U.S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos.	50-206/93-09, 50-361/93-09, 50-362/93-09
Docket Nos.	50-206, 50-361, 50-362
License Nos.	DPR-13, NPF-10, NPF-15
Licensee:	Southern California Edison Company Irvine Operations Center 23 Parker Street Irvine, California 92718
Facility Name:	San Onofre Units 1, 2 and 3
Inspection at:	San Onofre, San Clemente, California
Inspection conducted:	April 1 through May 12, 1993
Inspectors:	C. W. Caldwell, Senior Resident Inspector J. J. Russell, Resident Inspector D. L. Solorio, Resident Inspector T. B. Sundsmo, Project Inspector C. M. Regan, NRR Intern C. C. Harbuck, NRR J. R. Ball, NRR S. P. Sanchez, NRR Intern

Approved By: H. J. Wong — 6/10/93

H. J. Wong, Chief
Reactor Projects Section II

Date Signed

Inspection Summary

Inspection on April 1 through May 12, 1993 (Report Nos. 50-206/93-09, 50-361/93-09, 50-362/93-09)

Areas Inspected: Routine resident inspection of Units 1, 2 and 3 Operations Program including the following areas: operational safety verification, radiological protection, evaluation of plant trips and events, bi-monthly surveillance activities, monthly maintenance activities, engineered safety feature walkdown, independent inspection, licensee event report review, and followup of previously identified items. Inspection procedures 41701, 61726, 62703, 64704, 71500, 71707, 71710, 82301, 90712, 92700, 92701, 92720, and 93702 were covered.

Safety Issues Management System (SIMS) Items: None

Results:

General Conclusions and Specific Findings:

Strengths:

The inspector noted that the licensee had developed a limited shutdown risk evaluation for the upcoming Unit 2 refueling outage. The inspector also noted that evolutions with a relatively high risk during the outage had been identified and a plan for defense in depth measures for those evolutions had been developed. This was done in accordance with the good practice guidelines of Nuclear Utility Management And Review Council (NUMARC) 91-06, "Guidelines for Industry Actions to Assess Shutdown Management." The inspector considered this evaluation of shutdown plant safety and the preparations that were made as a consequence to be a strength.

Weaknesses:

Weaknesses were noted with the Unit 1 procedures used for sluicing spent resin from the demineralizer to the spent resin storage tank. The procedure weaknesses noted were with verification of storage tank level and for determining when the sluicing operation was complete. The procedure weakness for determining spent resin storage tank level contributed to a lack of understanding why the increased radiation levels were occurring (Paragraph 3.c).

The inspectors observed minor weaknesses with configuration control regarding unrestrained equipment near safety-related equipment and vent and drain valves not listed on P&IDs (Paragraph 8.a). The inspectors also noted minor weaknesses with contractor attention-to-detail regarding degradation of a radiation posting, improper placement of a dosimeter, and damage to a valve (Paragraph 3.b). Similar weaknesses in the area of configuration control were also noted by the inspectors in NRC Inspection Report 50-361/93-02.

The inspectors noted a minor weakness with the licensee's wear calculation for water entrainment in steam piping for the Unit 3 turbine driven auxiliary feedwater pump (Paragraph 8.c).

During this period, it was also determined that the licensee inadequately evaluated a 1989 10 CFR Part 21 report regarding problems with 125 VDC vital battery chargers. This resulted in corrective actions and a temporary waiver of compliance being required in February 1993 (Paragraph 9.b).

Summary of Violations:

None

Open Items Summary:

During this inspection report period, no new followup items were opened and ten followup items were closed; one was examined and left open.

DETAILS

1. Persons Contacted

Southern California Edison Company

H. Ray, Senior Vice President, Nuclear
*R. Krieger, Station Manager
*J. Reilly, Manager, Nuclear Engineering & Construction
*B. Katz, Manager, Nuclear Oversight
*R. Rosenblum, Manager, Nuclear Regulatory Affairs
*G. Gibson, Supervisor, Generic Licensing
*K. Slagle, Deputy Station Manager
*R. Waldo, Operations Manager
L. Cash, Maintenance Manager
*R. Joyce, Maintenance Manager, Units 2/3
*D. Breig, Manager, Station Technical
M. Short, Manager, Site Technical Services
*D. Irvine, Supervisor, Technical Services
*M. Wharton, Manager, Nuclear Design Engineering
P. Knapp, Manager, Health Physics
*J. Fee, Assistant Manager, Health Physics
W. Zintl, Manager, Emergency Preparedness
D. Herbst, Manager, Quality Assurance
C. Chiu, Manager, Quality Engineering
*J. Schramm, Plant Superintendent, Unit 1
*V. Fisher, Plant Superintendent, Units 2/3
*G. Hammond, Supervisor, Onsite Nuclear Licensing
*A. Llorens, Engineer, Onsite Nuclear Licensing
*M. Farr, Onsite Nuclear Licensing
J. Reeder, Manager, Nuclear Training
H. Newton, Manager, Site Support Services
*M. Herschthal, Manager, Nuclear Systems Engineering
*A. Thiel, Manager, Electrical Systems Engineering
*S. Graham, Control Room Supervisor

*Denotes those attending the exit meeting on May 21, 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 1

The Unit was permanently shutdown on November 30, 1992. The core was offloaded to the spent fuel pool (SFP) on March 6, 1993. Primary and secondary systems were placed in a "SAFSTOR" condition and the inspector participated in a walkdown of containment with licensee staff on May 12, 1993, in preparation for final containment closure.

Unit 2

The Unit operated at essentially full rated power during the inspection period. On April 2 through 4, 1993, the Unit downpowered to 75% power for circulating water heat treatment and circulating pump work.

On April 29, 1993, main turbine stop valve 2200D failed closed. No significant reactor power perturbation resulted as the operators took manual action to initiate steam bypass control. The operators reopened valve 2200D two hours after it failed closed.

Unit 3

The Unit operated at essentially full rated power during the inspection period. On April 23 through 26, 1993, the Unit downpowered to 75% power for circulating water heat treatment and cleaning of the condenser water boxes.

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. Units 2/3 Component Cooling Water

The inspector observed that on April 27, 1993, the licensee placed one train of component cooling water (CCW) in standby in both Units 2 and 3. Since initial Unit startup, the licensee has operated CCW with both critical trains in operation. The inspector made the observations as described below, and considered the change of normal operation of Units 2 and 3 of minimal safety significance.

Background

The CCW system is arranged in two full-capacity critical cooling loops and one noncritical cooling loop for each Unit. CCW transfers heat from system loads to the saltwater cooling (SWC) system. A third CCW pump (swing pump) is provided and could be aligned to either loop. The noncritical loop could be supplied from either critical loop. Each critical loop receives an automatic start from a safety injection signal and provides cooling for a train of high pressure safety injection (HPSI), low pressure safety injection (LPSI), containment spray, containment emergency coolers, an emergency chiller (shared between units 2 and 3), post accident cleanup units (PACUs) and other loads. The non-critical loop provides cooling for reactor coolant pumps, control element drive mechanisms, and other loads. Since initial startup, the licensee had normally operated Units 2 and 3 with both critical loops in operation (the CCW pump running and flow established through the system loads) and the trains split.

The licensee placed one train of CCW in standby (i.e., the CCW pump off with no system flow) on May 27, 1993. The licensee informed the inspectors that this change was intended to effect a cost savings and to minimize system degradation through excessive operation. The licensee originally performed this evolution as a test, but made it a permanent operating configuration after the test results proved satisfactory. The standby pump would automatically start on a safety injection signal, or loss of the running pump. However, the inspector noted that it would not auto-start in the event of a fuel handling accident.

Concerns

After one train of CCW was placed in standby, the inspector noted the following:

- Four expected annunciators alarmed in each Unit and remained illuminated. These were the low-flow annunciators for the loop that was in standby. The inspector was concerned that this was contrary to a "clean boards" goal. In addition, one low-pressure annunciator for Unit 3 illuminated that was unexpected. This low-pressure alarm should have only illuminated when the respective CCW pump was operating. Operations personnel submitted a site problem report (SPR) in order to modify these annunciators to illuminate only when an abnormal condition was present.

- Various procedures, such as annunciator response procedures (ARPs), normal operating procedures, abnormal operating procedures (AOPs), and surveillance procedures, were more difficult to use because they were generally written assuming two loops of CCW in operation. The licensee had not performed a detailed analysis of which procedures required changes prior to operating in this mode. However, upon review, they identified 35 separate procedures that required revision to make them more clear. After the change in system operation had been implemented, the licensee changed the pertinent ARPs and AOPs and was in the process of changing the other, less important, procedures.

- Both Units entered Technical Specification (TS) 3.9.12, which was applicable any time irradiated fuel was in the storage pool. TS 3.9.12 required that two PACUs be operable. The PACUs are charcoal forced-air filtering units used to clean the atmosphere in the fuel handling building following an accident. A fuel handling isolation signal did not automatically start CCW or SWC. Since these PACUs use CCW to cool incoming steam or gas, the PACU that was cooled by the CCW train that was placed in standby was declared inoperable by the licensee. The inspectors reviewed the Final Safety Analysis Report and concluded that even without the use of both PACUs the projected offsite dose from a design basis fuel handling accident was less than 10 CFR Part 100 limits. The licensee was in the process of reevaluating the need of CCW for PACUs. The licensee was performing an engineering calculation to evaluate this need, and expected this calculation to be complete by July 1993. The inspector considered this approach to be adequate and will review the calculation when it is completed.

Conclusion

The inspectors discussed these issues with personnel from the Office of Nuclear Reactor Regulation (NRR) and concluded that the concerns mentioned above were of minimal safety significance and were being adequately addressed by the licensee.

b. Contractor Inattention-To-Detail - Units 1, 2 and 3

During a tour of Units 1, 2 and 3, the inspectors observed three examples of minor weaknesses involving inattention-to-detail displayed by contract personnel while performing work in the protected area of the station.

- During a routine walkdown of Unit 2 on April 6, 1993, the inspector noted that radiological postings had been degraded. These postings had designated a high conductivity sump as a contaminated materials storage area. The postings had consisted of a yellow and magenta rope surrounding the sump at waist height, and signs hung from the railing that supported the rope. The inspector noted that the rope was on the ground on one side, and that two signs attached to it were not readable since they were also on the ground. The inspector noted that contractor personnel were chipping and grinding on wooden platforms above the sump, and that they may have inadvertently degraded the barrier. The inspector notified Units 2/3 Health Physics (HP) personnel, who reposted the area. The inspector was concerned that the contract personnel did not observe the degradation of the posting and inform HP themselves.

- During a walkdown of Unit 1 containment on May 3, 1993, the inspector observed a contractor dressed in full protective clothing (PC) who was moving pipe through the Unit 1 containment equipment hatch. This person was wearing his self-reading dosimeter (PD-1) under his PCs. The inspector was concerned that the individual could not read his dose or his dose rate because his PD-1 was not accessible without removing his PCs. The inspector was also concerned that the individual would not be able to hear the PD-1 if it alarmed. These concerns were discussed with Unit 1 HP personnel, who then had the contractor place the PD-1 on the exterior of his PCs. The licensee also conducted additional training on proper placement of the PD-1 for the individual and his entire work group.

- During a review of Unit 3 Control Operator logs dated April 27, 1993, the inspector noted that contract personnel had damaged relief valve 3 PSV 3993 (for air receiver V048) while painting the Unit 3 condensate polisher area. The log indicated that the relief valve had been broken by the contractors and required replacement. The inspector was concerned that the contractors did not have adequate attention to the equipment in the area where the painting was being conducted.

The inspector was concerned that the three examples above indicated a less than adequate attention-to-detail on the part of contract personnel doing work at the site. The inspector considered these cases to be indicative of a minor weakness in the training of contractor personnel by the licensee. The licensee routinely provided training to all contract personnel prior to allowing them access to the station protected area. In response to the inspector's concerns, the licensee agreed to emphasize training given to contract personnel, particularly in the area of radiological controls. This training would be emphasized during the initial access training and at pre-job tailboards. The inspector considered the licensee's corrective actions to be adequate.

c. Very High Radiation Areas During Resin Transfer - Unit 1

On April 5, 1993, the inspector observed that a very high radiation area (VHRA) had been established in the Unit 1 lower level Rad Waste Building. This VHRA was established in the ion exchanger alley. The inspector was informed that contact readings on two T-sections of piping were 330 Rem/hour and 170 Rem/hour. These T-sections were the only exposed piping that was used to sluice the four ion exchangers to the spent resin storage tank (SRST). The radiation levels noted were for the C and D ion exchangers, and A and B ion exchangers (respectively) to the SRST. The T-sections branched off the main, shielded pipe that led from the north and south demineralizers (DMs) to the SRST. The inspector was informed that the radiation levels had increased as the operators attempted to sluice 25 cubic feet of resin from the north DM to the SRST. The very high radiation levels were indicative of spent resin being stuck in that piping. (Normally, during sluicing operations, radiation levels in the ion exchanger alley remain essentially constant as resin is transferred and the DM is emptied. In addition, the operators have indication of water flow through the pipe, but not of resin flow. The SRST vents to a holdup tank and water flow is indicated by an increasing water level in that hold up tank.)

After the resin transfer, radiation levels remained constant and elevated for 23 days. The inspector reviewed the radiological controls put into place due to the change in conditions and concluded that Unit 1 personnel took appropriate radiological precautions in posting the area and restricting access.

Subsequent to the resin sluice, on April 26, 1993, the inspector observed that 110 cubic feet of spent resin was sluiced from the SRST to a spent resin storage cask. On April 28, 1993, the inspector observed that the north DM was verified to be empty of resin and that the C and D ion exchangers were successfully sluiced to the SRST. Radiation levels in the T-joints decreased to 23 Rem/hour and 70 Rem/hour respectively.

The licensee initially informed the inspector that the data indicated that the SRST had been full when the attempt was made to sluice to it on April 5, 1993. Attempting to sluice to a full tank would have caused the resin to back up in the inlet line and into the T-sections. Subsequent investigation by the licensee revealed that the SRST had sufficient volume available to receive the demineralizer contents and that it was not full. The licensee concluded this based on draining and re-filling the SRST and measurement of the volume to fill the SRST. The licensee further concluded that the VHRAs were caused by continuing to sluice the demineralizer after it had been successfully sluiced during one of the first of the four flush attempts. The licensee was not clear on the exact mechanism causing the spent resin to flow into these branches of piping, which were at an acute angle to the direction of flow of the spent resin and were isolated at the T-section by isolation valves.

The inspector reviewed procedure S01-5-5, Revision 2, "Sluicing and Replacement of the Mixed Bed Demineralizers," which was the procedure in effect on April 5, 1993, when the sluice was first attempted. The inspector noted the following weaknesses with the procedure:

- Step 1.4 of the procedure required that the operators verify that the SRST had sufficient volume to receive the spent resin. However, there was no specific guidance in procedure S01-5-5 on how to make this verification. The inspector considered that the procedure weakness for determining SRST level, as described above, contributed to the licensee's initial misunderstanding of this incident.

- Step 2.27 of the procedure required that the operator record the amount sluiced in a spent resin tank log. This was in turn used to maintain a record of available volume in the SRST. Each Unit 1 DM and each ion exchanger had 25 cubic feet of internal volume available for resin. The total internal volume available for resin in the SRST was 550 cubic feet, as indicated in the SRST log, when the tank was empty. The inspector noted that although the SRST had level indication, it was not a valid indication of resin volume since it would only indicate water level in the tank, not resin level.

- Unit 1 Operations personnel maintained the log of SRST contents in order to track available volume. The inspector noted that this log indicated that the SRST had last been completely emptied of resin on December 17, 1990. The inspector also noted that the log indicated 125 cubic feet of available volume on April 5, 1993, when the operators attempted to sluice the north DM. The inspector observed an apparent addition error in the November 9, 1992 log entry which would have decreased available volume by 25 cubic feet. The log indicated 25 cubic feet of spent resin going into the SRST; however, this amount had not been subtracted from the available volume. Discussions with the licensee indicated that there had not been an addition error in the log, but that the 25 cubic feet indicated as going into the SRST was in error. The inspector also noted that the log indicated 30 cubic feet had remained in the tank when it had supposedly been completely drained in December 1990. This 30 cubic feet had been lined out in the log, and the SRST was assumed to be at zero contents on this date.

  The inspector noted that the log was not formally reviewed by personnel other than the operator who made the particular entry. The inspector concluded that this lack of formal review caused the errors mentioned above to go uncorrected. Procedures did require that log entries be made when an ion exchanger or demineralizer was sluiced to the SRST, and when it was sluiced to a cask for offsite removal. However, no second check of these log entries or the subsequent subtraction of available volume was required.

- Various steps in procedure SO1-5-5 referred to radiation levels increasing in the valve alley as indication that the sluice was removing spent resin and that when these levels decreased this was indication that the sluice was complete. This procedure also provided for reinitiating the sluice as many times as necessary to sluice the entire contents of the demineralizer. The inspector was informed that four attempts were made on

April 5, 1993 to sluice the demineralizer to the SRST. Each attempted sluice raised radiation levels in the T-sections mentioned above. The inspector considered that, in this instance, elevated radiation levels were indicative of resin lodged in the piping and not of resin flowing through the piping. The inspector concluded that this procedural weakness at least partially contributed to the creation of these VHRAs.

The licensee acknowledged these comments and were evaluating whether procedure changes were appropriate. This issue is considered closed (Inspector Followup Item 50-206/93-09-01).

No violations or deviations were identified.

4. Evaluation of Plant Trips and Events (71500, 93702)

Main Turbine Stop Valve Inadvertent Closure - Unit 2

On April 29, 1993, one of the Unit 2 main turbine stop valves (non-safety related), 2200D, failed closed. Operators quickly took manual action to initiate the steam bypass control system before reaching the system automatic setpoint and stabilized reactor coolant temperature. Engineering and Maintenance personnel conducted an inspection (electrical and hydraulic components were inspected) of the valve and were not able to determine a root cause for the valve closure. The only abnormality observed was a minor oil leak at the base of one of two accumulators for the unitized actuator. The operators reopened 2200D two hours after it had failed closed.

On April 30, 1993, Maintenance Department personnel determined that the nitrogen-filled bladders in the accumulators were depressurized. The bladders were subsequently replaced. Additionally, maintenance personnel installed electrical monitoring equipment on the valve position and closure circuitry. At the end of the inspection period, the Engineering Department was evaluating whether the depressurized bladders were responsible for the valve's closure. The inspector will monitor the licensee's corrective actions as part of routine inspection activities.

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)

S02-3-3.13, "Containment Cooling Monthly Tests."

The inspector reviewed the component cooling water (CCW) system Unit 2 containment emergency cooler flow surveillance test results, documented in Nonconformance Report (NCR) 93030041 dated March 24, 1993. Flow testing of Unit 2 containment emergency cooler E402 with the control room chiller E335 aligned to Unit 3 yielded results of 2170 GPM and 2180 GPM. These flows did not meet the required minimum flow criteria for the emergency cooler specified in S02-3-3.13, "Containment Cooling Monthly Tests - Unit 2," which defined the minimum flow through E402 to be 2200 GPM, with E335 aligned to Unit 3. The minimum flow criteria for E402, with both E335 and E402 aligned to Unit 2, was 2000 GPM. Further testing with E335 aligned to Unit 2 yielded flow results which met the acceptance criteria. Corrective actions which resulted from the NCR were to change the flow acceptance criteria in S02-3-3.13 and S03-3-3.13 to 2150 GPM. Subsequently, NCR 93030041 recommended a change to Procedures S02-3-3.13 and S03-3-3.13 to reflect an acceptance criteria of 2150 GPM for E402 when E335 is aligned to the Unit not being tested. The inspector reviewed the surveillance procedure to determine the applicability of the flow criteria to Technical Specification requirements. In addition, the inspector reviewed Design Calculation M26.11, Revision 1, "CCW Flow/Pressure Distribution Analysis," to validate the flow criteria as stated in the NCR. The inspector considered that the licensee's corrective action were adequate.

S023-II-5.17, "Surveillance Requirement NI (nuclear instrument) Safety Channel C Drawer Test Linear Power Subchannel Gains Functional Test and Channel Calibration."

On April 8, 1993, the inspector observed S023-II-5.7, "Safety Channel C Drawer Linear Power Subchannel Gains Channel Functional Test and Channel calibration," conducted by licensee personnel for Unit 2. The inspector had three areas of minor concern:

- The inspector noted a missing locking screw on the safety channel drawer of the reactor protective system (RPS) "C" cabinet. The inspector informed cognizant maintenance personnel who replaced the screw.

- The Test Procedure Manager did not have pages 15 and 16 of the surveillance procedure. The manager did not note this prior to the start of the surveillance. However, he did note the omission and obtained the missing pages as he came to that step of the procedure. The inspector was concerned that if the technicians used incomplete procedures, and did not identify the condition, it could lead to mis-operation of the switches and unanticipated response of the Reactor Protection System (RPS). The Units 2/3 Instrumentation and Control (I&C) Manager noted this concern and stated that they had been and would continue to emphasize procedure verification prior to the start of the evolution.

- The inspector noted that steps 6.6.6 and 6.7.15 of the surveillance procedure directed the operator to place the rate trip test knob and the log trip test knob respectively in the "TEST" position. The inspector noted that there was no "TEST" position indicated on the cabinet for these knobs. The technicians knew the proper position based on their experience. The inspector was concerned that a less experienced technician might not know the proper position. The I&C maintenance supervisor agreed to evaluate changing this procedure to clarify the actual manipulation required for these knobs.

The inspector concluded that the concerns mentioned above were minor and that overall the surveillance activities were adequately performed.

b. Observation of Routine Surveillance Activities (Unit 3)

S023-II-11.172, "Auxiliary Feedwater (Terry) Turbine Governor Calibration."

The inspector observed an overspeed test of the Unit 3 turbine-driven auxiliary feed pump on April 19, 1993. Comments on this observation are in Paragraph 9.c.

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 which were performed satisfactorily:

a. Observation of Routine Maintenance Activities (Unit 2)

MO92110358000, "Handling Fuel Assemblies."

b. Observation of Routine Maintenance Activities (Unit 3)

MO93040485000, "Repair CCW Valve 3HV6371 Actuator."

MO93040661000, "Perform MOVATS On 3HV6371."

No violations or deviations were identified.

7. Engineered Safety Feature Walkdown (71710)

a. Emergency Diesel Generator System Discrepancies - Unit 3

The inspector walked down portions of the Unit 3 emergency diesel generator system. Piping and instrument diagrams (P&IDs) 40110ES03, 40110AS03, 4011BS03, and procedure S023-2-13, "Diesel Generator Operation," were used. The inspector noted some instances in which valves in the plant were not on the P&IDs and other discrepancies in the P&IDs. These are further explained in Paragraph 9.a as examples of problems with configuration control.

The inspector also noted minor problems with the valve lineup for emergency diesel generator (EDG) 3G002, Attachment 3 to S023-2-13. These problems included instances of "to" and "from" being incorrectly identified and lube-oil filters being incorrectly identified. These minor errors were discussed with licensee operations procedures personnel for resolution.

During the course of the walkdown of EDG 3G002, the inspector also noted an event which occurred at approximately 1:00 a.m. on May 5, 1993. In preparation for a EDG 3G002 monthly surveillance test and prior to synchronizing across the EDG output breaker, the operator was directed by procedures to place the synchronizing circuit across an already closed breaker. Operations personnel energized the synchronization circuit across the reserve auxiliary transformer breaker (152) to vital bus 3A04. When the operator did this, there was indication of 0 volts and 0 hertz which was not appropriate for the known plant conditions. At 9:00 a.m., 3G002 was declared inoperable because of the inability to parallel across breaker 152. A 3 ampere fuse on the sensing tap for the reserve auxiliary transformer, in the synchronization circuit, was discovered blown and was replaced. The synchronization circuit was then operationally checked by placing the circuit across breaker 152. The circuit functioned normally and the EDG was declared operable. NCR 93050010 was generated to track any additional fuse failures. Maintenance order (MO) 93050323, originally initiated to troubleshoot the circuit, was canceled when the circuit successfully passed the operation check. The inspector was concerned that this fuse might blow and give the control room personnel no indication that the synchronization circuit would not function across breaker 152.

The failure of the fuse would not prevent automatic loading of the EDGs. However, this function was necessary in the event that EDG 3G002 was powering its vital bus and that the operators would desire to unload the bus to offsite power. In order to verify correct operation of the synchronization scope when it was most necessary, the licensee agreed to evaluate incorporating an operability check of the synchronization circuit (from the control room) in the event that one train of emergency alternating current (AC) power was declared inoperable. The synchronization circuit check would be of the other (operable) train of emergency AC power.

The inspector considered that the minor problems mentioned above had been adequately addressed by licensee staff.

b. Final Closeout For Unit 1 Containment

The inspector walked down Unit 1 containment on May 12, 1993, in preparation for final closure of containment. All debris had been removed; the reactor was defueled and drained to the bottom of the loop penetrations; all other fluid systems were drained; all oil systems were drained; forced air was secured; and one pressurizer code safety valve was removed venting the reactor coolant system (RCS) to containment atmosphere. The reactor vessel head was in place. The inspector was informed that ventilation and electrical power would be secured with the exception of limited fire detection and communications equipment. The inspector noted that tools and equipment specific to Unit 1 remained in containment and were being stored on the 42 foot level. The tools appeared to be properly labeled for radiological control and also properly stored.

The inspector was also informed that containment would be vented to outside atmosphere via a spare equalizing line which was 6" in diameter and had isolation valves failed passively open. This line led to the suction area of the Unit 1 plant vent stack. This maintained a slight negative pressure on containment, due to the action of the plant vent stack fans and provided a monitored release path. Although the inspector noted that radiological postings and barriers remained, the licensee indicated that they would be removed, as the facility had no plans for periodic reentry into the containment. The inspector had no significant concerns. The inspector was told that the equipment hatch, the escape hatch, and the personnel hatch would be locked. Future reentry would require keys from the Security, Health Physics, and Operations Departments.

No violations or deviations were identified.

8. Independent Inspection (64704, 71710)

a. Configuration Control - Units 2 and 3 (71710)

Several problems involving proper configuration control were identified by the inspectors during this period. The discrepancies noted were as follows:

- During a routine walkdown of the Unit 3 control room operating panels, the inspector noted a red "Mag Tag Instruction" adjacent to the non-Class 1E pressurizer heaters. "Mag Tag Instructions" were red tags affixed to magnetic backings and used in the Units 2 and 3 control rooms on the control panels to serve as caution tags. The inspector noted that the heaters were energized. The inspector was concerned that the "Mag Tag" appeared the same as a red "Men at Work" tag, except the top of the "Mag Tag" read "Mag Tag Instruction" and a "Men at Work" tag would have read the required component position at the top.

The "Mag Tag" did read "Personnel at Work, Do Not Operate" at the bottom. The inspector was concerned that the operators might be hesitant to operate these heaters in the event that an underpressure condition developed in the reactor coolant system, when operation would become necessary. The inspector interviewed operators on watch who indicated that they would indeed operate these heaters if necessary. The facility operations staff acknowledged the inspector's concern that the "Mag Tag" too closely resembled a red "Men at Work" tag. The licensee operations staff changed the automatic program for printing out "Men at Work" tags to have the "Mag Tags" read "For Information Only" and not "Men at Work, Do Not Operate".

- During a routine walkdown of the Units 2 and 3 remote shutdown room, the inspector noted three unanchored, wheeled chairs adjacent to the shutdown panels. This appeared contrary to procedure SO123-I-1.20, "Seismic Controls - Seismic Controls During Maintenance, Testing, and Inspections," section 6.5, which specified that movable equipment be secured or anchored. The inspector was particularly concerned about one chair that was directly in front of the panel and had a heavy metal chain wrapped around its base. During a seismic event this chair could have damaged plant indication necessary in the event the control room was evacuated, and necessary for safe shutdown of the Units. The inspector mentioned this concern to the on-watch shift superintendent and these chairs were removed from the remote shutdown room. Similar housekeeping concerns had been noticed in past inspections and are being tracked as open item 50-361/93-02-02. The inspector will continue to monitor the licensee's performance in this area as part of routine inspection activities.

- During a safety system walkdown of the Unit 3 diesel generator, 3G002, the inspector noted that two drain valves and one vent valve, located on fuel oil lines from the fuel oil day tank to the diesel engine, were physically in the plant, but not on the applicable P&ID.

  The inspector also noted that auxiliary turbo-filter 841 was incorrectly identified as 541 on the applicable P&ID. The inspector was concerned that the P&ID did not correctly reflect the 3G002 system as it was configured in the plant. The licensee acknowledged these concerns and changed the applicable P&ID to incorporate these valves and correct the auxiliary turbo-filter. The inspector concluded that these discrepancies were minor in safety significance. However, the lack of accuracy of P&ID's had been noted in past safety system walkdowns of other safety-related systems. This lack of accuracy is being tracked as inspector followup item 50-361/93-02-03. The inspector will continue to monitor the licensee's performance in this area as part of routine inspection activities.

The inspector concluded that the licensee had taken adequate action for the three specific actions mentioned above.

b. <u>Thermo-Lag Applications - Units 1, 2 and 3</u> (64704)

The inspector reviewed correspondence from the licensee, dated April 13, 1993, documenting a change in the status of compensatory measures being taken to insure train separation of fire areas that utilize Thermo-Lag 330-1.

Unit 1 utilized Thermo-Lag 330-1 in three separate applications to satisfy the requirements of 10 CFR 50.48. Two of these applications no longer applied due to the permanent shutdown status of Unit 1. The remaining application, in Unit 1 on the north wall of the turbine building, required a 1-hour fire rating per Amendment 44 to the Provisional Operating License. An hourly fire watch was being performed in this area as a compensatory measure. The licensee stated that this will continue until the fire separation is no longer required by Technical Specifications.

Thermo-Lag 330-1 was also used as a fire barrier in Units 2 and 3. Four tendon access hatches, providing train separation for redundant safety-related components, were required to provide a two-hour fire rating. The access hatches were covered by the Thermo-Lag 330-1 material. As a compensatory measure, the licensee instituted an hourly fire watch in these areas.

The inspector performed several plant tours of these fire areas in Units 1, 2 and 3, and verified the performance of hourly fire watches. Thermo-Lag 330-1 that was being used in Units 2 and 3 was scheduled to be replaced by December 30, 1993.

c. <u>Auxiliary Feedwater Steam Supply -- Water Entrainment (Unit 3)</u> (71710)

During a routine start of the Unit 3 turbine-driven auxiliary feedwater (AFW) pump on April 19, 1993, the licensee observed a pump discharge pressure fluctuation (dip and spike) and concurrent overspeed trip pre-alarm about 12 seconds after the pump was started, and after discharge pressure had initially stabilized. As expected, the AFW pump did not trip, and continued to operate satisfactorily. The licensee considered the discharge pressure fluctuations to be indicative of entrained water in the steam supply line passing through the turbine's governor control valve.

Similar previous problems with entrained water causing AFW pump trips were discussed in NRC Inspection Reports 50-206/92-12 and 50-206/92-20. To prevent water entrainment in the steam supply, the licensee implemented several actions: (1) the bypass valves for all steam traps on this system have been left open; (2) the steam supply piping temperatures were routinely monitored; and (3) a plant modification to change the steam supply connection into the main steam lines was planned for the next refueling outages for Units 2 and 3. The inspector reviewed the surveillance data sheets and control room log entries associated with the previous three startups of the turbine-driven AFW pump and noted that no abnormal indications had been recorded.

As part of the April 19, 1993, event analysis, the licensee reviewed piping temperatures on the steam supply lines, ensuring that they were all above 500° Fahrenheit (F). The AFW pump (P-140) was run again on the afternoon of April 19, while being closely monitored by plant personnel. No alarms were observed during this pump startup. However, after discharge pressure reached 1400 psig (normal minimum flow value), it dipped momentarily to approximately 1225 psig. During this dip the change in turbine speed could be heard, but there was no indication (noise) of water hammer at the turbine.

After the events of April 19, the licensee took additional temperature readings on the steam supply lines to the AFW turbine. Two steam lines that have individual isolation and check valves, one isolation and check valve pair from each steam generator, join a common header to supply steam to the AFW turbine. Normally, one line is isolated and the other line pressurizes the header. At one location, between the closed steam supply isolation valve and the supply check valve, a radial temperature profile was taken. Temperatures uniformly ranged from 512°F at the bottom of the pipe to 529°F at the top of the pipe. Licensee engineers felt that the lower temperature on the bottom of the pipe was an indication of water inside the pipe. The closed steam supply isolation valve on this line was opened to ensure that this portion of piping was being adequately heated and drained. With this valve open, the radial temperature profile at the same location changed to 521°F at the bottom of the pipe, and 526°F at the top of the pipe.

After the second steam supply valve was opened, the licensee conducted an overspeed test of the turbine driven AFW pump in accordance with SO23-II-11.172, "AFW (Terry) Turbine Governor Calibration," to ensure that the alarm indication (overspeed pre-trip) received on the morning of April 19 was valid. The pump start for this test run was smooth, without a discharge pressure dip at 1400 psig, as had been observed on previous startups. The overspeed alarm and trip functioned properly.

Because of small oscillating pressure variations between steam generators, the two check valves (which prevents back-flow from the common header) repeatedly lift off of their seat, and then re-seat; this is commonly referred to as chattering. Licensee engineers reviewed the wear calculation for these check valves, dated May 9, 1986, that indicated check valve component lifetimes of two to five years. One result of opening both steam supply valves to the AFW turbine opening was the resulting check-valve chattering, which may cause increased wear of check valve components.

The inspector independently reviewed the wear calculation and observed that it accounted for wear caused by a natural swinging motion (i.e., like a pendulum) of the disc caused by vortex-shedding induced forces. The calculated oscillation frequency was 3 hertz, which appears to be reasonable based on chatter noise heard at the valves. However, it was not clear that the calculational method, natural motion, was a conservative estimate for forced disc motion caused by cyclic variations in steam generator pressures. The calculation also assumed, without justification, that the disc would oscillate through a maximum span of 20 degrees. The inspector could not identify the conditions that would limit this valve, which has an 80 degree full open swing, to swing only 20 degrees. Finally, the wear calculation did not account for cracking or fatigue considerations that may be induced by the disc impacting the valve seat. The inspector relayed these concerns to the licensee, who stated they would consider them in their disposition of this event.

The licensee documented their review of this concern in a 10 CFR Part 50.59 safety evaluation performed to ensure that operating with both AFW steam isolation valves open did not present an unreviewed safety question. The licensee included discussion of concerns similar to those discussed above in their safety evaluation and concluded that the wear calculation was conservative. They determined, based on previous maintenance history, that the wear effects due to chattering had been accounted for in the calculation and that this was acceptable.

The licensee has initiated actions to revise operational procedures to support maintaining both steam supply valves to the AFW turbine open in order to minimize water build up in the lines in both Units 2 and 3. Action was also initiated to revise the periodic AFW steam supply line temperature monitoring procedure (SO23-V-3.4.1) to include a sample of radial temperature profiles on the AFW steam supply piping. The inspector considered that the corrective actions were adequate.

d. <u>Emergency Preparedness (EP) Training Drill</u> (82301)

On May 12, 1993, the inspector observed a quarterly EP training drill from the simulator control room; there was no other NRC participation in this drill. The drill scenario was initiated from a post-trip, shutdown condition with 4% failed fuel, and was gradually escalated to GENERAL EMERGENCY conditions due to a leak, and subsequent non-isolable rupture in the shutdown cooling (SDC) system outside of containment. Overall, the scenario was a very effective training experience. It was also the first EP drill at

San Onofre Units 2 and 3 that had been initiated from a shutdown condition.

The inspector observed two issues during the drill which indicated that improvements may be needed during scenario development and validation. First, use of either procedure "Reactor Coolant Leak" (abnormal operating instruction) or "LOCA" (emergency operating instruction) to mitigate the SDC leaks (70 and 1000 gallons per minute) was possible, and could have been anticipated. However, the scenario summary and prescripted plant data forms anticipated use of only the leak procedure. Some of the major differences between these two procedures included initiation of automatic containment isolation systems, tripping reactor coolant pumps (natural circulation cooldown), use of steam generator atmospheric dump valves, and use of auxiliary feedwater. Both procedures required substantial modifications to be used effectively, and there was no guidance identifying which procedure should be used under different plant conditions. The former procedure specifically addressed plant conditions with the RCS pressure boundary open for maintenance; the latter procedure appeared to provide more effective guidance for mitigating a large leak with a normal plant lineup.

The second issue indicated that the scenario development improvements which may be needed involved the postulated sequence of events leading to the SDC rupture. The scenario proposed that the operators would perform a sequence of events to place SDC on line with a failed open (inoperable) containment isolation valve, in apparent disregard of the requirements of TS 3.6.3, "Containment Isolation Valves." During the drill, the inspector identified to the drill controllers that the operators probably would not open the outboard containment isolation valve after they identified that the inboard valve was failed open, and inoperable. The drill controllers then made changes to the scenario malfunctions which effectively avoided the concern. However, these changes likely contributed to the simulator modeling failure (i.e., "crash") that occurred just after the changes were made. The remainder of the drill was satisfactorily conducted using prepared hard copy data. Actions by the drill coordinators to adapt to these differences during the drill, and to control the scenario seemed appropriate.

The inspector attended the drill critique on May 14, 1993, and noted that the licensee effectively evaluated the emergency preparedness aspects of the drill. Licensed operator performance was satisfactory, with only minor weaknesses that were noted by the licensee drill controllers. The concerns that are discussed above appeared to be well documented, with assigned corrective actions.

No violations or deviations were identified.

9. Review of Licensee Event Reports (90712, 92700, 92720)

a. Through direct observations, discussion with licensee personnel, or review of the records, the following Licensee Event Reports (LERs) were closed:

Unit 1

88-04, Revision 3 "Safety Injection Valve Failure To Open"

90-17, Revision 1 "Environmental Discrepancies At SONGS 1"

Unit 3

90-11, Revision 1 "Auxiliary Feedwater Steam Generator Feed Control Bypass Valve Inoperable"

93-01, Revision 0 "Reactor Trip Due To Rain Water On Main Generator"

The inspector reviewed the corrective actions for this event with the licensee. The licensee stated that the caulking for the sheet metal joints of the Unit 3 main generator terminal enclosure had been replaced. In addition, water flow diverters were installed on the turbine deck above the enclosure. These corrective actions appeared to be adequate to minimize the chance of repeating the event.

b. The following LER was examined and left open:

Unit 2

93-02, Revision 0 "125 VDC Battery Chargers 2B1 and 2B2 Inoperable Due to Incorrect 10 CFR Part 21 Evaluation"

On February 25, 1993, the licensee determined that battery chargers 2B1 and 2B2 were inoperable following replacement of the reactor balance circuit cards. These printed circuit cards, six per charger, had been replaced in chargers 2B1 and 2B2 on February 19, 1993, and December 15, 1992, respectively, because of fluctuations in output voltage. Following the circuit card replacement on February 19, 1993, the system engineer observed that included with each circuit card was an instruction tag which stated that "settings must be checked and adjusted in your equipment. Please refer to service manual for complete instructions." Uncertain of the meaning of this instruction, the engineer found that the vendor, Morrison-Knudsen Company, Inc., (Charter Power Systems, Inc., was the manufacturer) had notified the licensee pursuant to 10 CFR Part 21 (Part 21) in August 1989 of a potential problem with C&D battery chargers being unable to meet the required current output following replacement of printed circuit cards. The licensee's actions to test battery chargers in which circuit cards had been replaced are described in NRC Inspection Report 50-206/93-05.

The licensee determined in the LER that the root cause of the event was an inadequate evaluation of the 1989 Part 21 report because that evaluation had dispositioned the report as not applicable to the battery chargers at Units 2 and 3. The inspector reviewed the Part 21 report and the licensee's evaluation, discussed the event with the system engineer, and concurred with the licensee's determination.

The licensee had concluded that the low setting on the output current limiter of the battery chargers had no safety significance because the chargers had, in fact, been capable of performing their specified function. FSAR Section 8.3.2.1.2.2, "Battery Charger Capacity," states that the capacity is "based on the largest combined demand of all steady-state loads and the charging current required to restore the battery from the design minimum charge state to a 95% charged state within 12 hours, irrespective of the status of the plant during [the time] which these demands occur." This is as specified in Regulatory Guide 1.32. The inspector noted that the battery charger sizing calculation satisfied this commitment because charger capacity was calculated using the minimum charge state data supplied by the manufacturer and it was included in Table 8.3C, Sheet 62, of Calculation E4C-017, Revision 12, dated September 30, 1992.

To evaluate the safety significance of the event, the licensee repeated the charger capacity calculation using a less conservative initial charge state of the battery that would result from the 90 minute worst case load profile used in the battery discharge surveillance test (Table 2.1A on Sheet 14 of calculation E4C-017). This calculation demonstrated the battery charger needed only be able to put out 200, instead of 300, amperes at 125 VDC to meet the 12-hour time limit for charging the battery. The as-found output current limiter was about 270 amperes, well above the 200 ampere value needed.

The inspector reviewed the status of the corrective actions that were stated in the LER. The inspector directly observed that all in-stock replacement circuit cards were segregated in the quarantine section of the licensee's warehouse. The inspector noted that these parts had been placed on the potential control of problem equipment (COPE) list (Item No. PC 93-05) in accordance with Nuclear Engineering Safety and Licensing (NES&L) procedure SO123-XXXII-2.9 "Control of Problem Equipment." This procedure required that NCR and Part 21 report components or items be designated as potential COPE items for further evaluation. When requesting a part for installation in the plant, the cognizant engineer is required to review the COPE and potential COPE lists to ensure observance of any special restrictions or considerations.

The inspector reviewed the status of the planned corrective actions stated in the LER. The system engineer stated that Maintenance Procedure S023-I-9.14, "Battery Charger Inspection, Cleaning and Testing," would be revised to include post-installation verification and adjustment of current limiter settings. Work on this procedure revision was delayed pending receipt of an updated service manual from the vendor (anticipated by the end of April 1993). The system engineer indicated that post-installation testing would most likely be ensured by placement of the cards on the permanent COPE list and by placing a post-installation test (PIT) tag on each circuit card in stock (Regulatory Commitment Tracking (RCTS) No. 9304020).

The Independent Safety Engineering Group (ISEG) engineer told the inspector that new information recently obtained (i.e., March 1993) by facsimile from the battery charger vendor indicated that replacement reactor balance circuit cards had a recommended service life of only five years. Because most of the original circuit cards had been in service for at least ten years, the licensee was planning to replace all the circuit cards in the eight battery chargers of Units 2 and 3 during the next refueling outages, scheduled for Unit 2 in June 1993 and Unit 3 in October 1993. The ISEG engineer also indicated that the cards would be replaced every four years thereafter. The inspector discussed the five-year service life with the a vendor representative by telephone. It was learned that the service-life limit had been taken from a recent environmental qualification report prepared for Vogtle Nuclear Plant (which had more severe environmental conditions than at SONGS) and was not based on any specific design requirement from the vendor. The vendor knew of no failures of the circuit cards other than the voltage oscillation problem. The inspector, therefore, concluded that the reliability of the battery chargers prior to the next refueling outages was not a concern.

The LER also stated that the original Part 21 report would be reevaluated (RCTS No. 9304019) and that additional corrective actions and procedure enhancements as appropriate would be identified. The inspector discussed the status of this reevaluation with the responsible licensee engineer from ISEG. The reevaluation of the Part 21 report was planned for completion by May 15, 1993.

This LER remains open pending review of the licensee's corrective actions stemming from the reevaluation of the

Part 21 report and the revision of the battery charger maintenance procedure.

In addition, the inspector reviewed NES&L procedure SO123-XXX-3.3, "Reporting Problems to the NRC and Posting of Notices." Attachment 1, "Guidelines for Determining if Conditions are Reportable Pursuant to 10 CFR 21," provided four criteria that must all be satisfied before an equipment defect must be reported pursuant to Part 21. It appeared that the criteria were consistent with the requirements of Part 21 and were, therefore, acceptable.

The inspector also reviewed two licensee Quality Assurance (QA) audits of Part 21 reporting:

a. SCE QA Audit SCES-541-92, Evaluating and Reporting to the NRC, approved April 22, 1992.

   This audit included verification of compliance with Part 21 requirements by the Nuclear Oversight Division (NOD), Nuclear Generation Site, and NES&L from September 1990 through March 1992. Corrective Action Request (CAR) P-1403 was issued to ISEG and to Station Technical to address deficiencies and weaknesses in the Part 21 program associated with the review, evaluation, determination, and notification process of potential Part 21 issues related to NCRs.

b. Internal NOD Audit SCES-326-93, approved March 31, 1993.

   This audit focused on ISEG's compliance with applicable procedures from April 1991 through February 1993. Included was verification that Part 21 evaluations were being performed, documented, and that corrective actions were identified and followed-up. On page 11, this audit report stated that no Part 21 reports have been made as a result of a licensee NCR. On page 19, the report stated that procedure revisions planned in response to CAR P-1403 had not yet been completed; thus the CAR remained open. (The procedures were: SO123-XV-5, QAP N2.08, QAP N2.24, and NES&L SO123-XXX-3.3.) The inspector noted that page 46 of procedure SO123-XV-5 had been upgraded by temporary change notice No. 3-16 to require that the manager of Nuclear Oversight review each NCR which had been marked as potentially reportable under Part 21.

Both audit reports concluded that the licensee was in compliance with the requirements of Part 21.

The inspector reviewed a 1991 Part 21 report from Foxboro that originated with the licensee's identification of a new failure mode for a Spec 200 Micro N-2CCA Controller Card. This report indicated that the licensee was sensitive to Part 21 considerations when evaluating NCRs.

The inspector concluded that the licensee appeared to be adequately implementing the requirements of Part 21.

No violations or deviations were identified.

10. Follow-Up of Previously Identified Items (92701)

As part of their routine inspection efforts, the inspector reviewed open Unit 1 followup items. Consideration was given to Unit 1's permanent shutdown status, and the applicability that these items may have to Units 2 and 3.

a. (Closed) Followup Item (50-206/91-30-01), "Residual Heat Removal Flow Rates for Mid-loop Operations."

This followup item tracked the concern that Unit 1 residual heat removal (RHR) pumps may not have adequate minimum flow when two pumps were operated in parallel during reduced inventory (mid-loop) and reduced flow conditions. The licensee evaluated this concern, determined that it was applicable only to Unit 1, and that procedural controls could be implemented to ensure that the pumps would maintain minimum flow in these conditions. However, because Unit 1 was permanently shutdown and defueled, the RHR system was no longer needed and the enhancements were not necessary. Therefore, this item is closed.

b. (Closed) Followup Item (50-206/91-30-02), "Adequacy of Installed Pump Miniflows."

This followup item tracked the concern that parallel pumps that shared a common minimum flow line may not have adequate minimum flow when both pumps were operated at the same time. The licensee evaluated this concern for all three units and determined that the Unit 1 RHR pumps were the only safety-related pumps susceptible to this problem. However, because Unit 1 was permanently shutdown and defueled, the RHR system was no longer needed and the enhancements were not necessary. Therefore, this followup item is no longer significant and is closed.

c. (Closed) Followup Item (50-206/92-12-04), "Environmental Qualification of Motor-Driven Auxiliary Feedwater Pumps."

This followup item tracked the concern that a commitment made in Unit 2 LER 90-15 to revise licensing documents was not performed by the specified completion date. The inspector reviewed the licensee's root cause analysis of this concern and the associated procedural changes that were implemented to meet the corrective action recommendations. The licensee's corrective actions appeared to establish a satisfactory procedural mechanism for all three units (i.e., improved communications) to ensure that future similar problems, if any, will be promptly identified and corrected. This item is closed.

d. <u>(Closed) Followup Item (50-206/92-29-01), "Ensure Monthly Check of Auxiliary Feedwater System Supports."</u>

This followup item tracked the concern that Unit 1 AFW piping supports, running through a trench with no drainage, were often covered with water. This water could have obscured inspection of the piping supports. The licensee evaluated this concern and revised procedure SO1-12.9-11, "Miscellaneous Surveillances," to include a monthly AFW pipe trench inspection which provides guidance to pump out excessive water in the trench. The inspector noted that this procedural change appeared to satisfactorily ensure that the trench would be routinely inspected. This item is closed.

e. <u>(Closed) Followup Item (50-206/92-06-01), "Long-Term Post-LOCA Containment Pressure/Temperature CONTRAN Analysis."</u>

This item identified the need for additional review of an inconsistency between an assumed power limit (92%) used in the post-Loss of Coolant Accident (LOCA) long-term cooling analysis for Unit 1 and the power level at which Unit 1 operated (94.5%) on February 11, 1992. The results of the analysis had not been communicated to the appropriate organizations of the licensee's staff. This event was documented in NCR 92020164 dated February 14, 1992.

The licensee issued RCE 92-008, "Evaluation of Inconsistency Between Unit 1 Post-LOCA Long-Term Cooling Analysis and Power Operating Levels," dated June 1, 1992. The licensee determined that, although results of the power level limitation were recognized and documented in the calculation reviews, the restriction was not communicated to appropriate organizations (e.g. Operations) or understood by the responsible engineer. In addition, the Nuclear Fuels Management Analysts, responsible for design calculations, were unaware of any procedural requirement for notifying Station organization of changes in operating parameters. The inspector reviewed licensee corrective actions and noted the following:

- To ensure that future calculation changes would be routed to appropriate organizations, the licensee added a check-list to the procedure used in the preparation of calculations. The inspector verified that Form 26-404, "Site Programs Impact Assessment," had been developed and incorporated into NES&L procedure SO123-XXIV-10.15, "Preparation, Review, and Approval of Facility Change Evaluations (FCEs) for SONGS 1, 2 & 3." In addition, the inspector noted that Problem Reports SO-014-92 and SO-016-92 were issued by the licensee as a result of an assessment of the Design Basis Documentation operating instruction review process. These Problem Reports resulted in NES&L procedure SO123-XXIV-7.15, "Preparation and Verification of Design Calculations." The inspector considered these procedural changes adequate.

- Training was provided to the Nuclear Analysts responsible for calculations controlled by procedure SO123-XXIV-7.15. This training was given to 15 individuals in the Nuclear Fuels group (12 individuals attended a class instructed by NES&L personnel and 3 were given a reading assignment to complete). The inspector considered this training to be appropriate.

The inspector considered the licensee's corrective action adequate. This item is closed.

f. <u>(Closed) Followup Item (50-361/93-05-04), "Latching Relay Failures - Units 2 and 3."</u>

This item identified the need for additional review of the licensee's root cause evaluation and corrective actions for the failures of Square D, Type LO, latching relays in Units 2 and 3. A total of five failures of this type of latching relay occurred between March 1992 and March 1993. Four of the five failures were associated with AFW discharge to steam generator 2-E088's electro-hydraulic isolation valve, 2HV4714. The fifth failure affected operation of spent fuel pool cooling pump P009. The inspector reviewed the licensee's final root cause analysis for these failures, documented on NCR 93020069 dated April 15, 1993, and discussed corrective actions taken by the licensee with plant technical support personnel.

No definitive cause was determined for the first two relay failures which occurred in March and May 1992. Each time, the licensee was unable to repeat these failures. However, when the relay failed the second time, it was replaced by a new, but similar, Type LO relay from the warehouse. The third failure occurred in September 1992 with the replacement relay for the May failure. At this time, the licensee sent the failed relay to the manufacturer, Square D, for their analysis. Square D was unable to reproduce an electrical malfunction whereby this relay would fail to latch.

It was not until the fourth failure of the relay, occurring in February 1993, that an aggressive analysis of both the September and February failed relays and three additional relays from the warehouse stock identified that a potential misadjustment problem was the probable cause for the relay failures. This misadjustment problem appeared to be confined to a specific lot of relays manufactured in November 1981, known as Lot 99.

The fifth failure occurred in March 1993 and related to spent fuel pool cooling pump P009. However, upon examination by the licensee and the manufacturer, the failure was determined to be due to a warped plastic component of the relay manual operator. This warpage appeared to be the result of age-related material degradation.

Following the SFP cooling pump failure, the licensee identified the location and function of all Type LO latching relays. A total of 46 relays were identified and targeted for replacement in both Units. The inspector reviewed the licensee's plans regarding replacement of the Type LO relays with newer Type XO relays. The licensee's plans included first replacing those relays found to be from the suspect Lot 99 and those whose lot number could not be determined. These replacements were to occur during the upcoming refueling outages for both Units.

The inspector questioned whether other relays not in the suspect lot should also be replaced sooner, rather than later, based upon the safety function they perform. On this basis, the licensee committed to also replace those relays associated with the diesel generator fuel oil transfer pumps and the emergency chilled water pumps at the earliest scheduled outages for those pieces of equipment.

The inspector concluded, although the licensee's actions in determining the cause of the relay failures and subsequent corrective actions could have been more aggressive, that the actions taken overall were both adequate and reasonable given the specific set of circumstances.

No violations or deviations were identified.

11. <u>Exit Meeting</u>

On May 21, 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.