ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

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Report No.:	50-361/96-11 50-362/96-11
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:	September 8 through October 19, 1996
Inspectors:	J. Sloan, Senior Resident Inspector D. Solorio, Resident Inspector J. Russell, Resident Inspector
Approved By:	D. F. Kirsch, Chief, Branch F Division of Reactor Projects
ATTACHMENT:	Partial List of Persons Contacted List of Inspection Procedures Used List of Items Closed List of Acronyms

EXECUTIVE SUMMARY

San Onofre Nuclear Generating Station, Units 2 and 3
NRC Inspection Report 50-361/96-11; 50-362/96-11

Operations

- Management focus was clearly directed at ensuring significant problems were promptly resolved and activities were effectively coordinated to support safe plant operation. In general, the conduct of operations in the control room was professional and well planned and coordinated (Section O1.1).

- Licensee operators and management were sensitive to indications of reactor coolant system (RCS) leakage, aggressively pursuing the source, and acted responsibly after identifying RCS pressure boundary leakage (Sections O1.1 and E2.3).

- Activities to drain the RCS to reduced hot leg inventory conditions, conducted on two occasions, were well controlled by Operations. Procedural requirements were effectively implemented, there was effective command and control by supervision; communications among operators were clear; and management oversight was evident (Section O1.2).

- Operations detected and aggressively pursued an abnormally high packing temperature and conservatively declared Auxiliary Feedwater Pump 3P504 inoperable. Incomplete communications from Station Technical led to confusion with Operations and Maintenance personnel regarding implementation of the pump packing performance temperature criterion. Licensee corrective actions were thorough (Section O2.1).

- A control room supervisor (CRS) who entered the wrong Technical Specification (TS) limiting condition for operation (LCO) condition for an inoperable hydrogen monitor channel was not adequately familiar with the specific LCO, and misread it. The shift technical advisor (STA) and the next shift's CRS missed opportunities to identify the error, also indicating a lack of familiarity with the recently revised TS. However, this was an isolated incident. The action for the LCO condition incorrectly entered was more conservative than the action for the correct LCO condition (Section O4.1).

- Although parallel operation is not a safety function, flawed procedure change management, which allowed important information to be removed from an operating procedure, was the primary cause of a failure of operators to parallel an emergency diesel generator (EDG) to its bus during surveillance testing. However, the licensee's process for procedure change management had recently been improved to prevent important instructions and information from being removed without an adequate evaluation (Section O4.2).

- In one instance observed, the licensed operator requalification examiners were conservative in evaluating annual dynamic simulator scenarios examinations. The training program was correctly implemented in responding to a crew failure (Section O5.1).

Maintenance

- Maintenance and surveillance activities were generally conducted professionally, in accordance with licensee procedures, by knowledgeable personnel (Sections M1.1 and M1.2).

- Overall, the maintenance activities to remove and install the internal inlet check valves in a charging pump were properly conducted. However, weaknesses were observed with regard to attention to detail in the planning of the maintenance order (MO) work plan, and implementation of the consumables program guidelines by Mechanical Maintenance personnel. However, corrective actions to ensure that future performance met management expectations were considered thorough (Section M1.3).

- The licensee's root cause investigation and actions to prevent recurrence for inadvertent radiation monitoring (RM) annunciation were aggressive. A preexisting ground that rendered the circuit susceptible to the failure had been present in the logic power supply for some period of time, and had probably been associated with other instances of blown fuses, and as such could have been reasonably detected by the licensee at an earlier point (Section M8.1).

Engineering

- The licensee's analysis of the effects of leaving a broken section of a thermowell in the RCS in Unit 3 was thorough. The licensee had not previously reviewed the effects of cold work performed on the thermowell, the effect of leaving a broken resistance temperature detector (RTD) tip in the thermowell, or the source of rust in the Inconel-600 thermowell. RCS pressure boundary leakage resulted from the failure of the thermowell subsequent to those activities (Section E2.3).

- The Onsite Review Committee (OSRC), during one meeting observed, maintained a good safety focus and carried out its responsibilities effectively (Section E7.1).

Plant Support

- The construction craft exhibited poor judgment by not using more caution when working near a deluge actuator, resulting in an inadvertent deluge actuation. Licensee actions to prevent recurrence were prompt and well focused. Licensee response to the deluge was prompt and effective (Section F2.1).

Report Details

Summary of Plant Status

Unit 2 operated at essentially 100 percent power throughout this inspection period, with the exception of reducing power to 75 percent on September 13 and 21 for waterbox cleaning, and on October 13, 1996, for a heat treatment of the circulating water system.

Unit 3 began this inspection period by increasing power to essentially 100 percent power, after performing a heat treatment of the circulating water system. The unit operated at essentially full power until September 23, 1996, when the unit shut down and cooled to Mode 5 to allow repairs to a leaking RCS cold leg thermocouple (Section E2.3). The unit was heated up and the reactor brought critical on October 12. The unit was synchronized to the grid on October 13, 1996, reached essentially 100 percent power on October 14, and operated at essentially 100 percent power until the last day of this inspection period. At that time, the unit reduced power to 75 percent to perform a heat treatment of the circulating water system.

I. Operations

O1 Conduct of Operations[1]

O1.1 General Comments (71707)

The inspectors performed frequent observations of ongoing plant operations. Management focus in daily plant meetings was clearly directed at ensuring that significant problems were promptly resolved and activities were effectively coordinated to support safe plant operation. In general, the conduct of operations in the control room was professional and well-planned and coordinated.

Licensee operators and management were sensitive to indications of RCS leakage, aggressively pursuing the source, and acted prudently after identifying RCS pressure boundary leakage (see Section E2.3).

O1.2 RCS Draindown to Midloop - Unit 3

a. Inspection Scope (71707)

On September 28, 1996, and during the night shift on October 3, the inspectors observed operators drain the Unit 3 RCS to 36 inches level in the hot leg of the RCS piping.

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[1]Topical headings such as O1, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics.

b. Observations and Findings

During both evolutions, the inspectors verified that the licensee had established the requisite number of level monitoring indicators in accordance with Procedure SO23-3-1.8, "Draining the RCS," Revision 8. The inspectors observed operators commence and terminate the draindown and observed that the evolution was conducted in a controlled and deliberate manner, and that supervisory oversight was effective. In addition, Operations management representatives had been present to provide additional oversight and guidance when needed. The inspectors also verified that operators performed level instrument correlations as procedurally required.

c. Conclusions

Activities to drain the RCS to reduced hot leg inventory conditions, conducted on two occasions, were well controlled by Operations. Procedural requirements were effectively implemented, there was effective command and control by supervision; communications among operators were clear; and management oversight was evident.

O2 Operational Status of Facilities and Equipment

O2.1 Auxiliary Feedwater Pump Stuffing Box Temperature - Unit 3

a. Inspection Scope (71707)

On September 25, 1996, with Unit 3 in Mode 5, Operations personnel declared Train B motor-driven Auxiliary Feedwater Pump 3MP504 inoperable due to a high pump outboard packing temperature. The pump had been started to add chemicals to Unit 3 steam generators. The inspectors reviewed MO 96010952000, to adjust pump packing for Pump 3MP504; observed a start and operation of the pump on September 26, 1996, in order to investigate the problem; and interviewed Maintenance, Operations, and Station Technical personnel.

b. Observations and Findings

Operators initially assessed the performance of the pump packing by feeling the temperature of the packing retainer ring with their hands. Maintenance personnel who responded to assess the performance measured the temperature of the packing retainer ring using an instrument.

Station Technical had previously sent a memorandum to the Operations manager listing one criterion as stuffing box temperature less than 160°F. This criterion was based on preventing the fluid from flashing to steam. If the fluid did flash to steam, it would not cool the packing. Station Technical personnel had meant for the

temperature to be taken about two-thirds of the way down the stuffing box gland. The stuffing box gland was normally cooler than the packing retainer ring.

After the confusion was resolved, Maintenance personnel took the temperature at the location intended by Station Technical and determined that the temperature was somewhat elevated but the packing performance was acceptable. Operations then declared Pump 3P504 operable.

Station Technical personnel planned on briefing all Operations crews to further clarify the criteria.

c. Conclusions

Operations detected and vigorously pursued an apparently abnormally high packing temperature and conservatively declared Auxiliary Feedwater Pump 3P504 inoperable. Incomplete communications from Station Technical led to confusion with Operations and Maintenance personnel regarding implementation of the pump packing performance temperature criterion. Licensee corrective actions were prudent.

O4 Operator Knowledge and Performance

O4.1 Hydrogen Monitor LCO - Unit 2

a. Inspection Scope (71707)

On September 26, 1996, the inspectors reviewed the Unit 2 CRS's classification of the LCO action requirement for the Train B containment hydrogen Analyzer 2AET8111-2, which had been taken out of service for surveillance testing.

b. Observations and Findings

The inspectors reviewed TS 3.3.11, "Post Accident Monitoring Instrumentation," to determine the appropriate LCO action requirements and determined that the CRS had entered the wrong LCO condition. The CRS entered Condition C, which specifically stated that it was not applicable to hydrogen monitoring channels, and was applicable when one or more functions with two required channels were inoperable. The required action for Condition C was to restore one channel to an operable status within 7 days. The correct LCO condition was Condition A, which applied when one of the two required channels was inoperable and required restoration of the inoperable channel within 30 days. A special report was required within the next 30 days if the action requirement was not met.

The TS equipment out-of-service tracking sheet, which was prepared by operations equipment control, initially correctly classified that Condition A was the applicable

LCO condition. However, the CRS stated he had misread TS LCO Condition C and entered it instead of Condition A.

The tracking form was subsequently reviewed by the STA on duty, and during turnover by the next shift's CRS. The inspectors determined that neither had questioned the change from Condition A to Condition C, nor identified the error. The inspectors reviewed Procedure SO123-0-2, "CRS's Authority, Responsibility and Duties," Revision 3, and determined that CRSs were required to review the LCO tracking forms at the beginning of each shift to be aware of operational limitations; however, the review did not include reverification of the applicability of the LCO conditions. In addition, the inspectors determined that, when possible, it was a licensee management expectation that the STAs review LCO conditions entered in order to independently verify the determinations made by the CRSs. As a result of the inspectors' observation, the STA supervisor stated that all STAs were coached to perform a thorough verification of LCO conditions and action requirements when performing the review.

In the course of routine duties the inspectors had routinely performed independent verification of the applicability of LCO condition determinations by operators and had not observed similar occurrences in the past.

c. Conclusion

The CRS who entered the wrong LCO condition was not adequately familiar with the specific TS LCO, and misread it. The STA and the next shift's CRS missed opportunities to identify the error, also indicating a lack of familiarity with the recently revised TS. However, this was an isolated incident.

The action for the LCO condition incorrectly entered was more conservative than the action for the correct LCO condition. However, a similar error in implementing the TS could have resulted in nonconservative operator action.

O4.2 EDG Synchronization - Unit 3

a. Inspection Scope (61726)

On September 20, 1996, operators experienced difficulty while attempting to close the diesel output breaker to tie EDG 3G002 to its 1E bus for monthly surveillance testing in accordance with Surveillance Procedure, SO23-3-3.23, "Diesel Generator Monthly," Revision 9.

b. Observations and Findings

Troubleshooting by Maintenance and Engineering personnel successfully determined that operators had not matched running and incoming voltages to less than

3 percent. The voltages needed to be within 3 percent of each other so that the synchronization check relay would allow the EDG output breaker to be closed.

Because operators on shift at the time did not remember the exact value of the tolerance and because the value was not included in the surveillance procedure or the EDG operating procedure, they initially did not realize that the voltages were outside of the tolerance.

The synchronization check relay was installed in the paralleling circuit as a protection feature approximately 12 years ago in accordance with Design Change Package 747.IE, Revision O. Construction Work Order 2804-002 set the tolerance for the synchronization check relay at 3 percent. Following implementation of the design change package, the Operations procedures group included the tolerance requirement in the EDG operating procedure such that the running and incoming voltages needed to be within 1 percent of each other to allow the EDG output breaker to be closed. In October 1995 the tolerance for the synchronization check relay was removed from Revision 10-35 of the EDG operating procedure.

The inspectors reviewed the procedure history records for procedure changes and interviewed personnel responsible for removing the guidance. The inspectors determined that the information was removed based on several electronic messages between Engineering and Operations personnel that did not fully evaluate the impact of removing the tolerance for the relay. Contributing to this problem, the original intent of the tolerance was not kept in the procedure history records available to either the procedure change author or Engineering personnel.

The inspectors reviewed the licensee's current process for making and documenting the bases for operating procedure changes. The inspectors observed that the operating procedures group had recently issued guidance in the procedure author guide to document the reasons that limits or values were derived. These reasons were contained in hidden comment blocks viewable during the procedure revision process on the procedure change electronic system.

c. Conclusions

A flawed procedure change management process, which allowed important information to be removed from an operating procedure, was the primary cause of a failure of operators to parallel the EDG for surveillance testing. However, the licensee's process for procedure change management had recently been improved to prevent important instructions and information from being removed without an adequate evaluation. The surveillance procedure had been revised before the procedure change process had been improved and had not been reviewed under the improved process.

O5 Operator Training and Qualification

O5.1 Simulator Observation

a. Inspection Scope (41500)

On September 19, 1996, the inspectors observed licensee training personnel administer an annual requalification dynamic simulator examination, consisting of two scenarios, to a licensed operator crew.

b. Observations and Findings

The first scenario included a loss of offsite power and a loss of all feedwater. The intent of the scenario was to enable the operators to recover offsite power to facilitate feeding the steam generators, using the condensate pumps, in order to remove core decay heat. The inspectors observed that, due to a hardware problem unrelated to simulator fidelity, the simulator did not allow the operators to completely restore nonvital power. This was because the feeder breakers supplied by non-Class 1E 4 KV Bus 2A07 failed to open. Consequently, the operators were unable to restore power to this bus and associated loads. This complicated the operators' efforts to align a condensate pump for steam generator feed; it was, however, still possible to do this with the electrical power available. The steam generators boiled dry prior to the operators introducing feed, causing the core heat removal safety function not to be recovered. Recovering this safety function was a critical task for the crew. Programmatically, failing a critical task necessitated an overall crew failure of this portion of the annual examination. The licensee examiners failed the crew.

The second scenario included a steam generator tube rupture and a failure of the steam bypass system. The crew completed all critical tasks for this scenario.

The inspectors found that the licensee training personnel were conservative in failing the crew because the simulator malfunction complicated the efforts to reestablish feedwater beyond the intent of the original scenario, and provided a difficult, although achievable, success path. The crew was removed from shift duties, retrained, and successfully passed a different dynamic simulator examination on September 20, 1996. This was the only dynamic simulator crew failure for the examination cycle.

c. Conclusions

In one instance observed, the licensed operator requalification examiners were conservative in evaluating annual dynamic simulator scenarios examinations, and that the training program was correctly implemented in responding to the failure.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62703)

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

- Component cooling water CR17 Loop A Flow 2FT62393 loop calibration (Unit 2)
- RCS hot leg temperature loop calibration, Loop 3TE112-3 (Unit 3)
- Lube motor and change oil in Emergency Chilled Water Pump MP162 Train A (Unit 2/3)
- Calibrate Train A Emergency Chiller ME336 condenser pressure Switch PCH 5897a (Unit 2/3)

b. Observations and Findings

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

In addition, see the specific discussions of maintenance observed under Section M1.3 below.

M1.2 General Comments on Surveillance Activities

a. Inspection Scope (61726)

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

- Containment spray Pump 2MP012 and valve testing (Unit 2)
- Reactor plant protection system logic matrix functional test (Unit 2)
- Low pressure safety injection Pump 3MP015 miniflow and valve testing (Unit 3)

- Turbine overspeed protection valve operability tests (Unit 2)
- Engineered safety features subgroup Relays K-108A and K-108B semiannual test (Unit 3)

b. Observations and Findings

The inspectors found all surveillances performed under these activities to be in accordance with applicable procedures. All surveillances observed were performed with the work package present and in active use. Technicians were knowledgeable and thorough. The inspectors frequently observed supervisors and system engineers monitoring job progress. When applicable, proper radiation controls were in place.

M1.3 Charging Pump 2P190 Check Valve Replacement - Unit 2

a. Inspection Scope (62707)

On August 22, 1996, the inspectors observed troubleshooting activities conducted by day and swing shift Maintenance personnel to evaluate the cause of brief reverse rotation of Charging Pump 2P190. The condition occurred after the pump had been stopped for routine swapping of running equipment.

b. Observations and Findings

The inspectors observed Maintenance personnel remove, inspect, and reinstall three of the pump's six internal check valves. The check valves were inspected because Engineering personnel suspected that improper seating of one of the inlet or outlet check valves had been responsible for allowing water back through the pump from its discharge piping, causing the reverse rotation. The licensee observed that all of the pump's internal check valves showed signs of normal wear, which it suspected contributed to improper seating of the valves and the resultant leakby. As a result, all the inlet and outlet check valves were replaced. Postmaintenance testing verified that the reverse flow condition had been corrected.

The inspectors observed a prejob briefing, held by the swing shift crew foreman, for installation of the inlet check valves. The inspectors considered that it was very comprehensive and contributed to a clear understanding by Maintenance personnel of the activities to be accomplished.

The inspectors reviewed the work plan for the pump internal check valve maintenance, MO 96081155. The inspectors observed that two steps of the MO work plan did not reference an applicable step from the charging pump maintenance procedure for performing a check of the valve seating contact in the pump block. The system engineer for the charging pumps stated that the step was necessary to ensure sufficient contact between the seat and the pump block to prevent the seat

from popping out of the block while the pump was in service. The inspectors observed that the step directing replacement of the internal check valves included a pen-and-ink change to include the additional step to perform the seating check. However, the work plan step which would have been used, had the original check valves been reinstalled, did not include the additional step.

The inspectors also observed that the licensee's procedure for disassembly and reassembly of the check valves was more detailed and comprehensive than the vendor manual guidelines.

During installation of the internal check valves the inspectors observed that a restricted-use consumable, "Dykem blue," was used to check the valve seat contact with the area of the pump block where the seat would be installed. Prior to the using the consumable the swing shift Maintenance crew could not obtain a Restricted Use Permit (RUP) because the computer application for obtaining RUPs was out of service. However, the Maintenance crew inferred that, since the procedure for reassembly of the check valves listed the consumable in an attachment, the consumable could be used without obtaining an RUP. Following this observation, the inspectors determined that it was a Maintenance management expectation that a restricted consumable's RUP be obtained prior to use of the consumable. In addition, there was no guidance which exempted the crew from obtaining the RUP if the consumable was listed in an attachment of the pump's maintenance procedure.

The following day shift crew, continuing work on the charging pump, did obtain the appropriate RUP for the consumable. The inspectors determined that the crew did not use a solvent, as stipulated on the RUP, to remove the consumable, but used a cleaner that was approved for unrestricted use.

As a result of the inspectors' observations, mechanical Maintenance management initiated interim and long-term corrective actions to reemphasize to mechanical Maintenance personnel its expectations regarding the consumables program. Specifically, training covering these observations was given at a weekly safety meeting, and formal training on program implementation was scheduled to be completed before the upcoming Unit 2 refueling outage.

c. Conclusions

Overall, the maintenance activities to remove and install the inlet check valves were properly conducted. However, weaknesses were observed with regard to attention to detail in the planning of the MO work plan, and implementation of the consumables program guidelines.

Mechanical Maintenance personnel did not meet management's expectations to obtain a RUP prior to the use of consumables. However, corrective actions to ensure that future performance met management expectations were considered thorough.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 <u>(Closed) Inspection Followup Item 50-362/96008-02: inadvertent RM annunciation</u>

A licensee Instrumentation and Control technician inadvertently caused all Unit 3 RM annunciation to alarm while installing a jumper to disable certain annunciation in preparation for conducting a surveillance. The inspectors interviewed licensee Station Technical personnel and reviewed Action Request 960700640, generated as a result of the incident, and Electrical Loop Diagram 52319, Revision 1, for Unit 3 Radiation Indicator 7847, which illustrated the power supply for the RM annunciation.

The licensee's root cause determination was that the technician had either allowed a jumper lead to come into contact with a portion of the cabinet or a terminal position to ground. The licensee also stated that the system was designed to be ungrounded, but that a previously unidentified ground existed and when the technician introduced the second ground a resultant overcurrent condition caused a logic main power supply fuse to open, causing the annunciation. The previously unidentified ground had probably been present during past occurrences of a similar nature in which the RM annunciation had inadvertently alarmed due to a blown fuse during surveillance. The licensee replaced a capacitor that had shorted, causing the unidentified ground. The licensee also provided training to all Instrumentation and Control technicians on jumper installation.

The inspectors found the licensee's root cause investigation and actions to prevent recurrence aggressive. The inspectors also found that the ground had been present in the logic power supply for some period of time, had probably been associated with other instances of blown fuses, and as such could have been reasonably detected by the licensee at an earlier point.

In this instance the licensee was aggressive in ascertaining root cause and preventing recurrence of a blown fuse in the RM logic power system, but did not evidence the same level of aggressiveness during previous similar occurrences.

III. <u>Engineering</u>

E2 Engineering Support of Facilities and Equipment

E2.1 <u>Review of Facility and Equipment Conformance to Updated Final Safety Analysis Report (UFSAR) Description</u>

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 descriptions. 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 inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

E2.2 Reactor Coolant Pump (RCP) Oil Collection System Deficiencies - Units 2 and 3

a. Inspection Scope (37751)

The inspectors reviewed the licensee's actions in response to the licensee's discovery that the oil collection system for most of the RCPs in Units 2 and 3 would not collect any leakage from sightglasses installed on the motor lower bearing oil fill line.

b. Observations and Findings

On September 28, 1996, while Unit 2 was in Mode 1 and Unit 3 was in Mode 5, a licensee cognizant engineer observed a small amount of oil on components under a Unit 3 RCP motor. The engineer determined that the oil came from a leaking sightglass installed on the motor lower bearing oil fill line. The engineer also determined that the oil collection pan should have been large enough to collect the oil; however, the sightglass extended beyond the edge of the oil collection pan.

The licensee determined that the design deficiency existed on all RCP motors in both units, with the exception of RCP 3P002 in Unit 3. The motor for RCP 3P002 had been replaced during the last refueling outage.

The licensee determined that the deficiencies were in violation of 10 CFR Part 50, Appendix R, Section III.O, "Oil Collection System for RCP," which requires that the collection systems be capable of collecting lube oil from all potential pressurized and unpressurized leakage sites in the RCP lube oil systems. License Condition 2.C.(14) for Unit 2, and Condition 2.C.(12) for Unit 3, require the licensee to implement and maintain in effect all provisions of the approved fire protection program as described in the Updated Fire Hazards Analysis, which states in Appendix D that 10 CFR Part 50, Appendix R, Section III.O, was implemented without deviation.

The licensee modified the design of the oil collection pans under the sightglasses in Unit 3 prior to restarting the reactor on October 11, and stated that the Unit 2 RCP oil collection pans would be modified during the upcoming refueling outage.

The licensee performed an operability assessment (documented in Action Request 960901231) that concluded that the deficiencies would not adversely affect the ability to achieve and maintain safe shutdown for fires inside containment. Licensee engineers stated that the design basis was for all of the oil from two RCPs in one steam generator bay to drain (a total of approximately 300 gallons), and that the lower oil reservoir would only lose 15 gallons if a sightglass broke. The inspectors reviewed the assessment and determined that it

addressed seismic design, the volume and properties of the synthetic oil in use, and the effect of any oil leakage on safe shutdown equipment.

The licensee subsequently identified some other fittings on the RCP oil system that lacked oil collection pans (Action Request 961000042), also contrary to the requirements of 10 CFR Part 50, Appendix R, Section III.O. These included fill and drain plugs on the lube oil cooler, an oil filter for the antirotation device, and temperature and flow instrument connections (threaded fittings) on the low pressure piping. The licensee determined that these additional deficiencies also did not affect safe shutdown capability. The licensee stated that modifications would be made during the next refueling outage to correct these deficiencies.

After the end of this inspection period, the licensee received information regarding an October 17, 1996, fire at another reactor facility (Arkansas Nuclear One), which had been caused by oil spraying from high pressure portions of the RCP oil system, and wicking into fibrous insulation on hot components, which altered the autoignition temperature of the oil. The licensee contacted the other facility to assess the applicability of the condition to the San Onofre design. The licensee's Station Technical manager stated that San Onofre does not have fibrous insulation in the area of the RCPs and that all high pressure components in the RCP oil system are encapsulated to collect any leakage.

c. Conclusions

The licensee identified that the RCP oil collection systems in Units 2 and 3 did not comply with 10 CFR Part 50, Appendix R, Section III.O, which was committed to in the licensee's Fire Hazards Analysis. This item is unresolved pending further review of the system design and Appendix R requirements, in light of lessons learned from the October 17 fire at Arkansas Nuclear One (Unresolved Item 50-361(362)/96011-0101).

E2.3 Pressure Boundary Leakage - Unit 3

a. Inspection Scope (71707, 62707, and 37551)

The inspectors reviewed the licensee's actions with respect to a leaking RCS cold leg thermowell.

The inspectors reviewed MOs 95090761001, 95090761002, 95090761000, 86080222000, 96091445000, and 960951000, which were associated with the repair and prior work on the thermowell location, which the licensee had found to be leaking. The inspectors also reviewed a composite drawing of a typical thermowell and participated in a conference call with the licensee and the NRC Office for Analysis and Evaluation of Operational Data on October 8, 1996. The inspectors reviewed Nonconformance Reports 941100027 through Revision 4, 920600009 through Revision 1, and 960901028 through Revision 2, also

associated with the repair and prior work. In addition, the inspectors reviewed Design Change Package 6189.0E, dated August 1, 1984, which was implemented to change this location from a single element RTD to a dual element RTD. The inspectors also visually inspected the leaking thermowell with the reactor shut down at normal operating pressure and temperature.

b. Observations and Findings

Operators shut down the Unit 3 reactor on September 24, 1996, to investigate unidentified RCS leakage. This leakage was indicated on water inventory balances, containment normal sump level increases, and containment radiation and humidity increases as approximately 0.3 gpm. Normal unidentified leakage was approximately 0.1 gpm.

The licensee discovered a leaking RCS cold leg piping thermowell, with steam coming from around threads where a plug had been installed. The thermowell RTD element had been partially removed during the previous outage, and the location had been plugged.

On September 28, 1996, operators drained the RCS to midloop. The licensee then discovered that the old thermowell had broken off, such that an approximate 9 7/8-inch in length by 3/8-inch in diameter portion of the Inconel-600 thermowell had been released into the RCS. This resulted in an approximate 0.255-inch in diameter hole in the pressure boundary of the RCS, with fluid flow out the hole mitigated by the screwed-in plug.

The licensee preliminarily postulated that the failure mechanism was due to fatigue cracking in the thermowell, caused by increased stress due to some previous cold working, along with leaving an approximate 1 1/4-inch RTD tip in the thermowell during the previous outage.

The licensee removed the old portion of the thermowell remaining, welded in a new thermowell, and put a dummy RTD element in the position with an integral cap. On September 29, 1996, the RCS was flooded up to one foot below the pressure vessel flange and then taken solid in preparation for drawing a pressurizer bubble.

The licensee planned trying to locate and retrieve the thermowell piece during the next refueling outage. The licensee determined that the piece was probably in the lower portion of the pressure vessel, and that it could not get to any location where it would be able to damage fuel.

Based on a review of the maintenance history of this thermowell location the inspectors found that:

- In September 1995, during restart from a refueling outage, the licensee had attempted to remove an RTD from this location because the RTD had

evidenced grounds on both elements. The licensee was unable to remove the RTD, and with some amount of force and jarring, using a hammer, attempted to effect removal. The tip of the RTD broke off, remained lodged in the thermowell, and the licensee abandoned the location. Although the cognizant engineer was present during the removal attempts, at that time no evaluation of the acceptable force to use, or any record of the actual force used, was documented. No evaluation of the effects on the thermowell by abandoning it in place, with the tip lodged, was done.

- During a June 1992 refueling outage the licensee had replaced the RTD in this location because the RTD had evidenced open circuits on both elements. Nonconformance Report 920600009 documented that the craft found rust on the interior of the thermowell. No evaluation was performed regarding why the Inconel-600 was rusting, or if it was indeed rust. Inconel-600 does not normally rust.

c. Conclusions

The licensee's analysis of the effects of leaving the thermowell in the RCS was thorough.

The licensee had not previously reviewed the effects of the cold work on the thermowell, the effect of leaving the broken RTD tip in the thermowell, or the source of rust in the Inconel-600 thermowell. The licensee's efforts to determine the final root cause were in progress at the end of this inspection report.

E7 Quality Assurance in Engineering Activities

E7.1 OSRC

On October 8, 1996, the inspectors attended a meeting of the OSRC. The inspectors observed that the requirements for the OSRC were contained in the licensee's Topical Report, Change 41, SCE-1-A. Prior to TS Improvement Program implementation, these requirements had been in TS. The inspectors observed that the committee maintained a good safety focus and carried out the responsibilities as described in the Topical Report. The inspectors found that the Operations manager, in particular, maintained an outstanding safety focus as plans were discussed for upcoming Unit 2 spent fuel pool work and a Unit 3 safety evaluation concerning foreign material in the RCS (a thermowell, discussed in Section E2.3).

E8 Miscellaneous Engineering Issues

E8.1 (Closed) Unresolved Item 50-361(362)/96005-02: charging pump seal water supply

This item involved NRC review of the licensing basis for the charging pumps, which were supplied with sealing water from a non-Class 1E source, contrary to statements in the UFSAR. Based on NRC review of the licensee's operability assessment that showed that the charging system was operable in the as-built configuration, the technical issue was determined to be of no significance. However, the UFSAR discrepancy will be reviewed as a followup item in conjunction with Violation 50-361(362)/95026-02, which identified other UFSAR discrepancies (Inspector Followup Item 50-361(362)/96011-02).

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Chemical Volume and Control System (CVCS) Letdown Filter Replacement - Unit 2

a. Inspection Scope (71750)

On September 27, 1996, during a routine replacement of Unit 2 CVCS Letdown Purification Filter F020, 13 personnel from Maintenance and Health Physics received low levels of contamination. The inspectors reviewed the licensee's preliminary investigation of the event and an analysis evaluating the effects of the contaminations.

b. Observations and Findings

Following the replacement of the CVCS filter, the personnel contaminations were first detected when personnel alarmed the personnel monitors as they attempted to exit the radiologically controlled area. Four of the 13 individuals were suspected to have received internal contamination and received whole body counts. Based on a review of the licensee's dose analysis, the inspector determined that relatively low doses were received by the four internally-contaminated individuals. The highest dose received was approximately 24 millirem, mostly due to cobalt-58 (normally present in the RCS), which was well below any regulatory or licensee control limits. The mechanism by which the cobalt became airborne had not been conclusively determined, but will be further evaluated by the licensee. Because several organizations were involved in the evolution, the licensee initiated an intradivisional investigation to determine the cause and to identify effective corrective actions. Although the licensee had not completed its evaluation of the cause of the event, the inspector concluded that the response to the multiple low-level contaminations was appropriate.

F2 Status of Fire Protection Facilities and Equipment

F2.1 Inadvertent Fire Water Deluge - Unit 2

a. Inspection Scope (71750)

On September 9, 1996, an inadvertent fire water deluge occurred in a Unit 2 cable spreading riser room. The inspector investigated the circumstances and effects of the deluge.

b. Observations and Findings

The licensee determined that a construction maintenance worker physically agitated the associated deluge actuator while stringing welding cables, causing the deluge to activate. The deluge actuator was in a hallway outside the cable spreading area. Based on changes to fire water storage tank level, the licensee estimated that between 15,000 and 20,000 gallons of water emptied into the space. The deluge was terminated approximately 15 minutes after it began when Operations personnel shut the deluge valve, after Operations and fire department personnel determined that no fire or smoke was present.

The inspector walked down the cable spreading riser room, adjacent spaces, and the Unit 2 main control boards after the deluge was terminated. The inspector observed that the cable spreading riser room was flooded with approximately 3 inches of water, and that water had flowed under nonwatertight fire doors to the main cable spreading area and into the Unit 3 cable spreading area. The floor drains were functioning, but unable to drain fast enough to prevent water from accumulating in the space. Cabling in the area was wetted; some cabling in trays, as well as in pits, was submersed.

Based on review of the UFSAR, the inspector found that the floor drains had functioned as designed, but were not designed to immediately drain the amount of water associated with a deluge. Based on anticipated flow rates, the inspector also found that the deluge system had functioned as designed. The wetted cabling did not affect Unit 2 control room indications, other than to cause related flooding annunciators to alarm. The inspector found that Operations' response was appropriate and timely. The inspector also found that the construction craft evidenced poor judgment, contrary to licensee management expectation, by agitating the deluge valve. The licensee took disciplinary action against the individuals directly involved, briefed all construction and maintenance personnel on the incident, and was considering either posting signs or constructing cages around the deluge actuators.

The inspector also observed that, over the last 3 years, approximately 25 inadvertent actuation of the fire water system had occurred in both units. Of

these, four were attributable to physical agitation of the deluge actuators, and the others to electrical or other mechanical faults or personnel error.

c. Conclusion

The construction craft exhibited poor judgment by not using more caution when working near the deluge actuator, and that licensee actions to prevent recurrence were prompt and well-focused.

Licensee response to the deluge was prompt and effective.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the exit meeting on October 22, 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. Clark, Manager, Chemistry
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

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 41500:	Training and Qualification Effectiveness
IP 61726:	Surveillance Observations
IP 62703:	Maintenance Observations (now Appendix B to IP 62707)
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92902:	Followup - Maintenance

ITEMS OPENED

50-361/96011-01 50-362/96011-01	URI	RCP oil collection system
50-361/96011-02 50-362/96011-02	IFI	charging pump seal water supply

ITEMS CLOSED

50-361/96005-02 50-362/96005-02	URI	charging pump seal water supply
50-362/96008-02	IFI	inadvertent radiation monitoring annunciation

LIST OF ACRONYMS USED

CRS	control room supervisor
CVCS	chemical volume and control system
EDG	emergency diesel generator
LCO	limiting condition for operation
MO	maintenance order
OSRC	Onsite Review Committee
RCP	reactor coolant pump
RCS	reactor coolant system
RM	radiation monitoring
RTD	resistance temperature detector
RUP	restricted use permit
STA	shift technical advisor
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report