U.S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos.	50-361/93-31, 50-362/93-31
Docket Nos.	50-361, 50-362
License Nos.	NPF-10, NPF-15
Licensee:	Southern California Edison Company Irvine Operations Center 23 Parker Street Irvine, California 92718
Facility Name:	San Onofre Units 2 and 3
Inspection At:	San Onofre, San Clemente, California
Inspection Conducted:	October 7, through November 17, 1993
Inspectors:	D. L. Solorio, Acting Senior Resident Inspector J. J. Russell, Resident Inspector J. R. Rajan, Mechanical Engineering Branch, NRR J. S. Winton, Intern, NRR
Approved By:	H. J. Wong, Chief Reactor Projects Section II 12/17/93 Date Signed

Inspection Summary

Inspection on October 7 through November 17, 1993 (Report Nos. 50-206/93-31, 50-361/93-31, 50-362/93-31)

Areas Inspected: Routine, announced resident inspection of Units 2 and 3 Operations Program including the following areas: operational safety verification, evaluation of plant trips and events, bi-monthly surveillance activities, monthly maintenance activities, refueling activities, independent inspection, and followup of previously identified items. Inspection procedures 35702, 37700, 60710, 61726, 62703, 71707, 92701, 92720, and 93702 were covered.

Safety Issues Management System (SIMS) Items: None

Results:

General Conclusions and Specific Findings:

Strengths:

To reduce exposure to workers during steam generator feedring nozzle repairs the licensee developed an inflatable rubber boot to allow water to be used for additional shielding (Paragraph 6.b).

A Nuclear Construction project engineer was knowledgeable of the need to perform post-modification tests in a specific sequence, even though the work order appeared to give the engineer some latitude in the performance of the work order steps (Paragraph 8.b).

Weaknesses:

Several instances were identified during the inspection period where plant personnel did not pay adequate attention-to-detail. These instances included: the use of an out-dated control room tag, removal of a control room deficiency tag that prior to completion of the work, the inadequate foreign material control in the refueling cavity, and the loss of control of dosimetry and a security badge in a steam generator (Paragraph 3.a).

The Quality Assurance Department identified that maintenance personnel were not properly documenting the use of measuring and test equipment (M&TE) and that some evaluations of failed M&TE were not adequate. (Paragraph 8.a.(1).

censee controls were not adequate to insure that seismic restraints were alled on a safety-related transformer prior to declaring the transformer operable (Paragraph 9.b).

Significant Safety Matters:

None.

Summary of Violations:

One violation was issued for several examples of failure to follow procedures (Paragraph 3.a). One non-cited violation was issued for the failure of licensee programs to assure that seismic supports for a safety-related transformer were installed prior to declaration of the transformer's operability (Paragraph 9.b). A violation involving plant equipment operator round records is also documented in this report for administrative purposes (Paragraph 9.c).

Open Items Summary:

During this report period, six new followup items were opened and six were closed.

DETAILS

1. Persons Contacted

Southern California Edison Company (SCE)

H. Ray, Senior Vice President, Power Systems
*R. Krieger, Vice President, Nuclear Generating Station
*R. Rosenblum, Vice President, Nuclear Engineering and Technical Support
*J. Reilly, Manager, Nuclear Engineering & Construction
B. Katz, Manager, Nuclear Oversight
*K. Slagle, Manager, Outage Management
R. Waldo, Operations Manager
*L. Cash, Maintenance Manager
*D. Breig, Manager, Station Technical
M. Short, Manager, Site Technical Services
*M. Wharton, Manager, Nuclear Design Engineering
P. Knapp, Manager, Health Physics
W. Zintl, Manager, Emergency Preparedness
*D. Herbst, Manager, Quality Assurance
C. Chiu, Manager, Quality Engineering
V. Fisher, Plant Superintendent, Units 2/3
*G. Gibson, Supervisor, Onsite Nuclear Licensing
J. Reeder, Manager, Nuclear Training
H. Newton, Manager, Site Support Services
*J. Hirsch, Manager, Power Generation
*M. Herschthal, Manager, Nuclear Systems Engineering
*J. Fee, Health Physics Assistant Manager
*R. Joyce, Maintenance Manager, Units 2/3
*A. Thiel, Manager, Electrical Systems Engineering
*P. Blakeslee, Supervising Engineer, Station Technical
*R. Giroux, Engineer, Onsite Nuclear Licensing
*D. Axline, Engineer, Onsite Nuclear Licensing
*R. Douglas, Engineer, Onsite Nuclear Licensing

*Denotes those attending the exit meeting on November 24, 1993.

The inspectors also contacted other licensee employees during the course of the inspection, including operations shift superintendents, control room supervisors, control room operators, QA and QC engineers, compliance engineers, maintenance craftsmen, and health physics engineers and technicians.

2. Plant Status

Unit 2

The Unit began the inspection period at 68% power due to a dropped control element assembly. The Unit returned to 98% power on October 7, 1993, and operated at 98% power through the end of the inspection period.

Unit 3

The Unit began the inspection period at full power. On October 10, 1993, the reactor was manually tripped, and the Unit entered Mode 3 in preparation for the Unit 3 Cycle VII refueling outage. The Unit entered Mode 6 on October 15, 1993. All fuel assemblies had been removed from the reactor core and were in the spent fuel pool by October 26, 1993. Core reload activities started on November 16, 1993, when the first fuel assembly was lowered into the reactor core. The Unit ended the inspection period in Mode 6, with 57 fuel assemblies in the core.

3. Operational Safety Verification (71707)

The inspectors performed several plant tours and verified the operability of selected emergency systems, reviewed the tag-out log and verified proper return to service of affected components. Particular attention was given to housekeeping, examination for potential fire hazards, fluid leaks, excessive vibration, and verification that maintenance requests had been initiated for equipment in need of maintenance. The inspectors also observed selected activities by licensee radiological protection and security personnel to confirm proper implementation of and conformance with facility policies and procedures in these areas.

a. Attention-To-Detail - Units 2 and 3

The inspector noted several examples in which licensee performance was not in accordance with procedural requirements. The inspector considered these examples to be of low safety significance when viewed individually. However, the inspector was concerned that these examples indicated a lack of attention-to-detail with regards to procedural compliance. The following examples were noted:

(1) On November 16, 1993, the inspector observed a Limiting Condition for Operability Action Requirement/Equipment Deficiency Mode Restraint (LCOAR/EDMR) tag hanging on an operable component, and an equipment deficiency tag had been improperly removed from another component. Both occurrences were found in the Unit 3 control room.

- An LCOAR/EDMR tag indicated that Startup Channel "A" was out-of-service for temporary power installation. The licensee was conducting core alterations at the time, and the startup channel was required to be operable by Technical Specifications (TS). After verifying that Startup Channel "A" was in-service and operable, the licensee removed the tag. The presence of the tag was contrary to SO123-0-13, "Technical Specification LCOAR and EDMRs," Attachment 4, Step 14, which stated that control room tags should be used to identify affected components and systems.

- High pressure safety injection pump flow indicator 3FI03112 was observed to be reading abnormally on October 13, 1993. As a result, the licensee hung an equipment deficiency tag and generated a maintenance order (MO) to repair the instrument. Subsequently, the inspector reviewed the MO and noted that a technician had written in the MO that the deficiency tag had been removed prior to completing work on the equipment. Specifically, the MO had a step to remove the deficiency tag once work was completed. The removal of the deficiency tag prior to completion of the work was contrary to station procedure SO123-I-1.7 "Maintenance Order Preparation, Use, and Performance," which stated that MOs must be followed in sequence unless specific conditions were met. The inspector noted that the MO did not contain exceptions for performing steps out-of-sequence nor were the specific conditions met.

(2) The inspector noted two instances of degraded controls of foreign material associated with the Unit 3 Cycle VII refueling outage:

- A single material wipe was adrift adjacent to the reactor vessel at the bottom of the refueling cavity when the reactor vessel head was removed and the refueling cavity was flooded. The licensee was in the process of removing the upper guide structure and incore instrumentation. At the time, foreign material controls were in effect over and adjacent to the refueling cavity. The inspector observed the control of the wipe had not been in accordance with Station Procedure SO23-I-3.1, "Minor Refueling Procedures," which directed that wiping material be held or otherwise controlled. The licensee later removed the wiping material using retrieval equipment.

- On November 5, 1993, a Health Physics (HP) engineer entered the feedring area inside steam generator (SG) E089 during work to replace the feedring nozzles. Entry into the area was made via an 18-inch manway. A rubber inflatable boot was installed about two feet below the feedring to provide a foreign material exclusion (FME) barrier to the downcomer area and to provide a partially watertight seal. To reduce radiation levels, the licensee had raised water level in the riser section of the steam generator, with the rubber boot partially blocking the water in the annulus section of the steam generator. The feedring area was controlled as an FME area, option 3, as defined in Station Procedure SO123-I-1.18, "Foreign Material Control During Maintenance Testing and Inspection." The procedure specified that loose objects such as badges and dosimeters were to be securely fastened to clothing, and an FME monitor was to conduct inspections

of all entering personnel to ensure that extra precautions were taken with all non-fail-safe material.

Prior to entering the steam generator, the HP engineer had taped his dosimeter and site badge to his upper thigh in accordance with the applicable radiation exposure permit. However, the HP engineer lost his dosimeter and site badge while inside the steam generator. This was contrary to procedure SO123-I-1.18, Attachment 2, Step 2.2, in that the badge and dosimeter were not securely fastened to the clothing. The licensee subsequently sent a person into the steam generator to locate and retrieve the lost objects, but the individual inadvertently uncoupled the rubber boot from its air supply and the boot deflated. The licensee reinflated the rubber boot, completed the nozzle repairs, and committed to find and remove the foreign material prior to Unit startup. The licensee informed the inspector on November 19, 1993, that the foreign material had been removed from the SG.

The above examples of the failure follow procedures is considered a violation (Violation 50-361/93-31-01).

b. Auxiliary Feedwater Trip/Throttle Valve 2HV4716, Failure to Close - Unit 2

On August 25, 1993, the Unit 2 turbine-driven auxiliary feedwater (AFW) pump trip valve, 2HV4716, failed to closed when an operator attempted to close the valve from the control room during an inservice test (IST). Valve 2HV4716 opens to admit steam to the pump turbine and closes to isolate the steam and stop the AFW pump, P140. During emergency operation, the valve trips close and shuts down the AFW pump on a turbine overspeed condition. The licensee attributed the failure to close the valve to dirty "seal-in" contacts (relay closing contactors). The licensee believed that the operator pressed the switch to close the valve and that the "seal-in" contacts failed to maintain contact and/or continuity during the closing sequence. The licensee was able to duplicate the failure and replaced the "seal-in" relay.

On October 20, 1993, while attempting to shut down the AFW pump after performance of its IST, operators attempted to close valve 2HV4716. However, the valve did not close. After detailed troubleshooting of the valve and control circuits, the root cause for this event could not be determined. The licensee replaced several parts [i.e., the motor-operated valve torque (MOV) switch and the closing relay from the August failure] and scheduled a root cause analysis to be performed on these components. The licensee committed to provide the inspector with a schedule for the completion of these root cause evaluations. The licensee also implemented an accelerated testing schedule on valve 2HV4716, and retested the valve several times since the October failure. No

other instances in which the valve failed to close on demand were noted.

The inspector noted that the valve had been previously tested satisfactorily under the licensee's MOV program (Generic Letter (GL) 89-10 program) during the Cycle 7 refueling outage which ended in August 1993. The inspector reviewed non-conformance reports S3080087 and 9310092 for the August and October 1993 failures. In addition, the inspector discussed the results of licensee inspections and corrective actions with applicable licensee personnel. The inspector considered that the licensee's corrective actions were reasonable for each failure. The inspector noted that this AFW pump is the most risk significant component, as identified in the licensee's "Top 100 Most Risk-Significant Components at San Onofre Unit 2 Based On The Results of the Individual Plant Examination."

The licensee informed the inspector that, as a result of the August failure of valve 2HV4716 to close, they had identified that the preventive maintenance (PM) program for relays did not include the valve's direct current relays. The licensee also identified that there were other relays in valve actuators similar to valve 2HV4716 which were also not included in the PM program. The licensee committed to revise the PM program to include these relays. In addition, the licensee committed to inspect the relay contactors which had not been previously included in the routine PM procedure. The inspector considered the review the licensee's root cause reports, the completion of the revision to the PM program, and inspection of affected relays an inspector followup item (IFI 50-361/93-31-02).

c. Emergency Chiller Valve ME399 Component Cooling Water Outlet Valve 3HV6371 - Unit 3

On November 12, 1993, maintenance personnel disassembled the Unit 3 emergency cooling unit (ECU), ME399, component cooling water outlet valve, 3HV6371, and discovered that: the valve had a missing shoe; the gate and segment were installed backwards; one locking arm was bent over and contacted the segment; the upstream skirt was installed in the downstream side; the downstream skirt was installed in the upstream side; and the upstream skirt was installed upside-down. Preliminarily, the licensee believed that the valve was previously dissembled during an 1988 refueling outage.

The licensee provided the inspector with motor-operated valve (MOV) static traces, taken in March of 1992, which showed an abnormality. The traces had been evaluated by the Maintenance Division in accordance with the licensee's existing MOV program. The abnormality was attributed to a slightly bent stem which was considered acceptable and considered to have no effect on the valve's operability.

The licensee documented the valve mis-assembly in non-conformance report (NCR) 9311005502. The inspector questioned the impact to the Unit 2 ECU MOVs. Station Technical (STEC) personnel evaluated this concern and concluded that the valves were operable because all the ECU MOVs had been recently (i.e., June through August 1993) tested in accordance with the licensee's Generic Letter 89-10 MOV program. In addition, STEC reviewed the MOV traces for the other ECU valves and noted that none exhibited the characteristics which were recorded for valve 3HV6371 in March 1992.

The inspector noted that in January 1993 the licensee had initiated NCR 93010041 to document that the breaker for valve 3HV6371 had tripped while trying to operate the valve. On April 8, 1993, Operations Department personnel secured valve 3HV6371 open as required by TS 3.6.3, in accordance with their abnormal alignment program. The Operations Department controlled the opening of valve 3HV6371 in accordance with their abnormal alignment program, S0123-0-23, "Control Of System Alignments." The inspector questioned why the licensee had written NCR 93010041 in January 1993, and had not initiated the abnormal alignment until April of 1993. The licensee committed to pursue this question and provide a response to the inspector.

The licensee also committed to provide the inspector with the MOV traces for the Unit 3 ECU valves which were to be obtained in accordance with the licensee's GL 89-10 MOV program during the Cycle VII outage. In addition, the licensee committed to incorporate lessons-learned from the evaluation of the March 1992 trace for valve 3HV6371 into their current GL 89-10 MOV program.

As a result of the mis-assembly of 3HV6371, the Maintenance Department initiated an Division Investigation Report (DIR) to determine the root cause of the valve mis-assembly and any corrective actions. The inspector will review the DIR and the licensee's response to questions and commitments as unresolved item (URI 50-362/93-31-03).

d. Use of Controlotron for Calculating Controlled Bleedoff Flow

The inspector noted that the licensee had installed a flow measuring device (a controlotron) on the common CBO piping from the four RCPs. This action was taken to provide an alternate indication of the Unit 2 reactor coolant pump (RCP) 2P003 controlled bleedoff flow (CBO) after the failure of the normal indication on the plant monitoring system (PMS). To obtain an indication of 2P003 CBO flow, the licensee subtracted the CBO flow from the three RCPs with PMS indication from the total flow measured by the controlotron.

The inspector was concerned that the controlotron was being used for the reactor coolant system water inventory balance calculations without having sufficient accuracy. The water balance calculation is required by Technical Specifications and is accomplished by

procedure SO23-3-3.37, "Reactor Coolant System Water Inventory Balance." The procedure had been revised to allow use of the controlotron in the water inventory balance calculation when one CBO flow was not available.

The licensee conducted a review of controlotron accuracy and concluded that the controlotron might not provide conservative flow information when used to determine one CBO flow. As a result, the licensee developed an alternate method to conservatively determine CBO flow for the water inventory balance calculation when PMS did not indicate one CBO flow. The inspector will complete the review the instrument accuracy during a future inspection and will follow this item as unresolved. (Unresolved Item 50-361/93-31-04).

e. Chemical Spill Inside the Protected Area

On October 13, 1993, the inspector observed a licensee refuse truck run over and rupture a 50 pound plastic tub of sodium nitrate located on the west side of the protected area. The sodium nitrate was not controlled and was not stored in an authorized location. The licensee's hazardous material response team contained and cleaned up the spill of sodium nitrate. Although this event did not affect plant equipment or personnel, it demonstrated the continuing need for personnel pay adequate attention-to-detail.

One violation of NRC requirements was identified.

4. Evaluation of Plant Trips and Events (93702)

Loose Parts and Vibration Alarms - Unit 3

The licensee received numerous loose part and vibration monitor alarms for Unit 3 as power changes and associated reactor coolant temperature changes were made during power operations preceding the Cycle VII refueling outage. These alarms were described in NRC Inspection Report (IR) 50-206,361,362/93-29. The alarms were associated with SGs E088 and E089. As described in IR 93-29, the licensee attributed these alarms to a sound external to the SGs, probably associated with movement of the SG as the reactor coolant system expanded or contracted.

The licensee conducted enhanced monitoring of the downpower and cooldown of Unit 3 for the Cycle VII outage. The licensee received approximately 140 alarms per SG during the downpower and cooldown. The inspector noted that the number of alarms was about the same for each SG, indicating that the alarms could be associated with movement of the SG support base plates. This was because the SGs moved approximately the same distance as the reactor coolant system contracted, and the SGs base plates may have been emitting the same number of sounds corresponding to the same amount of movement.

The inspector visually inspected the SG base plates, the reactor coolant piping support pads, the main steam piping supports, and the SG snubbers.

The inspector found that the sliding base plates appeared to be functional with no readily apparent metal deformation, irregularities, or interferences that might cause the SG to not slide freely on its associated pads and thereby cause alarms.

The inspector did note that some of the studs for SG E088 that anchored the base plate to the containment floor may have been slightly misaligned away from the reactor vessel, and not entirely vertical. The inspector and the licensee also noted that one keyway for SG E088 appeared to have an irregular meeting surface. The inspector considered these observations of minor importance because they did not appear to have any effect on the structural integrity of the base plates. The inspector discussed these observations with the licensee. The licensee committed to evaluate the inspector's observations.

All pipe restraints for the reactor coolant and main steam systems appeared to have the proper clearance, and the clearance was uniform, indicating that the piping had room to expand during Unit heatup. The licensee also conducted a visual inspection of the SG base plates. The inspector will review the results of their analysis during the course of routine inspection activities, including the licensee's conclusions concerning the base plate studs and the condition of the keyways. The licensee also planned to conduct enhanced monitoring of SG movement during the Unit 3 heatup and return to power following the Cycle VII outage.

No violations or deviations were identified.

5. Bi-Monthly Surveillance Activities (61726)

During this report period, the inspectors observed or conducted inspection of the following surveillance activities:

a. Observation of Routine Surveillance Activities (Unit 2)

SO23-V-3.4.1, "Auxiliary Feedwater Inservice Pump Test."

No violations or deviations were identified.

6. Monthly Maintenance Activities (62703)

During this report period, the inspectors observed or conducted inspection of the following maintenance activities:

a. Observation of Routine Maintenance Activities (Unit 2)

93101240000, "Attach an Omnilight to Points C2, C22 and C32 and Perform a Valve Stroke Test Per Step #11 of Non-conformance Report 93100092."

b. Observation of Routine Maintenance Activities (Unit 3)

93032671000, "Move Main Missile Shield Section(s) to Support Removal/Installation of Reactor Coolant Pump/Motor."

92110211000, "Perform Eddy Current Testing, Tube Marking, Mechanical Tube Plugging and Stabilizing in Accordance With SCE Approved Contractor Procedures During The Unit 3 Cycle VII Outage. Provide Comms/Video Support as Requested. Provide Support to Site Technical Services for Leak Test of the Steam Generators."

93010682001, "(Turbine) Complete Internal Inspection and Replacement of EG-4 Actuator and Remote Servo. Niel Inspection Requirement - 10 Year or 100 Hour. Replace Rotor in Accordance with NCR 9300142."

93100709000, "High Pressure Safety Injection to Tank 3T008 Flow Indication Indicates Flow With Low Pressure Safety Injection Shut Down Cooling in Service. May Need to Vent Differential Pressure Cell."

93081514000, "Remove and Replace 40 "J" Nozzles on the Steam Generator Feed Ring in Accordance With Field Change Notice F-8700M."

The inspector reviewed this MO and observed work in progress on the feedring of SG E089 as the licensee cut off 40 old "J" nozzles and welded new nozzles to the feedring. The inspector had the following concerns, which the licensee adequately addressed:

- Five "J" tubes had been cut off with no tape applied to prevent excessive debris from entering the feedring. The tape was not required by the MO. However, three out of four workers were taping the hole left in the feedring immediately after it was made and the MO did require the workers to clean out the feedring as nozzles were removed. The licensee informed the inspector that the feedring was inspected with a camera throughout its length at the termination of the nozzle removal, and that all foreign material had been cleaned out. The inspector considered this response adequate.

- One firewatch was posted external to the generator with four grinding jobs going on simultaneously inside the SG. This appeared to be contradictory to management expectation, which was proceduralized as one firewatch per

job, or the grinder being a firewatch. No fire extinguisher was observed in the SG. The inspector verified that an exemption had been granted by fire protection, based on ALARA concerns, to allow the one firewatch as observed. The inspector considered the licensee's response adequate.

- An FME option was in effect (option 2) with no accountability log for material entering the steam generator, and no fail-safe methods to prevent the loss of foreign material. The inspector did note that a rubber inflatable boot acted as an FME shield beneath the feedring. The licensee informed the inspector that the work area would be cleaned and the secondary side of the SG would be inspected with a video camera prior to final SG closeout. Any loose dust that penetrated around the sides of the rubber boot was permissible for a class "C" system. The inspector considered the licensee's response adequate.

- No monitoring for airborne contamination was present. The inspector was informed that contamination levels did not warrant airborne monitoring. The inspector reviewed the applicable survey map and verified that airborne contamination would not be expected, given the surface contamination levels present. The inspector considered this response adequate.

Overall, the inspector considered this maintenance adequate, and noted one strength. The licensee had raised the water level in the riser section of the steam generator to act as shielding to minimize radiation levels in the area where work was in progress. The rubber boot mentioned above served to stop the water from rising in the work area, as the water would have equalized between the two areas. The licensee had also evaluated water level rise if the rubber boot failed, and determined that it would still not rise to the level of the feedring. Thus, workers would be protected. The inspector considered these preparations to minimize radiation exposure a strength.

No violations or deviations were identified.

7. Plant Modification and Refueling Activities (60710)

a. Fuel Pin Inspections - Unit 3

On November 4, 1993, the licensee initiated ultrasonic testing of fuel assemblies scheduled to be reused in Cycle VII. The licensee discovered that fuel pin O16 had failed in fuel assembly H207. Specifically, there were two failures on the same pin. The most severe failure was from secondary hydriding. The licensee believed that the hydriding was caused by the existence of contaminants (moisture) in the failed area. The second failure was attributed to grid tab fretting at the bottom of the pin. The grid tabs acted to prevent the pin from vibrating due to flow. The grid tab had been pushed away from the pin which allowed the pin to vibrate against the grid, resulting in a hole at the bottom of the pin. Fuel assembly H207 was reconstituted with a replacement solid stainless steel rod, in accordance with guidance from Combustion Engineering (CE), as documented in NCR 930110025, and was returned to the reactor vessel.

In addition, fuel pin A2 in fuel assembly H314, was found to be slightly misaligned due to a failure of a backup arch in the bottom spacer grid. The failure of the arch did not result in damage to the pin. The fuel pin was replaced with a solid stainless steel rod in accordance with guidance from CE, as documented in NCR 93110026, and the assembly was returned to the reactor vessel.

The licensee noted that both reconstituted fuel pins were located at the corners of their respective fuel assemblies. During the Unit 2 Cycle VI outage, a failed fuel pin was also found on the corner of an assembly. That fuel pin failure was also caused by grid tab fretting, similar to the failure noted in H207. The licensee stated that discussions were ongoing with the fuel vendor, CE, as to the potential of a generic problem with respect to grid tab induced fuel pin failures. The inspector will monitor the licensee's actions.

b. Control Room Communications during Core Reload - Unit 3

The inspector observed portions of the Unit 3 Cycle VII core reload communications activities from the control room. The inspector considered that these activities were conducted in a controlled and deliberate manner, and that personnel were cognizant of their duties and responsibilities.

No violations or deviations were identified.

8. Independent Inspection (35702, 92720, 37700)

a. Corrective Action (35702 and 92720)

While the inspector's review of the following events is not complete, the events preliminarily appear to indicate that licensee

corrective actions may not have been effective in preventing recurrence of problems.

(1) Maintenance and Test Equipment Issues - Units 2 and 3

On November 22, 1993, Quality Assurance (QA) issued audit SCES-305-93, which identified that the licensee's maintenance organization had taken ineffective corrective actions to address programmatic deficiencies in the Maintenance and Test Equipment (M&TE) program as outlined in SCE's December 21, 1992, Notice of Violation (NOV) response. The QA department issued corrective action request (CAR) 009-93, to the maintenance organization for the purpose of tracking the resolution of the repeated deficiencies.

Specifically, QA identified that several groups within the maintenance organization had a high error rate for not appropriately documenting the use of M&TE on traveler forms as required by the licensee's program, SO123-II-1.2, "Preparation and Responsibility of the M&TE Traveler Form SO(123)21." In addition, QA identified several inadequate evaluations of M&TE calibration failures, as required by SO123-II-1.5, "Evaluation of Calibrated Items After M&TE Failure."

The inspector noted that QA first identified similar problems with the M&TE program in 1990 when similar deficiencies were identified during an audit. In addition, the NRC identified similar problems during a routine resident inspection in 1992, which resulted in the issuance of a NOV.

The inspector was concerned because the licensee's NOV response, dated December 21, 1992, Section 3, "Corrective Steps That Have Been Taken And The Results Achieved," included statements that the "...training will ensure that personnel properly document the use of M&TE on travelers as required by the current procedure." However, the November 1993 QA audit identified that several groups within the maintenance organization were not consistently documenting M&TE on travelers, and the audit noted deficiencies with M&TE calibration failure evaluations.

The inspector considered the safety significance of these repeated failures to be low because the licensee had initiated an alternate method, as also outlined in the December 1992 NOV response, to ensure that calibration failures of M&TE would be evaluated against plant equipment if maintenance personnel were not documenting M&TE on travelers. Nevertheless, the inspector was concerned that these failures were indicative of an overall problem with the implementation of corrective actions.

The inspector also noted that QA routinely verifies the completion of NOV response and Licensee Event Report corrective

actions prior to forwarding these documents to the NRC. However, the inspector noted that the verification was not performed with the intent to determine if corrective actions were adequate to prevent reoccurrence. The inspector noted that QA does perform "random" audits of completion of corrective actions for NOV responses and Licensee Event Reports. While QA's identification of this continuing problem is considered a strength, the inspector considered that additional attention by line management to effectively implement corrective actions appears to be warranted.

The licensee committed to submit a supplement to the December 21, 1993, NOV response to discuss Maintenance's response to CAR-009-93. The inspector will review the licensee's supplemental response as unresolved item (URI 50-361/93-31-05).

(2) Water in Reactor Cavity to Spent Fuel Pool - Unit 3

On October 22, 1993, during core alterations on Unit 3 (removing fuel from reactor vessel) operators isolated containment purge to implement the changeout of a radiation monitor filter for containment purge stack monitor 3RI7828.

The filter changeout took longer than expected, and before containment purge could be unisolated and returned to service (such that operators could use the purge to depressurize the containment), the water level in the reactor cavity was lowered slightly below the TS limit of 23 feet by the increasing containment pressure. The water overflowed the spent fuel pool (SFP) to the SFP sump. The water transfer from the refueling cavity to the spent fuel pool occurred due to the open refueling transfer canal which connected the refueling cavity and the spent fuel pool. The containment pressure increase was attributed to various air lines routed into containment to support outage activities.

On February 8, 1992, a similar event occurred when containment purge was secured following the discovery of the failed containment purge isolation signal monitor, RT7804. At that time, there were also various air supply lines to the Unit 3 containment which resulted in an increasing containment pressure. The containment pressure increase lowered the level in the refueling cavity and increased the level in the SFP. As a result of that event, Operations completed a Division Experience Report (ODER), 3-92-07A, "Personnel Injuries Due to Pressurizing the Fuel Handling Building," to identify the root cause and implement corrective actions to mitigate possible future events. Specifically, Operating Instruction SO23-1-4.2, "Containment Purge and Recirculation Filtration System," was revised to provide guidance on limiting reactor cavity level loss and/or SFP rise if the main purge was to be secured while the fuel transfer tube was open.

The inspector noted that the ODER had not been reviewed by Nuclear Oversight Division (NOD) personnel. However, the inspector also noted that the NOD had recently initiated review of ODERs by NOD "coaches" to enhance the effectiveness of corrective actions.

The inspector noted that on October 22, 1993, operators did not execute the guidance in SO23-1-4.2 to preclude draining the reactor cavity below the TS limit during core alterations. The inspector was concerned that the corrective actions taken as the result of the previous event were not sufficient enough to preclude the draining of the reactor cavity on October 22, 1993. The inspector noted that operators were aware of the guidance in SO23-1-4.2, but elected to continue efforts to return the radiation monitor to service, so that containment could be vented via the purge, because they perceived that the radiation monitor would be returned to service before a significant loss of level in the reactor cavity. The inspector considered that a contributing factor to the October 22, 1993, event was the delay in informing the Shift Supervisor (SS) of the difficulties associated with returning the radiation monitor to service. The SS was informed approximately 2.5 hours after the initiation of the filter changeout.

In addition, the inspector determined that there was a perception by Operations personnel during the October 22, 1993, event that the implementation of the guidance in SO23-1-4.2 would have resulted in a delay to the critical path (removing fuel from the reactor and transferring to the SFP).

The licensee stated that an ODER had been initiated to determine how the more recent event occurred and to implement corrective actions where warranted. The inspector considered this an unresolved item pending review of the licensee's ODER and corrective actions (URI 50-362/93-31-06).

(3) <u>High Pressure Safety Injection Indicator Abnormality - Unit 3</u>

On October 13, 1993, the inspector noted that the Unit 3 high pressure safety injection (HPSI) flow indication into the loop 1A cold leg (via the safety injection tank 3T008 connection), 3FI-0311-2, on the Unit 3 control boards was oscillating between 0 and 50 gallons per minute (gpm). The Unit was on shutdown cooling at the time with low pressure safety injection (LPSI) providing shutdown cooling flow into loop 1A. There should have been no flow through the HPSI piping because a motor-operated isolation valve indicated shut on the HPSI pump side of the flow indicator, and a check valve should have been shut on the reactor coolant cold leg side of the flow indicator.

The inspector was concerned that the flow indicator should have indicated zero and questioned the operators, who agreed that this was an abnormal indication (i.e., forward oscillating flow was not expected). The inspector was also concerned because the indicator was one of the instruments the operators would use if they had to enter the Emergency Operating Procedures and had to verify Emergency Core Cooling flow to maintain sufficient core cooling. The licensee generated an maintenance order (MO) to investigate and correct this abnormality.

The inspector reviewed MO 93100709 and the instrument calibration data cards for flow indicator 3FI-0311-2, and flow transmitter 3FT-0311-2. The inspector noted that a loop verification had been previously performed on these instruments during January 1991 and again in August 1992. The loop verification included a calibration check of the meters and circuitry as well as a prime standard alignment of the detector. The inspector noted that the "as-found" data was not in tolerance for the alignment check of the flow transmitter. However, the "as-left" data was verified to be in tolerance.

On October 26, 1993, the licensee performed a loop verification of the transmitter and indicator as directed by the MO generated to diagnose and correct the problem with oscillating flow indicator. The licensee also back-filled and vented the transmitter. Although the licensee considered the MO completed, the licensee could not observe meter response as shut down cooling was not in operation with the core offloaded. The inspector noted that the MO did not specify a check of the meter's performance after shutdown cooling was placed into service. When shut down cooling flow was initiated during core reload on November 16, 1993, the inspector again observed that the same indicator was reading between 0 and 50 gpm. As before, the inspector concluded that the indicator should have been reading 0 gpm.

The licensee informed the inspector after the exit meeting that the transmitter and downstream circuitry was operating satisfactorily. The licensee theorized that water was present at the flow orifice and movement of the check valve was causing differential pressure oscillations which were being indicated as flow. The inspector considered the licensee's explanation to be plausible, but noted that the licensee had not performed any field measurements or calculations to support their explanation. The inspector will monitor performance of this indicator and any further licensee actions during routine inspections.

b. Emergency Diesel Generator Lube Oil Modification - Unit 3 (37700)

The inspector reviewed selected parts of design change package (DCP) 3-6754, "Pre-Lubrication Modification Units 2&3 Diesel Generator

Lube Oil Systems San Onofre Nuclear Generating Station." Specifically, the inspector reviewed the functional testing requirements in Section 7, "Testing Requirements & Acceptance Criteria," of the DCP, and their implementation by Nuclear Construction (NC) in accordance with Construction Work Order (CWO) 93050523000, "Perform Functional Testing on the Unit 3 Train 'A' 16 & 20 Cylinder Engines To Verify Proper Installation and Function of the Diesel Lube Oil System Modifications Per DCP 3-6754.00SP."

The inspector discussed the methodology used to determine the various functional testing acceptance criteria with the DG system design engineer. The inspector determined through these discussions that there was a specified order for the performance of certain functional tests and that the functional testing specified in the DCP was adequate.

The inspector noted that Section III, "Functional Testing Work Plan," of the CWO included the following statement: "NOTE: STEPS IN THIS WORK PLAN MAYBE PERFORMED OUT OF SEQUENCE WITH THE APPROVAL OF THE NUCLEAR CONSTRUCTION ENGINEER." The inspector was concerned that this statement might result in the performance of the DCP tests out-of-sequence, which would have invalidated the modification's functional testing. However, the inspector noted that the NC engineer was aware of the need to perform certain steps in order. Through interviews, the inspector determined that the statement was placed in the CWO to allow the NC project engineer flexibility to troubleshoot minor abnormalities during performance of the test. The inspector also noted that within the station maintenance organization a similar statement was used which allowed the Maintenance General Foreman to authorize the performance of maintenance order steps out-of-sequence. However, licensee management stated that when used in maintenance orders the statement was only used in the specific sections where the steps could actually be performed in any order, as opposed to CWOs, where the statement was applicable throughout the document.

The inspector witnessed the performance of the functional testing and concluded that testing was performed in accordance the design requirements. In addition, the inspector noted that the NC project engineer responsible for implementation of the DCP functional testing was very knowledgeable in all aspects of the test. The inspector considered this a strength given that the functional testing criteria as listed in the DCP did not specifically call out the requirement that certain functional tests needed to be performed in a specific order.

During the exit meeting, licensee management stated that they would evaluate improvements with respect to the use of statements in CWOs allowing steps to be performed out-of-sequence. The inspector considered the licensee's proposed actions adequate.

c. Steam Generator Tube Inspections - Unit 3 (37700)

During this inspection period, the licensee conducted extensive eddy current inspections of the Unit 3 steam generators in conjunction with the Unit 3 Cycle VII refueling outage. These inspections were performed to determine if there was degradation of steam generator tubes. The inspector reviewed licensee eddy current inspection and evaluation procedures, eddy current inspection scope changes and analysis, management oversight, and observed eddy current inspections.

(1) Eddy Current Data Analysis

The inspector reviewed licensee procedure SO23-XXVII-23.1, "Data Analysis Guidelines," Revision 3. The procedure was reviewed to determine if requirements for bobbin coil and motorized rotating pancake coil (MRPC) eddy current data analysis and evaluation had been defined. The inspector reviewed the procedure to assess the licensee's criteria for equipment calibration and bobbin coil and MRPC data discrepancy resolution. The procedure was also reviewed to determine if flaw indications expected by the licensee in certain areas of the steam generator had been identified.

The inspector noted that specific requirements for bobbin coil and motorized rotating pancake coil eddy current data analysis and discrepancy resolution had been defined in the licensee's procedure. The inspector also noted that equipment calibration and particular types of flaw indications for each section of each steam generator area had been defined in the procedure.

The inspector observed licensee activities at four MRPC and two bobbin coil data acquisition stations to determine if the licensee had been obtaining and recording data in accordance with licensee procedures. The inspector also reviewed eddy current test equipment calibration records.

The inspector found that the licensee had been performing the bobbin coil and MRPC eddy current steam generator tube examinations in accordance with procedures. The inspector also found that the licensee had been recording data on approved data sheets and that eddy current inspection equipment calibrations had been performed and were being checked in accordance with procedures.

The inspector also observed activities at four data analysis stations. The inspector found that each of the four stations had a current technique sheet. The inspector noted that the eddy current operator was utilizing frequencies and mixes specified on the technique sheet for eddy current testing analysis in accordance with SO23-XVII-23.1.

The inspector concluded that licensee procedure SO23-XVII-23.1 included appropriate requirements for bobbin coil and motorized rotating pancake coil (MRPC) eddy current data analysis and evaluation. In addition, the inspector concluded that the procedure also included equipment calibration criteria, bobbin coil and MRPC data discrepancy resolution criteria, and descriptions of particular flaw indications expected to be found in certain areas of the steam generator tubes.

The inspector concluded that licensee personnel had been performing steam generator tube eddy current inspections, data recording and data analysis in accordance with licensee procedures.

(2) Sampling Methodology and Expansion Criteria

The inspector reviewed the licensee's Unit 3 steam generator sampling methodology inspection plan. The inspection plan was reviewed to determine if the licensee included inspection expansion criteria, historical steam generator data from licensee inspections and other utilities, and loose parts monitoring.

The inspector found that the licensee's Unit 3 steam generator sampling plan included criteria for expanding the inspection scope. The inspector noted that the licensee's inspection plan included:

- a full tube length bobbin coil inspection of 60% of the approximately 9350 tubes in the two Unit 3 steam generators,

- an MRPC inspection at the top of the tubesheet for 100% of the hot leg tubes,

- approximately 355 tubes in the upper bundle area (in the arc of interest that analysis indicates to be most susceptible to free span cracking) from the first vertical support to the 08H support,

- the transition region (top of tubesheet) for approximately 6% of the tubes on the steam generator outlet (cold leg) side of the steam generator (this inspection included 20% of the tubes in an estimated region of interest which was based on the San Onofre Unit 2 steam generator inspections; the estimated region of interest is a mirror image of the region on the hotleg side of the steam generators where indications were identified at San Onofre Unit 2 during the Cycle VII refueling outage) and,

- full length eddy current profilometry inspection of all the Unit 3 steam generator tubes adjacent to the tie rods.

The inspector also found that the licensee's inspection plan included previous tubing indications found in San Onofre steam generators and problems identified by other utilities, vendors, and the NRC.

The inspector concluded that the sampling methodology used to develop the inspection plan included the areas necessary to provide information needed to ascertain the condition of the steam generators tubes. The inspector found that the sample expansion criteria was satisfactory.

(3) Inspector and Analyst's Qualification

The inspector reviewed licensee qualification and certification requirements for steam generator eddy current inspectors and data analysts. Licensee requirements for steam generator eddy current inspectors were included in SO23-XXVII-23.1.

The inspector reviewed approximately thirty eddy current and analysis personnel qualifications. The inspector found that licensee and contractor personnel qualification and certification records were up to date and that the inspectors or analysts were qualified in accordance with SO23-XXVII-23.1. The inspector also found that the licensee and contractor inspectors were certified level I, II, or III in accordance with American Society for Nondestructive Testing Standard SNT-TC-1A.

d. Pre-Outage Work - Unit 3

The licensee performed a considerable amount of pre-outage work on the shutdown cooling system (SDC) for Unit 3, prior to the Cycle VII refueling outage. This work was in preparation for installing a cross-tie between the LPSI and the containment spray systems in accordance with DCP 2-6863.00, "Shutdown Cooling and Containment Spray Crossconnect." The main purpose of this design change was to achieve greater flexibility in responding to post-accident equipment failures by increasing the number of available pumps for shutdown cooling and spent fuel pool cooling.

The inspector considered that the extensive pre-outage construction activities during normal plant operation had the potential to impact plant safety. These concerns were primarily related to the following issues: (a) adequacy of the design and installation of the temporary rigging and scaffolding necessary during the construction process, (b) potential risk to standby safety equipment in the proximity of the construction work, and (c) potential risk of an unanticipated accident resulting from the construction practices.

These concerns were described in NRC Inspection Report 50-260,361,362/93-29, Paragraph 7.

To address these concerns a special inspection was conducted by the Mechanical Engineering Branch of the Office of Nuclear Reactor Regulation. The inspection reviewed the engineering calculations on the scaffolding and the rigging and their ability to withstand seismic loads. On October 7, 1993, the inspector walked down the scaffolding and rigging supporting the tie-line in Rooms 2, 5 and 15 of the Unit 3 Safety Equipment Building (SEB). The inspector noted that trains A and B of the HPSI, LPSI and containment spray lines passed through these rooms.

The inspector held discussions with the licensee's design staff responsible for designing the scaffolding and the pipe supports which were utilized for rigging the cross-tie line. The inspector noted that the licensee had evaluated these supports to account for the impact of deadweight and seismic loads on the pipe supports during the rigging of the cross-tie line S3-1201-ML-321-10"-C-LLO. The licensee evaluated the pipe support loads to verify that these loads were within the allowable limits. The licensee also verified that during a seismic event, the displacements would not impact safety-related equipment or other surrounding objects. During the installation process, temporary horizontal and vertical seismic restraints were provided for the piping sections greater than ten feet in length. In addition, axial seismic restraints were installed at the loose ends. The inspector reviewed the licensee's pipe support evaluation in Section 8.1 of Calculation No. M-DSC-283. A comparison of the design and new loads for the rigging was performed to determine whether additional temporary supports were needed. The inspector reviewed the assumptions and design methodology for these evaluations and considered that they were adequate.

In addition, the inspector questioned the licensee's field personnel to verify that they properly interpreted the results of these evaluations and that the temporary supports were installed properly. The calculations for determining the loads for the rigging relative to 17 supports (Tag Nos. S3-RC-321-H-001 through 017) were reviewed. The inspector noted that NRC Generic Letter 91-18, "Information To Licensee's Regarding Degraded and NonConforming Conditions," required that degraded or potentially non-conforming conditions be evaluated for acceptability. However, no specific acceptance criteria to evaluate temporary loads had been provided.

The inspector noted that a diverse range of methods had been used in the industry to evaluate temporary loads. In some instances, overly conservative criteria would limit the amount of lead shielding that could be placed on piping. Limiting the amount of shielding would increase personnel radiation exposure. The use of increased allowables to account for the short duration of temporary loads would remove some needless conservatism and thereby avoid some of

the resulting adverse effects. The use of increased allowables for short duration loads was consistent with current practice for loadings such as test loads. The ASME Committee on Operations and Maintenance, Subcommittee on Condition Monitoring is currently developing a standard which will provide the general requirements for the evaluation and control of temporary loads on piping during maintenance (such as maintenance activities performed at Unit 3 in order to reduce outage durations). The temporary loads include rigging loads and loads resulting from temporary support removal and addition. Specifically addressed are the application of temporary loads on system piping and components, acceptance criteria and applicable design basis loadings used for evaluating temporary loads. Based on a review of the licensee's calculations (Calculation No. M-DSC-283) to determine the impact of deadweight and seismic loads on the pipe supports during the rigging of the cross-tie line, the inspector found that the licensee's assumptions and review methodology were consistent with those being proposed in the ASME standard and are considered adequate. The results of the analysis indicate that ASME Code requirements and applicable design criteria had been satisfied.

During a walkdown of the tieline in Rooms 2, 5 and 15 of the Unit 3 SEB, the inspector observed extensive scaffolding below the piping. The licensee stated that the purpose of this scaffolding was to protect objects and tools used in the pipe installation from falling down and also to provide an intermediate location to place the pipe sections while they were being moved from the floor to the permanent pipe supports. At the time of the inspection, all the pipes had already been removed from the floor and installed in the pipe supports. However, during the installation process, it seems likely that access to various safety equipment in the vicinity may have been temporarily prevented. The licensee's plant procedures specified that loads may be left unattended if seismically secured. The inspector observed two instances where the retaining rope strap was subject to damage due to the manner of installation. In one instance, a heavy spool piece near the spray pump in Room 5 was restrained by a rope going through the bolt hole in the flange. The rope in this restraint was subject to wear at the edge of the bolt hole. In the other instance, a temporary piping restraint consisting of a fabric strap was installed around an I-beam in Room 5. The inspector noted that SO123-I-7.24, "Rigging-Standards Guidelines and Prior-to-Use Inspections," required that all sharp corners be padded and all sharp angles should be softened. The inspector considered that although the pads were not used, the significance of their omittance was minimal. The inspector noted that pads were more appropriately used for loads being moved, not stationary restraints as was the case in Unit 3.

No violations or deviations were identified.

9. Follow-Up of Previously Identified Items (92701 and 92702)

a. (Closed) Followup Item (50-361/93-26-02), "Fire Protection Licensing Basis Review."

This item involved identifying the requirements for training of the site fire department in equipment necessary for safe shutdown of the plant, and verifying that the licensee met the requirement. The licensee identified, and the inspector verified, that the requirement was contained in an NRC safety evaluation dated November 15, 1982, and identified in Section C.14 of Amendment 69 to the Unit 2 and 3 operating licenses. The requirement was to have each operating shift have an assistant control operator serve as a member of the fire brigade to provide an acceptable level of plant systems knowledge within the fire brigade. The inspector reviewed procedure SO23-13-21, "Fire," which was the abnormal operating procedure the operators would use in the event of a fire. The inspector noted that this procedure directed the common control operator to respond to the scene of the fire with the fire department, and serve as a technical advisor. The inspector interviewed three on-shift common control operators who were aware of the responsibility and their duties should this happen. The inspector noted that the operators had recently received training in this area. The inspector concluded that the common control operators possessed the knowledge required, and that the licensee was meeting the requirement as stated above. This item is closed.

b. (Closed) Followup Item (50-361/93-19-02), "Seismic Supports Missing In Unit 2 & 3 Transformers."

This item involved the installation, determination of operability, and operation of two Class-1E transformers, 2B04X and 2B06X, during the Unit 2 Cycle VII refueling outage without vendor-supplied and recommended seismic support braces. The inspector reviewed the licensee's Division Investigation Report (DIR) and the licensee's calculation concerning operability of the transformers without the seismic braces installed. The inspector also conducted interviews with relevant personnel immediately after the occurrence. In addition, the inspector reviewed construction work order (CWO) 930030995000 used for initial installation of 2B06X, and CWO 93030993000 used for initial installation of 2B04X. These CWOs referenced drawings SO23-302-15-1-0 and SO23-302-15-2-1, which were also reviewed. The inspector also reviewed the vendor- supplied installation and maintenance instructions for the transformers assigned as licensee tracking number SO23-302-14-18-0.
Based on this independent review and the review of the licensee's DIR, the inspector concluded that the causes of the occurrence were accurate as described in the DIR. The inspector concluded that the basic cause was personnel error, compounded by a lack of proper quality control, as well as a failure of the turnover process to act as a final quality check of the system. Based on the licensee's operability calculation, the inspector also concluded that the

transformers probably would have remained functional during a design basis earthquake, but lacked the proper design margins to be seismically qualified without the seismic supports. This was because the supporting skid for the transformers could have undergone minimal yielding without the seismic braces during a design basis seismic event. The supporting skid co[illegible]d "hat" shaped steel components that could have been "crimped" in.

The inspector concluded that this was a violation because the applicable CWOs directed that the transformers be installed per the drawings referenced above. Drawing S023-302-15-1-0, referenced in the CWOs, showed the transformer with the seismic supports. As a result of DIR NC-93-08, the licensee instituted corrective actions to include requiring personnel to verify assumptions made for installation of equipment, and instituting procedural requirements to ensure final validation of installation is performed in accordance with the seismic qualification report. The inspector also noted that the violation was licensee-identified and the safety significance was minimal, as the transformers probably would have remained operable during a design basis earthquake. Also, the transformers were in operation without the seismic supports for 29 days (2B06X) and 3 days (2B04X), which was a relatively short period of time. Therefore, this violation is not being cited because the requirements of Section V.B of the Enforcement Policy were satisfied. This is a non-cited violation (NCV 50-361/93-31-07)

c. <u>(Closed) Unresolved Item (50-361/92-23-02). "Incomplete/Inaccurate Plant Record Logs."</u>

This item identified that a non-licensed plant equipment operator (NPEO) did not make the required vital area entries to perform shiftly surveillance on three occasions, but signed the surveillance indicating that he had. The licensee identified this instance of failure to make appropriate area entries during the conduct of its surveillance program for comparative analysis between documented division surveillance requirements and security access records data.

The Nuclear Regulatory Commission (NRC) issued a Notice of Violation (NOV) on October 15, 1993, associated with Inspection Report 50-206/361/362/92-23 for the actions mentioned above. The NOV was for failing to meet the requirements of 10 CFR 50.9, "Completeness and Accuracy of Information." The violation was not assigned a severity level and no response by the licensee was required (Violation 50-362/93-31-08). The licensee was informed in the cover letter that forwarded the NOV that similar violations in the future could result in escalated enforcement action. This item is closed.

d. <u>(Closed) Unresolved Item (50-361/92-23-03). "Plant Log Readings Not Taken By Authorized Personnel."</u>

This item identified three examples in which two NPEOs allowed their trainees to enter an area without the assigned responsible NPEO in

attendance to perform rounds. The licensee identified this instance of failure to make appropriate area entries during the performance of its surveillance program for comparative analysis between documented division surveillance requirements and security access records data.

These examples were reviewed and considered to be instances in which management expectations were not met, rather than instances in which plant operators falsified records. In these cases, entries into the areas had been made by trainees, rather that the assigned personnel. This item is considered closed.

10. Unresolved Items

In Paragraphs 3, and 8 of this report, unresolved items were identified. An unresolved item is a matter about which more information is required to ascertain whether it is an acceptable item, an deviation, or a violation.

11. Exit Meeting

On November 24, 1993, an exit meeting was conducted with the licensee representatives identified in Paragraph 1. The inspectors summarized the inspection scope and findings as described in the Results section of this report.

The licensee acknowledged the inspection findings and noted that appropriate corrective actions would be implemented where warranted. The licensee did not identify as proprietary any of the information provided to or reviewed by the inspectors during this inspection.