ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

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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:	October 20 through November 30, 1996
Inspectors:	J. A. Sloan, Senior Resident Inspector J. J. Russell, Resident Inspector D. L. Solorio, Resident Inspector B. J. Olson, Project Inspector
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ATTACHMENT:	Supplemental Information

EXECUTIVE SUMMARY

San Onofre Nuclear Generating Station, Units 2 and 3
NRC Inspection Report 50-361/96-15; 50-362/96-15

Operations

- The inspector identified that volume control tank (VCT) inlet diversion Valve 3LV0227A was in "auto" with the block valve to radwaste closed. This was not in accordance with Abnormal Alignment 3-96-34, in effect at that time, and was a violation of Technical Specification (TS) 5.5.1.1.a for failure to follow procedures (Section O1.2). Operations management had previously identified several component mispositioning events in recent months as a performance concern, and had performed a self-assessment. The licensee's Nuclear Oversight Division had also recently raised a concern regarding the large number (47) of mispositioning events reported in 1996 (Section O7.1).

- The licensee was monitoring a slow increase in containment gaseous activity, and was proactive in planning to reset the Critical Functions Monitoring System (CFMS) alarms to avoid operator distractions. However, the licensee missed an opportunity to avoid the Containment Purge Isolation Signal (CPIS) A actuation, primarily because of a general lack of awareness of the CPIS setpoint. The licensee could have predicted that the CPIS setpoint would be reached and taken actions to reset the setpoint (Section O1.4).

- Operator actions in response to a dropped control element assembly (CEA) were in accordance with TS requirements. Oversight by Operations management and reactor engineering was effective in ensuring activities were coordinated and that TS and Core Operating Limits Report requirements were accurately understood (Section O1.3).

- A noncited violation was identified after operators failed to follow procedural controls for removal of a control element assembly calculator (CEAC) from service. Inattention to these controls by operators led to a surveillance being missed. Operators missed several opportunities to ensure that the surveillance would be completed. Operators exhibited weak command and control, in that the control operator (CO) did not provide direction to the assistant control operator (ACO) to perform the surveillance, and the control room supervisor (CRS) did not adequately oversee the activities to ensure operators had initiated a surveillance required by TS (Section O4.1).

Maintenance

- Instrumentation & Control (I&C) technicians lacked sufficient knowledge of licensee computer systems used to identify and retrieve current drawings, which contributed to an unplanned core protection calculator (CPC) channel trip (Section E3.1).

Engineering

- The licensee did not have data to confirm that leakage from the emergency chilled water (ECW) system was within the values added to the design basis document (DBD) in 1993. Until the inspector identified the issue, Engineering did not follow up on recommendations made at that time to evaluate the need for safety related makeup and for development of a system leakage test, indicating an isolated weakness in system management (Section E2.2).

- The licensee's identification and correction of a methodology error in a vendor calculation was an excellent finding demonstrating strength in the licensee's reload technology transfer program (Section E4.1).

- The nonconformance report (NCR) process used to modify the CPC inputs did not ensure that affected procedures were identified and revised. This weakness had not been fully addressed in recent NCR program changes (Section E3.1).

Plant Support

- The inspector's observation that scaffolding rendered some safe-shutdown emergency lighting ineffective revealed a programmatic weakness in the licensee's program for control of emergency lighting, in that emergency lighting inspections were ineffective in identifying the lighting deficiencies and the scaffolding procedures did not address the effect of scaffolding on the lighting. Licensee corrective actions were thorough (Section P2.1).

Report Details

Summary of Plant Status

Unit 2 operated at essentially 100 percent power from the beginning of this inspection period until November 23, 1996, when the unit began a power coastdown to refueling. The unit shut down to Mode 3 on November 30, 1996, and commenced its Cycle 9 refueling outage. The unit was in Mode 4 at the end of this inspection period.

Unit 3 operated at essentially 100 percent power from the beginning of this inspection period until October 31, 1996, when a CEA dropped into the core (Section O1.3), and power was reduced to approximately 43 percent. After the CEA was recovered, power was increased. The unit operated at essentially 100 percent power from November 2, 1996, until the end of this inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Operators were observed to generally carefully monitor control board indications, refer to procedures frequently during many evolutions, and make conservative decisions regarding plant safety. Routine control room oversight by Operations management was evident. Operators were responsive to emergent conditions and alarms. However, several system valve linup problems have been identified recently, demonstrating the need for improved attention to detail (Section O7.1).

O1.2 VCT Inlet Diversion Valve Controller in an Incorrect Mode - Unit 3

a. Inspection Scope (71707)

On October 18, 1996, the inspector inspected the Unit 3 main control boards and observed that the VCT inlet diversion Valve 3LV0227A controller was not in the correct position per an abnormal alignment in effect at that time. The inspector reviewed documents and interviewed personnel associated with this observation.

b. Observations and Findings

On October 18, 1996, the inspector identified that VCT inlet diversion Valve 3LV0227A was in "auto," with the block valve to radwaste, Valve 3MU924, closed. This was not in accordance with Abnormal Alignment 3-96-34 in effect at that time. The inspector notified Unit 3 operators, who repositioned the controller to "manual/VCT" and initiated Action Request (AR) 961001022. Abnormal Alignment 3-96-34 had been initiated on April 25, 1996, because Valve 3LV0227A, which is a three-position valve, leaked fluid to radwaste when positioned to the VCT. Abnormal Alignment 3-96-34 required that Valve 3MU924 be closed, except as needed to divert to radwaste, and that Valve 3LV0227A be maintained in

"manual/VCT," except when diverting to radwaste. A precaution in Abnormal Alignment 3-96-34 warned operators not to divert to radwaste without opening Valve 3MU924. With Valve 3LV0227A in "auto," the valve would automatically reposition to divert letdown flow to radwaste when the VCT level increased to 78 percent.

The inspector determined that positioning Valve 3LV0227A to divert to radwaste, while Valve 3MU924 was shut, would result in a loss of letdown flow. Letdown system pressure would increase, causing the backpressure regulating valves to close and the pressure relief valves in the system to lift. The intermediate pressure letdown relief valve, 3PSV9206, had a setpoint of 650 psig, and the low pressure letdown relief valve, 3PSV9208, had a setpoint of 200 psig. Operators would then have had to take prompt action to restore letdown flow. The plant was designed to withstand 100 loss of letdown flow transients.

The inspector determined that, during steady-state operations, operators generally controlled reactor coolant system (RCS) inventory, such that additions to the RCS did not result in VCT level changes, by simultaneously diverting letdown to radwaste. Operators did not normally rely on the automatic VCT water level control capability, and Valve 3LV0227A would not normally shift position automatically without a plant transient causing an approximate 8 degree elevation in RCS temperature or a control system failure.

Licensee corrective actions addressed incorporating instructions from long-standing abnormal alignments into permanent operating procedures. The licensee also counseled the operators involved.

The failure to have Valve 3LV0227A aligned as required by Abnormal Alignment 3-96-34 was a violation of TS 5.5.1.1.a for failure to follow procedures (Violation 50-362/96015-01). Although the safety consequence of this violation was low, the inspector found that the condition existed during a shift turnover (the mispositioning was a result of not changing the controller mode after performing a water inventory balance the preceding day) and should have been noted by operators at that time. The inspector also found that the abnormal alignment, despite having been in effect for approximately 6 months, placed the controller in a mode that was different from the mode called for in permanent procedures and no measures were in effect to resolve the opportunities this created for the controller to be mispositioned.

Operations management had previously identified several component mispositioning events in recent months as a performance concern, and had performed a self-assessment. Additionally, Nuclear Oversight recently addressed an observed high number of such events by various line divisions, including Operations (Section O7.1).

The inspector also observed that the Updated Final Safety Analysis Report (UFSAR) states, in Section 9.3.4.2.1.2, that an automatic system maintains the water level in the VCT, and that the letdown flow is automatically diverted to the boric acid recycle system when the highest permissible water level is reached in the VCT. The licensee initiated AR 961100216 to review the accuracy of this statement in the UFSAR.

The inspector found that the UFSAR description of VCT operation was misleading in that it stated that VCT level was maintained by the automatic system when, in fact, during normal steady-state operations, operators manually controlled VCT level. However, the VCT level control capability was normally selected for automatic control. Licensee changes to the UFSAR will be reviewed as a followup item (inspector Followup Item 50-361(362)/96015-02).

c. Conclusion

The failure to have Valve 3LV0227A aligned as required by Abnormal Alignment 3-96-34 was a violation. A followup item was created to review licensee changes to the UFSAR because of a discrepancy identified by the inspector.

O1.3 Dropped CEA - Unit 3

a. Inspection Scope (71707)

At 7:17 p.m. on October 31, 1996, while Unit 3 was operating at approximately 99 percent power, Shutdown Group A CEA 49 dropped fully into the core. The inspector responded to the site and reviewed the circumstances of the event.

b. Observations and Findings

Operators responded by initiating a power reduction in accordance with TS Limiting Condition for Operation (LCO) 3.1.5, Condition C (one shutdown CEA misaligned greater than 7 inches), to meet the requirements of the Core Operating Limits Report, which required an 18 percent power reduction. However, azimuthal power tilt increased to 0.30 as a result of the dropped CEA, which was near the periphery of the core. TS LCO 3.2.3, Condition C, required that power be reduced to less than 50 percent within 4 hours with tilt greater than 0.10; thus, operators continued the downpower, reaching approximately 43 percent power by approximately 10:30 p.m.

A plant equipment operator observed that indications in the CEDMCS cabinets were abnormal for CEAs 49 and 53, both in Shutdown Group A Subgroup 13. He also observed that a toggle switch at the bottom of the cabinet, controlling blowers in the cabinet, was in the "off" position. He turned the blowers on. Additionally, one of the two CEDMCS room coolers was out of service for maintenance, with work in progress, at the time the CEA dropped.

At 9:17 p.m., operators entered TS LCO 3.1.5, Condition D, requiring shutdown to Mode 3 within 6 hours, as the result of the CEA misalignment not having been corrected within 2 hours (Condition C).

I&C technicians and the system engineer responded to troubleshoot and repair the cause of the dropped CEA. They took coil traces and determined that all four CEAs in Shutdown Group A Subgroup 13 were missing at least one phase of power. Further inspection identified that six optical isolator chips were loose in their sockets. The technicians tested the chips, determined that they were functional, and reseated them. Additional coil traces showed that all four CEAs were still missing one phase. This condition was determined to be caused by a blown fuse. The fuse was replaced and the system was retested satisfactorily.

At approximately 10:33 p.m., CEA 49 was relatched and operators began to fully withdraw it to align it with the rest of Shutdown Group A. A reactor engineer and the Operations superintendent were present to advise and monitor operator actions. CEA 49 was aligned at approximately 11:53 p.m. Power was slowly increased, and was restored to 100 percent on November 2, 1996.

The licensee initiated AR 961100003 to document the event, the root cause determination, and associated corrective actions. The licensee's preliminary determination was that high temperature in the CEDMCS cabinet caused the CEA to drop. As of the end of this inspection period the licensee had not determined how or when the blower switch had been turned off.

c. Conclusions

Operator actions in response to the dropped CEA were in accordance with TS requirements. Oversight by Operations management and reactor engineering was effective in ensuring activities were coordinated and that TS and Core Operating Limits Report requirements were accurately understood.

O1.4 CPIS - Unit 3

a. Inspection Scope (71707, 71750)

The inspector reviewed licensee activities surrounding a CPIS A actuation that occurred in Unit 3 on October 25, 1996.

b. Observations and Findings

The CPIS was initiated by containment gaseous Radiation Monitor (RM) 3RE7807C reaching its setpoint (900 cpm). Because a purge was not in progress at the time, no equipment changed state.

The licensee had been aware of, and had been actively monitoring, an increasing trend in containment gaseous activity since approximately October 20. The increased activity was approximately linear between October 20 and October 25.

The trend was also apparent on Train B containment gaseous RM 3RE7804C. The licensee had initiated AR 961001168 on October 24, stating that the CFMS alarm point for RM 3RE7804C should be increased to avoid nuisance alarms and to provide an alarm based on approximately 1.0 gpm RCS leakage. This sensitivity was described in the UFSAR and was in accordance with NRC Regulatory Guide 1.45.

AR 961001168 documented that the increased gaseous activity was apparently due to approximately 0.1 gpm of RCS leakage from the pressurizer steam space, since particulate activity was not increasing.

After the return to full power on November 2, following a dropped CEA (see Section O1.3), the containment gaseous activity again increased. The licensee made a containment entry on November 5 and observed that the vent to containment from the pressurizer, Valve 3HV0298 was leaking at approximately 0.05 gpm. This was consistent with observed gaseous activity. In the days following the containment entry, the activity level stabilized at approximately 1000 cpm.

c. Conclusions

The licensee was monitoring a slow increase in containment gaseous activity, and was proactive in planning to reset the CFMS alarms to avoid operator distractions.

The license missed an opportunity to avoid the CPIS A actuation primarily because of a general lack of awareness of the CPIS setpoint. The licensee could have predicted that the CPIS setpoint would be reached on October 25, and taken actions to reset the setpoint.

O4 Operator Knowledge and Performance

O4.1 Failure to Complete Surveillance - Unit 2

a. Inspection Scope (71707)

The inspector reviewed the circumstances surrounding Operation's failure to perform a conditional surveillance.

b. Observations and Findings

On November 1, 1996, Unit 2 operators declared CEAC #1 inoperable for performance of an 18-month surveillance. The same day the licensee reported to

the NRC that operators failed to complete a 4-hour surveillance within the required time period, required by TS 3.3.3, Action A, when they made the CEAC inoperable. However, Action B of TS 3.3.3 allowed continued operation in the event Action A was not completed within the required 4-hour period, as long as the actions of Condition B were completed within the next 4-hour period. Because operators completed the surveillance required by Action A within the second 4-hour period, the TS allowed continued operation in accordance with the provisions of Action A until the CEAC was returned to service.

Operators logged the inoperability in the CEAC log book. The book included a column, that was signed and verified by the CO and ACO, respectively, to ensure the 4-hour surveillance was initiated when making a CEAC inoperable. However, the CO did not direct the ACO to initiate the 4-hour surveillance. Additionally, the ACO did not verify who had initiated the surveillance. This was more significant since the ACO is normally responsible for performing surveillances such as the 4-hour surveillance for CEA position.

Work Authorization Record 2-9603373 for the CEAC work did not list the 4-hour surveillance needed to be performed, but did direct the CEAC to be removed from service in accordance with Procedure SO23-3-2.13.

The CO had made an entry in the CO log at 8:40 a.m. stating that CEAC #1 was removed in accordance with Procedure SO23-3-2.13, "Core Protection/Control Element Assembly Calculator Operation," Revision 7. The CO stated that he had reviewed the procedure, but had failed to review Section 6.5.2, which directed the 4-hour surveillance to be initiated when a CEAC was removed from service.

At the time the CO and ACO were making the CEAC inoperable the CRS was in the control room. The CO stated that the CRS was not observing their activities directly. Procedure SO123-0-2, "CRS Authority, Responsibilities, and Duties," Revision 3, Step 6.2.3, required the CRS to direct and coordinate the activities of the operating crew with approved procedures, TS, and Licensee Controlled Specifications (LCS). The procedure also required the CRS to review the TS when removing equipment from service. The CRS d' ' not direct and coordinate the activities of the crew nor review the TS when equipment was removed from service. Procedure SO123-0-3, "CO's Responsibilities and Duties," Revision 1, Step 6.2.4.1, also required the CO to "ensure control room round sheets or shift relief status and surveillances are completed in the assigned time frame." The CO did not ensure the surveillance was completed within 4 hours.

Shortly after the CEAC was taken out of service the operators became involved in a long evolution to support a pump retest. Following completion of the pump retest, approximately 6 hours after removing the CEAC from service, operators realized they had missed the 4-hour surveillance.

TS 3.3.3, Action A.1, required that if one CEAC was inoperable, to perform a SR 3.1.5.1 once every 4 hours. SR 3.1.5.1 required verification that the position of each full and part length CEA was within 7 inches of all other CEAs in its group. At 3:15 p.m. the CO made a log entry that position verification required by the TS had been completed. However, Condition B stated that, if the required action for Condition A was not met within its required completion time, to verify that the departure from nucleate boiling ratio requirement of LCO 3.2.4 was met within 4 hours. Because operators completed this verification within 4 hours, the TS requirements were met.

The licensee briefed all operators regarding this event, emphasized the need to ensure that a timer is started to ensure that the surveillances are performed.

c. Conclusions

The 4-hour surveillance required by Action A of TS 3.3.3 was not completed within the required time frame; however, the licensee complied with Action B within the required time frame, which was provided in the event Action A was not completed. Therefore, TS requirements were met.

Operators failed to follow procedural controls for removal of a CEAC from service. Operators missed several opportunities to ensure that the surveillance would be completed. The licensee's administrative controls for roles and responsibilities for operators were sufficiently detailed to ensure operators understood they should follow TS and perform surveillances required when removing equipment from service. Inattention to these controls by operators led to the surveillance being missed. While the operators were aware of the requirement to perform the surveillance, they did not take action to ensure that it would be performed. The failure to follow the procedures was a violation of TS 5.5.1.1.a. This licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (NCV 50-361/96015-03).

Operators exhibited weak command and control, in that the CO did not provide direction to the ACO to perform the surveillance, and the CRS did not adequately oversee the activities to ensure operators had initiated a surveillance required by TS.

O7 Quality Assurance in Operations

O7.1 Component Mispositioning Events

Recently, the licensee had experienced certain valve mispositioning situations (i.e., RCS head vent valve in Unit 3 and pressurizer spray line drain valves in Unit 2). These situations were of concern to the NRC and the mispositioned head vent valve was the subject of a recent special NRC inspection.

Operations management maintained an ongoing list and analysis of performance issues. In this program, component mispositioning by operators had been identified as a concern. Operations had performed a self-assessment in this area in about July 1996.

On November 5, 1996, Nuclear Oversight sent a memorandum to the Vice President, Nuclear Generation, requesting action regarding 47 component mispositioning events that had been reported in ARs in 1996, validating NRC concerns in this area. The events involved personnel from Operations and other divisions. In the memorandum, Nuclear Oversight requested identification of a responsible manager to address the broad issue, including establishing appropriate metrics for evaluating and tracking progress in improving performance in this area. The inspector considered Nuclear Oversight's assessment to be significant and timely in that it established a larger scope to this important issue.

O8 Miscellaneous Operations Issues (71707, 92700)

O8.1 (Closed) Licensee Event Report (LER) 50-362/96006-00: containment purge isolation actuation. This issue is discussed in Section O1.

O8.2 (Closed) LER 50-362/96004-00: RCS pressure boundary leakage due to a failed resistance temperature detector (RTD) thermowell. This issue was previously discussed in NRC Inspection Report 50-361(362)/96011.

O8.3 Institute of Nuclear Power Operations Report

The inspector reviewed the Institute of Nuclear Power Operations report of its periodic evaluation of performance of San Onofre. The report had been received by the licensee in September 1996.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707)

The inspector observed all or portions of the following work activities:

- Replace spent fuel pool cooling branch connection with new style fitting - Unit 2

- Install flat bar support brackets on refueling water storage tanks - Unit 3

b. Observations and Findings

The inspectors found the work performed under these activities to be thorough. All work observed was performed with the work package present and in active use. Technicians were knowledgeable and professional. The inspectors frequently observed supervisors and system engineers monitoring job progress, and quality control personnel were present whenever required by procedure. When applicable, appropriate radiation controls were in place.

In addition, see the specific discussions of maintenance observed under Section E3.1, below.

M1.2 General Comments on Surveillance Activities

a. Inspection Scope (61726)

The inspector observed all or portions of the following surveillance activities:

- Engineered safety feature group relay K-112A, K-625A, and K-725A semiannual test - Unit 3

- Main and auxiliary feedwater valve testing - cold shutdown and refueling interval - Unit 2

b. Observations and Findings

The inspectors found all surveillances performed under these activities to be thorough. All surveillances observed were performed with the work package present and in active use. Technicians were knowledgeable and professional. The inspectors frequently observed supervisors and system engineers monitoring job progress, and quality control personnel were present whenever required by procedure.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) Violation 50-361(362)/96008-01: performance of maintenance activities on the wrong components. This violation involved two instances where technicians performed work on wrong components after being briefly interrupted in their work. The licensee's corrective actions for the violation were identified in a letter to the NRC dated September 11, 1996. The inspector reviewed licensee documents and determined that the corrective actions were either completed or scheduled for completion. The inspector also spoke with Maintenance technicians and determined that management was emphasizing self and cross checking to ensure that correct components are worked on.

M8.2 (Closed) Inspector Followup Item 50-361/93016-02: differences in ultrasonic testing wall thickness measurements. This item was opened after repetitive measurements indicated that component wall thickness had changed by more than five percent, which was the accuracy range of the test equipment. The licensee evaluated the measurements and determined that wall thickness was greater than the code specified minimum thickness. The licensee also determined that the measurement differences were attributable to operator technique and component variability. The inspector discussed the issue with licensee personnel and agreed with their evaluation of the issue. The inspector also noted that the licensee's program required an examination of the entire grid area if one measurement was less than the manufacturer's minimum wall thickness.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Review of Facility and Equipment Conformance to UFSAR Description

A recent discovery of a licensee operating its facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR description. While performing the inspections discussed in this report, the inspectors reviewed the applicable sections of the UFSAR that related to the inspection areas inspected. The following inconsistency was noted between the wording of the UFSAR and the plant practices, procedures and/or parameters observed by the inspectors:

- The description of the method used to control VCT level, in UFSAR Section 9.3.4.2.1.2, was found to be inconsistent (Section O1.2).

E2.2 ECW System Leakage Detection

a. Inspection Scope (37551)

The inspector interviewed cognizant engineers and walked down portions of the (common to both units) ECW system in order to determine leakage detection methods in place. The inspector also reviewed DBD SO23-800, "Auxiliary Building Emergency Chilled Water System," Revision 0.

b. Observations and Findings

The ECW system is a closed-loop safety-related system that supplies chilled water for cooling safety-related equipment (such as emergency core cooling pump room coolers and charging pump room coolers) and to provide habitability. The system automatically starts on various engineered safety signals. Two emergency chiller units provide chilled water to both units. A nominal 60-gallon compression tank

provides for compression and contraction of the chilled water, maintains suction head to the chilled water pump, and prevents voiding in the system high points. The system normally contains approximately 1200 gallons of water with 42 separate cooling coils located throughout both units. Tank pressure is provided by a closed volume of air. The tank has an automatic makeup, based on low tank pressure, that comes from nonsafety-related nuclear service water. There is no control room indication of initiation of automatic makeup.

If an event occurred, and the nonsafety automatic makeup for the system was lost, and if system leakage was sufficient, the system compression tank could lose level. Air from the compression tank could then enter the suction of the pump, and the system could fail.

The licensee logged compression tank level locally. In addition it was normal practice for operators and the cognizant engineer, if they observed leakage during normal plant tours, to evaluate the amount of the leakage, and generate ARs for Maintenance to repair the leakage. However, the inspector found that although these methods would detect some leakage, they did not quantify system leakage with reasonable assurance at any one time. The inspector found that operators had no ready means to determine, nor did they determine, the amount of makeup taking place. However, the inspector found that these monitoring methods did provide some assurance that significant undetected leaks would not occur.

Immediately after inspector questioning during October 1996, Station Technical personnel discovered, and Maintenance personnel repaired, a 60 cc/hr leak in a compression tank drain line. The licensee had determined in 1993, as a result of DBD in 1992, that with a low compression tank level, 200 cc/hr leakage was acceptable; with a high tank level, 950 cc/hr leakage was acceptable. The licensee also generated ARs 961000554 and 961200136 to reevaluate the acceptable leakage numbers and to initiate a test for leakage.

The inspector also observed that Revision 0 to DBD SO23-800, completed in 1992, left as an open item for engineering to resolve the need to install a safety-related makeup source and the need of performing a system leakage test. The inspector found that acceptable leakage amounts had been developed, but that these other issues had not been addressed as of this inspection report period.

c. Conclusion

The licensee did not have data to confirm that leakage from the ECW system was within the values added to the DBD in 1993. Until the inspector identified the issue, Engineering did not follow up on recommendations made at that time to evaluate the need for safety-related makeup and for development of a system leakage test, indicating an isolated weakness in system management.

E2.3 Charging Pump 2P190 Breaker Failure - Unit 2

a. Inspection Scope (37551)

The inspector reviewed the licensee's response to the failure of the safety-related 480 volt breaker for Charging Pump 2P190.

b. Observations and Findings

On October 22, 1996, the breaker for Charging Pump 2P190 failed to close on demand from the control room. It failed to close on a second attempt, and on a third attempt it closed and then tripped open after approximately 3 minutes. The licensee documented these failures in AR 961001008.

The licensee determined that the cause of the failures was that the roller assembly was sticking, resulting in the breaker not being properly aligned in the cubicle and the secondary contacts not being fully engaged.

The roller assembly was not included in the preventive maintenance program, and had not been lubricated since assembly by the manufacturer. The vendor manual for the breaker did not address preventive maintenance for the roller assembly. The licensee contacted the vendor to determine the appropriate lubricant, and intended to add inspection and lubrication of the roller assembly to the preventive maintenance program for similar breakers.

The licensee replaced the breaker with a spare and restored the system to service.

c. Conclusion

The licensee's resolution of a failed 480 volt safety-related breaker was prompt and thorough.

E3 Engineering Procedures and Documentation

E3.1 RCS Temperature Element Wiring Modification - Unit 3

a. Inspection Scope (37551, 71707)

During a review of the Unit 3 CO logs, the inspector determined that I&C technicians caused a trip of CPC Channel A while performing a surveillance of RCS cold leg temperature Indicator 3TI-0925-1. The inspector reviewed the circumstances leading up to the event.

b. Observations and Findings

RTD 3TE-0925-1 once had been only used as the input to Indicator 3TI-0925-1. However, because of a failure of another RTD in 1994, wiring changes and modifications were made, in accordance with NCR 941100027, resulting in RTD 3TE-0925-1 also supplying an input to CPC Channel A.

I&C technicians calibrating Indicator 3TI-0925-1 caused the trip of CPC Channel A (on departure from nucleate boiling ratio and linear power density) during the calibration activities. Work Authorization Record 3-9603339 referenced Maintenance Order (MO) 96052709, which referenced Procedure SO23-II-9.657, "Surveillance Requirement Qualified Safety Parameter Display System A (QSPDS-A) Calibration," Revision 6, for calibration of Indicator 3TI-0925-1. The procedure did not mention that the RTD feeding Indication 3TI-0925-1 performed a dual purpose. The inspector considered that under other licensee design modification processes the impact to the I&C procedure would have normally been evaluated.

Apparently, the technicians did not obtain the drawing change showing that the RTD for Indication 3TI-0925-1 also supplied a temperature signal to CPC Channel A. I&C supervision stated that the drawing change documents were not obtained because the technician was unfamiliar with the software application used to obtain drawings and missed the information in the computer system that stated there were changes outstanding against the drawing.

The inspector determined that Maintenance personnel had received no training on the used of the computer application used to obtain drawings. Apparently, the technicians learned it on their own. In response to this weakness, the licensee planned to conduct training of Maintenance personnel and to evaluate enhancements to the computer application.

The inspector reviewed Procedure SO123-XV-5, "Nonconforming Material, Parts, or Components", Temporary Change Notice 3-22, which was in effect when the modification was made. The procedure did not require review of Operations or Maintenance procedures when making a design modification, as the licensee's other design change processes would. As a result, the inspector considered that the opportunity was missed to identify that the modification of the RTD inputs could affect the unit in an adverse manner.

The inspector reviewed the current procedure for NCRs and noted that it still allowed plant modifications if operational instructions and drawings were reviewed for impact. However, the inspector determined that the process still did not require an impact review of surveillance and maintenance procedures. In response to this programmatic weakness, the licensee agreed to revise the NCR process.

c. Conclusions

I&C technicians lacked sufficient knowledge of licensee computer systems used to identify and retrieve current drawings. which contributed to an unplanned CPC channel trip.

The NCR process used to make modify the CPC inputs did not ensure that affected procedures were identified and revised. This weakness had not been fully addressed in recent NCR program changes.

E4 Engineering Staff Knowledge and Performance

E4.1 Reload Analysis Error

a. Inspection Scope (37551)

The inspector reviewed licensee performance in the identification and resolution of an error in the fuel reload analysis.

b. Observation Findings

While reviewing vendor calculations as part of the reload technology transfer program, licensee engineers identified a discrepancy in the data related to core power distributions for dropped part-length CEAs (PLCEAs). Because the PLCEAs are not uniform along their length, they introduce an axial asymmetry when inserted into the core. The asymmetry was not properly addressed in the calculations, resulting in a nonconservative acceptable operating region being included in the LCS. The curve affected was LCS Figure 3.1.105-3, "Required Power Reduction after Single PLCEA Deviation," which is part of the Core Operating Limits Report. The licensee contacted the vendor, who confirmed the error as identified by the licensee.

The licensee determined that TS operating limits prior to issuance of the LCS were more conservative than required, and that the units had never operated in what was now determined to be an unacceptable region.

Had the licensee operated in the unacceptable region, which was applicable after a PLCEA dropped over halfway into the core, departure from nucleate boiling limits could have been exceeded.

The licensee documented the condition in AR 961100053, and implemented immediate corrective action to require operators to comply with LCS Figure 3.1.105-2, "Required Power Reduction After Single Group 6 Full Length CEA Deviation," if a PLCEA dropped. LCS Figure 3.1.105-2 was more conservative than required for plant safety for a dropped PLCEA.

c. Conclusions

The licensee's identification and correction of a methodology error in a vendor calculation was an excellent finding demonstrating strength in the licensee's reload technology transfer program.

E8 Miscellaneous Engineering Issues (92712)

E8.1 (Closed) LER 50-362/96002-00,01: potential decalibration of log power level instrumentation. On February 9, 1996, the licensee was notified by Asea-Brown Boveri Combustion Engineering (CE) that a potential nonconservatism in the calibration of logarithmic power channels reported by Waterford may exist at San Onofre Units 2 and 3. The potential decalibration was attributed to physics effects, which may cause the log power indication to vary significantly from actual plant power during low power operation due to factors such as CEA position, temperature shadowing, boron changes, etc. CE estimated that the effects had the potential to cause the log power trip to be high by a factor of two, but less than a factor of 10. In response, the licensee reduced the high logarithmic power trip setpoints, in both units on all four channels, by a factor of 10, while CE performed a reanalysis to determine the actual effect of the nonconservatisms. The inspector verified that the licensee initiated MOs to change the setpoints.

The inspector reviewed portions of the reanalysis performed by CE, which concluded that the total of the decalibration effects was a factor of two. Based on the calculated decalibration effect the log power trip setpoint was reanalyzed. The results demonstrated that the previously installed setpoints would have allowed the log power trips to perform their intended safety functions. Following receipt of the reanalysis, the licensee restored the trip setpoints to their previous values. The licensee submitted Revision 1 of the LER to document that, based on the results of CE's analysis, the condition previously reported was no longer reportable.

The inspector concluded that the licensee's actions were conservative.

IV. Plant Support

R8 Miscellaneous Radiological Protection and Chemical Issues (92904)

R8.1 (Closed) Inspector Followup Item 50-362/96009-05: steam generator (SG) blowdown RM valve misalignment. The licensee found an open bypass valve for SG 3E088 blowdown RM 3RE6759 that was unidentified on plant drawings. The licensee also found similar bypass valves for the other three SG blowdown RMs; however, those bypass valves were in the closed position. The four bypass valves were not depicted on plant drawings or specified in plant procedures.

The inspector discussed this item with Engineering, Operations, and RM personnel. The inspector also reviewed alarm response instructions, abnormal operating instructions, and emergency operating instructions applicable to the SG blowdown RMs. The SG blowdown RMs are used in conjunction with other RMs and sample results to diagnose a SG tube rupture. While the open bypass valve rendered the RM inoperable, the inspector concluded that operators could have diagnosed a SG tube rupture using the other RMs and sample results. The inspector found that the SG blowdown RMs were not required to be operable by TS. In addition, the inspector reviewed the UFSAR and determined that the SG blowdown RMs were not covered by the quality assurance provisions of 10 CFR Part 50, Appendix B. Although the unidentified valves represented a configuration control problem, the inspector concluded that no violation of NRC requirements occurred. A field change was performed to remove the four bypass valves from the SG blowdown RMs. The licensee inspected other RMs and found no other unidentified valves.

P2 Status of Emergency Preparedness Facilities, Equipment, and Resources

P2.1 Safe Shutdown Emergency Lights Blocked By Scaffolding - Unit 2

a. Inspection Scope (71707, 71750)

The inspector walked down portions of Unit 2 during an electrical outage and observed that some emergency lights were blocked by scaffolding. The inspector evaluated licensee controls for temporary scaffolding erected in the Unit 2 main steam safety valve (MSSV) area.

b. Observations and Findings

On October 17, 1996, during a plant walkdown of the MSSV area, the inspector observed that temporary scaffolding, erected for painting, was blocking safe shutdown 8-hour emergency lights illuminating an access and egress path to safe shutdown components and illumination of two safe shutdown components, atmospheric dump Valve 2HV8421, and turbine auxiliary feedwater pump steam supply Valve 2HV8200. The inspector informed the licensee of the degradation of the emergency lighting and determined that the licensee had been previously unaware of the condition. The inspector determined that plant equipment operators routinely, at least once per shift, toured the MSSV areas on both units.

The inspector reviewed the LCS for safe shutdown emergency lights, LCS 3.7.114, and determined that the LCS required that when a light was made inoperable, operators were directed to utilize portable lanterns after a 14-day time period. However, since the operators were previously unaware of the degradation, no tracking mechanism was initiated to ensure that after 14 days portable lanterns would be used in the affected areas. However, the inspector observed that plant operators routinely carried flashlights. The inspector verified that, in the safe shutdown from outside the control room, backpacks given to all operators during

implementation of the emergency operating instruction for safe shutdown outside the control room contained portable lanterns. In addition, as discussed below, the inspector also could not determine that the lights were blocked for more than 14 days. Once the operators were aware that the lights were blocked, tracing was initiated in accordance with LCS 3.7.114.

The inspector determined that the procedure controlling scaffolding erection did not provide guidance to sensitize craft personnel that the illumination path of emergency lights should not be blocked. In addition, the inspector determined that the Emergency Preparedness procedure for weekly plant inspections did not sensitize fire inspectors to the potential of scaffolding blocking emergency lights. The inspector verified that a weekly inspection of the MSSV had been performed; however, because the fire inspection procedure did not state the need to look for degradation of emergency lighting, the licensee inspectors did not identify the scaffolding problem. As a result, the licensee revised these program procedures to reflect the need to prevent scaffolding from blocking emergency lighting or to take the appropriate compensatory actions if not preventable.

The inspector reviewed the "work done" section of MO 96052477, used for control of the scaffolding activities. The scaffolding blocking the lighting illuminating safe shutdown Valves 2HV8200 and 2HV8421 was documented as being built less than 14 days prior to the observation. The date for when the scaffolding blocking the access and egress paths to the area was built could not be determined.

c. Conclusions

The scaffolding that was blocking the safe shutdown emergency lights was not documented as being erected for more than 14 days. Therefore, no LCS violation occurred. The inspector considered that even though operators were not tracking the inoperability of the emergency lights to ensure that at 14 days they needed to utilize portable lanterns, the safety consequence was minimal because, during a shutdown from outside the control room, emergency supply kits provided to operators contained portable lanterns. While the root cause was a programmatic breakdown in the programs for control of scaffolding erection and inspection of fire protection equipment, the licensee corrective actions were thorough.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the exit meeting on December 4, 1996. The licensee acknowledged the findings presented.

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

ATTACHMENT

PARTIAL LIST OF PERSONS CONTACTED

Licensee

D. Brieg, Manager, Station Technical
J. Fee, Manager, Maintenance
G. Gibson, Manager, Compliance
D. Herbst, Manager, Site Quality Assurance
P. Knapp, Manager, Health Physics
R. Krieger, Vice President, Nuclear Generation
D. Nunn, Vice President, Engineering and Technical Services
T. Vogt, Plant Superintendent, Units 2 and 3
R. Waldo, Manager, Operations
M. Wharton, Manager, Nuclear Engineering Design

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92700:	On Site LER Review
IP 92712:	Inoffice Review of LER
IP 92902:	Followup - Maintenance
IP 92904:	Followup - Plant Support

ITEMS OPENED AND CLOSED

Opened

50-362/96015-01	VIO	VCT inlet diversion valve controller in incorrect mode
50-361 (362)/96015-02	IFI	UFSAR changes to VCT operation

Opened and Closed

50-361/96015-03	NCV	missed CEAC surveillance

Closed

50-361/93016-02	IFI	differences in ultrasonic testing wall thickness measurements
50-361/96008-01	VIO	performance of maintenance activities on wrong unit
50-362/96006-00	LER	containment purging isolation actuation
50-362/96004-00	LER	RCS pressure boundary leakage
50-362/96002-00, 01	LER	potential decalibration of log power level instrumentation
50-362/96009-05	IFI	SG blowdown RM misalignment

LIST OF ACRONYMS USED

ACO	assistant control operator
AR	action request
CE	Combustion Engineering
CEA	control element assembly
CEAC	control element assembly calculator
CEDMCS	control element drive mechanism control system
CFMS	critical functions monitoring system
CO	control operator
CPC	core protection calculator
CPIS	containment purge isolation signal
CRS	control room supervisor
DBD	design basis document
ECW	emergency chilled water
I&C	instrumentation and controls
LCO	limiting condition for operation
LCS	licensee-controlled specifications
LER	licensee event report
MO	maintenance order
MSSV	main steam safety valve
NCR	nonconformance report
PDR	Public Document Room
PLCEA	part-length control element assembly
RCS	reactor coolant system
RM	radiation monitor
RTD	resistance temperature detector
SG	steam generator
TS	technical specification
UFSAR	Updated Final Safety Analysis Report
VCT	volume control tank