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

April 28, 2003

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
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SUBJECT: SAN ONOFRE NUCLEAR GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 50-361/03-02; 50-362/03-02

Dear Mr. Ray:

On March 29, 2003, the NRC completed an inspection at your San Onofre Nuclear Generating Station, Units 2 and 3, facility. The enclosed report documents the inspection findings which were discussed on January 22 and 24, February 5 (by telephone), and April 1, 2003, with Mr. D. Nunn and other members of your staff.

This inspection 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. Within these areas, the inspection consisted of selected examination of procedures and representative records, observations of activities, and interviews with personnel.

Based on the results of this inspection, the NRC has identified six issues that were evaluated under the Significance Determination Process as having very low safety significance (Green). The NRC has also determined that violations are associated with five of these issues. These violations are being treated as noncited violations (NCVs), consistent with Section VI.A of the Enforcement Policy. These NCVs are described in the subject inspection report. If you contest the violation or significance of these NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the San Onofre Nuclear Generating Station, Units 2 and 3, facility.

In accordance with 10 CFR 2.790 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).

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

/RA/

Claude E. Johnson, Chief
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Dockets: 50-361
50-362
Licenses: NPF-10
NPF-15

Enclosure:
NRC Inspection Report
50-361/03-02; 50-362/03-02

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Dockets:	50-361, 50-362
Licenses:	NPF-10, NPF-15
Report No.:	50-361/03-02, 50-362/03-02
Licensee:	Southern California Edison Co.
Facility:	San Onofre Nuclear Generating Station, Units 2 and 3
Location:	5000 S. Pacific Coast Hwy. San Clemente, California
Dates:	December 29, 2002, through March 29, 2003
Inspectors:	C. C. Osterholtz, Senior Resident Inspector M. A. Sitek, Resident Inspector R. V. Azua, Project Engineer W. M. McNeill, Senior Reactor Inspector M. P. Shannon, Senior Health Physicist
Approved By:	C. E. Johnson, Chief Project Branch C Division of Reactor Projects

SUMMARY OF FINDINGS

San Onofre Nuclear Generating Station, Units 2 and 3
NRC Inspection Report 50-361/03-02; 50-362/03-02

IR 05000361/2003-002, 05000362/2003-002; 12/29/2002-3/29/2003; San Onofre Nuclear Generating Station, Units 2 & 3; Integrated Resident/Region Rpt; Inservice Insp, Maint Effectiveness, Maint Risk Assmts & Emergent Work Eval, Surv Test

The inspection was conducted by resident inspectors and regional reactor inspectors. This inspection identified six Green findings, five of which were noncited violations. The significance of the issues is indicated by their color (Green, White, Yellow, Red) using NRC Inspection Manual Chapter 0609 "Significance Determination Process." 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. <u>Inspector-Identified and Self-Revealing Findings</u>

Cornerstone: Barrier (Reactor Coolant System)

- Green. During the Unit 3 Cycle 11 refueling outage in January 2001, eddy current technicians failed to identify a steam generator tube flaw indication in Row 54, Column 90, for additional examination and evaluation, as required by procedure. As a result, the steam generator tube remained in service for an additional operating cycle without the appropriate verification that the tube met its barrier integrity design requirements.

  A self-revealing noncited violation of Appendix B, Criterion V, was identified. This finding was more than minor because it affected the Barrier System cornerstone objective of barrier performance in that it created the potential to permit tubes to remain in service that did not meet design requirements for accident conditions. The finding has very low safety significance because, although degraded, the tube remained operable until taken out of service in the Cycle 12 refueling outage (Section 1R08).

Cornerstone: Initiating Events

- Green. The licensee failed to have an adequate preventive maintenance procedure to conduct functional testing of the Unit 3 main transformer/generator protective relays. As a result, a maintenance technician inadvertently caused a reactor trip of Unit 2.

  This self-revealing finding was considered to be more than minor because it resulted in an unnecessary challenge to the reactor protective system and upset plant stability. However, the finding was considered to have very low safety significance because the reactor trip was uncomplicated; operations personnel quickly placed the plant in a stable shutdown condition; and mitigating equipment responded as designed (Section 1R12.1)

- Green. The licensee failed to ensure that a reactor coolant pump vapor stage gasket had been properly installed in accordance with procedural requirements. A crosscutting human performance deficiency in the compliant use of procedures directly contributed to this violation.

  A self-revealing noncited violation of Technical Specification 5.5.1.1 was identified. The issue had a credible impact on safety because, if left uncorrected, the leak could become a more significant safety concern in that corrosive boric acid could have degraded a reactor coolant pump casing and reactor coolant system piping. The issue is therefore more than minor. However, the finding was determined to have very low safety significance because the leak was very small, did not contribute to the likelihood of a loss of coolant accident or a reactor trip, did not affect the likelihood that mitigation equipment functions would not be available, and did not increase the likelihood of fire or flooding (Section 1R13.1).

- Green. An inadequate procedure was implemented to remove the core barrel from the Unit 3 reactor vessel during the Unit 3 Cycle 12 refueling outage. The use of the inadequate procedure resulted in a small amount of damage to the stainless steel reactor vessel lining.

  A self-revealing noncited violation of Technical Specification 5.5.1.1 was identified. The issue had a credible impact on safety because, if left uncorrected, it would become a more significant safety concern in that it could result in the inadvertent introduction of foreign material into the reactor coolant system and unnecessary personnel exposure to implement repairs. The issue is therefore more than minor. However, the finding was determined to have very low safety significance because the damage to the reactor vessel lining did not affect its operability and did not contribute to the likelihood of an initiating event (Section 1R13.2).

- Green. The licensee failed to ensure that packing material for a heated junction thermocouple penetration on the Unit 3 reactor vessel head was installed in accordance with procedural requirements. A crosscutting human performance deficiency in the compliant use of procedures directly contributed to this violation.

  A self-revealing noncited violation of Technical Specification 5.5.1.1 was identified. This issue had a credible impact on safety because, if left uncorrected, the finding would become a more significant safety concern in that reactor coolant system inventory would be lost and boric acid would be introduced to the reactor vessel head. However, the finding was determined to have very low safety significance because the leak was small, did not affect any plant mitigating equipment, and was discovered and repaired while the plant was in a shut down and cooled down condition with primary system pressure equal to or less than 150 psig (Section 1R13.3).

Cornerstone: Mitigating Systems

- Green. The licensee implemented an inadequate procedure that did not ensure that electrical leads in safety-related circuitry were properly landed.

A inspector identified noncited violation of Technical Specification 5.5.1.1 was identified. The finding was considered to be more than minor because the reliability and capability of a portion of the safety injection system was compromised when Valve 2HV9323 failed to open on a simulated safety injection actuation signal. However, the finding was determined to have very low safety significance because the three other Train B high pressure safety injection header isolation valves were operable and capable of opening on a safety injection actual signal to allow injection into the reactor coolant system. As a result, the actual safety function of Train B of the safety injection system remained intact because only two of the four valves are needed (Section 1R22.1).

REPORT DETAILS

Summary of Plant Status:

Unit 2 began this inspection period at approximately 100 percent power. On the morning of February 1, 2003, a maintenance technician inadvertently caused the Unit 2 main generator to trip on loss of excitation voltage which led to a turbine trip and subsequently a reactor trip. The generator trip resulted in a slow transfer of some of the non-class 1E electrical buses, unexpectedly causing the loss of some electrical loads. For example, the main feed pump lubricating oil pumps tripped, in turn causing the main feed pumps to trip and auxiliary feedwater to be initiated. The plant operated as designed; however, operations personnel were not fully aware that the loss of main feedwater (tripping of the main feed pumps) was expected for that type of generator-induced reactor trip. Operators, however, entered Procedure SO23-12-1, "Standard Post Trip Actions," Revision 18, and stabilized the plant in Mode 3. After understanding the cause of the trip and the status of plant equipment, operators returned Unit 2 to Mode 1 later that same day. Reactor power was held at 98.6 percent for several days while a 5th-point feedwater heater tube leak was repaired. Unit 2 was returned to approximately 100 percent power on February 6, 2003, where it remained through the rest of this inspection period.

Unit 3 began this inspection period at approximately 100 percent power. On January 6, 2003, Unit 3 was shut down for a scheduled refueling outage (Cycle 12) and entered Mode 6 refueling operations on January 10, 2003. Refueling operations were completed, and Unit 3 entered Mode 5, on February 9, 2003. Operations personnel commenced a reactor startup and entered Mode 2 on February 16, 2003. Unit 3 entered Mode 1 on February 17, 2003, and reached approximately 98.6 percent power on February 19, 2003. Unit 3 was limited to, and remained at, approximately 98.6 percent power while the calibration of newly installed ultrasonic flow and temperature measuring devices was performed. On March 12, 2003, Unit 3 returned to approximately 100 percent power, where it remained through the end of this inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

The inspectors performed two partial walkdowns of the following trains of equipment during maintenance outages of their redundant trains:

- Unit 2 Trains A and B ac electrical alignment, during maintenance on Unit 3 Bus 3A04. Maintenance on Bus 3A04 caused the loss of the cross-connect function to the Unit 3 reserve auxiliary transformer (the alternate source of off site power for Unit 2) on January 15, 2003

- Unit 3 Train A saltwater cooling system during Train B saltwater cooling online valve test on February 3, 2003

The inspectors physically verified critical portions of the trains to identify any discrepancies between the existing and proper alignment as determined by electrical distribution drawings and plant procedures.

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 important to reactor safety:

- Unit 2/3 turbine building 9' level secondary relay room
- Unit 2/3 turbine building 9' level cable spreading room
- Unit 3 Battery Room 3D5 (Battery Bank 3B011)
- Unit 3 Battery Room 3D1 (Battery Bank 3B007)
- Unit 2 Battery Room 2D2 (Battery Bank 2B008)
- Unit 2 Battery Room 2D4 (battery bank 2B010)

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 the portions of the Updated Fire Hazards Analysis Report.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

a. Inspection Scope

The inspectors reviewed performance tests for Unit 3 component cooling water Heat Exchangers S31203ME001 and S31203ME002 and reviewed the test acceptance criteria and results.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

a. Inspection Scope

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

The inspectors observed licensee and contractor NDE personnel perform the ASME Code Section XI examinations listed below:

System	Component/Weld Identification	Examination Method
Reactor Coolant	Reactor Vessel Closure Studs Zone 03-001 #37 to #42	Ultrasonic Examination
Main Steam	Pipe to Elbow Zone 053-120 to 150	Ultrasonic Examination
Main Steam	Pipe to Valve Zone 053-260	Magnetic Particle Examination

During the performance of each examination, the inspectors verified that the licensee used the correct NDE procedure, met the procedural requirements specified in the procedure, and used properly calibrated test instrumentation or equipment. The inspectors verified that the licensee compared the indications revealed by the examinations against the previous outage examination reports. The licensee found the only geometric recordable indications.

The licensee performed 19 welding repairs under Section III of the ASME Code for Class 1 and 2 components since the last outage. The inspectors reviewed a sample of two maintenance orders on the repair and replacement of a charging pump discharge check valve. The inspectors reviewed the radiographic film of the replacement welding. The inspectors verified that the repair activities met ASME Code requirements.

The inspectors found 10 repair or replacement activities underway during the current outage. The inspectors reviewed a sample of two ASME Code Section XI valve repair/replacements activities (Construction Work Orders 0106705000 and 01071370000) on replacement of two pressurizer heaters. The inspectors observed the welding and nondestructive examinations performed in accordance with these work orders. The inspectors verified that the replacements met ASME Code requirements.

.2 SG Tube Inspection Activities

The inspectors reviewed the leakage history for the SGs to verify that the leakage was less than 3 gallons per day during operations. The licensee and licensee contractors used properly qualified eddy current probes and equipment for the expected types of tube degradation. The inspectors observed the collection and analysis of eddy current data by contractor personnel performed to evaluate tubes and a possible loose part in a

SG. The inspectors found that the licensee had reviewed the areas of potential degradation based on site-specific and industry experience. The recent industry experience included the events which occurred at the Comanche Peak Steam Electric Station late in 2002. The inspectors verified that the licensee compared flaws detected during the current outage against the previous outage data. The inspectors reviewed the repair criteria used. The inspectors also verified that the licensee's eddy current examination scope and expansion criteria met the Technical Specifications, industry guidelines, and commitments to the NRC.

At the time of this inspection, the inspectors found the scope of in-situ pressure testing had not been established. The inspectors verified that the predictions of tube plugging appeared to be the same as experienced in the past. Plugging had not begun at the time of this inspection.

.3 Identification and Resolution of Problems

The inspectors reviewed the condition reports and disposition requests issued during the past year and reviewed in detail four action requests on SG eddy current inspection activities. The licensee issued only four action requests (ARs) in the past 2 years on the subject of inservice inspection and SG eddy current inspection activities. The inspectors verified that the licensee identified, evaluated, corrected, and trended problems.

b. Findings

Introduction

During the Unit 3 Cycle 11 refueling outage in January 2001, eddy current technicians failed to identify a SG tube flaw indication in Row 54, Column 90, for additional examination and evaluation, as required by procedure. As a result, the SG tube remained in service for an additional operating cycle without the appropriate verification that the tube met its barrier integrity design requirements.

Description

During the Cycle 12 refueling outage, the licensee eddy current technicians found a wear indication (71 percent through wall) in Tube Row 54, Column 90, in SG 3E089. The contractors found that the flaw at Elevation DBC (the first diagonal bar in the cold leg) existed in the previous outage (Cycle 11) bobbin probe data. When the contractors reviewed the data from the Cycle 11 refueling outage during the Cycle 12 refueling outage, they found the primary and secondary analysts did not report the indication during the Cycle 11 outage. During the current outage, the contractors found the flaw indication clearly identifiable in the Cycle 11 refueling outage data. Based on the bobbin coil data, the licensee estimated the flaw depth at 40 percent through the wall. The inspectors noted that the flaw did not exceed the Technical Specification repair limit (44 percent through wall). The SG tube subsequently passed in-situ pressure testing at three times the normal operating pressure, indicating that the tube had retained the ability to withstand design basis pressures under accident conditions. The inspectors concluded that the degraded tube had remained operable until taken out of service during the Cycle 12 refueling outage.

Analysis

The finding was more than minor since it affected the barrier system cornerstone objective of barrier performance in that it created the potential to permit tubes to remain in service that did not meet design requirements for accident conditions. The finding is of very low safety significance (Green) because, although degraded, the tube remained operable until taken out of service in the Cycle 12 refueling outage.

Enforcement

The inspectors concluded that failure to report a wear indication was a noncited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." Criterion V requires procedure compliance. Procedure SO23-XXVII-23.1, "Multi-Frequency Eddy Current Examination of Tubing," Revision 10, Temporary Change Notice 2, paragraph 8.2, requires the analyst to follow the applicable bobbin exam, “Examination Technique Specification Sheet.” The applicable bobbin exam, “Examination Technique Specification Sheet,” requires the reporting of an indication during bobbin examination so that the indication may be more fully evaluated by a resolution analyst with, perhaps, a rotating pancake probe. The failure to identify flaws which required re-examination could result in a degraded SG. The licensee entered this finding in its corrective action program as AR 30101328-01. As corrective action, the licensee staff again reviewed the current outage data and found four additional indications not reported during the original Cycle 12 refueling outage analysis (NCV 361; 362/20003002-01).

1R12 Maintenance Effectiveness (71111.12)

.1 Unit 2 Loss of Generator Excitation Trip

a. Inspection Scope

The inspectors reviewed the effectiveness of the preventive maintenance that was performed on February 5, 2003, on the protective circuits of the Unit 3 main transformer which resulted in an automatic actuation of the reactor protective system (RPS) on Unit 2, causing Unit 2 to automatically trip.

b. Findings

Introduction

The inspectors determined that the licensee did not have an adequate preventive maintenance procedure for performing work on the protective circuits for the Unit 3 main transformer that tripped the Unit 3 non-Class 1E 6.9 kV supply breakers. The failure to have an adequate procedure resulted in the inadvertent actuation of the Unit 2 RPS, causing Unit 2 to trip automatically. This finding is being documented as a noncited violation with a very low safety significance (Green).

Description

On February 1, 2003, as part of Unit 3 outage activities, a maintenance technician set up test equipment in Unit 3 Relay Protection Cabinet 3L070 to conduct functional testing on the protective circuit schemes for the Unit 3 main transformer and main generator. The technician intended to verify that the Unit 3 6.9 kV transformer breakers would trip open on valid main transformer or generator protection signals. In order to prevent actual cycling of the 6.9 kV breakers during each protective scheme circuit test, the maintenance technician installed a 100 watt light bulb into the protective circuit at the final terminal that provides the trip signal to the 6.9 kV breaker. The lighting of the bulb would demonstrate that sufficient current existed to force open the 6.9 kV breaker. The Unit 2 dc distribution system supplied the control for the Unit 3 6.9 kV breaker. As a result, the technician needed to establish a control power reference within Unit 2 Relay Protection Cabinet 2L070, to allow the test light bulb to complete the simulated trip circuit. The technician incorrectly identified Terminal TT-6 in Relay Protection Cabinet 2L070-07 as the reference terminal. The technician failed to recognize that the use of this terminal would complete the circuit for the field suppression relay for the Unit 2 main generator. Consequently, when the functional test was initiated, the Unit 2 field suppression relay immediately actuated, resulting in the actuation of the Unit 2 generator loss of field relay trip and, subsequently, a turbine trip and a reactor trip. The reactor trip was uncomplicated and all mitigating systems responded as designed for this type of generator-induced reactor trip.

The inspectors reviewed the procedural guidance that was developed for conducting the relay functional tests. The licensee relied on the generic instructions in Procedure SO123-II-11.152, “Circuit Device Tests and Overall Functional Tests,” Revision 6; prejob briefings; a generic trip test checklist; and technician skill-of-the-craft to set up the test circuit for the functional tests. A specific procedure did not exist to provide instructions on how to complete the test circuit or from where to establish the control power reference voltage.

The 6.9 kV voltage buses are non-Class 1E and are normally supplied from the unit auxiliary transformer (UAT). These buses can also be supplied from a reserve auxiliary transformer or through a cross-tie to one of the other unit’s UATs. The 6.9 kV voltage buses supply power to the unit’s four reactor coolant pumps. The control power for the 6.9 kV breakers is normally supplied from the opposite unit’s dc distribution system.

Analysis

The inspectors evaluated the significance of the finding using the Significance Determination Process. The inspectors determined that the issue had a credible impact on the initiating events cornerstone because a reactor trip event occurred. The finding was considered to be more than minor because it resulted in an unnecessary challenge to the reactor protective system and upset plant stability. However, the reactor trip was uncomplicated, operations personnel quickly placed the plant in a stable shutdown condition, and mitigating equipment was available and responded as designed. As a result, the event did not contribute to the likelihood of a primary or secondary system loss of coolant accident, and it did not increase the likelihood of a fire or a flood. Subsequently, the finding was considered to have very low safety significance (Green).

Enforcement

No violation of regulatory requirements occurred. This finding (FIN 361/2003002-02) is in the licensee's corrective action program as AR 030200027.

.2 Reactor Coolant Pump 3P002 Corrective Maintenance

a. Inspection Scope

The inspectors independently reviewed the licensee's corrective maintenance plan for decreasing erosion in the Reactor Coolant Pump 3P002 heat exchanger. The inspectors reviewed AR 030200567 and discussed the maintenance plan and postwork results with engineering and maintenance personnel.

b. Findings

No findings of significance were identified.

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

.1 Reactor Coolant Pump 3P004 Vapor Stage Leakoff Line Leak

a. Inspection Scope

The inspectors reviewed emergent work associated with a reactor coolant system (RCS) leak through a reactor coolant pump vapor stage leakoff line.

b. Findings

Introduction

The inspectors determined that the licensee did not adequately follow procedures when scheduled maintenance was performed on Reactor Coolant Pump 3P004 during the March 1998 Unit 3 Midcycle 9 refueling outage. This finding is being documented as a noncited violation with a very low safety significance (Green).

Description

On January 6, 2003, the licensee performed a Unit 3 containment walkdown. The unit was in Mode 3 in preparation for the scheduled Cycle 12 refueling outage. During the walkdown, dry boric acid was observed on the top of the seal adapter for Reactor Coolant Pump 3P004. On January 7, the licensee accessed the pump shroud and noted a small buildup of boric acid on the Reactor Coolant Pump 3P004 heat exchanger. On January 17, the licensee disassembled the Reactor Coolant Pump 3P004 heat exchanger and discovered that the gasket for the vapor stage leakoff line was missing.

The Reactor Coolant Pump 3P004 heat exchanger had not been worked on since the Unit 3 Midcycle 9 refueling outage that was performed in March 1998. At that time, the Reactor Coolant Pump 3P004 vapor stage leakoff line was noted to be clogged and was therefore disassembled and inspected. A portion of the vapor stage leakoff line piping was replaced. During this piping replacement, maintenance workers reassembled the leakoff line flange joint to Reactor Coolant Pump 3P004 without its gasket to prevent foreign material exchange. During leakoff line reassembly, maintenance workers inaccurately assumed that the gasket was installed, since the flange joint to Reactor Coolant Pump 3P004 was already connected.

The licensee concluded that the gasket had been missing since March 1998. The vapor stage line is normally at containment pressure and delivers a few drops a minute of expected vapor stage leakoff to a containment sump. The licensee concluded that the observed boric acid was the result of an extremely small leak rate over a long period of time. The leak rate was estimated to be approximately 0.001 gpm. The licensee also noted that the area around Reactor Coolant Pump 3P004 had been inspected in March 2001 with no evidence of leakage observed.

The inspectors reviewed Maintenance Order (MO) 98030745002, the maintenance work order used in March 1998 for working on Reactor Coolant Pump 3P004. Step 08 of the Work Plan Detail section of the MO stated:

> When directed, reassemble the leakoff lines flange joints to their original configuration. Tighten all flange bolting using torque manual, M-37204.

The inspectors determined that the vapor stage gasket for Reactor Coolant Pump 3P004 was not installed in accordance with procedural requirements. The gasket was installed and Reactor Coolant Pump 3P004 was successfully reassembled prior to the end of the Unit 3 Cycle 12 refueling outage.

Analysis

The inspectors evaluated the significance of the finding using the Significance Determination Process. The inspectors determined that the issue had a credible impact on safety because, if left uncorrected, the leak could become a more significant safety concern in that corrosive boric acid could have degraded a reactor coolant pump casing and reactor coolant system piping. The issue is therefore more than minor. The inspectors also determined that a human performance deficiency in the compliant use of procedures directly contributed to the finding. However, the finding was determined to have very low safety significance because the leak was very small, did not contribute to the likelihood of a loss of coolant accident or a reactor trip, did not affect the likelihood that mitigation equipment functions would not be available, and did not increase the likelihood of fire or flooding.

Enforcement

Technical Specification 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. Section 9 of Regulatory Guide 1.33, “Procedures for Performing Maintenance,” specifies that maintenance affecting the performance of safety-related equipment should be performed in accordance with written procedures appropriate to the circumstances. Contrary to this criterion, the licensee did not ensure that a reactor coolant pump vapor stage gasket had been properly installed in accordance with procedural requirements. This violation of Technical Specifications is being treated as a noncited violation (NCV 362/2003002-03) consistent with Section VI.A of the Enforcement Policy. This violation is in the licensee’s corrective action program as AR 030100383.

.2 Unit 3 Reactor Vessel Lining Scrape During Core Barrel Removal

a. Inspection Scope

The inspectors reviewed emergent work associated with damage to the Unit 3 reactor vessel lining that occurred during core barrel removal for a 10-year inservice inspection.

b. Findings

Introduction

The inspectors determined that the licensee did not implement an adequate procedure for removing the core barrel from the Unit 3 reactor vessel during the Unit 3 Cycle 12 refueling outage in January 2003.

Description

On January 28, 2003, the licensee implemented Procedure SO23-I-3.8, “Core Support Barrel Removal and Installation,” Revision 4, to remove the Unit 3 core barrel from the reactor vessel in order to perform a 10-year inservice inspection of the reactor vessel. During the core barrel lift, maintenance workers noted an increase in measured load from 211 kips to 270 kips and stopped the lift. The core barrel was lowered, the polar crane was slightly repositioned, and the lift was recommenced. The core barrel was then removed without any further observed load changes.

The licensee subsequently performed visual inspections of the reactor vessel lining and the core barrel using underwater video equipment. The inspections revealed four areas where damage had occurred to the inside vertical surfaces of the reactor vessel hot leg nozzle bosses. The licensee determined that two keyways located on the lower core barrel, approximately 180 degrees apart and aligned with each hot leg, had impacted the surfaces of the hot leg nozzle bosses. The four damaged areas varied in size from 8 inches long to 4 inches long. All four were approximately 1.5 inches wide. The four areas varied in depth from 0.04 inches to 0.085 inches. The depth of the stainless steel cladding in each hot leg boss was 0.219 inches.

The licensee determined that the degradation to the reactor vessel lining did not affect operability of the vessel. The pressure boundary was unaffected, and the damage to the stainless steel lining was minimal. However, the licensee determined that there was raised and loose material that would have to be removed from the affected areas to ensure that foreign material exchange would not occur. Underwater grinding and material removal was successfully performed on the affected areas. Final visual inspections were performed to ensure that all raised and loose material was removed. The effort to perform the emergent work resulted in additional personnel exposure of 382 millirem.

The licensee performed a structural analysis evaluation in accordance with 10 CFR 50.59. The evaluation concluded that the degradation of the bosses would not directly affect the probability of occurrence of any malfunction or affect any other components. The inspectors reviewed the evaluation and found that it adequately addressed the design functions of the reactor vessel.

The licensee concluded that the procedure used to perform the core barrel removal should be enhanced to allow for larger clearances between the core barrel keys and the reactor vessel hot leg bosses. The inspectors reviewed Procedure SO23-I-3.8, "Core Support Barrel Removal and Installation," Revision 4, and concluded that the procedure was not adequate in that it did not provide guidance to ensure that adequate clearance was provided to ensure that the core barrel did not come in contact with the reactor vessel during core barrel removal. The licensee modified Procedure SO23-I-3.8 to provide for rotating the core barrel 30 degrees prior to removal. This would increase the minimum distance between the core barrel and reactor vessel from approximately 0.33 inches to approximately 1.5 inches while removing the core barrel. The inspectors concluded that the modification was satisfactory in that it increased the margin for contact between the core barrel and reactor vessel during core barrel removal.

<u>Analysis</u>

The inspectors evaluated the significance of the issue using the Significance Determination Process (Green). The inspectors determined that the issue had a credible impact on safety because if left uncorrected, it could become a more significant safety concern in that it could result in the inadvertent introduction of foreign material into the reactor coolant system and unnecessary personnel exposure to implement repairs. The issue is therefore more than minor. However, the finding was determined to have very low safety significance because the damage to the reactor vessel lining did not affect its operability and did not contribute to the likelihood of an initiating event.

<u>Enforcement</u>

Technical Specification 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. Section 9 of Regulatory Guide 1.33, "Procedures for Performing Maintenance," specifies that maintenance affecting the performance of safety-related equipment should be performed in accordance with written procedures appropriate to the circumstances.

Contrary to this criterion, the licensee did not implement an adequate procedure to remove the core barrel from the Unit 3 reactor vessel during the Unit 3 Cycle 12 refueling outage. This violation of Technical Specifications is being treated as a noncited violation (NCV 362/2003002-04) consistent with Section VI.A of the Enforcement Policy. This violation is in the licensee's corrective action program as AR 030102193.

.3 Unit 3 Reactor Vessel Heated Junction Thermocouple Leak

a. Inspection Scope

The inspectors reviewed emergent work associated with a RCS leak through a heated junction thermocouple penetration on the Unit 3 reactor vessel head.

b. Findings

Introduction

The inspectors determined that the licensee did not adequately follow procedures when conducting planned maintenance on a heated junction thermocouple penetration to the Unit 3 reactor vessel head. Packing material had not been installed at the penetration hub as required by maintenance procedures, which caused a leak path between the RCS and the containment atmosphere. This finding is being documented as a noncited violation with a very low safety significance (Green).

Description

During the Unit 3 refueling outage, planned maintenance was performed on the two heated junction thermocouple penetrations on the Unit 3 reactor vessel head to allow for additional expansion of the heated junction thermocouple zirconium thimbles. The zirconium thimbles had been expanding at a greater rate than originally anticipated due to high energy neutron fluence-induced growth. The expansion of the thimbles could cause undesired inelastic strain on the detector, which in turn could cause premature failure of the heated junction thermocouple. A detector failure had caused an emergent work item at the conclusion of the recent Unit 2 refueling outage in June 2002 (see NRC Inspection Report 50-361; 362-2002-05, Section 13.3). The planned maintenance provided for a modified flange adapter hub at the reactor vessel head penetration that would allow additional room for detector expansion. Modifications to the Trains A and B heated junction thermocouple penetrations on the Unit 3 reactor vessel head were completed in early February 2003.

On February 10, 2003, Unit 3 primary pressure was increased to approximately 150 psig to fill and vent the RCS while the plant was still shut down and cooled down in Mode 5. Maintenance workers were also performing reinstallation of control element drive mechanism ventilation manifolds during this time. During performance of the ventilation manifold installation, a maintenance worker noted water weeping from a bolt hole in the head lift rig skirt for the reactor vessel. The ventilation manifolds were removed and the licensee discovered an approximate 0.12 gpm primary coolant leak coming from the

Train A heated junction thermocouple reactor vessel head penetration flange adapter hub. Unit 3 was depressurized and the Train A flange adapter hub was disassembled and inspected. The licensee discovered that Grafoil packing had not been replaced in the heated junction thermocouple seal plug, causing the leak path through the reactor vessel head penetration.

The inspectors reviewed the maintenance procedure for replacement of the heated junction thermocouple flange assembly. Procedure SO23-I-3.31, "Incore Instrument Flange and Bullet Nose Installation and Removal," Revision 8, step 6.4.28, stated:

> Place two packing rings over the incore instrument assembly or heated junction thermocouple seal plug. Using the packing tamper or Chesterton packing tamper, push the packing down carefully until some resistance is met when the packing has bottomed in the instrument flange adapter hub.

The inspectors determined that the packing rings had not been replaced in accordance with procedural requirements. The licensee could offer no immediate explanation why the packing had not been installed. The packing was replaced and the flange adapter hub was reassembled. The inspectors further determined that the postmaintenance test to verify that the packing was properly installed was inadequate. Previously, proper installation of the heated junction thermocouple was verified by measuring the distance between the seal plug hex flats and the top of the penetration hub. However, the licensee had not considered that the use of a new modified flange adapter hub would alter the appropriate distance. The licensee determined that proper packing installation for the modified flange adapter hub could be verified by measuring the distance between the top of the heated junction thermocouple seal plug hex flats and the top of the penetration hub, a distance of 4 5/8'' to 4 13/16". The licensee verified that the packing for Train B had been appropriately installed using this method. The primary plant was successfully pressurized to 150 psig with no observed leakage on February 12, 2003.

<u>Analysis</u>

The inspectors evaluated the significance of the finding using the Significance Determination Process. The inspectors determined that the issue had a credible impact on safety because, if left uncorrected, the finding would become a more significant safety concern in that RCS inventory would be lost and boric acid would be introduced to the reactor vessel head. The finding is therefore more than minor. The inspectors also determined that a human performance deficiency in the compliant use of procedures directly contributed to this finding. The inspectors determined that Phase 2 analysis in accordance with Manual Chapter 0609, "Significance Determination Process," was not required because the finding did not contribute to the likelihood of a loss of coolant accident initiator. The leak would have been self-revealing at normal operating pressure through leak rate calculations, containment sump monitors, and containment radiation monitors. Additionally, the inspectors determined that the finding had very low safety significance because the leak was small, did not affect any plant mitigating equipment, and was discovered and repaired while the plant was in a shut down and cooled down condition with primary system pressure equal to or less than 150 psig.

Enforcement

Technical Specification 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. Section 9 of Regulatory Guide 1.33, "Procedures for Performing Maintenance," specifies that maintenance affecting the performance of safety related equipment should be performed in accordance with written procedures appropriate to the circumstances. Contrary to this criterion, the licensee did not ensure that packing material for a heated junction thermocouple penetration on the Unit 3 reactor vessel head was installed in accordance with procedural requirements. This violation of Technical Specifications is being treated as a noncited violation (NCV 362/2003002-05) consistent with Section VI.A of the Enforcement Policy. This violation is in the licensee's corrective action program as AR 030200899.

.4 Quarterly Review

a. Inspection Scope

The inspectors verified the accuracy and completeness of assessment documents and that the licensee's program was being appropriately implemented. The inspectors also ensured that plant personnel were aware of the appropriate licensee-established risk category, 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 five activities:

- Catastrophic failure of crankshaft of Unit 2 Charging Pump 2MP192 on December 30, 2002 (AR 021201204)
- Troubleshooting of Unit 3 Control Element Assemblies 25, 27, and 52 following discrepancies in control rod speeds noted during testing on February 16, 2003 (AR 030201382)
- Induced pressure transient of Unit 3 during high pressure Stop Valve 2200D return to service on February 19, 2003 (AR 030201657)
- Unit 2 saltwater cooling heat exchanger leak repair on March 4, 2003 (AR 030100085)

- Inspection plan and implementation for examining Unit 2 motor-operated valve auxiliary contacts for potential chemical attack (AR 030101366)

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Nonroutine Evolutions (71111.14)

a. Inspection Scope

The inspectors observed operator response to three nonroutine evolutions during this 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 to that required by procedures and training. The following three operator responses were reviewed:

- Unit 2 automatic reactor trip on February 1, 2003
- Unit 3 pressure transient during high pressure Stop Valve 2200D return to service on February 19, 2003
- Unit 2 Heater Drain Pump 2HP058 inadvertent trip on March 5, 2003

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 Technical Specifications. The inspectors also discussed the evaluations with cognizant licensee personnel.

The inspectors reviewed eight operability evaluations and cause assessments documented in the following ARs to ensure the operability was properly justified:

- AR 020701529: Common cause evaluation for three operational problems associated with the June 2002 Unit 2 refueling outage
- AR 030100336: Unit 3 pressurizer spray line check valve operability

- AR 030101136: Residual reactor coolant pump oil on Unit 3 control element drive mechanism nozzles
- AR 030102134: Loss of a Unit 3 cold leg injection nozzle thermal sleeve
- AR 030200011: Unit 2 main feedwater pump ac lube oil pump trips
- AR 030100902: Unit 3 turbine-driven auxiliary feedwater pump minor shaft blistering
- ARs 030202055 and 030202085: Unit 3 loose parts monitoring system operability
- AR 030202237: Main steam isolation valve operability under accident conditions (Units 2 and 3)

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

The inspectors performed a programmatic review of operator workarounds to evaluate their cumulative effect on the operators' ability to implement abnormal or emergency procedures. The inspection included a review of 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.

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 six activities to verify that the test procedures and activities adequately demonstrated system operability:

- Unit 3 Control Element Assembly 25 postmaintenance test per MO 02121316001, performed on January 3, 2003, following corrective maintenance activities. The inspectors also reviewed Procedure SO23-13-13, "Misaligned or Immovable Control Element Assembly," Revision 9, as part of the inspection

- Unit 3 Main (Turbine) Lube Oil Coast Down Pump 3P1029 preoperational test per Procedure SO3-XXVI-9.2002.3005.99-9.1, “Main Lube Oil Coast Down Pump Preoperational Test,” Revision 0, performed on February 3, 2003, following installation of the pump

- Unit 3 Train A Shutdown Cooling Heat Exchanger Outlet Valve 3HV8150 linestarter postmaintenance test inspection per Procedure SO123-I-9.13, “480 VAC Linestarter Inspection, Coil, and Power Contact Replacement,” Revision 3, performed on February 13, 2003, following scheduled maintenance under MO 02101773000

- Unit 3 Train B Shutdown Cooling Heat Exchanger Outlet Valve 3HV8151 linestarter postmaintenance test inspection per Procedure SO123-I-9.13, “480 VAC Linestarter Inspection, Coil, and Power Contact Replacement,” Revision 3, performed on February 13, 2003, following scheduled maintenance under MO 02101826000

- Unit 2 High Pressure Safety Injection Pump 2P017 postmaintenance test per Procedure SO23-3-3.60.1, “Surveillance Operating Instruction,” Revision 3, performed on February 19, 2003, following emergent maintenance activities due to high vibration measurements

- Unit 2 Saltwater Cooling Pump 2P113 postmaintenance test per Procedure SO23-3-60.4, “Saltwater Cooling Pump Valve Testing,” Revision 4, performed on February 28, 2003, following corrective maintenance under MO 03022769000

The inspectors determined that the affect of testing on the plant had been adequately addressed, that the tests were adequate for the scope of the maintenance work performed, and that the acceptance criteria were clear and consistent with design and licensing basis documents.

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 12 refueling outage. Observations and reviews included the Unit 3 shutdown, drain to midloop, refueling operations, and shutdown maintenance. The inspectors verified that the activities were performed in accordance with approved procedures and Technical Specification 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 also verified that RCS 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 2.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

.1 High Pressure Safety Injection (HPSI) Header Isolation Valve 2HV-9323 Failure to Open on Subgroup Relay Testing

a. Inspection Scope

The inspectors reviewed the surveillance test of Unit 2 subgroup Relay K-403B that resulted in HPSI header Isolation Valve 2HV9323 failing to open on a simulated safety injection actuation signal (SIAS).

b. Findings

Introduction

The inspectors determined that the licensee implemented an inadequate procedure to ensure that electrical connections were secure and electrical leads properly landed in safety-related motor control centers. The use of the inadequate procedure contributed to HPSI header Isolation Valve 2HV9323 failing to open on a simulated SIAS. This finding is being documented as a noncited violation with a very low safety significance (Green).

Description

On December 29, 2002, the licensee implemented Procedure SO23-3-3.43.13, “ESF Subgroup Relays K-308A, K-403A, K-308B, and K-403B Semiannual Test,” Revision 3, to conduct a 6-month sub-group relay surveillance test of safety-related Relay K-403B on Unit 2. This relay controls five valves in the safety injection system to ensure that they are aligned to their proper position on an SIAS. During the surveillance, HPSI header to cold leg Loop 1A Isolation Valve 2HV9323 failed to stroke open when the relay was actuated on a simulated SIAS. This valve is required to open on an SIAS to allow borated water from the refueling water storage tank to be injected, by Train B of the HPSI system, into Loop 1A of the RCS. As a result of the failure, the licensee declared Train B of the emergency core cooling system inoperable, in accordance with Technical Specification 3.5.2, “ECCS - Operating.” In addition, the licensee secured Valve 2HV9323 in its SIAS position (open) in accordance with Action E of Technical Specification 3.6.3, “Containment Isolation Valves,” to return the train to service.

The licensee initially attributed the failure of the valve to open to a failure in Relay K-403B. Following replacement of the relay, the subgroup test was performed again and the valve successfully stroked open on a simulated SIAS. However, the valve's over-ride circuitry unexpectedly failed to seal in. The circuitry is required to seal in to prevent the inadvertent closing of Valve 2HV9323 following an SIAS. Subsequent troubleshooting by maintenance technicians revealed that there were loose wire connections in the override relay circuitry in Motor Control Center (MCC) 2BJ14. The override relay has a normally closed contact in series with the K-403B SIAS contact. The licensee concluded that the failures of Valve 2HV9323 to stroke open and the override relay to seal in were a result of the loose wires found in the override relay circuitry. The looseness of the wires was attributed to a compression washer that, sometime in the past, was improperly landed on the terminal screw of the override relay. The licensee reviewed a 20-year history of maintenance work orders for Valve 2HV9323 and MCC 2BJ14, but was not able to identify when the lead was improperly landed. However, the failure to open on December 29, 2002, was the only time Valve 2HV9323 did not function properly during surveillance testing of subgroup Relay K-403B. The licensee replaced the damaged screw/washer assembly and verified that all of the other wire connections in MCC 2BJ14 were properly secured. An additional subgroup relay test of Relay K-403B following the corrective maintenance verified that Valve 2HV9323 would open on an SIAS.

The inspectors reviewed the portions of the licensee's preventive maintenance procedures that address verifying the integrity of electrical connections. Procedures SO123-I-9.12, "Motor Control Center Cleaning, Inspection, and Megger Testing," Revision 4; SO123-I-9.13, "480 VAC Linestarter Inspection, Coil, and Power Contact Replacement," Revision 5; and SO123-II-11.152, "Circuit Device Tests and Overall Functional Tests," Revision 6, contain steps and definitions, in varying degrees, to verify the tightness of electrical connections. However, specific steps were not included in those procedures to ensure that electrical connections were securely landed.

<u>Analysis</u>

The inspectors evaluated the significance of the finding using the Significance Determination Process. The inspectors determined that the finding had a credible impact on the mitigating systems cornerstone because Valve 2HV9323 is designed to open on an SIAS to inject to cold leg Loop 1A of the RCS. The finding was considered to be more than minor because the reliability and capability of a portion of the safety injection system was compromised when Valve 2HV9323 failed to open on a simulated SIAS. However, the finding was determined to have very low safety significance because the three other Train B HPSI header isolation valves were operable and capable of opening on an SIAS to allow injection into the RCS. As a result, the actual safety function of Train B of the safety injection system remained intact because only two of the four valves are needed.

<u>Enforcement</u>

Technical Specification 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. Section 9 of Regulatory Guide 1.33, “Procedures for Performing Maintenance,” specifies that maintenance affecting the performance of safety-related equipment should be performed in accordance with written procedures appropriate to the circumstances. Contrary to this criterion, the licensee implemented Procedures SO123-I-9.12, SO123-I-9.13, and SO123-II-11.152, none of which contained adequate acceptance criteria to ensure that electrical leads in safety-related circuitry were properly landed. The use of these inadequate procedures contributed to HPSI header Isolation Valve 2HV9323 failing to open on December 29, 2002, during a surveillance test of subgroup Relay K-403B. The licensee determined that an electrical lead in the override relay in MCC 2BJ14 for Valve 2HV9323 was not properly landed sometime in the past, which prevented the circuit connection from operating properly. The inspectors determined that the procedures used to land electrical leads were inadequate. The licensee indicated they planned to modify the inadequate procedures to correct the problem and verified through a sampling of 240 terminals in similar relays that no loose connections existed. This violation of Technical Specifications is being treated as a noncited violation (NCV 361/2003002-06) consistent with Section VI.A of the Enforcement Policy. This violation is in the licensee’s corrective action program as ARs 021201350 and 021201414.

.2 Routine Surveillance Testing Review

a. Inspection Scope

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

- Unit 3 Train A Engineered Safety Feature Test per Procedure SO23-3-3.12, “Integrated ESF System Refueling Test,” Revision 20, performed on January 8, 2003

- Unit 2 Saltwater Cooling Pump 2P113 surveillance test per Procedure SO23-3-60.4, “Saltwater Cooling Pump Valve Testing,” Revision 4, performed on February 25, 2003

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety (OS)

2OS1 Access Control to Radiologically Significant Area (71121.01)

a. Inspection Scope

To review and assess the licensee's performance in implementing physical and administrative controls for airborne radioactivity areas, radiation areas, and high radiation areas, the inspectors interviewed radiation workers and radiation protection personnel involved in high dose rate and high exposure work activities during the Unit 3 Cycle 12 refueling outage. The inspectors also conducted plant walkdowns within the radiologically controlled area and conducted independent radiation surveys of selected work areas. The following items were reviewed and compared with regulatory requirements:

- Area postings, access, and engineering controls for airborne radioactivity areas, radiation areas, and high radiation areas in the Unit 3 reactor containment building and the Units 2 and 3 auxiliary building
- Radiation exposure permits and radiological surveys involving airborne radioactivity areas and high radiation areas
- Dosimetry placement when work involved a significant dose gradient
- High radiation area key controls
- In-place controls for areas that have the potential to become a very high radiation area during plant operations
- Controls involved with the storage of highly radioactive items in the spent fuel pool
- Selected corrective action documents involving worker and radiation protection personnel work performance and access controls to radiologically significant areas (ARs 021100593, 021200624, 021200992, 021201052, 030100504, 030100716, and 030100762)
- Nuclear Oversight Surveillance SOS-079-02 and Third Quarter 2002 Health Physics Division Self-Assessment Report involving operational radiation protection activities
- ALARA prejob briefing prior to the movement and inspection of the upper guide structure thimbles
- Conduct of work in Unit 3 with the potential for high radiation dose (SG, reactor coolant pump and primary valve work activities)

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Quarterly review

a. Inspection Scope

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

- IE1 Unplanned Scrams
- IE2 Scrams with Loss of Normal Heat Removal

The inspectors reviewed the performance indicator data for the last three quarters of 2002 and the first quarter of 2003. The inspectors reviewed NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," and licensee operating logs. The inspectors discussed the status of the performance indicators and compilation of data with engineering personnel. The inspectors noted that Unit 2 unplanned scrams reached the white threshold of greater than three in the previous four quarters with the unplanned scram that occurred on February 1, 2003. A supplemental inspection per Manual Chapter 95001 will be scheduled within the following year.

.2 Occupational Exposure Control Effectiveness

a. Inspection Scope

The inspectors reviewed corrective action program records involving locked high radiation areas (as defined in Technical Specification 5.8.2), very high radiation areas (as defined in 10 CFR 20.1003), and unplanned exposure occurrences (as defined in NEI 99-02), since the last inspection of this area, to confirm that these occurrences were properly recorded as performance indicators. Radiologically controlled area entries with exposures greater than 100 millirems since the last inspection of this area were reviewed, and selected examples were examined to determine whether they were within the dose projections of the governing radiation exposure permits. Whole body counts or dose estimates were reviewed if the radiation worker received a committed effective dose equivalent of more than 100 millirems. Where applicable, the inspectors reviewed the summation of unintended deep dose equivalent and committed effective dose equivalent to verify that the total effective dose equivalent did not surpass the performance indicator threshold without being reported.

b. Findings

No findings of significance were identified.

.3 Radiological Effluent Technical Specification/Offsite Dose Calculation Manual Radiological Effluent Occurrences

a. Inspection Scope

The inspectors reviewed radiological effluent release program corrective action records, licensee event reports, and annual effluent release reports documented since the last inspection of this area to determine if any doses resulting from effluent releases exceeded the performance indicator thresholds (as defined in NEI 99-02).

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

a. Inspection Scope

The inspectors reviewed the licensee’s response to a 10 CFR Part 21 notification issued by the Whiting Corporation. The notification was issued because of the potential for overstressing two gear case internal support bolts for certain Whiting cranes manufactured prior to 1980. The inspectors discussed the notification with licensee personnel to ensure that actions taken in response to the notification were appropriate.

b. Findings

No findings of significance were identified.

4OA3 Crosscutting Issues

The inspectors determined that human performance deficiencies in procedure compliance directly contributed to two findings in Section 1R13. In the first finding, maintenance workers did not install a Unit 3 reactor coolant pump gasket in accordance with procedural requirements. In the second finding, maintenance workers did not install packing for a heated junction thermocouple penetration on the Unit 3 reactor vessel head in accordance with procedural requirements.

4OA5 Other

.1 Temporary Instruction 2515/145: Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles

a. Inspection Scope

The inspectors observed and reviewed licensee activities in response to NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," issued on August 3, 2001, in response to identified circumferential cracking in control element drive mechanism (CEDM) nozzles at other facilities.

The licensee performed a 100 percent visual inspection of the Unit 3 reactor vessel head during the Cycle 12 refueling outage. Additionally, ultrasonic and nondestructive eddy current testing was performed on the inner diameters of all 91 CEDM penetrations, all 10 in-core instrumentation penetrations, and the head vent penetration. Also, the outer diameter weld surfaces of all 91 CEDM penetrations received additional nondestructive eddy current testing. The integrity of four CEDM penetrations was initially inconclusive because the results of the inner diameter ultrasonic and eddy current tests indicated the possible presence of a defect. However, the results of the outer diameter eddy current examinations of these four penetrations were conclusive and verified that no defects were present in these penetrations.

The inspectors reviewed the testing methodology and reviewed the overall results with licensee and contract personnel, which indicated no detectable defects on any of the Unit 3 reactor vessel head penetrations. The inspectors also independently reviewed samples of the initial ultrasonic and eddy current test results, and also independently reviewed the additional eddy current tests performed on the eight penetrations where the initial results were not totally conclusive. Additionally, the inspectors performed an independent visual inspection of the reactor vessel head through both physical inspections and video tape observations.

b. Findings

No findings of significance were identified.

.2 Temporary Instruction 2515/149: Mitigating Systems Performance Index (MSPI) Pilot Verification

a. Inspection Scope

The inspectors verified that the licensee had correctly implemented the MSPI pilot guidance for reporting unavailability and unreliability of the monitored safety systems. The inspectors audited the development of the MSPIs for the saltwater cooling, component cooling, and auxiliary feedwater systems. For those systems, the inspectors confirmed that success criteria had been correctly identified, active components were properly scoped, unavailability boundaries were properly defined, and planned unavailability was consistent with information contained in operating logs and facility

ARs. The inspectors also verified that pertinent information, such as Fussell-Vesely coefficients, was properly transferred to the appropriate informational spreadsheets. Sections 03.11.a and 03.11.c were not completed as written because the staff did not qualify the licensee's updated probabilistic risk assessment for use prior to or during the MSPI pilot. However, the activities conducted and the results obtained for these sections are documented in an attachment to this inspection report.

b. Findings

No findings of significance were identified.

4OA6 Meetings

Exit Meeting Summary

The inspectors presented the inspection results to Mr. D. Nunn and other members of licensee management at an exit meeting on January 22 and 24, February 5 (by telephone), and April 1, 2003. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether or not any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. Wambold, Vice President, Nuclear Generation
R. Allen, Supervisor, Reliability Engineering
C. Anderson, Manager, Site Emergency Preparedness
D. Brieg, Manager, Maintenance Engineering
G. Cook, Supervisor, Compliance
M. Cooper, Manager, Plant Operations
J. Fee, Manager, Maintenance
M. Goettel, Manager, Business Planning and Financial Services
J. Madigan, Manager, Health Physics
D. Nunn, Vice President, Engineering and Technical Services
N. Quigley, Manager, Mechanical/Nuclear Maintenance Engineering
A. Scherer, Manager, Nuclear Oversight and Regulatory Affairs
M. Short, Manager, Systems Engineering
T. Vogt, Manager, Operations
R. Waldo, Station Manager

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Opened and Closed During this Inspection

361; 362/2003002-01	NCV	Failure to identify an eddy current indication during the previous outage (Section 1R08.2)
361/2003002-02	FIN	Unit 2 loss of generator excitation trip (Section 1R12.1)
362/2003003-03	NCV	Reactor coolant pump gasket not installed in accordance with procedural requirements (Section 1R13.1)
362/2003003-04	NCV	Inadequate procedure results in reactor vessel lining damage (Section 1R13.2)
362/2003003-05	NCV	Thermocouple packing not replaced in accordance with procedural requirements (Section 1R13.3)
361/2003002-06	NCV	High Pressure Safety Injection Header Isolation Valve 2HV-9323 failure to open on sub-group relay testing (Section 1R22.1)

Previous Items Closed

None

Previous Items Discussed

None

LIST OF ACRONYMS USED

AFW	auxiliary feedwater
AOV	air-operated valve
AR	action request
CCW	component cooling water
CEDM	control element drive mechanism
CFR	Code of Federal Regulations
CSAS	containment spray actuation system
CSR	containment spray recirculation
DGN	diesel generator
EDG	emergency diesel generator
EPS	electric power system
FIN	finding
FTO	failure to open
FTR	failure to run
FTS	failure to start
HPI	high pressure injection
HPSI	high pressure safety injection
HPR	high pressure recirculation
INEEL	Idaho National Engineering and Environmental Laboratory
LLOCA	large-break loss of coolant accident
LCCW	loss of all component cooling water
LECH	loss of essential chilled water
LOOP	loss of offsite power
MCC	motor control center
M/D	motor-driven
MLOCA	medium-break loss of coolant accident
MDP	motor-driven pump
MFW	main feedwater
MO	maintenance order
MOV	motor-operated valve
MSPI	mitigation systems performance indicator
NCV	noncited violation
NRC	Nuclear Regulatory Commission
PRA	probabilistic risk assessment
RCS	reactor coolant system
RHR	residual heat removal system
SLOCA	small-break loss of coolant accident

SG	steam generator
SGTR	steam generator tube rupture
SI	safety injection
SIAS	safety injection actuation system
SOSV	stuck open relief valve
SSC	support system cooling
SWC	salt water cooling
TDP	turbine-driven pump
TM	test and maintenance

PARTIAL LIST OF DOCUMENTS REVIEWED

Action Requests
020600661-01
020601302-01
020601302-04
030101328-01

Construction Work Orders
01060705000, Replace Pressurizer Heater S31201ME603
01071370000, Replace Pressurizer Heater S31201ME614

MOs
00060142000, Remove and replace body to bonnet seal weld for Discharge Check Valve 3P192
01030668000, Replace discharge check Valve 3P192

Procedures
SO123-XII-9.301, “Liquid Penetrant Examination,” Revision 2 with Temporary Change Notice 2-3

SO23-SG-1, “Steam Generator Program,” Revision 3 with Temporary Change Notice 3-1

SO23-XXVII-30.5, “Ultrasonic Examination of Ferritic Piping Welds,” Revision 0

SO23-XXVII-30.7, “Ultrasonic Examination of Bolts and Studs,” Revision 0

SO23-XXVII-20.47, “Magnetic Particle Examination,” Revision 01

SO23-XXVII-23.1, “Multi-Frequency Eddy Current Examination of Tubing,” Revision 10 with Temporary Change Notices 10-1 and 10-2

SO23-XXXIII-4.2, “Steam Generator Tube Inspection and Corrective Action,” Revision 0

WPS 43-8-GT, “Welding Procedure Specification,” Revision 0

Test Reports
Liquid Penetrant Examinations
3PT-021-03
3PT-022-03

Magnetic Particle Examinations
303-12MT-002
393-071MT-026

Radiographic Examinations
3RT-021-01
3RT-022-01

Ultrasonic Examinations
303-12UT-005
303-12UT-015
19-086

Miscellaneous
Data Analysis Reference Manual San Onofre Nuclear Generating Station (SONGS) Units 2 and 3, Revision 13

TI 2515/149 Mitigating System Performance Index Pilot Verification

Inspection Requirements

03.02 Risk Significant Functions

No discrepancies were noted. The licensee correctly identified the risk significant functions for trains within the selected systems.

03.03 Success Criteria

Each of the above functions had appropriate success criteria at the train level which were consistent with the licensee's PRA analysis, Technical Specifications, and design basis documentation. The senior reactor analysts reviewed the INEEL Standardized Plant Analysis Risk Model for San Onofre, Revision 3 (SPAR model) and the Risk-Informed Inspection Notebook for San Onofre Nuclear Generating Stations, Units 2 and 3, Revision 1 (Risk-Informed Notebook) to determine if they were consistent with the licensee's PRA functional success criteria for the MSPI. This comparison is provided in Table 1.

TABLE 1
San Onofre
Functional Success Criteria

System	**Success Criteria**	**Applicable Transients**	**SPAR**	**Notebook**
AFW	Controllable flow of feedwater to S/G when MFW is not operating during normal operations	None	not modeled	not modeled
AFW	Reliable and sufficient source of feedwater to stabilize plant in hot shutdown conditions following accident	All except MLOCA, LLOCA, and LCCW	FTR/FTS	Table 2/3
EDG	Re-power vital ac buses following loss of preferred sources to achieve safe shutdown	LOOP	FTR/FTS	Table 2/3
HPSI	Supply borated water to RCS following SIAS to cool core and provide reactivity control	SLOCA, SOSV, MLOCA, LLOCA, LOOP, SGTR	FTR/FTS	Table 2/3
RHR	Provide water spray to containment atmosphere after CSAS	SLOCA, SOSV, MLOCA, LLOCA, LOOP	MDP:FTS/FTR MOV:FTO	Table 2/3
RHR	Cool the water drawn from the containment emergency sump	SLOCA, SOSV, MLOCA, LLOCA, LOOP	not modeled	Table 2/3
SSC	CCW removes component and decay heat	All	FTR/FTS	Table 2/3
SSC	SWC cools component cooling water	All	FTR/FTS	Table 2/3

03.04 Unreliability Boundary Definitions

The inspectors confirmed that the licensee's definition of the system/train boundaries and the identification of active components was in accordance with the guidance. The inspectors also confirmed that the active components were accounted for in the site-specific spreadsheet, and that the spreadsheet used industry reliability values in accordance with the guidance.

Additionally, the senior reactor analysts reviewed the INEEL Standardized Plant Analysis Risk Model for San Onofre, Revision 3 (SPAR model) and the Risk-Informed Inspection Notebook for San Onofre Nuclear Generating Stations, Units 2 and 3, Revision 1 (Risk-Informed Notebook) to determine if they were complete and consistent with the licensee's list of active components for the MSPI. This comparison is provided in Table 2.

TABLE 2
San Onofre
Active Components

System/Train	**Component**	**Function**	**SPAR Basic Event**	**Notebook Location**
AFW-1	Pump M/D AFWP-141	Motor Injection Pump	AFW-MDP-**-141[2]	Table 2
	Valve MOV HV-4713	Discharge valve	AFW-MOV-CC-4713	Table 3.*[3]
AFW-2	Pump M/D AFWP-504	Motor Injection Pump	AFW-MDP-**504[2]	Table 2
	Valve MOV HV-4712	Discharge valve	AFW-MOV-CC-4712	Table 3.*[3]
AFW-3	Pump T/D AFWP-140	Turbine Injection Pump	AFW-TDP-**-140[2]	Table 2
	Valve MOV HV-4716	Discharge valve	AFW-MOV-CC-4716	Table 3.*[3]
EDG-1	Diesel Generator DG-2	Emergency AC power	EPS-DGN-**-DG2[2]	Table 2
EDG-2	Diesel Generator DG-3	Emergency AC power	EPS-DGN-**-DG3[2]	Table 2
HPSI-1	Pump M/D HPSIP-017	Injection Pump	HPI-MDP-FR-017	Table 2

	Valve MOV HV-9303	Sump Suction	HPR-MOV-CC-9303	Table 3.*[3]
	Valve MOV HV-9305	Sump Suction	HPR-MOV-CC-9305	Table 3.*[3]
	Valve MOV HV-9420	Hot Leg Injection	Not modeled[1]	Table 3.*[3]
HPSI-2	Pump M/D HPSIP-019	Injection Pump	HPI-MDP-FR-019	Table 2
	Valve MOV HV-9302	Sump Suction	HPR-MOV-CC-9302	Table 3.*[3]
	Valve MOV HV-9304	Sump Suction	HPR-MOV-CC-9304	Table 3.*[3]
	Valve MOV HV-9434	Hot Leg Injection	Not modeled[1]	Table 3.*[3]
HPSI-SWING	Pump M/D HPSIP-018	Injection Pump	HPI-MDP-FR-018	Table 2
RHR-1	Pump M/D CSP-012	Containment Spray Pump	CSR-MDP-**-P012[2]	Table 2
	Valve MOV HV-9367	Header Discharge	CSR-MOV-CC-9367	Table 3.*[3]
	Valve MOV HV-9303	Sump Suction	HPR-MOV-CC-9303	Table 3.*[3]
	Valve MOV HV-9305	Sump Suction	HPR-MOV-CC-9305	Table 3.*[3]
RHR-2	Pump M/D CSP-013	Containment Spray Pump	CSR-MDP-**-P013[2]	Table 2
	Valve MOV HV-9368	Header Discharge	CSR-MOV-CC-9368	Table 3.*[3]
	Valve MOV HV-9302	Sump Suction	HPR-MOV-CC-9302	Table 3.*[3]
	Valve MOV HV-9304	Sump Suction	HPR-MOV-CC-9304	Table 3.*[3]
CCW-1	Pump M/D CCWP-024	Cooling Water Pump	CCW-MDP-**-024[2]	Table 2

CCW-2	Pump M/D CCWP-026	Cooling Water Pump	CCW-MDP-**-026[2]	Table 2
CCW-SWING	Pump M/D CCWP-025	Cooling Water Pump	CCW-MDP-**-025[2]	Table 2
SWC-1	Pump SWCP-112	Saltwater Cooling Pump	SWS-MDP-**-112[2]	Table 2
	Valve AOV HV-6200	Discharge Valve	SWS-AOV-CC-6200	Table 3.*[3]
	Pump SWCP-307	Saltwater Cooling Pump	SWS-MDP-**-307[2]	Table 2
	Valve AOV HV-6202	Discharge Valve	SWS-AOV-CC-6202	Table 3.*[3]
SWC-2	Pump SWCP-113	Saltwater Cooling Pump	SWS-MDP-**-113[2]	Table 2
	Valve AOV HV-6201	Discharge Valve	SWS-AOV-CC-6201	Table 3.*[3]
	Pump SWCP-114	Saltwater Cooling Pump	SWS-MDP-**-114[2]	Table 2
	Valve AOV HV-6203	Discharge Valve	Not modeled	Not modeled
[1]Hot leg injection not modeled in SPAR [2]The "**" is replaced by FS, FR, TM (one each) [3]The "*" is replaced by various SDP worksheet numbers				

03.05 Train/Segment Unavailability Boundary Definition

No discrepancies were noted. The licensee appropriately defined the scope of the trains being monitored for unavailability within the selected systems.

03.06 Entry of Baseline Data - Planned Unavailability

No discrepancies were noted.

03.07 Entry of Baseline Data - Unplanned Unavailability

No discrepancies were noted.

03.08 Entry of Baseline Data - Unreliability

No discrepancies were noted.

03.09 Entry of Performance Data - Unavailability

No discrepancies were noted.

03.10 Entry of Performance Data - Unreliability

No discrepancies were noted.

03.11 MSPI Calculation

The analysts reviewed the licensee's MSPI basis documents and spreadsheets to determine the validity of the Fussell-Vesely coefficients used in the MSPI calculation. The following observations were made:

- The staff did not qualify the licensee's updated PRA for use prior to or during the MSPI pilot. Therefore, these line items could not be performed as written.

- All Fussell-Vesely coefficients were greater than zero, indicating that the associated components or trains were modeled in the licensee's PRA.

- A review of a sample of coefficients for each site indicated that the relative significance of the components and/or trains were in keeping with their expected relative risk significance.

- Most Fussell-Vesely coefficients were too small to verify using hand calculations because the associated core damage frequencies were equal out to 4 significant digits.

- Based on a sample of coefficients, large enough to verify using hand calculations, the Fussell-Vesely coefficients provided by the licensee were consistent with those produced by the licensee's model of record.

- Based on a sample of coefficients, the SPAR model results were within a factor of 2 of the Fussell-Vesely coefficients provided by the licensee.

No discrepancies were noted in the licensee's performance.