UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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February 14, 2005

Harold B. Ray, Executive Vice President
San Onofre, Units 2 and 3
Southern California Edison Co.
P.O. Box 128, Mail Stop D-3-F
San Clemente, CA 92674-0128

SUBJECT: SAN ONOFRE NUCLEAR GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000361/2004005; 050000362/2004005

Dear Mr. Ray:

On December 31, 2004, 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 report documents the inspection findings, which were discussed on October 15 and December 17, 2004, with Mr. J. Wambold and other members of your staff.

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

Based on the results of this inspection, this report documents four self-revealing findings of very low safety significance (Green). All four 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 four findings as noncited violations (NCVs), consistent with Section VI.A of the NRC Enforcement Policy. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator Region IV; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at San Onofre Nuclear Generating Station, Units 2 and 3.

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

Sincerely,

/RA/

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

Dockets: 50-361, 50-362
Licenses: NPF-10, NPF-15

Enclosure:
NRC Inspection Report 05000361/2004005; 05000362/2004005
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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Dockets:	50-361, 50-362
Licenses:	NPF-10, NPF-15
Report No.:	05000361/2004005 and 5000362/2004005
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:	September 27 through December 31, 2004
Inspectors:	C. C. Osterholtz, Senior Resident Inspector, Project Branch C M. A. Sitek, Resident Inspector, Project Branch C M. E. Murphy, Senior Operations Engineer, DRS W. C. Sifre, Reactor Inspector, Engineering Branch, DRS J. P. Adams, Reactor Inspector, Engineering Branch, DRS D. L. Proulx, Senior Resident Inspector, Project Branch E G. Warnick, Senior Resident Inspector, Project Branch D
Approved By:	M. C. Hay, Chief Project Branch C Division of Reactor Projects

Enclosure

CONTENTS

SUMMARY OF FINDINGS

IR 05000361/2004005, 05000362/2004005; 09/27/04 - 12/31/04; San Onofre Nuclear Generating Station, Units 2 & 3; Integrated Resident and Regional Report; Equipment Alignment, Maintenance Risk Assessment and Emergent Work, and Crosscutting Areas.

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

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A self-revealing, noncited violation of Technical Specification 5.5.1.1 was identified for the implementation of inadequate procedures which led to the inadvertent crosstie of the Unit 3 Train B refueling water storage tank to the Unit 3 spent fuel pool cooling system on November 8, 2004. The two systems were crosstied for approximately 45 minutes, which resulted in approximately 6000 gallons of borated water being transferred from the Train B refueling water storage tank to the Unit 3 spent fuel pool. The Unit 3 spent fuel pool overflowed to the Unit 3 fuel handling building sump, causing the excess water to backup into the fuel handling building through its floor drains.

  The finding was determined to be more than minor because it was associated with the procedure quality attribute of the initiating events cornerstone. It also affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during shutdown conditions. This finding cannot be evaluated by the significance determination process because Manual Chapter 0609, "Significance Determination Process;" Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations;" and Appendix G, "Shutdown Operations Significance Determination Process," do not apply to the spent fuel pool. However, this finding was determined to be of very low safety significance by management review because spent fuel pool cooling and the fuel handling building ventilation system were still available and no personnel contamination events occurred. The finding had crosscutting aspects in the area of human performance because the inadequate procedures directly contributed to the cause of the finding (Section 1R04.1).

- Green. A self-revealing, noncited violation of Technical Specification 5.5.1.1 was identified for the failure of a maintenance technician to follow a maintenance order, which led to the inadvertent actuation of several Unit 3 safety-related

relays and the temporary loss of one qualified electrical circuit between the offsite transmission network and the Unit 2 onsite Class 1E electrical power distribution system.

The finding was determined to be more than minor because the initiating events cornerstone objective was affected by a human performance error that increased the likelihood of a loss of offsite power event. Based on the results of the significance determination process (Phase 1 evaluation), the finding was determined to have very low safety significance (Green) because the failure of the maintenance technician to follow the work plan of the maintenance order did not contribute to both the likelihood of a reactor trip and simultaneously the lack of availability of mitigating equipment or functions. Both of Unit 2's emergency diesel generators were available. The finding had crosscutting aspects in the area of human performance because the failure of the maintenance technician to follow the work plan of the maintenance order was the direct cause of the finding (Section 1R04.2).

Cornerstone: Mitigating Systems

- Green. A self-revealing, noncited violation of Technical Specification 5.5.1.1 was identified for the failure of the licensee to implement adequate maintenance procedures which led to refueling water storage tank inventory to inadvertently be introduced into the reactor coolant system.

  The finding was determined to be more than minor because it affected the procedure quality attribute of the mitigating systems cornerstone. Based on the results of the significance determination process (Phase 1 evaluation), the finding was determined to have very low safety significance (Green) because the improper maintenance performed did not result in an actual loss of safety function. The finding had crosscutting aspects in the area of human performance because the inadequate MO directly contributed to the cause of the finding (Section 1R13.1).

- Green. A self-revealing, noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, was identified for the licensee’s failure to determine the cause of missing taper pins in component cooling water 28-inch Fisher butterfly valves and to take appropriate corrective actions to prevent recurrence.

  The finding was more than minor because it affected the equipment performance attribute of the mitigating systems cornerstone and, if left uncorrected, could result in a more significant safety concern. Missing taper pins increase the potential to render the component cooling water system inoperable due to crosstrain leakage because the 50 gpm leak caused by a missing taper pin exceeds the operability leak rate limit of 18 gpm. Based on the results of the Significance Determination Process, Phase 1 evaluation, the finding was

determined to have very low safety significance (Green) because it did not result in an actual loss of safety function of the component cooling water system. This finding also had crosscutting aspects associated with problem identification and resolution, because the condition was not properly corrected when previously identified (Section1R13.2).

B. Licensee-Identified Violations

None

REPORT DETAILS

Summary of Plant Status

Unit 2 began the inspection period at approximately 100 percent reactor power. On November 19, 2004, a deionization plate associated with the terminal box of the main electrical generator became dislodged and fell onto the Phase A isolated phase bus. The main electrical generator subsequently tripped, which led to a turbine trip and ultimately a Unit 2 reactor trip. The terminal box deionization plate was repaired and Operations personnel commenced a reactor startup on November 20, 2004. The unit entered Mode 1 on November 23, 2004, and synchronized to the electrical grid later that same day. Unit 2 ended the inspection period at approximately 100 percent reactor power.

Unit 3 began the inspection period in the process of reducing reactor power in preparation for the Unit 3 Cycle 13 planned refueling outage. At approximately noon on September 27, 2004, Unit 3 was shut down and entered Mode 3. Unit 3 entered Mode 6 refueling operations on October 3, 2004. The refueling outage was extended past its original end date in order to replace the Unit 3 pressurizer heaters and heater sleeves. The pressurizer scope of work was expanded as a result of the discovery of flaws in two of the original pressurizer heater sleeves. The pressurizer work was successfully completed and Unit 3 entered Mode 5 on December 17, 2004. Operations personnel commenced a reactor startup and the unit entered Mode 2 on December 25, 2004. Unit 3 entered Mode 1 on December 26, 2004, and was synchronized to the electrical grid on December 28, 2004. Unit 3 maintained approximately 70 percent reactor power while the licensee searched for the cause of an abnormal noise coming from Main Feedwater Pump Turbine K006. The cause of the noise was not found by the end of the inspection period. Unit 3 ended the inspection period at approximately 70 percent reactor power.

1. REACTOR SAFETY

   Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R04 Equipment Alignment

1. Unit 3 Spent Fuel Pool Overfill

   a. Inspection Scope

      On November 9, the inspectors walked down the Unit 3 Shutdown Cooling and Spent Fuel Pool Cooling systems following an inadvertent crosstie of the Unit 3 Train B refueling water storage tank to the Unit 3 spent fuel pool cooling system (one inspection sample).

b. Findings

Introduction. A Green, self-revealing, noncited violation (NCV) of Technical Specification (TS) 5.5.1.1, was identified for the implementation of inadequate procedures which led to the inadvertent crosstie of the Unit 3 Train B RWST to the Unit 3 SFP cooling system.

Description. On November 8, 2004, the licensee completed planned maintenance on the suction side of the Unit 3 emergency core cooling system (ECCS) during the Unit 3 Cycle 13 refueling outage. Following the completed maintenance, Operations personnel began to fill and vent the ECCS piping and pumps in order to begin to return the ECCS system to operable status. Operations personnel were utilizing Procedure SO23-3-2.7.2, "Safety Injection System Removal/Return to Service Operation," Revision 11. When operations reached the step in the procedure to fill and vent Train B Containment Spray (CS) Pump 3P013, they transferred to Procedure SO23-3-2.9, "Containment Spray System Operation," Revision 22. While in the process of filling and venting CS Pump 3P013, the Unit 3 control room received the fuel handling building sump high level alarm. Operations personnel then recognized that the Unit 3 Train B RWST had been inadvertently crosstied with the Unit 3 SFP cooling system through the CS Pump 3P013 suction isolation valve from SFP Valve 3MU993. This valve was opened as part of the filling and venting procedure. Operations personnel closed Valve 3MU993 to terminate the crosstie.

The two systems were crosstied for approximately 45 minutes, which resulted in approximately 6000 gallons of borated water being transferred from the Train B RWST to the Unit 3 SFP. The Unit 3 SFP overflowed to the Unit 3 fuel handling building sump, causing the excess water to backup into the fuel handling building through its floor drains. The contamination in the building did not extend to any personnel. The inspectors noted that an earlier opportunity for Operations personnel to mitigate the overfilling was missed because the nonsafety-related Unit 3 SFP high level alarm had failed.

At the time of the event, normal SFP cooling was isolated because corrective maintenance was being performed on its component cooling water (CCW) support system. As a result, operations personnel were following Procedure SO23-3-2.6.1, "CS/SDC/SFP Cooling Crosstie Operation," Revision 5, in order to establish an appropriate SFP cooling alignment. In accordance with the procedure, Train A CS Pump 3P012 was aligned to provide the Unit 3 SFP cooling through the Train A SDC heat exchanger. The opening of Valve 3MU993 aligned the suction of CS Pump 3P012 to the Train B RWST, which allowed for the overfilling of the Unit 3 SFP.

The inspectors reviewed the three previously described procedures that the licensee utilized at the time of the event. The procedures did not contain any steps nor guidance to prevent the crosstie event. The inspectors noted that reviews by work planning and Operations did not identify the procedural deficiencies.

The licensee implemented interim corrective actions following the event, which included placing caution tags on the crosstie valves, maintaining drawings of the current plant configuration instead of solely relying on procedural control, and placing the RWSTs on an alarming trend to warn the operators of any unexpected level changes. Long-term corrective actions included appropriate procedural changes to prevent recurrence.

Analysis. The failure of the licensee to have adequate procedures was considered to be a performance deficiency. The finding was determined to be more than minor because it was associated with the procedure quality attribute of the initiating events cornerstone. It also affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during shutdown conditions. This finding cannot be evaluated by the significance determination process because Manual Chapter 0609, "Significance Determination Process," Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," and Appendix G, "Shutdown Operations Significance Determination Process," do not apply to the SFP. However, this finding was determined to be of very low safety significance by management review because SFP cooling and the fuel handling building ventilation system were still available and no personnel contamination events occurred.

The finding had crosscutting aspects in the area of human performance because the inadequate procedures directly contributed to the cause of the finding.

Enforcement. TS 5.5.1.1 states, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, Section 3, “Procedures for Startup, Operation, and Shutdown of Safety-Related PWR Systems,” specifies, in part, that instructions for filling, venting, and draining should be prepared, as appropriate, for the SDC, emergency core cooling, and the fuel storage pool cooling systems. Contrary to this criterion, on November 8, 2004, the licensee failed to prepare adequate procedures for filling and venting of the Unit 3 Train B ECCS system while portions of the Train A ECCS system were crosstied to the SFP cooling system. This violation of the Technical Specifications is being treated as an NCV (NCV 05000362/2004005-01, failure to provide adequate ECCS/SFP crosstie procedures) consistent with Section VI.A of the Enforcement Policy. This violation is in the licensee’s corrective action program as Action Request (AR) 041100534.

2. Inadvertent Start of Unit 3 Train A Emergency Diesel Generator (EDG) 3G002

a. Inspection Scope

On December 2, 2004, the inspectors walked down the Unit 2 normal and emergency ac power systems following the inadvertent loss of one qualified electrical circuit between the offsite transmission network and the onsite Class 1E electrical power distribution system for approximately one hour (one inspection sample).

b. Findings

Introduction. A Green, self-revealing, NCV of TS 5.5.1.1 was identified for the failure of a maintenance technician to follow a maintenance order (MO) which led to the inadvertent actuation of several Unit 3 safety-related relays.

Description. On December 2, 2004, at approximately 2:47 a.m., the Unit 3 control room experienced several unexpected alarms associated with random safety-related equipment. In addition, the Unit 3 Train A EDG automatically started, along with the actuation of various safety-related equipment. Most of the equipment that actuated had no impact on Unit 3 because the unit was shut down and defueled as part of its Cycle 13 refueling outage.

The automatic start of the Unit 3 Train A EDG, however, resulted in the loss of the automatic crosstie feature of the Unit 3 Train A Class 1E 4 kV electrical safety bus and the Unit 2 Train A Class 1E 4 kV electrical safety bus. Because Unit 2 was operating at approximately full reactor power in Mode 1 at the time of the event, the loss of the automatic crosstie feature caused Unit 2 operators to enter the action statements for TS LCO 3.8.1, "AC Sources - Operating." This TS requires, in part, that two qualified electrical circuits between the offsite transmission network and the onsite Class 1E electrical power distribution system be operable in Mode 1. The two credited offsite circuits were derived from: (1) the Unit's own reserve auxiliary transformer and (2) the crosstie from the other Unit's 4 kV electrical safety bus. Unit 2 remained in the TS action statements for approximately one hour until Operations personnel determined that the cause of the automatic Unit 3 EDG start was due to the inadvertent manual actuation of the EDG's safety injection actuation system relay. The automatic crosstie feature between the two Units' safety buses was lost, as expected, because the actuation of the EDG from the safety injection actuation system relay caused the automatic crosstie feature of the safety buses to switch to manual.

The licensee determined that the event was caused by a maintenance technician who was working in the back panel area outside of the control room under MO 04110282000. The MO work plan required the technician to relocate a dropping resistor associated with a Unit 3 safety-related relay in the emergency feedwater actuation system. The relay and resistor were located in the Unit 3 Train A engineered safety features actuation system (ESFAS), Cabinet 3L034. Cabinet 3L034 remained energized as part of the approved MO. The maintenance technician indicated to the licensee that he believed that he needed to install two electrical jumpers in the relay circuitry in order to maintain the continuity of the electrical circuit. The first jumper was installed without any consequences. The second jumper was installed across the dropping Resistor R66 and Relay K-625A, which caused a voltage drop in the cabinet relay circuitry. The voltage drop resulted in the actuation of seven ESFAS relays and various safety-related equipment, including the Unit 3 Train A EDG.

The inspectors reviewed the work plan in MO 04110282000 and reviewed the relay electrical diagram with maintenance personnel. The installation of the two jumpers was

not specified in the MO work plan. The maintenance technician's assessment that the two jumpers were needed was determined to be incorrect. The inspectors also interviewed Operations personnel that were involved with the event and determined that they responded in accordance with plant operating instructions.

The inspectors also noted that this work could have been performed with Unit 3 at full power. Had the work been attempted then, Unit 3 could have received a main steam isolation and reactor trip signals.

Analysis. The failure of the maintenance technician to follow the work plan of the MO was determined to be a performance deficiency. The finding was determined to be more than minor because the initiating events cornerstone objective was affected by a human performance error that increased the likelihood of a loss of offsite power event. Based on the results of the significance determination process (Phase 1 evaluation), the finding was determined to have very low safety significance (Green) because the failure of the maintenance technician to follow the work plan of the MO did not contribute to both the likelihood of a reactor trip and simultaneously the lack of availability of mitigating equipment or functions. Both of Unit 2's EDGs were available.

The finding had crosscutting aspects in the area of human performance because the failure of the maintenance technician to follow the work plan of the MO was the direct cause of the finding.

Enforcement. TS 5.5.1.1 states, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, Section 9, "Procedures for Performing Maintenance," specifies that maintenance that can affect the performance of safety-related equipment should be properly preplanned and performed in accordance with documented instructions appropriate to the circumstances. Contrary to this criterion, on December 2, 2004, a maintenance technician failed to perform maintenance in accordance with MO 04110282000 for the relocation of a dropping resistor in Unit 3 Train A ESFAS Cabinet 3L034. This violation of the TSs is being treated as an NCV (NCV 05000362/2004005-02, failure to follow instructions for dropping resistor relocation) consistent with Section VI.of the Enforcement Policy. This violation is in the licensee's corrective action program as AR 041200074.

3. Complete System Walkdown

a. Inspection Scope

The inspectors conducted a detailed review of the alignment and condition of the Unit 3 CCW system (one inspection sample). The inspectors used the licensee procedures and other documents listed in the attachment to verify proper system alignment. The inspectors also verified electrical power requirements, labeling, hangers and support installation, and associated support systems status. Operating pumps were examined

to ensure that any noticeable vibration was not excessive, pump leakoff was not excessive, bearings were not hot to the touch, and the pumps were properly ventilated.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

The inspectors performed routine fire inspection tours, and reviewed relevant records, for the following six plant areas (six inspection samples) important to reactor safety:

- Containment (Unit 3)
- Train A safety equipment building pump Room 005 (Unit 2)
- Train B safety equipment building pump Room 002 (Unit 2)
- Train A CCW pump Room 008 (Unit 2)
- Train B CCW pump Room 006 (Unit 2)
- Charging Pump 2P192 Room 106C (Unit 2)

The inspectors observed the material condition of plant fire protection equipment, the control of transient combustibles, and the operational status of barriers. The inspectors compared in-plant observations with the commitments in portions of the Updated Fire Hazards Analysis Report.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

The inspectors performed an annual visual inspection of the plant intake structure (Units 2 and 3) to determine the operational status of seals, barriers, sumps, drains, and alarms to identify the existence of any unanalyzed flooding hazards. The inspectors also reviewed Updated Safety Analysis Report Chapter 3.4, “Water Level (Flood) Design,” revised June 2003.

The inspectors also performed periodic visual inspections to determine adequate safeguards were in place for the associated risk significant structures, systems, and components. The following two areas were inspected (two inspection samples):

- Unit 2 Safety Equipment Building
- Unit 3 Safety Equipment Building

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

1. Performance of Nondestructive Examination (NDE) Activities Other than Steam Generator Tube Inspections

a. Inspection Scope

The inspectors observed the ultrasonic system calibration and observed ultrasonic, magnetic particle, and visual examinations. The inspectors observed 15 examinations, which are listed below.

System	Component/Weld Identification	Examination Method
Main Feedwater	18" Nozzle Extension to Elbow / 03-044-010	Ultrasonic Examination
Main Feedwater	Nozzle to Extension / 03-042-043	Ultrasonic Examination
Main Steam	Header Extrusion to 6" Elbow / 03-052-500	Ultrasonic Examination
Main Steam	6" Elbow to Pipe / 03-052-510	Ultrasonic Examination
Main Steam	6" Pipe to Elbow / 03-052-520	Ultrasonic Examination
Main Steam	6" Elbow to Reducing Tee / 03-052-530	Ultrasonic Examination
Main Steam	6" Reducing Tee to Pipe / 03-052-540	Ultrasonic Examination
Main Steam	6" Pipe to Elbow / 03-052-550	Ultrasonic Examination
Main Steam	6" Elbow to Pipe / 03-052-560	Ultrasonic Examination
Main Steam	6" Pipe to Weld Cap / 03-052-570	Ultrasonic Examination
Main Steam	Header Extrusion to 6" Elbow / 03-052-500	Magnetic Particle Examination

System	Component/Weld Identification	Examination Method
Main Steam	6" Elbow to Pipe / 03-052-560	Magnetic Particle Examination
Main Steam	6" Pipe to Weld Cap / 03-052-570	Magnetic Particle Examination
Main Steam	Y-Stop / 03-052-740	Visual Examination, VT-3
Main Steam	Snubber / 03-052-810	Visual Examination, VT-3

During the review of these examinations, the inspectors verified that the correct NDE procedure was used, examinations and conditions were as specified in the procedures, and test instrumentation or equipment was properly calibrated and within the allowable calibration period. The inspectors also reviewed the documentation to determine whether indications revealed were compared against the American Society of Mechanical Engineers (ASME) Code-specified acceptance standards and whether the indications were appropriately dispositioned. The NDE certifications of those personnel observed performing examinations or identified during review of completed examination packages were reviewed by the inspectors.

b. Findings

No findings of significance were identified.

2. Steam Generator Tube Inspection Activities

a. Inspection Scope

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

The inspectors selected and reviewed the acquisition technique sheets and their qualifying EPRI examination technique specification sheets to verify that the essential variables regarding flaw sizing accuracy had been identified and qualified through demonstration.

The inspection procedure specified comparing the estimated size and number of tube flaws detected during the current outage against the previous outage operational assessment predictions to assess the licensee's prediction capability. The inspectors

reviewed the licensee's report, "Steam Degradation Assessment for the Cycle 13 Refueling Outages in 2004, Updated for Unit 3 in 2004." The purpose of the assessment is to identify degradation mechanisms and, for each mechanism, to determine proper detection technique; determine number of tubes; establish structural limits; and establish flaw growth rates.

The inspection procedure specified that confirmation be made that the steam generator tube eddy-current testing (ET) scope and expansion criteria meet TS requirements, EPRI guidelines, and commitments made to the NRC. The inspectors' review determined that the steam generator tube ET scope and expansion criteria were being met.

The inspection procedure also specified that, if the licensee identified new degradation mechanisms, then verify that the licensee had fully enveloped the problem in an analysis and had taken appropriate corrective actions before plant startup. At the time of this inspection, no new degradation mechanisms had been identified.

The inspection procedure also required confirmation that all areas of potential degradation were being inspected, especially areas which were known to represent potential ET challenges (e.g., top-of-tubesheet, tube support plates, and U-bends). The inspectors confirmed that all known areas of potential degradation, including ET-challenged areas, were included in the scope of inspection and were being inspected.

The inspection procedure further required that repair processes being used were approved in the TSs for use at the site. At the time of this inspection, the licensee had not performed or used the designated TS-approved repair processes; thus, there was no opportunity to observe implementation of any potential repairs (e.g., plugging operations). The inspectors also verified that none of the flawed tubes identified by the licensee required in-situ pressure testing.

The inspection procedure also required confirmation that the TS plugging limit was being adhered to and determination whether depth sizing repair criteria were being applied for indications other than wear or axial primary water stress corrosion cracking in dented tube support plate intersections. The inspectors confirmed that the licensee was adhering to these specifications.

The inspection procedure stated, if steam generator leakage greater than 3-gallons per day was identified during operations or during postshutdown visual inspections of the tubesheet face, to assess whether the licensee had identified a reasonable cause and corrective actions for the leakage based on inspection results. The inspectors did not conduct any assessment because this condition did not exist.

The inspection procedure required confirmation that the ET probes and equipment were qualified for the expected types of tube degradation and assessment of the site-specific qualification of one or more techniques. The inspectors observed portions of all ET

performed. During these examinations, the inspectors verified that: (1) the probes appropriate for identifying the expected types of indications were being used, (2) probe position location verification was performed, (3) calibration requirements were adhered to, and (4) probe travel speed was in accordance with procedural requirements. The assessment of site-specific qualifications of the techniques being used, including a listing of the specific techniques and qualifications reviewed, is addressed and identified in the table above.

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

b. Findings

No findings of significance were identified.

3. Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed eight inservice inspection-related condition reports issued during the current and past refueling outage and verified that the licensee identified, evaluated, corrected, and trended problems. In this effort, the inspectors evaluated the effectiveness of the licensee's corrective action process, including the adequacy of the technical resolutions.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

1. Quarterly Review of Requalification Activities

a. Inspection Scope

The inspectors reviewed licensed operator requalification training activities, including the licensed operators' performance and the evaluators' critique. The inspectors compared performance in the simulator on December 7, 2004 (one inspection sample), with performance observed in the control room during this inspection period.

The inspectors placed an emphasis on high-risk operator actions, operator activities associated with the emergency plan, and previous lessons-learned items. These items were evaluated to ensure that operator performance was consistent with protection of the reactor core during postulated accidents.

b. Findings

No findings of significance were identified.

2. Biennial Review of Requalification Activities

a. Inspection Scope

The inspector reviewed the annual operating examination test results for 2004 conducted between August 23 and September 23 and November 15 and December 15, 2004. This was the biennial requalification cycle in which the licensee administered the written and operating examination. These results were assessed to determine if they were consistent with NUREG 1021, "Operator Licensing Examination Standards for Power Reactors," Revision 8, Supplement 1, guidance and Manual Chapter 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process," requirements. This review included examination of test results, which included one failure during the job performance measures, no crew failures out of 14 crews and seven failures during the written examination out of 81 licensed operators. All personnel who failed were remediated and passed their remediation examinations prior to returning to licensed duties.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

1. Unit 3 Pressurizer Heater Sleeve Replacement

a. Inspection Scope

The inspectors independently verified that the licensee appropriately handled safety significant component performance associated with the Unit 3 pressurizer heater sleeve inspections (one inspection sample) and subsequent replacement. The inspectors reviewed ARs 041001522, 041001523, and 041100813 and discussed the replacement plan with Engineering personnel. The inspectors also independently examined the heater sleeves before, during, and following the replacement activities. The inspectors reviewed the NDE results for the replacement heater sleeves and discussed them with Engineering personnel.

b. Findings

No findings of significance were identified.

2. Radiation Monitors

a. Inspection Scope

The inspectors independently verified that the licensee appropriately handled safety significant component performance associated with the Units 2 and 3 radiation monitors (one inspection sample). The inspectors reviewed ARs 020101395, 020700544, and 040201606 and discussed the plan for improving radiation monitor performance with engineering and maintenance personnel.

b. Findings

No findings of significance were identified.

3. Pressurizer Spray Valve Maintenance

a. Inspection Scope

The inspectors reviewed the licensee's maintenance improvement plans to improve pressurizer spray valve performance (one inspection sample) following a November 4, 2002, Unit 2 pressurizer spray valve failure to close, which prompted Operations personnel to manually trip the reactor Licensee Event Report (LER) 05000361/2002-007-00, "Pressurizer Spray Valve Malfunction Results in a Reactor Trip," dated December 31, 2002). The inspectors reviewed the root cause and corrective actions proposed in the LER. Additionally, the inspectors reviewed AR 021100192, the results of valve inspections performed during the Unit 2 refueling outage performed in February 2004, and the Unit 3 refueling outage performed in November 2004. The inspectors also reviewed the maintenance improvement plan with plant Maintenance and Engineering personnel.

b. Findings

No findings of significance were identified.

4. EDG Maintenance

a. Inspection Scope

The inspectors reviewed the licensee's Directed Assessment Report to review EDG performance (one inspection sample). This assessment was performed by the licensee's engineering department in an effort to determine the actions necessary to improve overall EDG performance. The assessment covered EDG performance problems from January 2002 through August 2004. The inspectors independently reviewed the report and discussed areas for improvement with licensee personnel. The inspectors also reviewed AR 040800682 as part of the inspection.

b. Findings

No findings of significance were identified.

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

1. Improper High Pressure Safety Injection (HPSI) Check Valve Maintenance

a. Inspection Scope

The inspectors reviewed emergent work activities associated with maintenance performed on Unit 3 HPSI Pump 3P018 Discharge Stop Check Valve 3MU016 (one inspection sample).

b. Findings

Introduction. A Green, self-revealing, NCV of TS 5.5.1.1 was identified for the implementation of inadequate procedures that resulted in improper maintenance being performed on HPSI Discharge Stop Check Valve 3MU016.

Description. On May 25, 2004, Maintenance personnel performed corrective maintenance on Unit 3 HPSI Discharge Stop Check Valve 3MU016. The purpose of the corrective maintenance was to add antirotation lugs on the valve yoke to prevent inadvertent backing out of the yoke bushing during routine valve operation. This corrective maintenance had been previously performed successfully on Unit 2 for HPSI Pumps 2P019 and 2P018 Discharge Stop Check Valves 2MU015 and 2MU016, respectively. During the Unit 2 maintenance activities, work packages included instructions to grind down the anitrotation lugs to prevent interference with the valve handwheel. This interference could prevent fully shutting the valve during manual operation. However, the work package for Valve 3MU016 did not contain the grinding instructions. As a result, the antirotation lugs were not appropriately modified.

On September 30, 2004, a surveillance test was performed on HPSI Pump 3P018. As part of the surveillance, Valve 3MU016 was manually shut as part of a valve lineup to circulate water back to the RWST. However, since the antirotation lugs had not been appropriately modified, Valve 3MU016 was able to open approximately 1/4". The failure of 3MU016 to remain fully shut created a flow path from the RWST into the reactor coolant system. After HPSI Pump 3P018 was started, Operations personnel noted that pressurizer level increased from approximately 42 percent to approximately 70 percent and secured the surveillance test. HPSI Pump 3P018 ran at near runout conditions for approximately 5 minutes, which prompted the licensee to perform additional testing to demonstrate pump operability. The inspectors reviewed the operability assessment and found it satisfactory.

The licensee subsequently determined that the reason for the inadvertent addition of RWST water to the reactor coolant system was because Valve 3MU016 was not fully

shut. The licensee could offer no immediate explanation as to why the modification to Valve 3MU016 had not been properly specified in the maintenance procedures, or why an appropriate postmaintenance test was not performed on Valve 3MU016. The licensee indicated that an apparent cause evaluation would be performed. The cause evaluation was still in progress at the end of the inspection period. However, the inspectors determined that the improper modification performed on 3MU016 would not have prevented the valve from performing its safety function, but did prevent it from being manually shut for maintenance or testing purposes.

Analysis. The failure of the licensee to implement adequate maintenance procedures was considered a performance deficiency. The finding was determined to be more than minor because it affected the procedure quality attribute of the mitigating systems cornerstone. Based on the results of the significance determination process (Phase 1 evaluation), the finding was determined to have very low safety significance (Green) because the improper maintenance performed did not result in an actual loss of safety function.

The finding had crosscutting aspects in the area of human performance because the inadequate MO directly contributed to the cause of the finding.

Enforcement. TS 5.5.1.1 states, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, Section 9, “Procedures for Performing Maintenance,” specifies, in part, that maintenance that can affect the performance of safety-related equipment should be properly preplanned and performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances. Contrary to this criterion, on May 25, 2004, the licensee failed to implement adequate procedures to ensure maintenance was properly performed on Unit 3 HPSI Discharge Stop Check Valve 3MU016. This violation of TSs is being treated as an NCV (NCV 05000362/2004005-03, failure to implement adequate procedures for HPSI discharge stop check valve maintenance) consistent with Section VI.A of the Enforcement Policy. This violation is in the licensee’s corrective action program as AR 040901961.

2. Missing Taper Pins in CCW System Butterfly Valves

a. Inspection Scope

The inspectors reviewed emergent work associated with missing taper pins in CCW 28-inch Fisher butterfly valves (one inspection sample).

b. Findings

Introduction. A Green, self-revealing NCV of 10 CFR Part 50, Appendix B, Criterion XVI, was identified for the licensee's failure to determine the cause of missing taper pins in CCW 28-inch Fisher butterfly valves and to take appropriate corrective actions to prevent recurrence.

Description. On August 10, 1998, the licensee identified leakage on the Unit 3 CCW swing pump (3P025) Train B discharge Isolation Valve 3HV6228B (AR 980800529). On August 14, 1998, the licensee identified a second leak on the Pump 3P025 Train A suction Isolation Valve 3HV6222A (AR 980800878). These valves were both 28-inch Fisher butterfly valves and were estimated to have had a 50 gallon per minute (gpm) leak. At that time, the licensee attributed the problem for both valves to seat leakage. Engineering personnel determined that CCW system operability was not affected because both Valves 3HV6228B and 3HV6222A had a second valve in series (Valve 3HV6228A and Valve 3HV6222B, respectively) which provided an appropriate boundary for the prevention of CCW crosstrain leakage. As a result, the licensee determined that repairs for these valves did not need to be scheduled until the Unit 3 Cycle 13 refueling outage in October 2004. On August 25, 2004, the licensee was transferring CCW Pump 3P025 from Train B to Train A, when they discovered that a third valve (Pump 3P025 Train B discharge Isolation Valve 3HV6228A, AR 040801442), was leaking approximately 50 gpm. This resulted in a significant amount of crosstrain leakage from the Train A CCW system to Train B CCW system through both Train B discharge Isolation Valves 3HV6228A and 3HV6228B. Because of the excessive crosstrain leakage through these valves, the licensee entered an 8-hour shutdown action statement, TS 3.7.7.1, Condition B, for failure to meet the allowable CCW system leak rate of 18 gpm.

During the Unit 3 Cycle 13 refueling outage, the licensee drained portions of the CCW system to perform scheduled maintenance. While disassembling Valves 3HV6222A, 3HV6228B, and 3HV6228A, the licensee discovered a single taper pin missing from each of the valves. Each 28-inch butterfly valve utilizes five taper pins to secure the butterfly valve disc to the shaft. These pins are approximately 5 inches in length and 3/4 inch in diameter. Upon a preliminary review of San Onofre Nuclear Generating Station (SONGS) and industry operating experience, vender information, and failure modes analysis, the licensee concluded that the most likely cause was flow-induced vibration limited to CCW Pump 3P025 suction and isolation motor-operated valves. The design of these 28-inch Fisher butterfly motor-operated valves is such that full open requires that the valve disc be parallel to the direction of flow (90 degrees), allowing water to flow on both sides of the valve disc. As a result, a condition known as flow-induced vibration occurred due to the flow of water on both sides of the valve disc, which led to the dislodging of the taper pins.

The licensee performed an engineering assessment to determine the most probable location of the missing taper pins. Based on this assessment, the licensee concluded that the missing taper pins traveled to and remained in the Unit 3 CCW heat

exchangers. The inspectors reviewed the assessment, and because of the minimal amount of flow inside the CCW heat exchangers, the weight of the pins, and the height that a pin would need to travel before escaping, the inspectors concluded that the pins were most likely located in the Unit 3 CCW heat exchangers. The licensee also provided the resident inspectors with an evaluation that discussed why Unit 2's CCW 28-inch Fisher butterfly valves were considered operable. The licensee indicated that no crosstrain leakage had been identified on Unit 2. However, the licensee also indicated that they also intend to stake all safety-related valves in the Unit 2 CCW system during its next refueling outage scheduled for October 2005.

In 1993, the licensee discovered that two valves in the Unit 2 CCW system (CCW Pump 2P025 Train A suction Isolation Valve 2HV6222A, and CCW Pump 2P025 Train B suction Isolation Valve 2HV6224A) each had a single taper pin missing. In these two instances, the licensee replaced and staked the missing taper pins and took no further corrective actions. The inspectors determined that the licensee did not adequately evaluate the CCW system in 1993 to determine the cause of the missing taper pins or whether other valves in the system were susceptible to the same deficiency. The inspectors also noted that in 1993 the licensee relied on vendor information and did not independently assess the root cause of the missing taper pins. Additionally, the inspectors noted that the licensee failed to properly review the performance history of CCW system valves in 1998 and incorrectly concluded that the valve leakage was due to a valve seat problem instead of dislodged taper pins.

The licensee concluded that the appropriate corrective actions were to mechanically stake the taper pins associated with the safety-related valves in the CCW system. This clearly differed from the corrective actions taken in 1993, which only required staking of the valve with the missing taper pin. These corrective actions also differed from those planned in 1998, when the licensee incorrectly concluded that the leakage was caused by a valve seating problem.

The concept behind staking is that it mechanically displaces metal on the mating surfaces of the butterfly valve disc and shaft, effectively preventing relative motion between the joined components. The licensee determined that each unit has 16 safety significant valves in the CCW system that require staking.

Analysis

The failure to properly identify a significant condition adverse to quality and take corrective actions to prevent recurrence for Fisher butterfly valves was considered a performance deficiency. The finding was more than minor because it affected the equipment performance attribute of the mitigating systems cornerstone and, if left uncorrected, could result in a more significant safety concern. Missing taper pins increase the potential to render the CCW system inoperable due to crosstrain leakage, because the 50 gpm leak caused by a missing taper pin exceeds the operability leak rate limit of 18 gpm. Based on the results of the Significance Determination Process,

Phase 1 evaluation, the finding was determined to have very low safety significance (Green), because it did not result in an actual loss of safety function of the CCW system.

This finding also had crosscutting aspects associated with problem identification and resolution, because the condition was not properly corrected when previously identified.

Enforcement

Appendix B, Criterion XVI of 10 CFR Part 50, states, in part, that measures shall be established to ensure that significant conditions adverse to quality are promptly identified and corrective actions taken to prevent recurrence. Contrary to this criterion, the licensee failed to take corrective actions to prevent the dislodging of taper pins from 28-inch diameter Fisher butterfly valves in the CCW system. The issue was first identified in 1993 when the licensee discovered taper pins missing on two valves in the Unit 2 CCW system. The corrective actions taken in 1993 failed to prevent the recurrence of missing taper pins that was identified in 2004 in the Unit 3 CCW system during the Cycle 13 refueling outage. The licensee also failed to promptly identify that taper pins were missing from two Unit 3 CCW valves in 1998. The violation is being treated as an NCV (NCV 05000361; 362/2004005-04, failure to correct deficiencies within CCW system, 28-inch diameter Fisher butterfly valves) consistent with Section VI.A of the Enforcement Policy. This violation was entered into the licensee's corrective action program as AR 041002041.

3. Quarterly Assessment

a. Inspection Scope

The inspectors verified the accuracy and completeness of risk assessment documents and that the licensee's maintenance risk assessment program was being appropriately implemented. The inspectors also ensured that plant personnel were aware of the appropriate licensee established risk categories for maintenance activities, according to the risk assessment results and licensee program procedures.

The inspectors also reviewed selected emergent work items to ensure that overall plant risk was being properly managed and that appropriate corrective actions were being properly implemented.

The inspectors reviewed the effectiveness of risk assessment and risk management for the following two activities (two inspection samples):

- Unit 3 spent fuel handling machine failed hoist (AR 041001135)

- Unit 2 turbine and subsequent reactor trip due to failed generator deionization plates (ARs 0411011239 and 041101274)

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors observed operator response to nonroutine events during the inspection period. In addition to direct observation of operator performance, the inspectors reviewed procedural requirements, operator logs, and plant computer data to determine that the response was appropriate with that required by procedures and training. The following operator response was reviewed:

- On November 19, 2004, the inspectors observed the site response to an automatic Unit 2 reactor trip. A deionization plate in the main generator terminal box became dislodged and fell onto the Phase A isolated phase bus, which caused the main generator to trip. The main generator trip resulted in a turbine trip and ultimately the reactor trip. The inspectors observed operations personnel respond to the event and effectively place the unit in a stable shutdown configuration.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed selected operability evaluations to evaluate technical adequacy and to verify that operability was justified. The inspectors considered the impact on compensatory measures for each condition being evaluated and referenced the Updated Final Safety Analysis Report and TSs. The inspectors also discussed the evaluations with cognizant licensee personnel.

The inspectors reviewed six operability evaluations (six inspection samples) and cause assessments documented in the following ARs to ensure the operability was properly justified:

- AR 041100092, Fisher butterfly valve taper pins in the Unit 2 CCW system

- AR 041101079, Unit 2 CCW system with degraded noncritical loop to radwaste Isolation Valves 2HV6465 and 2HV6217

- Unit 2 steam generator thermal performance degradation due to secondary side tube scale deposits
- AR 041200363, Unit 3 Train A containment spray system with the SDC heat exchanger Outlet Valve 3HV8150, degraded
- AR 041101695, Unit 3 Startup Channel 2 count rate oscillations
- AR 041001213, Unit 2 Battery Bank 2B10 Cell 55 individual cell voltage below acceptance criteria

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

Cumulative Effects. The inspectors reviewed 15 operator workaround items (one inspection sample) to evaluate their cumulative effects on the reliability, availability, and potential for misoperation of a system and on the ability of operators to respond in a correct and timely manner to plant transients and accidents. The inspection included a review of the licensee's criteria and processes used for identifying and tracking deficiencies as operator workarounds. The review also focused on the length of time the identified workarounds had been in existence and the efforts initiated to resolve them.

Individual Effects. The inspectors reviewed the following operator workaround (one inspection sample) to determine if the functional capability of the system or human reliability in responding to an initiating event was affected by the workaround. The inspectors evaluated the effect that the operator workaround had on the operator's ability to implement abnormal or emergency operating procedures.

- Isolating Unit 2 letdown if temperature Isolation Valve 2TV0221 does not fully close when the close pushbutton is depressed due to insufficient pressure differential across the valve

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors observed and/or reviewed postmaintenance testing for the following three activities (three inspection samples) to verify that the test procedures and activities adequately demonstrated system operability:

- Unit 3 Train B SDC heat exchanger Outlet Isolation Valve 3HV8151 postmaintenance test per Procedure SO23-3-3.31.7, "Containment Spray/Shutdown Cooling Valve Testing - Offline," Revision 7, performed on November 4, 2004

- Unit 3 Train B CCW noncritical/critical loop Return Isolation Valve 3HV6219 postmaintenance test per Procedure SO23-3-3.31.3, "Component Cooling Water Valve Testing - Offline," Revision 10, performed on November 21 and 24, 2004

- Unit 3 Train B EDG 3G003 postmaintenace test per Procedure SO23-3-3.23, "Diesel Generator Monthly and Semi-Annual Testing," Revision 23, performed on December 17, 2004

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

The inspectors periodically observed and reviewed shutdown activities during the scheduled Unit 3 Cycle 13 refueling outage to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense in depth. The inspectors also verified that activities were performed in accordance with approved procedures and TS requirements.

The inspectors periodically evaluated plant conditions to verify that safety systems were properly aligned and that maintenance activities were controlled in accordance with the outage risk control plan. The inspectors verified that reactor coolant system inventory was properly controlled and that containment closure requirements were met. The inspectors also performed an independent inspection of containment prior to entry into Mode 3.

The following activities were evaluated:

- Plant shutdown in accordance with Procedure SO23-5-1.4, “Plant Shutdown to Hot Standby,” Revision 11
- Plant cooldown in accordance with Procedure SO23-5-1.5, “Plant Shutdown from Hot Standby to Cold Shutdown,” Revision 24
- Midloop operations in accordance with Procedure SO23-3-1.8, “Draining the Reactor Coolant System,” Revision 23
- Shutdown operations in accordance with Procedure SO23-5-1.8, “Shutdown Operations (Mode 5 and 6),” Revision 14
- Refueling operations in accordance with Procedure SO23-I-3.5, “Refueling Sequence,” Revision 9
- Containment inspection prior to startup in accordance with Procedure SO23-V-8.15, “Boric Acid Leak Inspection,” Revision 0
- Plant startup in accordance with Procedures SO23-5-1.3, “Plant Startup from Cold Shutdown to Hot Standby,” Revision 28, and SO23-5-1.3.1, “Plant Startup from Hot Standby to Minimum Load,” Revision 22

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed and/or reviewed performance and documentation for the following two surveillance tests (two inspection samples) to verify that the structures, systems, and components were capable of performing their intended safety functions and to assess their operational readiness:

- Unit 3 Main Steam Isolation Valve 3HV8204 surveillance test per Procedure “Main Steam Valve Testing - Offline,” Revision 6, performed on November 30, 2004
- Unit 2 Reactor Coolant System Daily Leak Rate Calculation per Procedure SO23-3-3.37, "RCS Leak Rate Calculation," Revision 20, performed on November 9, 2004

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

The inspectors verified the accuracy of data reported by the licensee for the following three performance indicators to ensure that the performance indicator color was correct for both Units 2 and 3:

Reactor Safety Cornerstone

- Reactor Coolant System Specific Activity (BI1)
- Reactor Coolant System Identified Leakage (BI2)
- Safety System Functional Failures (MS5)

The inspectors reviewed the performance indicator data for the last quarter of 2003 and the first three quarters of 2004. The inspectors reviewed NEI 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 2, and licensee operating logs. The inspectors discussed the status of the performance indicators and compilation of data with engineering personnel. Licensee performance indicator data were also reviewed against the requirements of Procedures SO23-NI-1, "NRC Performance Indicator Program," Revision 3, and SO23-XV-24, "Quarterly NRC Performance Indicator Process," Revision 2.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

1. Semiannual Review

a. Inspection Scope

The inspectors performed a semiannual review of licensee internal documents, reports, audits, and PIs to identify trends that might indicate the existence of more significant safety issues. The inspectors reviewed the following:

- ARs generated during the previous 6 months
- Station performance reports
- Weekly production performance reviews

- Corrective maintenance backlog
- Quality assurance audit executive summaries
- SONGS system health reports
- SONGS performance indicators

b. Findings

No findings of significance were identified. However, during the review the inspectors noted a trend where the licensee relied on vendor and/or contractor recommendations and analyses without adequately assessing the impact to SONGS. In each case, the lack of an adequate assessment by the licensee impacted a safety-related system. The following examples illustrate this trend:

- In August 2004, the Unit 2 Train B EDG 2G003 had its electronic governor upgraded from an analog version to a digital one. During the postmaintenance testing, the EDG unexpectedly tripped due to the actuation of a Volts/Hz relay. This relay provides an equipment protection feature to the generator portion of the EDG by comparing the ratio of the generator's voltage and engine's speed to a predetermined trip setpoint. As a result of the unexpected trip, the EDG remained unavailable for approximately 72 hours past it's original planned outage end time. The licensee's investigation of the incident revealed that the governor vendor recommended that the diesel engine speed be set at its minimum increasing ramp rate. The licensee accepted the recommendation without considering the effect on the Volts/Hz protective relay trip feature of their EDG. Had the licensee performed an adequate evaluation of the vendor recommendation, the unexpected tripping of the EDG would likely have been precluded.

- During the Unit 3 Cycle 13 refueling outage held this inspection period, the licensee replaced 29 pressurizer heater sleeves. Part of the work scope included the welding of sacrificial plugs into each pressurizer sleeve bore to allow for the partial filling with water of the pressurizer. A minimum weld pad thickness was needed over the sacrificial plug to ensure that the pressurizer would be leaktight. After the pressurizer was partially filled, the weld work continued and the licensee recognized that four weld pads were leaking. The licensee's analysis revealed that hot cracking of the weld pad had occurred at the interface of the sacrificial plug and the pressurizer base metal. The licensee determined that this type of cracking was expected given the materials involved and the geometry of the pressurizer. The cracking of the weld material did not affect the integrity of the in-service pressurizer pressure boundary because the cracked weld material was machined away as part of the original heater sleeve replacement work scope. The heater sleeve replacement and weld work were planned and conducted by a contract firm. This firm had performed similar work at another nuclear power facility. The only difference in the work at SONGS was the partial filling of the pressurizer before the completion of the entire heater

sleeve replacement work. If the licensee had adequately evaluated the contract firm's work plan, the unexpected pressurizer leaks would likely not have occurred.

- As described in Section 1R13.2 of this inspection report, the licensee discovered that 28-inch Fisher butterfly valves in the CCW system were susceptible to losing taper pins that attach the valve disk to the valve stem. The licensee originally identified the issue in 1993 and had the valve vendor evaluate the potential for the taper pins to become dislodged. The vendor concluded that properly seated taper pins would not become dislodged and did not recommend any corrective actions to prevent the loss of additional pins. During the Unit 3 Cycle 13 refueling outage, additional taper pins were discovered to have been dislodged in 1998 and 2004. The licensee subsequently took appropriate corrective actions to preclude the loss of additional taper pins. If the licensee would have taken these corrective actions in 1993 or in 1998 and not solely relied on the vendor recommendation not to take corrective actions, then the loss of additional taper pins in 1998 and 2004 would likely not have occurred.

2. Quarterly Review of Corrective Action Documents

a. Inspection Scope

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

b. Findings

No findings of significance were identified.

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

Section 1R13 describes a finding for a failure to take appropriate corrective actions to prevent taper pins from becoming dislodged from CCW 28-inch Fisher butterfly valves. The licensee initially identified this issue in 1993 and did not take the appropriate measures for ensuring that other valves within both units were not susceptible to this same condition.

4OA3 Event Followup

(Closed) LER 05000361/2002-007-00: Pressurizer Spray Valve Malfunction Results in a Reactor Trip

The LER was reviewed by the inspectors and was discussed in Section 1R12.3 of this report. No findings of significance were identified. This LER is closed.

4OA4 Crosscutting Aspects of Findings

Cross-References to Human Performance Findings Documented Elsewhere

Section 1R04 describes a finding where a maintenance technician failed to follow the work plan of an MO associated with work on a safety-related relay, which resulted in the temporary inadvertent loss of one qualified electrical circuit between the offsite transmission network and the onsite Class 1E electrical power distribution system for Unit 2.

Section 1R04 describes a finding where the implementation of inadequate procedures led to the inadvertent crosstie of the Unit 3 Train B refueling water storage tank to the Unit 3 SFP, which ultimately led to the flooding of the Unit 3 fuel handling building.

Section 1R13 describes a finding where a maintenance order failed to include adequate instructions to implement a design modification for safety injection Valve 3MU016, which resulted in the transfer of refueling water storage tank water into the RCS while Unit 3 was shut down.

4OA5 Other Activities

1. Temporary Instruction 2515/150: Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles

   a. Inspection Scope

   The inspectors observed and reviewed licensee activities associated with the reactor pressure vessel head and vessel head penetration nozzle inspection that were implemented in accordance with the requirements of Order EA-03-009.

   The licensee performed ultrasonic and eddy current examinations of all 91 control element drive mechanism (CEDM) penetrations, as well as, all 10 in-core instrumentation penetrations and the head vent penetration. The inspectors independently reviewed the inspection results for 12 of the penetrations. The licensee identified four nozzles (32, 56, 57, and 64) with axial indications that extend upward from below into the j-groove region. Three of the indications were bounded by the Westinghouse topical report limit of 75 percent throughwall. The indication on Nozzle 56 was 78 percent through-wall and required additional evaluation. The licensee

performed an embedded flaw repair consistent with a plant-specific relief request submittal that was approved on December 23, 2004, by the NRC headquarters staff.

The inspectors reviewed four examinations from the previous refueling outage. The licensee had not previously performed repairs so there were no prior repairs to review. The inspectors independently reviewed the licensee's implementation of the Westinghouse inspection method. This review included applicable procedures and personnel qualifications.

The licensee performed a 100 percent visual inspection of the Unit 3 reactor vessel head during the Cycle 13 refueling outage.

b. Findings

No findings of significance were identified.

2. Temporary Instruction (TI) 2515/153: Reactor Containment Sump Blockage

a. Inspection Scope

The inspectors reviewed licensee activities in response to NRC Bulletin 2003-01, "Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized Water Reactors (PWRs)." The TI was issued to assess the impact of potential postaccident debris blockage effects for the ECCS and containment spray system. The TI was inspected against Unit 2 during the Unit 2, Cycle 13, refueling outage and was documented in San Onofre Integrated Inspection Report 05000361/2004002; 05000362/2004002. This inspection period, the inspection of the TI, as it relates to Unit 3, was conducted during the Unit 3, Cycle 13, refueling outage.

In addition to reviewing the licensee's response to NRC Bulletin 2003-01, the inspectors reviewed the licensee's programs and procedures for performing containment walkdowns and controlling containment coating and insulating materials, as well as a comprehensive survey of current Unit 3 containment materials and their susceptibility during accident conditions to quantify potential debris sources.

The inspectors reviewed surveillance data obtained during the Unit 3 Cycle 13 refueling outage for ensuring containment integrity and containment recirculation sump operability. The inspectors verified that the surveillances included checks for gaps in recirculation sump screen flowpaths and for potential obstructions upstream of the recirculation sumps. The inspectors also verified that the surveillances contained steps to quantify potential debris sources.

b. Findings

No findings of significance were identified.

4OA6 Meetings, Including Exit

On October 15 and December 17, 2004, the inspectors presented the inspection results to Mr. J. Wambold, Mr. D. Nunn, and others who acknowledged the findings. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. The licensee identified several documents that were proprietary. The inspectors informed the licensee that these documents would be destroyed upon completion of their review.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

R. Allen, Supervisor, Reliability Engineering
C. Anderson, Manager, Site Emergency Preparedness
D. Axline, Engineer, Nuclear Regulatory Affairs
D. Brieg, Manager, Maintenance Engineering
G. Cook, Supervisor, Compliance
M. Cooper, Manager, Plant Operations
M. Goettel, Manager, Business Planning and Financial Services
M. Love, Manager, Maintenance
J. Madigan, Manager, Health Physics
A. Mahindrakar, ISI System Engineer, Maintenance Engineering
A. Matheny, Engineer, Systems Engineering/Steam Generators
C. McAndrews, Manager, Nuclear Oversight and Assessment
M. McBrearty, Engineer, Nuclear Regulatory Affairs
M. McDevitt, Supervisor, System Engineering
A. Meichler, Supervisor, Maintenance Engineering
M. Ney, Operator Initial Training Supervisor
D. Nunn, Vice President, Engineering and Technical Services
N. Quigley, Manager, Mechanical/Nuclear Maintenance Engineering
A. Scherer, Manager, Nuclear Regulatory Affairs
E. Schoonover, System Engineer, System Engineering
M. Short, Manager, Systems Engineering
T. Vogt, Manager, Operations
R. Waldo, Station Manager
T. Yackle, Manager, Design Engineering
J. Wambold, Vice President, Nuclear Generation

NRC personnel

Christian Araguas, Nuclear Safety Professional Development Program Participant

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Opened and Closed

05000362/2004005-01	NCV	Failure to provide adequate ECCS/SFP crosstie procedures (Section 1R04.1)

05000362/2004005-02	NCV	Failure to follow instructions for dropping resistor relocation (Section 1R04.2)
05000362/2004005-03	NCV	Improper HPSI check valve maintenance (Section 1R13.1)
05000361; 362/2004005-04	NCV	Missing taper pins in CCW system butterfly valves (Section 1R13.2)

Closed

05000361/2002-007-00	LER	Pressurizer Spray Valve Malfunction Results in a Reactor Trip (Sections 1R12.3 and 4OA3.1)

Discussed

None

LIST OF DOCUMENTS REVIEWED

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

Section 1R04: Equipment Alignments

Procedures
SO23-3-2.6.1, "CS/SDC/SFP Cooling Crosstie Operation," Revision 5

SO23-3-2.9, "Containment Spray System Operation," Revision 22

SO23-3-2.7.2, "Safety Injection System Removal/Return to Service Operation," Revision 11

SO23-2-17, "Component Cooling Water System Operation," Revision 18

SO23-2-17.1, "Component Cooling Water System Alignments," Revision 6

SO23-2-17.2, "Component Cooling Water System Outage Evolutions," Revision 5

SO23-3-3.27.2, "Weekly Electrical Bus Surveillance," Revision 13

Drawings
Piping and Instrument Diagram 40127ASO3, "Component Cooling Water System (Pumps) System No. 1203," Revision 24

Piping and Instrument Diagram 40127BSO3, “Component Cooling Water System (Tanks) System No. 1203,” Revision 25

Piping and Instrument Diagram 40127CSO3, “Component Cooling Water System (Heat Exchangers) System No. 1203,” Revision 27

Section 1R08 Inservice Inspection Activities

Procedures

SO23-V-8.15 ISS2, “Boric Acid Leak Inspection,” Revision 0

SO23-XXVII-3.51.3, “IntraSpect Eddy Current Analysis Guidelines for Inspection of Reactor Vessel Head Penetrations,” Revision 4

SO23-XXVII-3.51.6, “Pulser/Receiver Linear Procedure,” Revision 2

SO23-XXVII-3.51.7, “Reactor Head Stand Extensions Installation at SONGS,” Revision 0

SO23-XXVII-3.51.9, “CRDM/ICI UT Analysis Guidelines,” Revision 13

SO23-XXVII-4.89, “J-Weld Overlay,” Revision 0

SO23-XXVII-4.90, “Ambient Temperbead Welding,” Revision 0

SO23-XXVII-4.94, “Remote Flourescent Post-Emulsifable Dye Penetrant Exam and Acceptance Standard,” Revision 0

SO23-XXVII-4.95, “Liquid Penetrant Examination and Acceptance Standards for Welds, Base Metal and Cladding,” Revision 0

SO23-XXVII-4.96, “Guide Funnel Reattachment (Stainless to Inconel),” Revision 0

SO23-XXVII-4.97, “ID Weld Non-Temperbead OD,” Revision 0

SO23-XXVII-4.99, “Head Vent Repair,” Revision 0

SO23-XXVII-4.100, “Manual Weld Overlay of J-Weld from RPV Nozzle to Stainless Steel Cladding,” Revision 0

SO23-XXVII-4.102, “General Welding Standard for ASME Applications,” Revision 0

SO23-XXVII-4.103, “Welding Control Procedure for Joint Design,” Revision 0

SO23-XXVII-4.104, “RVHI Vent Tube J-Weld Eddy Current Examination,” Revision 0

SO23-XXVII-4.105, “RVHI Vent Tube ID &CS Wastage Eddy Current Examination,” Revision 0

SO23-XXVII-4.106, “RVHI CEDM Bottom OD Inspection,” Revision 0

SO23-XXVII-4.107, “Eddy Current Inspection of J-Groove Welds in Vessel Head Penetrations,” Revision 0

SO23-XXVII-4.108, “IntraSpect Eddy Current Inspection Procedure,” Revision 0

SO23-XXVII-4.109, “IntraSpect Ultrasonic Procedure,” Revision 0

SO23-XXVII-4.110, “Vent Tube Inspection Procedure Using Ultrasonic and Eddy Current,” Revision 0

SO23-XXVII-4.111,”Reactor Vessel Head Penetration Inspection Tool Operation for San Onofre,” Revision 0

SO23-XXVII-4.113, “Welding Control Procedure for Joint Design,” Revision 0

SO23-XXVII-4.114, “Visual Examination of Welds,” Revision 0

SO23-XXVII-4.116, “RVHI ICI Bottom Surface EC Array Probe Inspection,” Revision 0

SO23-XXVII-4.119, “RVHI ICI Bottom OD Surface EC Manual Probe Inspection,” Revision 0

SO23-XXVII-4.120, “UT Inspection of the ICI Penetrations from the ID and the Bottom Face,” Revision 0

SO23 XXVII-4.121, “SONGS ICI ID Tool Operation,” Revision 0

SO23XXVII-4.122, “Data Compliance Tracking for SONGS 3R13,” Revision 0

SO23-XXVII-20.47, “Magnetic Particle Examination,” Revision 2

SO23-XXVII-20.48, “Liquid Penetrant Examination (PT-10),” Revision 1

SO23-XXVII-20.49, “Visual Examination Procedure to Determine the Condition of Nuclear Parts, Components, or Surfaces (VT-1),” Revision 2

SO23-XXVII-20.51, “Visual Examination Procedure for Operability of Nuclear Components and Supports and Conditions Relating to Their Functional Adequacy (VT-3),” Revision 2

SO23-XXVII-20.55, “Ultrasonic Examination of Austenitic Vessels, Two Inches and Less in Thickness,” Revision 4

SO23-XXVII-20.59, “Planar Flaw Characterization to ASME Section XI Code Requirements,” Revision 1

SO23-XXVII-20.66, “Ultrasonic Examination of Vessel Welds and Adjacent Base Metal,” Revision 2

SO23-XXVII-30.1, “Ultrasonic Thickness Measurements,” Revision 0

SO23-XXVII-30.3, “Visual Examination Procedure to Determine the Condition of Containment Surfaces and Gaskets, Seals, and Moisture Barriers,” Revision 0

O23-XXVII-30.4, “Visual Examination Procedure to Detect Evidence of Degradation of Containment Structural Integrity or Leak Tightness,” Revision 0

SO23-XXVII-30.5, “Ultrasonic Examination of Ferritic Piping Welds,” Revision 1

SO23-XXVII-30.6, “Ultrasonic Examination of Austenitic Piping Welds,” Revision 2

SO23-XXVII-30.7, “Ultrasonic Examination of Bolts and Studs,” Revision 1

SO23-XXVII-30.8, “Ultrasonic Through Wall Sizing in Pipe Welds,” Revision 1

SO23-XXVII-30.10, “Ultrasonic Examination of Reactor Vessel Closure Head Welds and Adjacent Base Metal,” Revision 2

SO23-XXVII-30.11, “Manual Through Wall and Length Sizing of Ultrasonic Indications in Reactor Pressure Vessel Welds,” Revision 1

Action Requests

020200056	020600777	030101368	030800241	031201398
020600661	030100634	030301214	031201002	040100049

Maintenance Order

04030057001

Weld Records

WR3-04-333
WR3-04-334
WR3-04-339
WR3-04-349

Section 4OA5.1: TI 2515/150: Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles

Procedures

SO23-V-8.15 ISS2, “Boric Acid Leak Inspection,” Revision 0

SO23-XXVII-3.51.3, “IntraSpect Eddy Current Analysis Guidelines for Inspection of Reactor Vessel Head Penetrations,” Revision 4

SO23-XXVII-3.51.6, “Pulser/Receiver Linear Procedure,” Revision 2

SO23-XXVII-3.51.7, “Reactor Head Stand Extensions Installation at SONGS,” Revision 0

SO23-XXVII-3.51.9, “CRDM/ICI UT Analysis Guidelines,” Revision 13

SO23-XXVII-4.89, “J-Weld Overlay,” Revision 0

SO23-XXVII-4.90, “Ambient Temperbead Welding,” Revision 0

SO23-XXVII-4.99, “Head Vent Repair,” Revision 0

SO23-XXVII-4.100, “Manual Weld Overlay of J-Weld from RPV Nozzle to Stainless Steel Cladding,” Revision 0

SO23-XXVII-4.102, “General Welding Standard for ASME Applications,” Revision 0

SO23-XXVII-4.103, “Welding Control Procedure for Joint Design,” Revision 0

SO23-XXVII-4.104, “RVHI Vent Tube J-Weld Eddy Current Examination,” Revision 0

SO23-XXVII-4.105, “RVHI Vent Tube ID &CS Wastage Eddy Current Examination,” Revision 0

SO23-XXVII-4.106, “RVHI CEDM Bottom OD Inspection,” Revision 0

SO23-XXVII-4.107, “Eddy Current Inspection of J-Groove Welds in Vessel Head Penetrations,” Revision 0

SO23-XXVII-4.108, “IntraSpect Eddy Current Inspection Procedure,” Revision 0

SO23-XXVII-4.109, “IntraSpect Ultrasonic Procedure,” Revision 0

SO23-XXVII-4.110, “Vent Tube Inspection Procedure Using Ultrasonic and Eddy Current,” Revision 0

SO23-XXVII-4.111, “Reactor Vessel Head Penetration Inspection Tool Operation for San Onofre,” Revision 0

SO23-XXVII-4.113, “Welding Control Procedure for Joint Design,” Revision 0

SO23-XXVII-4.114, “Visual Examination of Welds,” Revision 0

SO23-XXVII-4.116, “RVHI ICI Bottom Surface EC Array Probe Inspection,” Revision 0

SO23-XXVII-4.119, “RVHI ICI Bottom OD Surface EC Manual Probe Inspection,” Revision 0

SO23-XXVII-4.120, “UT Inspection of the ICI Penetrations from the ID and the Bottom Face,” Revision 0

SO23 XXVII-4.121, “SONGS ICI ID Tool Operation,” Revision 0

SO23XXVII-4.122, “Data Compliance Tracking for SONGS 3R13,” Revision 0

Section 4OA5.2: TI 2515/153: Reactor Containment Sump Blockage

San Onofre Response to NRC Bulletin 2003-01, “Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized Water Reactors,” dated August 1, 2003

San Onofre Final Safety Analysis Report Section 6.2, “Containment Systems,” Revision 16

Southern California Edison Memorandum on Unit 3 Containment Coating Walkdowns dated October 1, 2004

Unit 3 Cycle 13 Refueling Outage Containment Coatings Walkdown Summary per MO 03210100

Procedure SO23-1-2.53, “Containment Emergency Sump Inspection Surveillance,” Revision 6

Procedure SO23-3-2.34, “Containment Access Control, Inspections, and Airlocks,” Revision 16

LIST OF ACRONYMS

AR	action request
ASME	American Society of Mechanical Engineers
CCW	component cooling water
CEDM	control element drive mechanism
CFR	*Code of Federal Regulations*
CS	containment spray
ECCS	emergency core cooling system
EDG	emergency diesel generator
EPRI	Electric Power Research Institute
ESFAS	engineered safety features actuation system
ET	eddy-current testing
HPSI	high pressure safety injection
ICI	incore instruments
LER	licensee event report
MO	maintenance order
NCV	noncited violation
NDE	nondestructive examination
RWST	refueling water storage tank
SDC	shutdown cooling
SFP	spent fuel pool
SONGS	San Onofre Nuclear Generating Station
TI	temporary instruction
TS	Technical Specifications