Findings

Introduction. A self-revealing Green non-cited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," was identified for the failure of maintenance personnel to follow maintenance order instructions to fully remove fuses to establish conditions necessary to perform valve testing on the auxiliary feedwater system. The failure to fully remove the fuses impacted the design configuration of the governor control circuit when the system was returned to service following the maintenance.

Description. On December 9, 2008, while Unit 3 was in Mode 4, maintenance personnel performed motor operated valve testing on turbine inlet steam trip and throttle Valve 3HV4716 per Maintenance Order 800077149. Maintenance personnel were instructed by the maintenance order to remove Fuses 3MS4716-FU3 and 3MS4716-FU4, located in the governor control circuitry, to establish conditions necessary to perform the maintenance. Following completion of the valve testing, the maintenance order instructed the maintenance personnel to reinstall Fuses 3MS4716-FU3 and 3MS4716-FU4 in preparations for returning auxiliary feedwater Pump P140 to service to support Mode 3 entry. The unit entered Mode 3 at 2214 hours on December 9, and reached 800 psia steam pressure at 0304 hours on December 10. Technical

Specification 3.7.5 requires performance of the inservice test for Pump P140 within 72 hours of reaching 800 psia steam pressure to confirm operability. During the inservice test, Valve 3HV4716 failed to close as designed upon a manual trip of Pump P140. Troubleshooting identified that the valve stem for Valve 3HV4716 was bent, mechanically preventing the valve from closing. The bent valve stem was replaced, and on December 12, the inservice test was completed satisfactorily to return Pump P140 to service. Plant startup continued and at 1026 hours on December 17, the unit entered Mode 1.

On December 19, at 1651 hours and approximately 65 percent reactor power, the "Turbine AFW pump governor over-speed alarm" annunciated in the control room. Pump P140 was declared inoperable and troubleshooting identified electrical discontinuity across the circuit associated with governor control power Fuse 3MS4716-FU3. Further investigation identified that the one of the clips for the fuse holder for Fuse 3MS4716-FU3 was deformed, in that, the fuse holder did not fully engage and securely hold the fuse as required by design. This configuration resulted in intermittent continuity so that the control system functioned properly during the inservice testing performed on December 10 and December 12, 2008, but may not have been capable of performing its required design function under all design basis accident conditions.

The apparent cause evaluation that was performed to determine the cause of the failure identified that the plastic deformation in the fuse clip holder resulted from an inappropriate maintenance activity. Specifically, maintenance personnel failed to follow the instructions of Maintenance Order 800077149 to remove Fuse 3MS4716-FU3 when establishing conditions to perform the valve testing on December 9, 2008. Instead of removing the fuse entirely from the fuse holder, maintenance personnel only removed one side of the fuse and left the other side inserted. This inappropriate maintenance practice caused plastic deformation on the associated side of the fuse holder. Consequently, when Fuse MS4716-FU3 was inserted following the completion of the valve testing, the fuse holder did not fully engage and securely hold the fuse as required by design.

<u>Analysis</u>. The failure to follow maintenance instructions while performing valve testing on the auxiliary feedwater system was the performance deficiency. The finding is greater than minor because it is associated with the configuration control attribute of the Mitigating Systems Cornerstone and affects the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

The inspectors evaluated the issue using the Significance Determination Process (SDP) Phase 1 Screening Worksheet for the Initiating Events, Mitigating Systems, and Barriers Cornerstones provided in Manual Chapter 0609, Attachment 4, "Phase 1 – Initial Screening and Characterization of Findings." The inspectors determined that this finding represented a loss of the system safety function for the ability to provide secondary heat removal during a station blackout. This required that a Phase 2 estimation be completed.

The inspectors performed a Phase 2 estimation in accordance with NRC Inspection Manual Chapter 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations." The inspectors assumed that the performance deficiency affected the risk of operating the plant from December 9 at 2214 hours when operability was required until December 20 at 0228 hours when the condition was identified, corrected and the pump was restored to a functional status. As a result, in accordance with Appendix A, Attachment 1, Step 2.1.2 “Determine the Appropriate Exposure Time,” the team selected an exposure period (EXP) of 3 - 30 days. Using the Risk-Informed Inspection Notebook for San Onofre Nuclear Generating Stations (SONGS) Units 2 and 3, Revision 2.1a, the inspectors selected “TDP of AFW fails (P-140),” as the appropriate target for the subject finding in the presolved table. The inspectors utilized the presolved table to determine that the finding was Yellow and that core damage frequency was the dominant contributor. Therefore, no large-early release frequency analysis was required.

Because the Phase 2 assumptions significantly overestimated the risk related to this finding, the senior reactor analyst conducted a Phase 3 evaluation to provide a best-estimate risk assessment.

The analyst evaluated the risk related to the unavailability of the turbine-driven pump in the following three different risk profiles:

1. Risk with the reactor in Mode 3 from December 9 through December 15;

2. Risk with the reactor in Mode 2 from December 15 at 1330 hours to December 17 at 1026 hours; and

3. Risk with the reactor in Mode 1 from December 17 at 1026 hours until December 20 at 0228 hours.

<u>Risk in Mode 3</u>:

The analyst noted that the performance deficiency occurred during an approximately 60 day outage. Using data from the Final Safety Analysis Report and estimation techniques from the Response Technical Manual, Volume 1, Revision 5, the analyst estimated the decay heat being produced by the Unit 3 core following a 60-day decay and replacement of approximately 1/3 of the fuel. The analyst estimated, given nominal steam generator water inventories in Mode 3, that there was sufficient water in the steam generators to cool the reactor for 35.5 hours without feedwater. During this time, the licensee could have recovered offsite power (1.167×10^{-2}), one of the diesel generators (2.482×10^{-2}), and/or repaired the turbine-driven pump. Therefore, the analyst estimated that the change in core damage frequency (ΔCDF) from the subject finding over the 6 days with the reactor in Mode 2, was 1.0×10^{-11}.

<u>Risk in Mode 2</u>:

Using similar methods to those used in evaluating the risk in Mode 3 the analyst estimated the decay heat following a scram in Mode 2, assuming that the core had reached steady state at 5% thermal power. The analyst estimated, given nominal steam generator water inventories at hot zero power, that there was sufficient water in the steam generators to cool the reactor for 18.5 hours following a reactor trip without feedwater. During this time, the licensee could have recovered offsite power (2.405×10^{-2}), one of the diesel generators (1.029×10^{-1}), and/or repaired the turbine-driven pump. Therefore, the analyst estimated that the ΔCDF from the subject finding over the 45 hours with the reactor in Mode 2 was 3.9×10^{-11}.

Risk in Mode 1:

As a bounding case, the analyst used the site-specific Standardized Plant Analysis Risk (SPAR) model for San Onofre, Revision 3.45 to assess the change in risk from the subject finding during the 54.5 hours that the reactor was at power. The analyst set the basic event AFW-TDP-FS-140, “AFW TDP P140 Fails to Start,” to the house event TRUE, indicating that the pump would always fail to start. Quantifying the model provided a ΔCDF of 3.81×10^{-5} over a 1-year period. Therefore, the ΔCDF over the 64 hour period that the finding existed with the reactor at power was 2.9×10^{-7}.

Internal Events Summary:

Because each of the risk profiles evaluated were specifically selected to be independent, the total ΔCDF can be calculated by adding the results from each profile. The analyst calculated that the total ΔCDF was 2.9×10^{-7}.

External Initiators:

The plant-specific significance determination process worksheets for the San Onofre Nuclear Generating Station do not currently include initiating events related to fire, flooding, severe weather, seismic, or other external initiating events. In accordance with Manual Chapter 0609, Appendix A, Attachment 1, Step 2.1.5, "Screen for the Potential Risk Contribution Due to External Initiating Events," experience with using the Site Specific Risk-Informed Inspection Notebooks has indicated that accounting for external initiators could result in increasing the risk significance attributed to an inspection finding by as much as one order of magnitude. The analyst determined that an evaluation of external risk would be required because the result of the Phase 3 indicated that the risk was greater than 1×10^{-7}.

Using the SONGS 2/3 Individual Plant Examination of External Events, dated December 1995, the analyst determined that the only external initiators with a potential to increase the ΔCDF were seismic events and internal fires. The analyst determined that the frequency of a fire in any risk-significant area in the plant was 2.85×10^{-1}. This would result in a probability of having a fire over any 64-hour period of 2.1×10^{-3}. Using a severity factor of 0.1 and a bounding nonsuppression probability of 0.1, this would mean that the probability of a fire that could grow to significantly damage plant equipment would be 2.1×10^{-5}. A qualitative assessment of the ten fire areas not screened by the licensee indicated a low likelihood that a fire would result in the loss of both trains of motor-driven auxiliary feedwater. The probability of having a fire that damages equipment and the stochastic failure of a train of auxiliary feedwater is approximately 2×10^{-7}. Given that specific fire areas would have automatic fire suppression, that not all fires would directly cause an initiator, and that not all fires would result in the loss of a train of auxiliary feedwater, the analyst determined that the ΔCDF caused by the impact of the subject performance deficiency on internal fire scenarios would be significantly less than 1.0×10^{-7}.

The analyst performed a seismic evaluation to determine the ΔCDF for the subject finding. Using the SPAR model, the analyst quantified the incremental conditional core damage probability for a seismically-induced loss of offsite power with a failure of the turbine-driven auxiliary feedwater pump as 3.63×10^{-4}. Using a spreadsheet to evaluate the ΔCDF for each of multiple bins from 0.03g to 7.0g spectral acceleration, the analyst determined that the total ΔCDF over the 11-day exposure period was 1.53×10^{-7}.

Large Early Release Frequency (LERF):

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, Step 2.2.6, "Screen for the Potential Risk Contribution Due To Large Early Release Frequency (LERF)," the analyst determined that the finding needed to be screened for its potential risk contribution to LERF using Manual Chapter 0609, Appendix H, “Containment Integrity Significance Determination Process,” because the estimated ΔCDF result provided a risk significance estimation of greater than 1×10^{-7}.

According to Appendix H, Section 4.1, the subject performance deficiency represented a Type A finding because the finding influenced the likelihood of accidents leading to core damage. As documented in Appendix H, Table 5.1, accident sequences that would lead to LERF for a pressurized water reactor with a large, dry containment were limited to intersystem loss of coolant accidents and steam generator tube ruptures. The analyst determined that approximately 0.26% of the total ΔCDF was from one of these initiators. Using Table 5.2, “Phase 2 Assessment Factors - Type A Findings at Full Power,” the analyst selected a LERF factor of 1.0 for these sequences. The sum of the LERF Score as stated in Step 3.2, “ΔLERF Significance Evaluation,” was then quantified. The change in LERF was estimated to be 1.2×10^{-9}.

Results:

Because each of the risk profiles evaluated were specifically selected to be independent, the total ΔCDF can be calculated by adding the results from each profile. The analyst calculated that the total internal ΔCDF was 2.9×10^{-7}. The external ΔCDF, dominated by the impact on seismic events, was 1.53×10^{-7}. This resulted in a total ΔCDF of 4.4×10^{-7}. The change in LERF was estimated to be 1.2×10^{-9}. Therefore, this finding is of very low risk significance (Green).

The finding has a crosscutting aspect in the area of human performance associated with work practices because maintenance personnel did not comply with expectations regarding procedural compliance to follow the procedure as written without deviating from its intent [H.4(b)].

Enforcement. 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures and Drawings,” requires that activities affecting quality shall be prescribed by instructions, procedures, or drawings and shall be accomplished in accordance with those instructions, procedures, and drawings. Maintenance Order 800077149 contained instructions to perform motor operated valve testing on turbine inlet steam trip and throttle Valve 3HV4716 associated with the auxiliary feedwater system. Contrary to the above, on December 9, 2008, maintenance personnel failed to properly implement Maintenance Order 800077149 to remove Fuses 3MS4716-FU3 and 3MS4716-FU4, located in the governor control circuitry, to establish conditions necessary to perform the maintenance. Specifically, maintenance personnel failed to follow the maintenance order instructions to remove Fuse 3MS4716-FU3. Instead of removing the fuse entirely from the fuse holder, maintenance personnel only removed one side of the fuse and left the other side inserted. This inappropriate maintenance practice caused plastic deformation on the associated side of the fuse holder, which impacted the design configuration of the auxiliary feedwater control system, and its ability to perform its required design function under all design basis accident conditions. Because the finding is of very low safety significance and has been entered into the corrective action program as Nuclear Notification 200253911, this violation is being treated as a non-cited violation, consistent with Section VI.A of the Enforcement Policy: NCV

05000362/2009002-01, “Failure to Follow Procedures when Performing Maintenance on the Auxiliary Feedwater System.”

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

a. Inspection Scope

The inspectors reviewed licensee personnel's evaluation and management of plant risk for the maintenance and emergent work activities affecting risk-significant and safety-related equipment listed below to verify that the appropriate risk assessments were performed prior to removing equipment for work:

- January 21 - 22, 2009, Unit 2, voluntary entry into Technical Specification 3.4.8 with reactor coolant system loops not filled to repair a component cooling water heat exchanger tube leak

- January 29 through February 4, 2009, Unit 2, control element Assembly 22 extension shaft inspection

- February 6, 2009, Unit 2, Train A emergency diesel generator fuel oil Tank T-035 inspection and governor replacement

- February 25, 2009, Unit 2, component cooling water supply Valve 2HV6293 to letdown heat exchanger troubleshooting

- February 25, 2009, Unit 2, reactivity management of charging Pump P191 start with boric acid trapped in suction line

The inspectors selected these activities based on potential risk significance relative to the reactor safety cornerstones. As applicable for each activity, the inspectors verified that licensee personnel performed risk assessments as required by 10 CFR 50.65(a)(4) and that the assessments were accurate and complete. When licensee personnel performed emergent work, the inspectors verified that the licensee personnel promptly assessed and managed plant risk. The inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst or shift technical advisor, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed the technical specification requirements and inspected portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of five maintenance risk assessments and emergent work control inspection samples as defined by Inspection Procedure 71111.13-05.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the following issues:

- January 7, 2009, Unit 3, emergency diesel Generator 3G002 exhaust system heat shield

- January 21, 2009, Unit 2, degrading heat exchanger tube leakage in component cooling water Train B

- February 9, 2009, Unit 3, high pressure safety injection check Valve S31204MU020 leakage

- February 19, 2009, Unit 2, auxiliary feedwater isolation Valve HV4712 engineering safeguard features system subgroup Relay K723B low voltage

The inspectors selected these potential operability issues based on the risk-significance of the associated components and systems. The inspectors evaluated the technical adequacy of the evaluations to ensure that technical specification operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the technical specifications and Updated Safety Analysis Report to the licensee's evaluations, to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors also reviewed a sampling of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of four operability evaluations inspection samples as defined in Inspection Procedure 71111.15-05.

b. Findings

Introduction. The inspectors identified a Green non-cited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," for the failure of operations and engineering personnel to follow procedures and adequately evaluate degraded conditions to support operability decision-making.

Description. On January 21, 2009, the inspectors became aware of a degrading condition associated with a tube leak in component cooling water heat Exchanger E002. The inspectors observed a meeting where engineering personnel expressed concerns to licensee management that the rate of tube degradation had increased, and had degraded to a leak rate of approximately 2 gallons per minute. The concern expressed to licensee management was associated with the potential risk of losing a train of shutdown cooling during an upcoming high-risk activity when the reactor would be at reduced inventory. A loss of shutdown cooling could occur if the component cooling water heat exchanger continued to degrade to an inoperable condition. The inspectors questioned operations personnel about the heat exchanger condition and learned that it had been identified months earlier, and was considered operable as determined by an immediate operability determination performed at the time of discovery. Further, the inspectors asked if a prompt operability determination had been performed to evaluate the potential operability impact of the identified leakage, and whether the leakage impacted the ability of the heat exchanger to perform its safety function for the required mission time. The inspectors observed that no prompt operability determination had been performed. The inspectors also determined that the original immediate operability determination had not been reviewed to ensure that a continued basis for operability existed with the changing tube leak rate trend.

The inspectors reviewed the degraded condition as documented in the nuclear notifications and on plant computer historical trends. The inspectors observed that operations personnel identified a tube leak in component cooling water heat Exchanger E002 on October 26, 2008, at a rate of approximately 0.047 gallons per minute. Operations personnel initiated Nuclear Notification 200198219 on October 30, 2008, and performed an immediate operability determination. The operability determination concluded that the heat exchanger was operable only because the leakage was well below the component cooling water emergency makeup pump ability of 18 gallons per minute. Operations personnel were required to fill the component cooling water surge tank on a weekly basis to make up for inventory losses. Procedure SO123-XV-52, "Functionality Assessments and Operability Determinations," Revision 9, Section 6.5, provided instructions for performing an immediate operability determination. The inspectors determined that the operability determination documented in Nuclear Notification 200198219 was inadequate since it did not include all of the information required by Procedure SO123-XV-52, Step 6.5.1. For example, the mission time in which the heat exchanger must perform the pertinent safety function was not identified. The immediate operability determination failed to evaluate the impact of the leak rate, and any adverse trends identified, on the ability of the heat exchanger to perform its safety function over the required mission time. Additionally, operations personnel did not initiate a prompt operability determination even though conditions described in Procedure SO123-XV-52, Step 6.5.2, were satisfied. Instead, requests for further engineering review were performed outside of the operability determination process. The supporting engineering evaluations concluded that the heat exchanger tube leak rate should be limited to 4 gallons per minute due to the allowable tube stress limits. However, operations personnel failed to consider the engineering recommendations and continued with the basis for operability documented in the original immediate operability determination associated with Nuclear Notification 200198219.

On November 10, 2008, engineering personnel observed that the heat exchanger tube leakage was at 0.2 gallons per minute and initiated Nuclear Notification 200210214. Operations personnel completed another immediate operability determination which was essentially identical to the determination documented in Nuclear Notification 200198219. The adverse trend in the tube leak rate was not recognized as a condition that could challenge the ability of the heat exchanger to perform its safety function for the required mission time. Instead, operations personnel continued to manage the degrading condition by increasing the frequency of making up to the component cooling water surge tank. On December 16, 2008, engineering personnel noted in an engineering support document associated with Nuclear Notification 200198219 that the tube leak continued to degrade to a rate of 0.432 gallons per minute, and reiterated the recommendation of a 4 gallon per minute operability limit. Operations personnel failed to reassess operability as required by Procedure SO123-XV-52, and continued to rely on the original immediate operability determination documented in Nuclear Notifications 200198219 and 200210214, despite the changing conditions.

On December 28, 2008, the unit was shutdown for a planned mid-cycle outage. The component cooling water heat exchanger leak rate had increased to approximately 0.66 gallons per minute at the time of the unit shutdown. The heat exchanger tube leak continued to degrade at an increasing rate until it was removed from service for corrective maintenance. The inspectors noted that the tube leak rate had degraded to approximately 2 gallons per minute and that operations personnel had continued to manage the degrading condition by making up to the surge tank at a frequency of four times per day. However, the increasing rate of degradation was not recognized as a condition that could impact the ability of the heat exchanger to perform its safety function for the required mission time. On January 22, 2009, four leaking tubes on component cooling water heat Exchanger E002 were plugged per Maintenance Order 800194368.

Analysis. The failure to adequately evaluate the degraded conditions to support the operability determination was the performance deficiency. The finding is greater than minor because the degraded component cooling water heat exchanger is associated with the equipment performance 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 Worksheets, the finding is determined to have very low safety significance because the finding did not result in a loss of safety function of component cooling water Train B for greater than the technical specification allowed outage time. The finding has a crosscutting aspect in the area of human performance associated with decision-making because the licensee did not review past operability decisions to verify the validity of the underlying assumptions [H.1(b)].

Enforcement. 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures and Drawings,” requires that activities affecting quality shall be prescribed by instructions, procedures, or drawings and shall be accomplished in accordance with those instructions, procedures, and drawings. The assessment of operability of safety-related equipment needed to mitigate accidents was an activity affecting quality and was implemented by Procedure SO123-XV-52, “Functionality Assessments and Operability Determinations,” Revision 9. Procedure SO123-XV-52, Step 1.0, stated that the objective of the procedure is to provide guidelines and instructions for evaluating the operability of a structure, system, or component when a degraded, nonconforming, or unanalyzed condition is identified. Contrary to the above, between October 26, 2008, and January 22, 2009, operations and engineering personnel failed to follow the operability determination process to adequately evaluate the operability of a degraded component cooling water heat exchanger. Specifically, operations and engineering personnel failed to adequately evaluate the operability of the Unit 2 component cooling water system Train B, when a tube leak was identified, and subsequently, when the leak exhibited a degrading trend. Because the finding is of very low safety significance and has been entered into the licensee’s corrective action program as Nuclear Notification 200289984, this violation is being treated as a non-cited violation, consistent with Section VI.A of the Enforcement Policy: NCV 05000361/2009002-02, “Failure to Properly Implement the Operability Determination Process.”

1R18 Plant Modifications (71111.18)

a. Inspection Scope

The inspectors reviewed the following temporary modification to verify that the safety functions of important safety systems were not degraded:

- March 17, 2009, Unit 2, temporary scaffold constructed near emergency diesel Generator 2G003 in preparation for planned maintenance

The inspectors reviewed the temporary modification and the associated safety evaluation screening against the system design bases documentation, including the Updated Final Safety Analysis Report and the technical specifications, and verified that the modification did not adversely affect the system operability/availability. The inspectors also verified that the installation and restoration was consistent with the modification documents and that configuration control was adequate. Additionally, the inspectors verified that the temporary modification was identified on control room drawings, appropriate tags were placed on the affected equipment, and licensee personnel evaluated the combined effects on mitigating systems and the integrity of radiological barriers.

These activities constitute completion of one sample for temporary plant modifications as defined in Inspection Procedure 71111.18-05.

b. Findings

Introduction. The inspectors identified a Green non-cited violation of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” for the failure of maintenance personnel to properly install and inspect scaffolding in safety-related areas in accordance with written procedural requirements. Four instances were found where the minimum separation distance between a scaffold and safety-related components was less than the minimum allowed by procedure and an approved engineering evaluation to justify the deviation was not performed.

Description. On March 17, 2009, the inspectors identified a scaffold approximately 0.75 inches from a fuel oil filter for emergency diesel Generator 2G003. The inspectors contacted the licensee who immediately moved the scaffold further away from the filter. Procedure SO123-I-1.34, “Scaffolding Erection,” Revision 24, Step 6.6.3.2, required a minimum separation distance of one inch from safety-related equipment or an approved engineering evaluation to document the acceptance of less than one inch. The scaffold near the fuel oil filter did not have an approved engineering evaluation to accept the as-found condition.

The licensee entered this issue into their corrective action program as Nuclear Notification 200356209 and moved the scaffold to comply with the minimum separation distance. Engineering personnel reviewed the as-found condition and determined that a minimum distance of approximately 0.30 inches was sufficient to ensure that the scaffold did not contact the engine during a seismic event. Additionally, the licensee performed a site-wide walkdown of all scaffolds.

On March 18, 2009, operations personnel identified an additional scaffold that did not meet the minimum separation distance erected near the fan housing for the Train A control room emergency air cleanup system supply Fan SA1510MA207. The scaffold was in direct contact with the filter housing. Operations personnel entered a 14-day technical specification action statement until the scaffold was moved at least one inch away from the housing. The licensee entered this deficiency in their corrective action program as Nuclear Notification 200357777. The licensee completed all scaffold walkdowns the following day and did not identify any other scaffolds that failed to meet the minimum separation criterion of one inch.

On March 20, 2009, the inspectors performed a plant walkdown to inspect scaffolds in safety-related areas. The inspectors identified a scaffold near the Unit 3 Train A low pressure safety injection Pump 3P015, that was attached to a nearby handrail. The handrail was less than one inch from the insulation for the pump suction Valve 3MU022. The inspectors considered the handrail to be an integral part of the scaffold and requested a copy of the evaluation that approved the deviation.

The licensee declared Pump 3P015 inoperable until engineering completed an evaluation of the handrail and entered the question into the corrective action program as Nuclear Notification 200361562. The subsequent evaluation determined that there was no loss of functionality and the licensee declared Pump 3P015 operable approximately three hours later. The inspectors learned that the scaffold had been inspected several times by engineering because it was considered permanent. In each instance, personnel failed to recognize the handrail interface and failed to identify and document an evaluation of the potentially increased loading that the scaffold could place on the handrail.

On March 25, 2009, the inspectors identified a scaffold in proximity to the Unit 2 Train A component cooling water heat exchanger end bell. The scaffold had been assembled and accepted on March 23, 2009. However, the inspectors determined it was less than 0.50 inches from the end bell in at least two different locations, and engineering had not approved the procedural deviation. Once identified, the licensee modified the scaffold to comply with the one inch minimum separation requirement and entered this issue into their corrective action program as Nuclear Notification 200367043.

<u>Analysis</u>. The failure to properly install and inspect scaffolding in safety-related areas was contrary to written procedural requirements and was the performance deficiency. The finding is greater than minor because if left uncorrected, it would have the potential to lead to a more significant safety concern. The inspectors concluded this finding was associated with the Mitigation Systems Cornerstone. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheets, the finding is determined to have very low safety significance because the finding did not affect both trains of any single mitigating system or represent an actual loss of a safety function. This finding has a crosscutting aspect in the area of human performance associated with work practices because the licensee did not utilize appropriate human performance techniques to ensure that scaffold construction was performed safely [H.4(a)].

<u>Enforcement</u>. 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Procedure SO123-I-1.34, "Scaffolding Erection," Revision 24, Step 6.6.3.2, required a minimum separation distance of one inch from safety-related equipment or an approved engineering evaluation to document the acceptance of less than one inch. Contrary to the above, on March 17, 2009, the maintenance personnel failed to ensure that scaffold was constructed in accordance with documented

procedures. Specifically, four scaffolds built within one inch of safety-related components did not have approved engineering evaluations to justify the deviation. Because this violation was of very low safety significance and it was entered into the licensee's corrective action program as Nuclear Notification 200356209, this violation is being treated as a non-cited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000361; 05000362/2009002-03, "Failure to Properly Inspect Scaffolding in Safety-Related Areas."

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed the following postmaintenance activities to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- January 14, 2009, Unit 3, component cooling water Pump 3MP1019 post maintenance test following alignment adjustments

- February 4, 2009, Unit 2, main steam Train B atmosphere dump Valve HV-8421 return to service following positioner calibration

- February 12, 2009, Unit 2, emergency diesel Generator 2G002 retest following maintenance and governor replacement

- February 12, 2009, Unit 2, control element Assembly CEA-22 testing following replacement of control element drive motor

- February 18, 2009, Unit 2, steam driven auxiliary feedwater inlet Valve 2HV4716 post maintenance testing

The inspectors selected these activities based upon the structure, system, or component's ability to affect risk. The inspectors evaluated these activities for the following (as applicable):

- The effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed

- Acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate

The inspectors evaluated the activities against the technical specifications, the Updated Final Safety Analysis Report, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed corrective action documents associated with postmaintenance tests to determine whether the licensee was identifying problems and entering them in the corrective action program and that the problems were being corrected commensurate with their importance to safety. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of five postmaintenance testing inspection samples as defined in Inspection Procedure 71111.19-05.

b. Findings

Introduction. The inspectors identified a Green non-cited violation of Technical Specification 5.5.1.1 for the failure of operations personnel to follow procedures for performing reactivity manipulations.

Description. On February 12, 2009, the inspectors observed pre-job briefings associated with the postmaintenance testing per Maintenance Order 800248033 following replacement of control element drive mechanism for control element Assembly 22. Following the pre-job brief, operations and maintenance personnel commenced preparations to perform the postmaintenance testing. The inspectors observed that the postmaintenance test plan lacked formality, in that, the engineering test plan consisted of a copy of an email from an engineer not present, was labeled as draft, and lacked procedure steps to appropriately control the control element assembly manipulations by a licensed operator. The inspectors also noted that there was no reference to the proposed test plan in the retest section of Maintenance Order 800248033.

The engineering test plan described the functional testing, which involved control element assembly manipulations. The proposed control element assembly manipulations met the definition of a reactivity manipulation defined in Procedure SO123-0-A1, "Conduct of Operations," Revision 16, Attachment 5. Procedure SO123-0-A1, Step 6.5.4, stated that all planned reactivity affecting activities defined in Attachment 5 will be conducted using a procedure in hand. Based on the inspectors' observations of the pre-job brief, review of the informal test plan, discussions with operations personnel, and review of the associated work control documents, it was not clear how the control element assembly manipulations would be procedurally controlled. Subsequently, the inspectors questioned the operations shift manager regarding the lack of formality for the associated planned reactivity manipulations. The shift manager agreed with the inspectors' observations, stopped work, and notified work control management that the work control plan needed to be revised to conform to the requirements defined in Procedure SO123-XX-5, "Work Clearance Application / Work Clearance Document / Work Authorization Record," Revision 22. Operations personnel identified that no formal procedures existed to perform the control element assembly manipulations as described in the test plan. Consequently, operations personnel completed a procedural modification to Procedure SO23-3-2.19.2, "Control Element Assembly Exercise and Troubleshooting," Revision 1, to enable the performance of the reactivity manipulations under the direct control of a licensed operator as required by Procedure SO123-0-A1. Following the development of an approved, formal plan, which was incorporated into the work control documents, the inspectors observed satisfactory completion of postmaintenance test activity.

Based on the observations on February 12, 2009, the inspectors questioned how a similar evolution, involving control element assembly manipulations, was performed on January 7, 2009. The inspectors were concerned since it was identified during the observations on February 12 that no formal procedures existed to perform similar control element assembly manipulations as required by Procedure SO123-0-A1. The licensee initiated Nuclear Notification 200339686 and performed Direct Cause Evaluation 800260446 to review the issue. The evaluation identified that operations personnel failed to adequately implement Procedure SO23-3-2.19.2, "CEA Exercise and Troubleshooting," in that, although a procedure modification had been made to the procedure, it was still inaccurate and incomplete. The procedure modification was deficient since it failed to recognize that the proposed evolution was an activity that affected reactivity management and consequently provided inaccurate and incomplete guidance to appropriately control the evolution. Because of the inaccurate and incomplete procedure modification, an adequate procedure was not in hand to perform reactivity manipulations as required by Procedure SO123-0-A1, Step 6.5.4.

Analysis. The failure to follow procedures for performing reactivity manipulations was the performance deficiency. The finding is greater than minor because it is associated with procedure quality attribute of the Initiating Events Cornerstone and affects the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Using 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, degrade the ability to terminate a leak path, or degrade the ability to recover decay heat removal. This finding has crosscutting aspect in the area human performance associated with work control because the licensee did not appropriately plan a work activity [H.3.(a)].

Enforcement. Technical Specification 5.5.1.1 requires, in part, that written procedures be established, implemented, and maintained covering the activities specified in 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. Appendix A, Item 3.u, requires procedures for operation of reactor control systems. Procedures SO123-O-A1, “Conduct of Operations” and SO23-3-2.19.2, “Control Element Assembly Exercise and Troubleshooting”, provided instructions for planned reactivity affecting activities. Contrary to the above, on January 7, 2009, a procedure modification performed to Procedure SO23-3-2.19.2, “Control Element Assembly Exercise and Troubleshooting,” was inaccurate and incomplete to appropriately control reactivity manipulations, and thus, an adequate procedure was not in hand as required by Procedure SO123-O-A1, “Conduct of Operations,” to operate the reactor control system. Because the finding is of very low safety significance, and has been entered into the licensee’s corrective action program as Nuclear Notification 200339686, this violation is being treated as a non-cited violation, consistent with Section VI.A of the Enforcement Policy: NCV 05000361/2009002-04, “Inadequate Procedure for Reactivity Manipulations.”

1R20 Refueling and Other Outage Activities (71111.20)

a. Inspection Scope

The inspectors reviewed the outage safety plan and contingency plans for the Unit 2 mid-cycle outage which began on December 28, 2008 through February 17, 2009, to confirm that licensee personnel had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. During the refueling outage, the inspectors observed portions of the shutdown and cooldown processes and monitored licensee controls over the outage activities listed below.

- Configuration management, including maintenance of defense-in-depth, is commensurate with the outage safety plan for key safety functions and compliance with the applicable technical specifications when taking equipment out of service.

- Clearance activities, including confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing.
- Installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication, accounting for instrument error.
- Status and configuration of electrical systems to ensure that technical specifications and outage safety-plan requirements were met, and controls over switchyard activities.
- Monitoring of decay heat removal processes, systems, and components.
- Reactor water inventory controls, including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss.
- Controls over activities that could affect reactivity.
- Maintenance of secondary containment as required by the technical specifications.
- Startup and ascension to full power operation, tracking of startup prerequisites, walkdown of the drywell (primary containment) to verify that debris had not been left which could block emergency core cooling system suction strainers, and reactor physics testing.
- Licensee identification and resolution of problems related to refueling outage activities.

Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one refueling outage and other outage inspection sample as defined in Inspection Procedure 71111.20-05.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the Updated Final Safety Analysis Report, procedure requirements, and technical specifications to ensure that the four surveillance activities listed below demonstrated that the systems, structures, and/or components tested were capable of performing their intended safety functions. The inspectors either witnessed or reviewed test data to verify that the significant surveillance test attributes were adequate to address the following:

- Preconditioning
- Evaluation of testing impact on the plant
- Acceptance criteria

- Test equipment
- Procedures
- Jumper/lifted lead controls
- Test data
- Testing frequency and method demonstrated technical specification operability
- Test equipment removal
- Restoration of plant systems
- Fulfillment of ASME Code requirements
- Updating of performance indicator data
- Engineering evaluations, root causes, and bases for returning tested systems, structures, and components not meeting the test acceptance criteria were correct
- Reference setting data
- Annunciators and alarms setpoints.

The inspectors also verified that licensee personnel identified and implemented any needed corrective actions associated with the surveillance testing.

- January 28, 2009, Unit 3, in-service testing per Procedure SO23-3-3.60.6, "Auxiliary Feedwater Pump and Valve Testing," Revision 15
- February 12, 2009, Unit 3, excore Channel D log power potentiometer replacement
- February 17, 2009, Unit 2, turbine driven auxiliary feedwater Pump 2P140 operational test following plant startup
- March 23, 2009, Unit 3, boric acid makeup Pump P175 quarterly surveillance test

Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of four surveillance testing inspection samples as defined in Inspection Procedure 71111.22-05.

b. <u>Findings</u>

No findings of significance were identified.

Cornerstone: Emergency Preparedness

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

a. Inspection Scope

The inspector performed an in-office review of Revision 22 to Section 6, "Emergency Measures," of the San Onofre Nuclear Generation Station Emergency Plan, received February 24, 2009. This revision provides authority for the Emergency Coordinator to modify protective action recommendations based on known hazardous offsite conditions, and divided the emergency planning zone into five protective action zones used to implement protective action strategies for the public.

This revision was compared to its previous revision, 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, and to the standards in 10 CFR 50.47(b) to determine if the revision adequately implemented the requirements of 10 CFR 50.54(q). This review was not documented in a safety evaluation report and did not constitute approval of licensee-generated changes; therefore, this revision is subject to future inspection. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one sample as defined in Inspection Procedure 71114.04-05.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine licensee emergency drill on March 17, 2009, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the simulator control room, the Emergency Operating Facility, the Technical Support Center, and Operation Support Center to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the licensee drill critique to compare any inspector-observed weakness with those identified by the licensee staff in order to evaluate the critique and to verify whether the licensee staff was properly identifying weaknesses and entering them into the corrective action program. As part of the inspection, the inspectors reviewed the drill package and other documents listed in the attachment.

These activities constitute completion of one sample as defined in Inspection Procedure 71114.06-05.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Data Submission Issue

a. Inspection Scope

The inspectors performed a review of the data submitted by the licensee for the 4^{th} Quarter 2008 performance indicators for any obvious inconsistencies prior to its public release in accordance with Inspection Manual Chapter 0608, “Performance Indicator Program.”

This review was performed as part of the inspectors’ normal plant status activities and, as such, did not constitute a separate inspection sample.

b. Findings

No findings of significance were identified.

.2 Unplanned Scrams per 7000 Critical Hours

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Scrams per 7000 Critical Hours performance indicator for Units 2 and 3 for the period from the second quarter 2008 through the fourth quarter 2008. To determine the accuracy of the performance indicator data reported during those periods, performance indicator definitions and guidance contained in NEI Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 5, was used. The inspectors reviewed the licensee’s operator narrative logs, issue reports, event reports and NRC Inspection reports for the period of March 25, 2008 through December 31, 2008 to validate the accuracy of the submittals. The inspectors also reviewed the licensee’s issue report database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. Specific documents reviewed are described in the attachment to this report.

These activities constitute completion of two unplanned scrams per 7000 critical hours samples as defined by Inspection Procedure 71151-05.

b. Findings

No findings of significance were identified.

.3 Unplanned Scrams with Complications

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Scrams with Complications performance indicator for Units 2 and 3 for the period from the second quarter 2008 through the fourth quarter 2008. To determine the accuracy of the performance indicator data reported during those periods, performance indicator definitions and guidance contained in NEI Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 5, was used. The inspectors reviewed the licensee’s operator narrative logs, issue reports, event reports and NRC integrated inspection reports for the period of March 25, 2008 through December 31, 2008 to validate the accuracy of the submittals. The inspectors also reviewed the licensee’s issue report database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. Specific documents reviewed are described in the attachment to this report.

These activities constitute completion of two unplanned scrams with complications samples as defined by Inspection Procedure 71151-05.

b. Findings

No findings of significance were identified.

.4 Unplanned Transients per 7000 Critical Hours

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Transients per 7000 Critical Hours performance indicator Units 2 and 3 for the period from the second quarter 2008 through the fourth quarter 2008. To determine the accuracy of the performance indicator data reported during those periods, performance indicator definitions and guidance contained in NEI Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 5, was used. The inspectors reviewed the licensee’s operator narrative logs, issue reports, maintenance rule records, event reports and NRC Integrated Inspection reports for the period of March 25, 2008 through December 31, 2008 to validate the accuracy of the submittals. The inspectors also reviewed the licensee’s issue report database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. Specific documents reviewed are described in the attachment to this report.

These activities constitute completion of two unplanned transients per 7000 critical hours samples as defined by Inspection Procedure 71151-05.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Physical Protection

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As part of the various baseline inspection procedures discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee’s corrective action program at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. The inspectors reviewed attributes that included: the complete and accurate identification of the problem; the timely correction, commensurate with the safety significance; the evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent of condition reviews, and previous occurrences reviews; and the classification, prioritization, focus, and timeliness of corrective. Minor issues entered into the licensee's corrective action program because of the inspectors' observations are included in the attached list of documents reviewed.

These routine reviews for the identification and resolution of problems did not constitute any additional inspection samples. Instead, by procedure, they were considered an integral part of the inspections performed during the quarter and documented in Section 1 of this report.

b. Findings

No findings of significance were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

In order to assist with the identification of repetitive equipment failures and specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's corrective action program. The inspectors accomplished this through review of the station's daily corrective action documents.

The inspectors performed these daily reviews as part of their daily plant status monitoring activities and, as such, did not constitute any separate inspection samples.

b. Findings

No findings of significance were identified.

.3 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a semi-annual review of the licensee's corrective action program and selected documentation to identify potential trends that might indicate the existence of a more significant safety issue. The inspectors conducted a review of the timely performance of technical specification required surveillances since an increase in the number of missed or overdue surveillances was noted since January 2008.

Inspectors also verified that minor issues identified during this inspection were entered into the licensee's corrective action program. The screening was by grouping the notifications associated with missed or late surveillances. These groups included items involving the same issue, same equipment/components, or the same program. For the period of review, the inspectors also obtained lists of all completed or ongoing licensee common cause investigations and all notifications where the title indicated a missed or overdue surveillance.

These activities constitute completion of one semi-annual trend review inspection sample as defined in Inspection Procedure 71152-05.

b. Assessment and Observations

The inspectors reviewed Apparent Cause Evaluation 080101726 which evaluated a deficiency identified on January 29, 2008, associated with tracking and scheduling of surveillances for loss of voltage signal relays as required by Technical Specification Surveillance Requirement 3.8.1.18. The evaluation determined that, in 2004, maintenance work planning made a fundamental change in the way they performed business, however, the transition plan for performing technical specification surveillances on-line did not have the formality and rigor necessary to ensure success. Further, the transition plan did not receive adequate review by personnel cognizant of surveillance scheduling prior to implementation. Consequently, on January 29, 2008, work control personnel discovered that surveillance testing of the loss of voltage signal relays was not properly completed in accordance with technical specification surveillance requirement. As a result of the inadequate scheduling, several surveillance tests, since March 24, 2006, exceeded the required technical specification test interval. This failure to meet technical specification requirements was reported to the NRC on March 28, 2008, in Licensee Event Report 2006-004, "Late Surveillances on Loss of Voltage Relays Results in SR 3.0.4 Violation."

Prior to July 2008, licensee personnel developed a transition plan to support a company wide change to the integrated Enterprise Resource Planning software program. This transition plan needed to manage the change since it impacted all data management aspects of San Onofre Nuclear Generating Station. On July 1, 2008, the licensee transitioned from the MOSAIC System, this was the tool for tracking work and corrective program issues, to the new Enterprise Resource Planning System. The new system significantly changed the process for scheduling technical specification surveillance testing.

Following the transition on July 1, 2008, the inspectors observed an increase in the nuclear notifications initiated for missed or overdue surveillances, including numerous technical specification required surveillances. Because of the observed increase, the inspectors performed a detailed review of the following surveillance issues to identify potential common causes.

- On July 15, 2008, maintenance personnel verified that all required technical specification surveillances were completed for Battery B00X, and subsequently, operations personnel placed Battery B00X in service to accommodate work on a 125Vdc Class 1E battery. Battery B00X was removed from service on July 17, 2008, following completion of the planned maintenance, and the system was restored to its normal alignment. On October 23, 2008, during a maintenance department audit of implementation of the surveillance program, it was discovered that required surveillance testing for Battery B00X had not been completed, and as a result, was inoperable when placed in service on July 15, 2008. The licensee initiated Root Cause Evaluation 800149188 to determine the cause of the error. The evaluation determined that maintenance personnel improperly tracked the completed quarterly surveillances and established incorrect scheduled due dates. Consequently, the required surveillance on Battery B00X should have been completed by June 10, 2008. However, due to the tracking and scheduling errors, the required surveillance was not completed until July 26, 2008, which was after the battery was placed in-service, and relied on for technical specification operability.

This violation of technical specifications was reported to the NRC on December 19, 2008, in Licensee Event Report 2008-008-00, “Missed Technical Specification Surveillance Requirement on Spare Station Battery B00X.” The most likely cause of the violation was identified as a failure of maintenance management to properly implement a transition plan during the change from MOSAIC to the Enterprise Resource Planning System for scheduling technical specification surveillances.

- On August 18, 2008, the required technical specification quarterly battery surveillance was missed for Battery 3B007. The missed surveillance was identified by maintenance personnel while performing a maintenance department audit on August 27, 2008. Following discovery of the missed surveillance for Battery 3B007, operations personnel entered Surveillance Requirement 3.0.3, and satisfactorily performed the required testing. The missed surveillance on Battery 3B007 was also evaluated as part of Root Cause Evaluation 800149188. The evaluation identified that cause for the missed surveillance was a failure of maintenance management to properly implement a transition plan during the change from MOSAIC to the Enterprise Resource Planning System for tracking and scheduling technical specification surveillances.

- On September 8, 2008, a licensed operator discovered that saltwater cooling system pump Train B discharge valves had exceeded the technical specification surveillance interval. Following discovery of the missed surveillances for the saltwater cooling valves, operations personnel entered Surveillance Requirement 3.0.3, and satisfactorily performed the required testing. Apparent Cause Evaluation 800158284 identified that operations personnel did not adequately track and schedule technical specification required surveillances to ensure that they were performed at the required interval. The inspectors concluded that the inadequate tracking and scheduling of surveillances by operations personnel was not directly related to the transition to the Enterprise Resource Planning System.

- On December 1, 2008, maintenance personnel identified that the 31 day post-test battery inspection, required by Technical Specification 3.8.6.A.3, was missed for 125 Vdc Battery 3B010. Unit 3 entered Mode 4 from Mode 5 on November 30, 2008. Since the required test on Battery 3B010 was not completed by the due date of November 29, 2008, an inappropriate mode change was made, resulting in a violation of Technical Specification 3.0.4. This violation was reported to the NRC on January 30, 2009, in Licensee Event Report 2008-003-00, “Missed TS Completion Time Results in TS Violation.” Apparent Cause Evaluation 800207301 determined that there was no formal process to ensure that the 7 day and 31 day inspections are effectively tracked and performed within the established due dates. The inspectors concluded that the inadequate tracking and scheduling of the 7 day and 31 day inspections was not directly related to the transition to the Enterprise Resource Planning System.

The inspectors observed that the maintenance department had surveillance scheduling and tracking weaknesses prior to the Enterprise Resource Planning System change, and the failure of maintenance management to properly implement a transition plan further challenged performance in this area. This was evidenced by the increased number of late and missed surveillances following the implementation of the Enterprise Resource Planning System. Following discussions with the director of work control, Nuclear

Notification 200383302 was initiated to perform a review of overdue surveillance issues, and evaluate the current process for tracking and scheduling surveillance. The review identified that the current process was fragmented, in that the process was controlled by multiple individuals in different workgroups, following multiple processes. The inspectors observed that actions have been initiated to centralize the surveillance tracking and scheduling process to alleviate the potential for continue missed surveillances.

Since the change to the Enterprise Resource Planning System in July 2008, the inspectors continued to observe: (1) equipment tagging issues (described in NRC Inspection Report 05000361; 05000362/2008-005); (2) preventive maintenance tracking and scheduling issues; and (3) data migration weaknesses in engineering related programs. During this trend review, the inspectors noted numerous nuclear notifications and evaluations associated with inadequate implementation of the Enterprise Resource Planning System. The inspectors observed a lack of coordinated efforts to more effectively implement the change management process. The licensee observed similar issues and performed Root Cause Evaluation 800178186, which identified that the implementation of the Enterprise Resource Planning System had an adverse impact on station operations. This adverse impact was seen in various areas of station operations, including data migration, tagging, change management process, and reporting information. The evaluation attributed the cause to ineffective change management resulting from poor departmental communication and coordination. Corrective actions for change management have been incorporated into the licensee's initiatives to improve organizational performance at San Onofre Nuclear Generation Station. Performance deficiencies associated with the late and missed surveillances reviewed during this inspection will be addressed during the closure review of the applicable licensee event reports.

.4 Selected Issue Follow-up Inspection

a. Inspection Scope

During a review of items entered in the licensee's corrective action program, the inspectors recognized corrective action items documenting the issues listed below. The inspectors considered the following during the review of the licensee's actions: (1) complete and accurate identification of the problem in a timely manner; (2) evaluation and disposition of operability/reportability issues; (3) consideration of extent of condition, generic implications, common cause, and previous occurrences; (4) classification and prioritization of the resolution of the problem; (5) identification of root and contributing causes of the problem; (6) identification of corrective actions; and (7) completion of corrective actions in a timely manner.

- January 9, 2009, Units 2 and 3, identification and resolution adequacy of control room deficiencies described in Nuclear Notification 200286475

- January 14, 2009, Unit 2, reactor coolant Pump 2P001 vapor seal boric acid leakage impact to reactor coolant system integrity described in Nuclear Notification 200258836

These activities constitute completion of two in-depth problem identification and resolution samples as defined in Inspection Procedure 71152-05.

b. Findings

Introduction. The inspectors identified a Green non-cited violation of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” for the failure of engineering personnel to properly perform an evaluation of reactor coolant pump vapor seal flow diversion and boric acid accumulation caused by a clogged vapor seal drain line, in accordance with boric acid corrosion control program procedures.

Description. On June 1, 2008, following a forced Unit 2 shutdown to address an emergent switchyard equipment issue, engineering personnel implemented Procedure SO23-V-8.15, “Containment Boric Acid Leak Inspection,” Revision 2, and identified boric acid accumulation on top of the reactor coolant Pump 2MP001 seal. Engineering personnel concluded that excessive vapor seal flow was being diverted through the area between the shaft and the shaft seal assembly. It was further observed that the drain line for the shaft seal assembly was plugged, which allowed this diversion of vapor seal flow to occur to an undesired area. As documented in Action Request 080600017, a boric acid inspection template was initiated, as required by Procedure SO23-V-8.15. The boric acid inspection was performed per Procedure SO23-XV-85, “Boric Acid Corrosion Control Program,” Revision 3, and concluded that the undesired accumulation of boric acid was limited to the stainless steel area of the seal and did not constitute a valid boric acid leak. Further, engineering personnel determined that the boric acid accumulation was dry, white in color, and non-excessive, such that no further evaluation was required. A maintenance order was initiated to unclog the drain line during a future outage opportunity.

On December 28, 2008, following a plant shutdown for the mid-cycle Outage U2M15, engineering personnel performed a containment walkdown per Procedure SO23-V-8.15, and identified significant boric acid accumulation on top of reactor coolant Pump 2MP001. The accumulation was found not only on the mechanical seal, but had also impacted numerous carbon steel components associated with the seal heat exchanger studs and nuts, piping flange connections for controlled bleed-off flow, vapor seal leakoff, seal stage pressure instruments, and the structural materials for the reactor coolant pump casing.

The inspectors observed the condition of Pump 2MP001 and questioned if the excessive boric acid accumulation was properly evaluated by the licensee’s boric acid corrosion control program. Procedure SO23-XV-85 provided definitions to distinguish between wet or dry, and excessive or non-excessive boric acid leak conditions. Wet boric acid accumulation was defined as translucent or exhibiting active water leakage. Active water leakage was defined as the formation and falling of a drop of liquid within a five minute period. The inspectors observed that typical vapor seal leakage from an un-clogged drain line was several drops per second. The inspectors concluded that the leakage observed on June 1, 2008, met the definition of wet boric acid per Procedure SO23-XV-85, since the drain line was clogged and all of the vapor seal flow was being diverted through the undesired area between the shaft and the shaft seal assembly. Procedure SO23-XV-85 defined non-excessive boric acid deposits as trace amounts of boric acid found in small gaps in fittings, flanges, and seals that do not contact bolting or structural materials. The inspectors concluded that the boric acid accumulation on top of the reactor coolant pump seal should have been considered excessive since the vapor seal flow was now being fully diverted, such that the accumulation would continue, and eventually contact the bolting and structural materials associated with the reactor coolant system boundary. Further, the inspectors observed that the condition identified on December 28, 2008, showed that the boric acid was discolored and no longer white, indicating active carbon steel corrosion. Therefore, degradation of components associated with the top of the reactor coolant pump, which included some structural materials associated reactor coolant system boundary, had occurred.

Analysis. The failure to follow procedures to properly evaluate boric acid leaks when required was the performance deficiency. The finding is greater than minor because if left uncorrected, excessive boric acid buildup would have a potential to lead to a more significant safety concern. The finding is associated with the Initiating Events Cornerstone. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheets, the finding is determined to have very low safety significance because the finding would not result in exceeding the technical specification limit for reactor coolant system leakage and would not have affected other mitigation systems resulting in a total loss of their safety function. The finding has a crosscutting aspect in the area of human performance associated with decision-making because engineering personnel did not use conservative assumptions to identify possible unintended consequences associated with the identified boric acid accumulation [H.1.(b)].

Enforcement. 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," requires that activities affecting quality shall be prescribed by instructions, procedures, or drawings, and shall be accomplished in accordance with those instructions, procedures, and drawings. The control of boric acid leakage to prevent degradation to quality, and quality augmented components, was implemented by Procedures SO23-XV-85, “Boric Acid Corrosion Control Program,” Revision 3, and SO23-XV-8.15, “Containment Boric Acid Leak Inspection,” Revision 2. Contrary to the above, on June 1, 2008, engineering personnel failed to follow the requirements of Procedures SO23-XV-85 and SO23-XV-8.15 to properly evaluate the impact of boric acid leakage to reactor coolant system pressure boundary components. Because this finding is of very low safety significance and has been entered into the licensee's corrective action program as Nuclear Notification 200258836, this violation is being treated as a non-cited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000361/2009002-05, “Failure to Properly Evaluate Boric Acid Leakage from the Reactor Coolant Pump Vapor Seal.”

4OA3 Event Follow-up (71153)

.1 Event Follow Up

a. Inspection Scope

The inspectors reviewed the below listed event for plant status and mitigating actions to: (1) provide input in determining the appropriate agency response in accordance with Management Directive 8.3, “NRC Incident Investigation Program”; (2) evaluate performance of mitigating systems and licensee actions; and (3) confirm that the licensee properly classified the event in accordance with emergency action level procedures and made timely notifications to NRC and state/governments, as required.

- January 16, 2009, Unit 3, auxiliary feedwater Pump P140 inoperable due to improperly installed fuse

Documents reviewed by the inspectors are listed in the attachment.

These activities constitute completion of one inspection sample as defined in Inspection Procedure 71153-05.

b. Findings

See Section 1R12 for findings associated with this event.

.2 Event Report Review

a. Inspection Scope

The inspectors reviewed the five below listed Licensee Event Reports and related documents to assess: (1) the accuracy of the Licensee Event Report: (2) the appropriateness of corrective actions; (3) violations of requirements; and (4) generic issues.

b. Observations and Findings

1. (Closed) Licensee Event Reports 05000361/2007-001-00 and 05000361/2007-001-01, "Instrument Air System Failure Results in Manual Reactor Trip"

An NRC special inspection was completed on September 13, 2007, to review this event. No new findings were identified in the inspectors' review. Results of the special inspection, including associated findings and observations, were documented in NRC Special Inspection Report 05000361; 05000362/2007013. This licensee event report and supplement are closed.

2. (Closed) Licensee Event Report 05000361/2007-002-00, "Operator Error Results in a Missed Shutdown Margin Verification Required by the Technical Specifications"

On June 20, 2007, Unit 2 was operating in Mode 1 when one channel of source range monitoring did not pass its surveillance requirements. The source range monitoring channel was declared inoperable at about 1030 PDT. Technical Specification 3.3.13, "Source Range Monitoring Channels," is applicable whenever the plant is in Modes 3, 4, and 5. When applicable and one source range monitor inoperable, operations personnel are required to, in part, perform a shutdown margin verification in accordance with Surveillance Requirement 3.1.1.2 within 4 hours of entering the applicable plant condition. On June 20, 2007, operations personnel manually tripped the unit at about 2250 PDT due to a loss of the instrument air system. When operations personnel manually tripped the reactor, the unit entered Mode 3 and entered the applicability of Technical Specification 3.3.13. Due to operator human performance errors, Surveillance Requirement 3.1.1.2 was not performed within 4 hours of entering Mode 3 conditions. On June 21, 2007, operations personnel identified that Surveillance Requirement 3.1.1.2 was not performed and satisfactorily completed the shutdown margin verification at about 0830 PDT. No new findings were identified in the inspectors' review. This finding constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. The licensee documented the problem in Action Request 070600881. This licensee event report is closed.

3. (Closed) Licensee Event Report 05000361;05000362/2007-003-00, "Saltwater Cooling System Surveillance Performed Incorrectly Due to Improper Flowmeter Calibration by M&TE Results in SR 3.7.8.3 Violation"

The inspector reviewed the information the licensee provided to describe and analyze this event. Between September 2006 and April 2007, the four plant installed flowmeters were replaced due to obsolescence. At the time of installation of the new flowmeters, original manufacturer's settings were verified by M&TE portable flowmeters. Following calibrations, indicated pump flows were inconsistent with expectations. Engineering personnel determined that the installed flowmeters had not been properly calibrated using the portable M&TE and the Technical Specification Surveillance Requirement 3.7.8.3 had not been properly performed. The safety significance of the error was determined to be minimal since the saltwater cooling pumps were capable of performing their required safety function when required by plant conditions. This error is being treated as a minor violation because there was no impact on plant safety and the item was entered in the corrective action program as Action Request 071000125. This failure to comply with technical specification requirement constitutes a violation of minor significance that is not subject to enforcement action in accordance with the NRC's Enforcement Policy. This licensee event report is closed.

4. (Closed) Licensee Event Report 05000361/2008-001-00, "Valid Actuation of Emergency Feedwater System following Main Feedwater Pump Trip"

   This issue was determined to be a finding and was documented in Section 1R22 of NRC Inspection Report 05000361; 05000362/2008002 as FIN 05000361/2008002-1, "Unit 2 Main Feedwater Pump Trip Results in Inadvertent Power Reduction." No additional findings were found in the review of this event. This licensee event report is closed.

5. (Closed) Licensee Event Report 05000362/2008-002-00, "Loose Fuse Results in Inoperable Auxiliary Feedwater Pump and TS Violation"

   This issue was determined to be a non-cited violation and is documented in Section 1R12 of this report and identified as NCV 05000362/2009002-01, "Failure to Follow Procedures when Performing Maintenance on the Auxiliary Feedwater System." This licensee event report is closed.

.3 Personnel Performance

a. Inspection Scope

The inspectors: (1) interviewed workers involved in the events below to evaluate licensee performance in coping with non-routine events; (2) verified that licensee 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 non-routine event. The inspectors also reviewed the event for reportability in accordance with NUREG 1022, Event Reporting Guidelines.

- February 7, 2009, Unit 2, control element drive mechanism vent valve mis-assembly

- February 17, 2009, Unit 2, letdown interruption and reactor coolant diversion

Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of two inspection samples as defined in Inspection Procedure 71153-05.

b. Findings

1. Introduction. A self-revealing Green non-cited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," was identified for the failure of work control and maintenance personnel to use work documents and procedures to reassemble the vent valve for the control element drive mechanism associated with control element Assembly 22, which resulted in a reactor coolant system leak during the fill and vent process.

Description. On February 7, 2009, the licensee identified that reactor coolant was leaking from the vent valve for the control element drive mechanism associated with control element Assembly 22 during the performance of Procedure SO23-3-1.4, "Filling and Venting the Reactor Coolant System," Revision 31. Investigation determined that the vent valve was not assembled per design.

The licensee performed Apparent Cause Evaluation 800245890 to determine the cause of the failure to correctly assemble the vent valve. The evaluation determined that maintenance personnel failed to use or follow procedures for the activities that affected quality. Specifically, on January 27, 2009, Westinghouse personnel requested disassembly of the vent valve for the control element drive mechanism associated with control element Assembly 22 to provide a vent path for welding on the upper pressure housing work during replacement of the control element drive mechanism. Maintenance personnel planned Maintenance Order 800236821 as a normal outage activity and failed to recognize that the work was a key work activity on the reactor coolant system pressure boundary as described in Procedure SO23-I-3.1, "Refueling Activity Guidelines and Minor Refueling Procedures," Revision 12, Attachment 2. Consequently, the licensee failed to appropriately request a work authorization as prescribed by Procedure SO123-I-1.3, "Work Activity Guidelines," Revision 19, and failed to develop an adequate work plan to incorporate the required work controls, including work documents, procedure usage, supervisory oversight, and levels of reviews for the maintenance activity.

On February 2, 2009, shortly after the weld on the upper pressure housing was completed, a call was made to a first line maintenance supervisor inside containment and he was verbally directed to reassemble the vent valve. The maintenance supervisor inside containment believed that he was instructed to reassemble the valve only for foreign material exclusion control purposes. Based on the supervisor's understanding of the task, two maintenance individuals inappropriately placed the ball for the vent valve on top of the vent stem and installed the housing nut without the use of work documents or procedures. Due to informal communications and the lack of appropriate work controls that Procedure SO23-I-3.1 would have required, work control and operations personnel believed that the vent valve had been reassembled as required.

Consequently, on February 7, 2009, the senior reactor operator (operations supervisor) incorrectly initialed Step 2.1.7 of Procedure SO23-3-1.4, Attachment 4, as complete. Step 2.1.7 required the operations supervisor contact outage work control to ensure all maintenance which could impact filling the pressurizer solid and pressurizing the reactor coolant system has been completed and all restraining deficiencies have been corrected. Because the vent valve reassembly per Maintenance Order 800236821 was not properly planned, it was not recognized as a prerequisite to the fill and vent. Therefore, Procedure SO23-3-1.4, Attachment 4, Step 2.1.7, was incorrectly initialed as complete and a reactor coolant system leak developed from the control element drive mechanism vent valve during the fill and vent of the reactor coolant system.

The licensee depressurized and drained down the reactor coolant system to correct the vent valve condition. Following the identification of the reactor coolant system leakage, radiation protection personnel took actions to minimize the amount of leakage to surrounding equipment and clean accessible areas to the extent possible. Nuclear Notification 200309453 was initiated to evaluate the effect of the reactor coolant system leakage on impacted structures, systems, and components. A boric acid leakage evaluation was performed per Procedure SO23-XV-85, "Boric Acid Corrosion Control Program," Revision 3. Additionally, engineering performed an electrical evaluation of control element drive mechanism components due to the potential impact of exposure to boric acid. The inspectors reviewed the actions taken, evaluations performed, and associated conclusions, and determined that the efforts were adequate.

<u>Analysis</u>. The failure to use procedures for the control and implementation of work affecting quality was the performance deficiency. The finding is greater than minor because it is associated with the reactor coolant system equipment and barrier performance attribute of the Barrier Integrity Cornerstone and affects the associated cornerstone objective to provide reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Using Manual Chapter 0609, "Significance Determination Process," Appendix G, "Shutdown Operations Significance Determination Process," Checklist 4, a phase 2 analysis is required since the finding increased the likelihood of a loss of reactor coolant system inventory. Manual Chapter 0609, Appendix M, "Significance Determination Process Using Qualitative Criteria," was used since the Significance Determination Process methods and tools were not adequate to determine the significance of the finding. The finding is determined to have very low safety significance through management review because the finding does 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. This finding has a crosscutting aspect in the area of human performance associated with work control because the licensee did not appropriately coordinate work activities by incorporating actions to address the impact of work on different job activities [H.3(b)].

<u>Enforcement</u>. 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," requires that activities affecting quality shall be prescribed by instructions, procedures, or drawings and shall be accomplished in accordance with those instructions, procedures, and drawings. Procedure SO23-I-3.1, "Refueling Activity Guidelines and Minor Refueling Procedures," Revision 12, Attachment 2, required, in part, the application of the full spectrum of human performance and error prevention tools, and compliance with existing programs, including SO123-I-1.3, "Work Activity Guidelines," SO23-I-1.43, "Maintenance Human Performance Application," and SO23-XX-8, "Critical Activities Work Process Manual," for reactor coolant system pressure boundary work. Contrary to the above, on February 2, 2009, work control and maintenance personnel failed to follow the requirements of Procedure SO23-I-3.1 for work on a reactor coolant system pressure retaining component. Specifically, work control and maintenance personnel did not use work documents and procedures to reassemble the vent valve for the control element drive mechanism associated with control element Assembly 22, which resulted in a reactor coolant system leak during the

fill and vent process. Because the finding is of very low safety significance and has been entered into the licensee's corrective action program as Nuclear Notification 200323460, this violation is being treated as a non-cited violation, consistent with Section VI.A of the Enforcement Policy: NCV 05000361/2009002-06, "Failure to Follow Procedures to Reassemble a Reactor Coolant System Pressure Retaining Component."

2. Introduction. A self-revealing Green non-cited violation of Technical Specification 5.5.1.1 was identified for the failure of operations personnel to follow procedures to place Ion Exchanger ME074 in service which resulted in an interruption of letdown flow and diversion of approximately 160 gallons of reactor coolant to the radiological waste system.

   Description. On February 17, 2009, operations personnel filled and vented Ion Exchanger ME074 per Procedure SO23-3-2.4, "RCS Purification and Deborating Ion Exchanger Operation," Revision 19, Attachment 14. Following the fill and vent operation, operations personnel performed Procedure SO23-3-2.4, Attachment 4, to align Ion Exchanger ME074 for service. Following completion of the alignment, control room personnel placed purification ion exchanger bypass Valve 2TV-0224B to the "Ion Exchange" position to establish letdown flow through Ion Exchanger ME074. The radwaste operator checked the differential pressure across Ion Exchanger ME074 and reported to control room personnel that the local indicator was pegged high. Concurrently with the radwaste operator report, the Relief Valve Leaking alarm annunciated in the control room. Control room personnel promptly returned purification ion exchanger bypass Valve 2TV-0224B to the "Bypass" position which restored letdown flow. The radwaste operator was directed to verify the system alignment and identified that the inlet isolation valve for Ion Exchanger ME074 was incorrectly positioned to "closed" instead of "open". The radwaste operator also identified that the inlet isolation valve for Ion Exchanger ME075 was incorrectly positioned to "open" instead of "closed" as required by Procedure SO23-3-2.4, Attachment 4. The valve misalignments resulted in an interruption in letdown flow and caused letdown line pressure to increase to 370 psig, which lifted letdown relief Valve PSV9208. Approximately 160 gallons of reactor coolant were discharged to Miscellaneous Waste Tank T063 before Valve PSV9208 reset.

   The inspectors reviewed the prompt investigation report and noted that the investigation was thorough in identifying the sequence of events and performance errors associated with the event. Procedure SO23-3-2.4 required a performer to position each valve and an independent verifier to verify the required position. Further, each step contained a sign-off to document completion. The prompt investigation identified that the required human performance independent verification and pre-job walkdown tools were not properly used. Specifically, the independent verifier assisted the performer in filling and venting the ion exchanger per Procedure SO23-3-2.4, Attachment 14, by opening and then closing the inlet to Ion Exchanger ME074. Additionally, the performer and independent verifier checked and verified, respectively, the position of 8 of 13 valves on Procedure SO23-3-2.4, Attachment 4, by referring to previous position verifications from Attachment 14. The following three primary errors were identified that resulted in the event: (1) The performer failed to use adequate self-checking and opened inlet isolation Valve MU007 for Ion Exchanger ME075 instead of opening inlet isolation Valve MU037 for Ion Exchanger ME074 as required by procedure; (2) The independent verifier did not verify the position of Valve MU007 since he had already signed for its position, as closed, as part of a performer and independent verifier agreement to take credit for valves previously signed for in Attachment 14; and (3) When the independent verifier checked the position of Valve MU037, his mindset was that the valve should be "closed" based on his previously having “opened” and “closed” the valve in support of the performer’s venting of Ion Exchanger ME074, and he subsequently left the valve in the incorrect position. The apparent cause evaluation determined that the errors occurred for three reasons: (1) The independent verifier did not remain truly independent when he agreed with the performer on the method for verifying the valve positions in Attachment 14; (2) Neither the performer not the independent verifier adhered to the requirements of Attachment 4 by using “hands-on” checking and verifying of all the valves and positions required by procedure; and (3) Neither the performer nor independent verifier used the human performance tools for self-checking and procedure use.

Analysis. The failure to follow procedures to perform system alignments was the performance deficiency. The finding is greater than minor because it is associated with the configuration control attribute of the Initiating Events Cornerstone and affects the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Using the Manual Chapter 0609, “Significance Determination Process,” Phase 1 Worksheets, the finding is determined to have very low safety significance because the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. The finding has a crosscutting aspect in the area of human performance associated with work practices because the licensee did not properly use human error prevention techniques [H.4(a)].

Enforcement. Technical Specification 5.5.1.1 requires, in part, that written procedures be established, implemented, and maintained covering the activities specified in 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. Appendix A, Item 3.n, requires procedures for operating the chemical volume control system, including the letdown and purification systems. Procedure SO23-3-2.4, “RCS Purification and Deborating Ion Exchanger Operation,” Revision 19, provided instructions for aligning an ion exchanger for service. Contrary to the above, on February 17, 2009, operations personnel failed to follow Procedure SO23-3-2.4 to align Ion Exchanger ME074 for service which resulted in an interruption of letdown flow and diversion of approximately 160 gallons of reactor coolant to Miscellaneous Waste Tank T063. Because the finding is of very low safety significance and has been entered into the corrective action program as Nuclear Notification 200319240, this violation is being treated as a non-cited violation, consistent with Section VI.A of the Enforcement Policy: NCV 05000361/2009002-07, “Failure to Follow Procedure for Aligning a Reactor Coolant System Ion Exchanger.”

4OA5 Other Activities

.1 Quarterly Resident Inspector Observations of Security Personnel and Activities

a. Inspection Scope

During the inspection period, the inspectors performed observations of security force personnel and activities to ensure that the activities were consistent with San Onofre Nuclear Generating Station security procedures and regulatory requirements relating to nuclear plant security. These observations took place during both normal and off-normal plant working hours.

These quarterly resident inspector observations of security force personnel and activities did not constitute any additional inspection samples. Rather, they were considered an integral part of the inspectors' normal plant status review and inspection activities.

b. Findings

No findings of significance were identified.

.2 Institute of Nuclear Power Operations (INPO) Assessment Review

The inspectors reviewed an Institute of Nuclear Power Operations assessment dated March 5, 2009. The biennial assessment was performed from July 21 through July 28, 2008. The inspectors noted that the assessment was consistent with performance observed by the NRC staff.

.3 (Closed) Notice of Violation 05000361; 05000362/2007005-04, "Failure to Prevent Recurrence of Premature Tripping of Square D Thermal Overloads"

a. Inspection Scope

On February 13, 2008, San Onofre Nuclear Generating Station received a notice of violation for the failure to take corrective actions to preclude repetition of the premature tripping of thermal overloads for safety-related equipment from February 6, 2007 through August 8, 2007. This notice of violation represented a significant condition adverse to quality.

On February 6, 2009, and February 26, 2009, the inspectors reviewed licensee performance on the corrective actions associated with thermal overloads to determine the appropriateness of the corrective actions, and to determine whether any generic weaknesses were identified in the licensee's corrective action program. The inspectors reviewed Nuclear Notification 200005170, written to perform a root cause assessment for ineffective implementation of the problem identification and resolution program as well as Nuclear Notification 200302826, written to evaluate the need to have root cause evaluation team members relieved of their regular duties while performing root cause evaluations. The inspectors also reviewed the lesson plan for all hands training titled "Rebuilding SONGS Together."

The inspectors discussed the initiatives with licensee representatives. The topics discussed included thoroughness of root cause evaluations and subsequent review by the corrective action review board, improving leadership in the management of root cause assessments, and relieving root cause evaluation members of distractions while performing the assessment.

The inspectors considered the root cause evaluation and the proposed corrective actions sufficient to address and correct the problem identification and resolution deficiencies at San Onofre Nuclear Generating Station. This notice of violation is closed.

b. Findings

No findings of significance were identified.

.4 (Closed) Unresolved Item 05000361; 05000362/2008005-03, "Failure to Report Changes to Mitigating Systems Performance Index Risk Coefficients"

During the previous inspection period, the inspectors identified that the licensee had made changes to the risk (Birnbaum) coefficients over several quarters and had failed to report these changes as required by Nuclear Energy Institute Document 99-02. The NRC reviewed the bases for the changes and the effect the changes had on the reported Performance Indicator data and determined that the effects did not significantly impact the reported data. Consequently, the color of the associated Mitigating Systems Performance Indices did not change and remained Green. The inspectors determined that the failure to report the changes in risk was a violation of 10 CFR 50.9, “Completeness and Accuracy of Information,” and constituted a violation of minor significance that is not subject to enforcement action in accordance with the NRC’s Enforcement Policy. This unresolved item is closed.

4OA6 Meetings, Including Exit

Exit Meeting Summary

On February 27, 2009, the inspector conducted a telephonic exit meeting to present the results of the in-office inspection of changes to the licensee’s emergency plan to Mr. B. Ashbrook, Manager, Onsite Emergency Preparedness, who acknowledged the findings.

On April 1, 2009, the inspectors presented the inspection results to Mr. A. Hochevar, and other members of the licensee staff. The licensee acknowledged the issues presented.

The inspector asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

J. Armas, Supervisor, Maintenance Engineering Fluid Process
B. Ashbrook, Manager, Emergency Preparedness
D. Axline, Technical Specialist, Compliance
D. Bauder, Plant Manager
P. Blakeslee, Supervisor, Mechanical Auxiliary Systems
S. Chun, Supervisor, Electrical/I&C Systems
B. Corbett, Manger, Performance Improvement
R. Elsasser, Manger, Training
J. Fee, Manager, Site Emergency Preparedness
S. Gardner, Engineer, Compliance
S. Genshaw, Manager, Maintenance Engineering Electrical/Controls
M. Graham, Manager, Plant Operations
A. Hochevar, Station Manager
E. Hubley, Director, Maintenance/Construction
G. Johnson, Jr., Senior Nuclear Engineer, Maintenance/Systems Engineering
K. Johnson, Manager, Design Engineering
M. Johnson, Manager, Support Services
L. Kelly, Engineer, Compliance
D. Legere, Director, Work Control
R. Nielsen, Supervisor, Nuclear Oversight
B. MacKissock, Director, Operations
A. Meichler, Supervisor, Engineering
N. Quigley, Manager, Maintenance/System Engineering
R. Richter, Engineering Supervisor, Fire Protection
C. Ryan, Manager, Maintenance & Construction Services
A. Scherer, Director, Nuclear Regulatory Affairs
M. Short, Vice President, Engineering and Technical Services
R. St. Onge, Director, Maintenance and Systems Engineering
J. Todd, Manager, Security
D. Wilcockson, Manager, Operations Training
C. Williams, Manager, Compliance

NRC Personnel

D. Loveless, Senior Reactor Analyst

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000362/2009002-01	NCV	Failure to Follow Procedures when Performing Maintenance on the Auxiliary Feedwater System (Section 1R12)
05000361/2009002-02	NCV	Failure to Properly Implement the Operability Determination Process (Section 1R15)
05000361; 05000362/2009002-03	NCV	Failure to Properly Inspect Scaffolding in Safety-Related Areas (Section 1R18)
05000361/2009002-04	NCV	Inadequate Procedure for Reactivity Manipulations (Section 1R19)
05000361/2009002-05	NCV	Failure to Properly Evaluate Boric Acid Leakage from the Reactor Coolant Pump Vapor Seal (Section 4OA2)
05000361/2009002-06	NCV	Failure to Follow Procedures to Reassemble a Reactor Coolant System Pressure Retaining Component (Section 4OA3)
05000361/2009002-07	NCV	Failure to Follow Procedure for Aligning a Reactor Coolant System Ion Exchanger (Section 4OA3)

Closed

05000361/2007-001-00	LER	Instrument Air System Failure Results in Manual Reactor Trip (Section 4OA3)
05000361/2007-001-01	LER	Instrument Air System Failure Results in Manual Reactor Trip (Section 4OA3)
05000361/2007-002-00	LER	Operator Error Results in a Missed Shutdown Margin Verification Required by the Technical Specifications (Section 4OA3)
05000361;05000362/2007-003-00	LER	Saltwater Cooling System Surveillance Performed Incorrectly Due to Improper Flowmeter Calibration by M&TE Results in SR 3.7.8.3 Violation (Section 4OA3)
05000361/2008-001-00	LER	Valid Actuation of Emergency Feedwater System Following Main Feedwater Pump Trip (Section 4OA3)

Closed

05000362/2008-002-00	LER	Loose Fuse Results in Inoperable Auxiliary Feedwater Pump and TS Violation (Section 4OA3)
05000361; 05000362/2007005-04	NOV	Failure to Prevent Recurrence of Premature Tripping of Square D Thermal Overloads (Section 4OA5)
05000361; 05000362/2008005-03	URI	Failure to Report Changes to Mitigating Systems Performance Index Risk Coefficients (Section 4OA5)

LIST OF DOCUMENTS REVIEWED

Section 1RO4: Equipment Alignment

Procedures

NUMBER	TITLE	REVISION
SO23-3-2.6	Shutdown Cooling System Operation	25
SO23-2-13.1	Diesel Generator 2G002 Alignment	3

NUMBER	TITLE	REVISION
40112C	P&I Diagram Safety Injection System	19
40112B	P&I Diagram Safety Injection System	35
40114B	P&I Diagram Containment Spray System	18

Calculations

NUMBER	TITLE	REVISION
DBD-SO23-740	Shutdown Cooling System	9

Section 1RO5: Fire Protection

Nuclear Notifications

NUMBER				
200127789	200320108	200320112	200320127	200320131
20030155	200320158	200320159	200320159	200320164

Miscellaneous

NUMBER	TITLE	REVISION
2DG13.DWG	Unit 2 SONGS pre-fire plan, emergency diesel generator Rooms A&B	6
3DG45.DWG	SONGS pre-fire plan, Rooms A&B	6
SE 2-007	Pre-fire Plan	5

Section 1R11: Licensed Operator Requalification Program

Procedures

NUMBER	TITLE	REVISION
SO23-13-27	Pressurizer Pressure and Level Malfunction	3
OSM-9	Standard EOI Goal Practices and Strategies	5
SO123-VIIII-10	Emergency Coordinator Duties	25
SCE EP(123)-10	Event Notification Form	12
SO23-12-10	Safety Function Status Checks	2

Nuclear Notifications

NUMBER
200333596

Section 1R12: Maintenance Effectiveness

Procedures

NUMBER	TITLE	REVISION
SO123-XV-5.3	Maintenance Rule Program	11

Nuclear Notifications

NUMBER

200253911	200283371	200241958	200253911	200235978
200200398	200229277			

Maintenance Orders

NUMBER

061001129	061001248	070701029	070300300

Drawings

NUMBER	TITLE	REVISION
32999, Sheet 1	Auxiliary Feedwater Pump Turbine Steam Inlet Valve HV4715	18
34088, Sheet 4	Tank Area Panels 3L298-C, 3L298-P, and 3L298-T	2
40160AS03	Auxiliary Feedwater System No. 1305	37

Calculations

NUMBER	TITLE	DATE
M-1305-222-AA	Auxiliary Feedwater Line Inside Containment 1305-222-6-C-GK1 to Penetration 78	April 23, 2007
M-1305-223-AB	Auxiliary Feedwater Line Inside Containment 1305-223-6-C-GK1 to Penetration 75	March 9, 2007

Miscellaneous

NUMBER	TITLE	DATE
NRC Information Notice 90-45	Overspeed of the Turbine-Driven Auxiliary Feedwater Pumps and Overpressurization of the Associated Piping Systems	July 6, 1990
NRC Information Notice 88-67	PWR Auxiliary Feedwater Pump Turbine Trip Failure	August 22, 1988
NRC Information Notice 94-66, Supplement 1	Overspeed of Turbine-Driven Pumps Caused by Binding in Stems of Governor Valves	June 16, 1995
NRC Information Notice 90-76	Failure of Turbine Overspeed Trip Mechanism Because of Inadequate Spring Tension	December 7, 1990
	Maintenance Rule Monthly Unavailability Report	January 2007 - February 2009
	Maintenance Rule Monthly Functional Failure Report	January 2007 -February 2009

Section 1R13: Maintenance Risk Assessment and Emergent Work Controls

Procedures

NUMBER	TITLE	REVISION
SO123-IT-1	Infrequently Performed Tests or Evolutions Controls Program	10 EC 10-2

Nuclear Notifications

NUMBER		
200284803	200284800	200283467

Work Orders

NUMBER			
800051272	800235840	800239542	800238539

Section 1R15: Operability Evaluations

Procedures

NUMBER	TITLE	REVISION
SO123-XV-52	Functionality Assessments and Operability Determinations	10
SO23-3-2.7	Safety Injection System Operation	22
SO23-2-17	Saltwater Cooling System Operations	26

Nuclear Notifications

NUMBER				
200268068	200270343	200286809	200324384	200304164
200093413	200289984	200198219	200319850	200210214

Drawings

NUMBER	TITLE	REVISION
30920	Elementary Drawing Steam Generator E088 Isolation Valve HV4714	13
40126A	P&I Diagram Component Cooling Water System	28

Calculations

NUMBER	TITLE	REVISION
EC-381	CCW Heat Exchanger Leak Rate	0

Miscellaneous

NUMBER	TITLE	REVISION
DBD-SO23-750	Emergency Diesel Generators- Design Bases Document	3

Section 1R19: Postmaintenance Testing

Procedures

NUMBER	TITLE	REVISION
SO23-3-3.60.3	Component Cooling Water Seismic Makeup Pump Test	9
SO123-XX-3	Fix it Now Program	12
SO23-II-9.457	Bailey Electronic Position Transmitter Type RQ Calibration	1
SO23-3-3.30.4	Main Steam System Online Valve Test	8
SO23-2-13	Diesel Generator Operation	36
SO23-3-3.23	Diesel Generator Monthly and Semi-Annual Testing	37
SO23- I-6.107	Control Element Drive Motor Ball Seal Replacement and Venting	12
SO23-3-2.19.2	CEA Exercise and Troubleshooting	1

Nuclear Notifications

NUMBER				
200278304	200319466	200319505	200339686	200209453
200315958	200323460	800229668	800219792	800248033

Work Orders

NUMBER				
70001284	203304816	800237249	8002410022	800066902
800219793	800231828	800231830	800235266	800237243
800238160	800067770	800219797	200316098	800241633

Drawings

NUMBER	TITLE	REVISION
SO23-906-6-6	Control Element Drive Motor Installation Drawing	7

Miscellaneous

NUMBER	TITLE	DATE
Fluke 787 Processor	Calibration M3-5267	04/22/09

Section 1R20: Refueling and Other Outage Activities

Procedures

NUMBER	TITLE	REVISION
SO23-XX-7.1	Defense in Depth Planning, Attachment 8	2
SO23-5-1.8.1	Shutdown Nuclear Safety	15
SO23-3-1.8	Draining the Reactor Coolant System to Reduced Inventory Conditions	26
SO23-3-1.6	Raising and Lowering Reactor Coolant System level	7

Work Orders

NUMBER	TITLE	DATE
WCD 30000894	Work control document 2G002 BOW	02/03/09
WCA 70000690	Work Control Authorization, 2G002	02/03/09

Miscellaneous

NUMBER	TITLE	DATE
DID 1e	Defense in Depth Sheet	02/03/09

Section 1R22: Surveillance Testing

Procedures

NUMBER	TITLE	REVISION
SO23-3-3.43.33	ESF Subgroup Relays K-211A, K-624A, K-724A Semiannual Test	5
SO23-3-3.2, attachment 4	Excore Nuclear Instrumentation Calibration	14
SO23-3-3.60.8	Boric Acid Makeup Pump Test	9

Maintenance Orders

NUMBER		
800188365	800068387	800190124

Drawings

NUMBER	TITLE	DATE
41069, Sh. 4	Boric Acid Makeup Pump Tag No. 3P175 IST Curves	October 28, 1992

Calculations

NUMBER	TITLE	DATE
M-0025-001	Boric Acid Makeup Pump Inservice Testing Minimum Requirements	September 2, 1992

Miscellaneous

NUMBER	TITLE	DATE
	Inservice Pump Test Record	May 22, 2007

Section 1EP6: Drill Evaluation

Procedures

NUMBER	TITLE	REVISION
SO123-VIII-40.1	Health Physic Coordinator Duties	26
SO123-VIII-80	Emergency Group Leader Duties	14
SO123-VIII-60	Security leader Duties	21
SO123-VIII-10.1	Station Emergency Director	18
SO23-13-14	Reactor Coolant Leak	13
SO23-12-1	Standard Post Trip Actions	21

Miscellaneous

NUMBER	TITLE	DATE
	Emergency Plan Drill 0902	March 17, 2009

Section 4OA1: PI verification (71151)

Miscellaneous

NUMBER	TITLE	REVISION / DATE
IE-01/03/04 Checklist	Units 2 and 3 CDE Data	1Q08
IE-01/03/04 Checklist	Units 2 and 3 CDE Data	2Q08
IE-01/03/04 Checklist	Units 2 and 3 CDE Data	3Q08
IE-01/03/04 Checklist	Units 2 and 3 CDE Data	4Q08
2008-001	Valid Actuation of Emergency Feedwater System Following Main Feedwater Pump Trip	00
2008-004	Malfunctioning Stator Water Cooling System Check Valve Causes Reactor Trip	00

Section 4OA2: Identification and Resolution of Problems

Procedures

NUMBER	TITLE	REVISION
SO123-XX-1	Notification Initiation and Processing	21

Nuclear Notifications

NUMBER				
200336599	200286475	200336616	200162648	200373833
200373183	200371967	200236580	200230582	200120994
200133323	200139120	200189059	200285837	200101977

200296672	200164617	200341747	200294042	200070499
200095148	200097137	200097451	200142318	200145546
200160815	200174717	200093492	200293337	200229863
200233178	200251782	200075312	200013282	200182890
200229991	200231437	200273894	200199654	200343069

Miscellaneous

NUMBER	TITLE	REVISION / DATE
	Operational Focus List	
	Operational Focus Index	

Section 4OA3: Event Follow-Up

Nuclear Notifications

NUMBER	
200253911	200283371

Calculations

NUMBER	TITLE	DATE
M-1305-223-AB	Auxiliary Feedwater Line Inside Containment 1305-223-6-C-GK1 to Penetration 75	March 9, 2007
M-1305-222-AA	Auxiliary Feedwater Line Inside Containment 1305-222-6-C-GK1 to Penetration 78	April 23, 2007

Drawings

NUMBER	TITLE	REVISION
90004	Piping Material Classifications	65
32999, Sheet 1	Auxiliary Feedwater Pump Turbine Steam Inlet Valve HV4715	18
34088, Sheet 4	Tank Area Panels 3L298-C, 3L298-P, and 3L298-T	2
40160AS03	Auxiliary Feedwater System No. 1305	37

Miscellaneous

NUMBER	TITLE	DATE
NRC Information Notice 90-45	Overspeed of the Turbine-Driven Auxiliary Feedwater Pumps and Overpressurization of the Associated Piping Systems	July 6, 1990
NRC Information Notice 88-67	PWR Auxiliary Feedwater Pump Turbine Trip Failure	August 22, 1988
NRC Information Notice 94-66, Supplement 1	Overspeed of Turbine-Driven Pumps Caused by Binding in Stems of Governor Valves	June 16, 1995
NRC Information Notice 90-76	Failure of Turbine Overspeed Trip Mechanism Because of Inadequate Spring Tension	December 7, 1990