U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos. 50-206/89-24, 50-361/89-24, 50-362/89-24

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
Irvine, California 92718

Facility Name: San Onofre Units 1, 2 and 3

Inspection at: San Onofre, San Clemente, California

Inspection conducted: July 30 through September 9, 1989

Inspectors: C. W. Caldwell, Senior Resident Inspector

A. L. Hon, Resident Inspector

C. D. Townsend, Resident Inspector

Approved By: M. M. Mendonca 10/10/89
P. H. Johnson, Chief — Date Signed
Reactor Projects Section 3

Inspection Summary

Inspection on July 30 through September 9,1989 (Report Nos. 50-206/89-24, 50-361/89-24, 50-362/89-24)

Areas Inspected: Routine resident inspection of Units 1, 2 and 3 Operations Program including the following areas: operational safety verification, radiological protection, security, evaluation of plant trips and events, monthly surveillance activities, monthly maintenance activities, engineered safety feature system inspection, independent inspection, licensee event report review, followup on items of noncompliance, and followup of previously identified items. Inspection procedures 30703, 60710, 61726, 62703, 71707, 71710, 90712, 92700, 92701, 93702 were covered.

Safety Issues Management System (SIMS) Items: None

Results:

General Conclusions and Specific Findings:

Concerned were raised over recent operational problems that have occurred in the last few months at San Onofre. In particular, problems occurred with identifying control room emergency air cleanup system boundaries in Unit 2, control of reactor power during partial insertion of a part length control element assembly in Unit 2, understanding the transient insertion limit curve in Unit 2, restoration of an atmospheric dump valve to automatic operation in Unit 2, and the occurrence of a negative axial shape index that led to a manual reactor trip in Unit 2. These problems are considered to be attributable to training and formality in the conduct of normal operations.

A Review of the licensee's quality oversight programs was performed by Region V personnel. The results of that review indicated that significant enhancements have been made in the quality oversight area.

Significant Safety Matters: None

Summary of Violations:

Two violations were identified during this inspection period. The first violation concerned the failure to declare equipment inoperable due to delinquent surveillance and take actions as specified by the Technical Specifications (Paragraph 4.a). The second violation was related to the lack of control over temporary cables routed through a control room emergency air cleanup system (CREACUS) door in Unit 2 (Paragraph 6.d).

Open Items Summary:

During this report period, two new followup items were opened and six were closed; one was examined and left open. In addition two unresolved items were identified during this inspection period.

DETAILS

1. Persons Contacted

Southern California Edison Company

*H. Ray, Vice President, NES&L
*R. Bridenbecker, Vice President and Site Manager
*H. Morgan, Station Manager
*D. Shull Jr., Nuclear Oversight Manager, NES&L
*K. Slagle, Deputy Station Manager
*R. Krieger, Operations Manager
*L. Cash, Maintenance Manager
*M. Merlo, Nuclear Design Engineering Manager, NES&L
*K. Johnson, Acting Technical Manager
P. Knapp, Health Physics Manager
D. Peacor, Emergency Preparedness Manager
P. Eller, Security Manager
*D. Herbst, Quality Assurance Manager, NES&L
D. Stonecipher, Quality Control Manager, NES&L
C. Chiu, Assistant Technical Manager
J. Schramm, Operations Superintendent, Unit 1
V. Fisher, Operations Superintendent, Units 2/3
J. Patterson, Assistant Maintenance Manager, Unit 1
R. Santosuosso, Assistant Maintenance Manager, Units 2/3
*R. Plappert, Compliance Manager
*D. Brevig, Supervisor, Onsite Nuclear Licensing

San Diego Gas and Electric Company

*D. Brickson, Senior Engineer

*Denotes those attending the exit meeting on September 8, 1989.

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

On August 3, 1989, a low reactor coolant system flow (Channel "C") trip occurred. At the time, no maintenance work or surveillances were in progress. The licensee initiated a root cause investigation and determined that the cause of the trip was a ground on the Channel "C" flow transmitter cable. The affected portion of the cable was replaced and the Unit was restarted on August 6. The Unit operated at power for the remainder of the period.

Unit 2

The unit operated at power until September 2, 1989 when it was shutdown for the Cycle V refueling outage. The shutdown was initiated a week earlier than originally planned because a local leak rate test (LLRT) on the refueling canal was due and it was considered prudent to perform the LLRT with the Unit shut down. During performance of the shutdown the reactor was manually tripped at 25% power instead of 15% (which is specified in the shutdown procedure). This was due to a difficulty in controlling the axial shape index (ASI) while the reactor was being shut down.

Unit 3

The unit operated continuously at power for 62 days toward the end of this inspection period.

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. Operator Performance for Abnormal Plant Condition (Unit 2)

On August 4, 1989 the unit was at 99.6% power. While the operator was attempting to move the part length control element assembly (PLCEA) for ASI control, PLCEA #32 slipped to 90" position. The slipped control element assembly (CEA) resulted in it being more than 19 inches misaligned from other CEAs in its group. Thus, the Unit entered into Technical Specification 3.1.3.1 Action c., which specifies that the operators continue to realign the CEA, initiate power reduction in 15 minutes, and reduce reactor power by 30% in one hour.

The operators calculated the boration needed for 30% power reduction to be approximately 840 gallons. The operators conducted a tailboard (briefing) for the power reduction and elected to inject 150 gallons in 5 successive batches of 20 gallons and one batch of 50 gallons. This action resulted in a slower power reduction. At 5:56 a.m., the operator inserted Group 6 CEAs to 120" which is the Long Term Steady State Insertion limit. At 6:01 a.m., reactor power was at 80% (20% power reduction) and decreasing. However, the Technical Specification Action of 30% power reduction at that time was not achieved.

The operator's delay in boration was probably influenced by the following factors:

- The previous day, the same operating crew used 200 gallons of borated water to reduce the reactor power by 20%. Thus, they believed that the 840 gallons was too much and that the calculation was incorrect. (However, during that evolution, the power was reduced slowly and xenon was used to aid in the power reduction).

- The reactor core was at the end of life and the boron concentration prior to the event was at 110 ppm. The operators were concerned that an excessive power reduction could start a xenon transient which could not be overcome (by dilution) and result in a complete reactor shutdown.

- The operators previous experience with the slow dilution effect led them to overestimate the effect of xenon buildup. They observed that a dilutions effect on power was much slower than a boration. (In reality, dilution starts with the addition of demineralized water to the volume control tank before it reaches the charging pump suction, whereas borated water is added directly to the charging pump suction during a boration).

- The Technical Specification states that if the power reduction action is not performed, be in at least Hot Standby within 6 hours. This led them to believe that if the 30% power reduction in one hour specification was not met, then they could rely on the unit shutdown action. Unit shutdown was not accomplished, since the rod control malfunction was corrected and the part length rod withdrawn within the action statement required time limit.

Thus, considering the above three factors, the operators attempted only to meet the power reduction specification instead of trying to stay within it.

Prior to this event, Operations management noted that the operators could not always maneuver the Unit (both at the simulator and in the plant) as precisely and proficiently as expected with such events as a boration. Thus, a number of corrective actions were initiated to improve the operator's proficiency. The inspector expressed concern about the operator's performance in normal plant evolutions and will continue to evaluate the licensee's improvement effort.

b. <u>Equipment Storage Inside Of Unit 1 Control Panels</u>

The inspector noted on several tours through Unit 1 (with station operators) that fuses, fuse pullers, lightbulbs, and other equipment were stored within many of the control panels. The inspector questioned whether storage of equipment inside these panels was appropriate and if the panels needed to be evaluated for seismic considerations. This concern was discussed with the licensee who indicated that they would evaluate this concern. This item will remain unresolved pending the licensee's review (See Paragraph 7).

No violations or deviations were identified.

4. <u>Evaluation of Plant Trips and Events</u> (93702)

a. <u>Failure To Comply With Technical Specification 3.0.3 Requirements in Unit 2</u>

On August 22, 1989, Edison Maintenance personnel were reviewing the surveillance frequencies for various Technical Specification (TS) related equipment when it was noted that the Unit 2 pressurizer level instruments may have exceeded the allowable 18 month time limit. (This review was associated with TS amendment requests to change the 18 month surveillance frequencies to 24 months to coincide with the refueling cycle). Further evaluation of these instruments indicated that they had not exceeded the allowable surveillance time. However, as a result of concerns over surveillance frequencies, the licensee initiated actions to identify if there were any other equipment that could have exceeded the allowable TS surveillance frequency.

At 1:00 p.m. on August 24, 1989, Maintenance personnel found that the four loss of voltage (LOV) relays for the "A" Train 4160 VAC emergency vital bus had exceeded the allowable 18 month channel calibration surveillance interval (plus the 25% extension). Operations was notified that the surveillance had been overdue since August 15, 1989 at approximately 1:30 p.m. At that time, the system was declared inoperable and a limiting condition for operation action requirement (LOCAR) was generated. However, the decision was made to continue power operation and complete the surveillance under the provisions of Generic Letter (GL) 87-09, "Sections 3.0 and 4.0 of the Standard Technical Specifications (STS) on the Applicability of Limiting Conditions For Operation And Surveillance Requirements." In particular, the GL indicated that up to 24 hours would be considered acceptable to complete a missed surveillance before commencing with the action requirements specified in the TS.

In the past, this surveillance was always performed while the unit was in Mode 5 or 6 and the entire safety train was removed from service. In order to conduct this test on-line, the licensee modified the test procedure and performed a safety analysis. The licensee commenced the channel calibrations later that evening. Region V discussed this problem with Edison management on August 25, 1989 and pointed out to the licensee that an approved TS amendment was required in order to use the provisions of the GL. As a result of that discussion, the licensee ordered the plant into TS 3.0.3 at 11:15 a.m. on August 25. However, the surveillance was completed at 12:02 p.m. that day and shutdown of the Unit was not necessary.

TS 3.3.2 states that the engineered safety features actuation system (ESFAS) instrumentation channels shall be operable in Mode 1 with 3 channels per bus as the minimum channels operable and 2 channels per bus as the number of channels to trip. With the condition identified, (all channels inoperable) TS 3.0.3 was applicable. However, Operations used the provisions of the GL and did not declare a TS 3.0.3 entry. This was apparently due to a lack of understanding on the part of Operations, that the GL was a basis for requesting a change to the TS and not for excusing deviation from them.

The failure to comply with the provisions of the TS is a violation (50-361/89-24-01).

The inspector also expressed the concern to licensee management that control of the surveillances during the transition period from 18 month to 24 month frequencies could have been handled more effectively to prevent this from becoming a last minute concern as the surveillance came due. A similar problem led to the shutdown of Unit 2 a week prior to the scheduled shutdown for the refueling outage. This was due to a LLRT that was pending on the refueling canal.

b. Unit 1 Trip On Low Reactor Coolant Flow

On August 3, 1989, a low reactor coolant system flow (Channel "C") trip occurred. At the time, no maintenance or surveillances were in progress. The licensee initiated a root cause investigation and determined that the cause of the trip was a ground on the Channel "C" flow transmitter cable. The inspector discussed this trip with the licensee relative to the concerns discussed in Paragraph 5.d of this report. In particular, the licensee did not have a program to perform periodic ground testing of equipment in the plant protective system (PPS). As a result of the inspector's concerns, the licensee committed to perform ground checks of PPS equipment in Units 2 and 3 by the dates specified in Paragraph 5.d. In addition, the need for a periodic ground testing program in Unit 1 will be evaluated by the licensee.

c. Unit 2 Manually Tripped Due to Excessive ASI During Plant Shutdown

On September 1, 1989, while reducing power for the planned Cycle 5 refueling outage, the operators experienced difficulties in controlling the ASI. As a result, the operators manually tripped the reactor at 25% power instead of 15% power (which was specified in the normal shutdown procedure).

During reactor shutdown, as the reactor power continued to decrease, the ASI became more negative (i.e., the relative power on the upper part of the core was higher than lower part). An engineering evaluation confirmed that this was partly due to the fact that, as expected, the reactor coolant system T-hot decreased faster than T-cold as the reactor power was reduced. This reactor coolant temperature change caused the local moderator temperature coefficient (MTC) to change which, in turn, resulted in a reactor local power change. This effect compounded itself as the peak power shifted to the top of the core. In particular, it caused more xenon burnup and resulted in a further power shift to the top of the core. An engineering evaluation indicated that this effect is more prominent for an end-of-life 24 month fuel cycle core. Because of prolonged operation, there was more fuel depletion in the center of the core which resulted in a peak at the top and a peak at the bottom verses the neutron flux cosine profile which is normally experienced.

Therefore, as the reactor power decreased, the peak shifted significantly to the top of the core which required prompt operator action to insert CEAs in order to control the ASI.

The shutdown was initiated at 19:00 on September 1, 1989 from 85% power. The operator reduced the reactor power at 5% per hour by boration and attempted to maintain ASI close to zero with the part length CEAs and the group 5 and 6 CEAs. The core analysis engineer supervisor was in the control room to advise the shutdown evolution until midnight. The operators attempted to control the ASI by inserting the control rods. However, the operator's action was limited by the CEA insertion limit. The operators did not insert the PLCEA beyond 115 inches (with reactor power at 50%) because it was not recognized that it was allowed under the transient insertion limit. As a result, ASI continued to become more negative. At 5:07 a.m., core protection calculator (CPC) channel "D" tripped on an ASI limit. The operators had not previously experienced or been trained for these plant conditions. At 5:45 a.m., channel "A" was approaching the trip set point. However, the reactor operators attempted to improve the ASI without success and had to manually trip the reactor. The standard post trip and recovery actions were taken without any significant complications.

A post trip meeting was conducted the following day to determine the preliminary cause of the trip and to identify any anomalies for further evaluation. Followup actions were also identified for further evaluation and correction. The inspector observed the meeting and found it to be a thorough review of the event.

From the preliminary assessment, the licensee believed this phenomenon was attributable to the 24 month core at end-of-life. This was the first time that this has been performed at San Onofre. Additional guidance to the operator was necessary to assure a smooth shutdown under similar conditions in the future for both Unit 2&3. The inspector will evaluate the licensee's final assessment and corrective actions when the LER is submitted. This item is closed. (50-361/89-24-02)

Within this area inspected, one violation was identified.

5. 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 1)

SO1-12.3-27	Monthly Sphere Isolation Channel Test
SO1-V-5.6	Neutron Noise Monitoring
SO1-II-1.1	Reactor Plant Instrumentation Testing (31 Day Interval)

b. Observation of Routine Surveillance Activities (Unit 2)

S023-I-2.5 Surveillance Testing of Main Steam Safety Valves.

c. Observation of Routine Surveillance Activities (Unit 3)

S023-II-1.11 Containment Post LOCA Hydrogen Concentration Monitoring System Channel "A" Calibration

S023-XXV-4.4 Monthly Channel Surveillance on Main Steam Line Radiation Monitor

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 1)

M089080340000 Investigation of Ground on Unit 1 Reactor Coolant System Flow Transmitter

M089051740000 Charging Pump Maintenance

M089062795002 Troubleshoot Main Feedwater Flow Oscillation on S/G "B"

b. Observation of Routine Maintenance Activities (Unit 2)

M089080814000 Plant Protection System Bistable Card Variable Setpoint Card Calibration

M089083159000 Performing Functional Test of LOV's Relays

c. Observation of Routine Maintenance Activities (Unit 3)

M089031458000 Emergency Chiller E-335 Overhaul

d. Improper Temporary Cable Installation Through CREACUS Boundary

On August 15, 1989, the inspector found door AC236 tied fully open with five temporary power cables (three single conductor AWG #2 and two 3 conductor AWG #8 cables) installed through the door. This door was part of the control room emergency air cleanup system (CREACUS) boundary and was required to be closed at all times (except for personnel and equipment passage). The inspector discussed the status of this door with control room personnel and found that there was a Technical Specification fire barrier impairment control (hourly fire patrol) in place for door AC236 since it is also a fire door. However, there was no CREACUS boundary impairment control established. In response to the inspector's finding, the Control Room Supervisor requested the electricians to remove the temporary cables. These were removed in approximately 15 minutes and the door was subsequently closed.

The inspector reviewed the maintenance order (MO)89071884000 for the installation of these temporary cables. It did not identify door AC236 for the routing of cables as a CREACUS door nor did it specify the appropriate actions to be taken per maintenance procedure SO123-I-1.7, "Maintenance Order Preparation, Use, and Scheduling." Attachment 6 to this procedure specified that cables through the CREACUS boundary doorway would have a quick disconnect device in the vicinity of the breached doorway. It also required that the MO specify that an individual be continuously stationed at the door ready to remove the obstruction and closed the door as directed by Operations or Security personnel. These measures were not included in the MO due to the oversight that AC236 was a CREACUS door, as well as, a fire door.

The inspector interviewed the planner, the Equipment Control staff, the Assistant Control Operator who authorized the MO and the electricians who were involved in the installation of these cables. The inspector found that there was a general lack of clear understanding of the significance of the CREACUS doors and how they differed from fire doors. This lack of understanding resulted in the planner's oversight not being identified by others in the review and implementation process.

In response to the inspector's concerns, the licensee initiated a Maintenance Division Incident Investigation. The finding of this investigation was similar to the inspector's assessment of the concerns. The licensee identified corrective actions to prevent recurrence. In addition, the licensee was evaluating the operability of the CREACUS with the condition found by the inspector. Furthermore, the licensee will establish the time required to secure the door for the CREACUS to be considered operable. This evaluation was scheduled to be completed on or about September 15, 1989.

Failure to follow procedure to implement compensatory action to maintain CREACUS boundary appears to be a violation (50-361/89-24-03).

e. ASCO Solenoid Valve Failures (Unit 1)

On August 23, 1989 the charging system loop "A" control valve (CV-304) failed to close when its actuator was deenergized. The actuator was an ASCO solenoid valve which, in turn, failed to operate. The FSAR describes CV-304 as a safety related component that is required to shut on a safety injection actuation signal. Upon investigation into this failure, the inspector found a history of problems related to ASCO solenoid valves at San Onofre and at other licensed facilities as indicated below:

- April to September 1987 - Unit 1 had four ASCO solenoid valves fail a total of five times. LER 87-016 was submitted on December 10, 1987, which explained valve failures on independent trains of multiple systems as a result of ASCO solenoid valve problems. It was concluded that the presence of a thin hard film formed between the top of the slug and the slug housing was the cause for these solenoid valve failures. In this LER, the licensee committed to submit a supplemental LER when the root cause of the ASCO valve failures was known.

- February 17 1988 - The Supplier Quality Assessment Section wrote a letter to ASCO identifying the thin hard film as the root cause of the valve failures experienced at San Onofre. The licensee asked ASCO to review their manufacturing processes to determine the cause of the film.

- March 11, 1988 - ASCO responded to the above letter by indicating that they apply a thin coat of Dow Corning 550 lubricating oil on some O-rings, the core face, and on the stem area of the subject valves. At this time, some licensee personnel assigned to this project believed that the Dow Corning 550 lubricant was the root cause of the valve failures. A letter was issued explaining ASCO's assessment on April 22, 1988 which also stressed that the Dow Corning 550 lubricant should be tested.

- April 1988 - The Nuclear Engineering & Construction (Projects) organization installed ASCO solenoid valves for CV-304 and CV-305.

- June 23, 1988 - NRC Information Notice 88-43, "Solenoid Valve Problems," was issued which identified ASCO solenoid valve failures at the Perry Plant which appeared to be caused by the Dow Corning 550 lubricant. The Dow Corning product literature indicated that this product gels at 200°C in 14 months and that the time lessens exponentially as temperature increases.

Subsequent to this time, two ASCO solenoid valves have failed at San Onofre in a similar fashion. The most recent one (effecting CV-304) was an ASCO solenoid valve that had been installed by the licensee's Projects group, as described above.

As a result of this investigation, the inspector had the following concerns:

- The Projects organization installed the ASCO solenoid valve that serves as the actuator for CV-304 even though it was known by other Edison personnel that the ASCO product could fail under high temperature conditions similar to this application. This was despite the fact that the licensee has programs such as Control Of Problem Equipment (COPE) and NCR's.

- A supplemental LER to LER 87-016 was not submitted to the NRC when it was believed that the Dow Corning 550 lubricant was the root cause of the solenoid failures.

- These failures were not evaluated for 10 CFR Part 21 applicability.

- It did not appear that the licensee's experience review program provided the necessary information to the Projects organization concerning ASCO solenoid valve problems such as NRC Notice 88-43.

- There may be other solenoid valves installed in the plant which could have the potential to cause similar problems due to apparent inadequacies noted above.

The inspector discussed these concerns with the licensee. As a result of these discussions, the quality oversight organization initiated an investigation to determine the root cause of the ASCO solenoid failures and to address the inspector's concerns. This item will remain unresolved pending completion of the licensee's evaluation (50-206/89-24-01).

Within this area inspected, one violation was identified.

7. <u>Engineered Safety Feature Walkdown</u> (71710)

The inspector walked-down the Class 1E 125 VDC systems at both Unit 2 and 3. Procedure SO23-6-15 "Operation of 125 VDC Systems" and related drawings were used to verify the system alignment.

The inspector found that the 125 VDC systems were properly aligned electrically. However, the inspector noted most of the battery chargers and inverters had loose fasteners on the panel doors. This item was brought to the attention of licensee management and the inspector questioned if the original seismic qualification configuration considered those screws to be securely fastened and the impact of the condition found. In response to this concern, the oncoming shift operators were instructed by management to tighten any fasteners that were found loose during plant tours. In addition, the licensee indicated that the practice of storing fuses and fuse pullers in safety related cabinets was not within the established program and will be discontinued (See Paragraph 3.b). Regarding the safety significance of the conditions found, the licensee was assessing the seismic qualification of the battery chargers and inverters with loose fasteners and equipment stored inside the panels that were found in Unit 1. This item remains unresolved pending additional information on the licensee's seismic qualification determination. (50-361/89-24-04)

No violations or deviations were identified.

8. Independent Inspection

a. Licensed Operator Medical Certification Audit

The inspector audited the medical certifications of the licensed reactor operators for all three units. A 25% sample of the total 46 licenses for Unit 1 and 103 licenses at Units 2 and 3 were reviewed. The inspector found most operators current with respect to the b[illegible]al certification requirement. However, there were 12 licensed reactor operators who had their last medical certification more than two years ago and the recertification was scheduled for the second anniversary of their license issuance date. Among them, four operators were licensed and performed duties in the control room. The inspector discussed these findings with the licensee and the licensee responded to the inspector's concern and completed these medical examinations on August 31, 1989. In addition, the licensee committed to using the actual medical examination date for biannual recertification instead of using the license date for all licensed personnel.

b. (Closed) Verification Of Quality Assurance Request Regarding Diesel Generator Fuel Oil (TI 2515/100)

The purpose of this Temporary Instruction was to assess the licensee's program for maintaining proper quality of the emergency diesel generator (EDG) fuel oil at the San Onofre site. The inspector examined the licensee's program for receipt, testing, transfer, and storage of the fuel oil and for maintenance of filters and other related components. No discrepancies were identified with the licensee's program.

This item is closed for Units 1, 2, and 3.

c) (Closed) Anchor Darling Model S350W Swing Check Valves Usage (NRC Bulletin No. 89-02)

The subject NRC Bulletin was issued to inform the industry of a generic problem with Anchor Darling model S350W swing check valves. In particular, internal bolting failure has occurred due to stress corrosion cracking.

The inspector discussed this Bulletin with the licensee's Independent Engineering Safety Group (ISEG) and noted that this model check valve has not been used at San Onofre in any of the units. As a result of the licensee's evaluation, this item is closed.

No violations or deviations were identified.

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

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

Unit 1

89-14	Battery Charger Cross Train Alignment Deficiency
89-16	Fire Protection Spray System Plugged Nozzles
89-17	Spurious Reactor Trip Due To Nuclear Instrumentation Noise
89-18	Technical Specification 3.0.3 Entry To Test A Containment Spray Pump

Unit 2

89-12	Foxboro Transmitter Mounting Configuration
89-12-01	Discrepancies Caused by Environmental Qualification and Design Control Program Weakness.
89-11	Technical Specification 3.0.3 Entry To Replace Plant Protective System Power Supply
88-36	Spent Fuel Handling Machine Operation With Cleanup Units Inoperable
88-31 88-31-01	Technical Specification Criterion For Control Element Assembly Drop Time Exceeded

Unit 3

89-07	Spurious Recirculation Actuation Signal During Surveillance Testing
89-01 89-01-01	Reactor Trip On Low Steam Generator Level Due To Partial Loss Of Power To Feedwater Controller

The inspector reviewed these LERs and the licensee's root cause assessment and found them to be satisfactory.

No violations or deviations were identified.

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

a. (Closed) Followup Item (50-206/89-18-02), "Loss Of Feedwater Resulting In Boiling A Steam Generator Dry"

This item discussed a concern with the Unit 1 reactor trip on a loss of main feedwater to one steam generator (S/G) in which that S/G was boiled dry. In particular, the inspector was concerned that the licensee's root cause evaluation indicated that this event would not be counted as a thermal cycle, that the procedure may have not provided the detailed guidance necessary for the operators to respond to a loss of main feedwater (MFW) to prevent boiling a S/G dry, and that a power excursion could have occurred if MFW had been restored to the dry S/G.

The licensee evaluated the inspector's concerns with the following results:

- The Westinghouse analysis of boiling a S/G dry was a one time analysis for each S/G. Both "A" and "B" S/G's have been boiled dry once. These events will be considered as a thermal cycle on the two S/G's and additional analyses will be performed to evaluate the effect of boiling a S/G dry for a second time. In addition, the licensee is working with Westinghouse to determine the amount of thermal cycles available on the S/G's.

- The operating instruction, SO1-2.3-5, "Abnormal Steam Generator Water Levels," was ambiguous in that it simply stated that the reactor and turbine should be tripped if the level in any one S/G is less than 10% narrow range with no sign of recovery. The licensee will revise the procedure to provide more definitive guidance for low levels in the S/G's.

- If MFW had been restored to the dry S/G, this event would have been bounded by a similar analysis (inadvertent start of a second MFW pump). In either case, the plant would be protected by an overpressure or departure from nucleate boiling (DNBR) reactor trip

The inspector considered that the licensee's intended efforts appeared adequate. This item is closed.

b. <u>(Closed) Followup Item (50-362/89-06-03) Painting Activities on Redundant Safety Systems</u>

During a previous inspection, the inspector found that the licensee's maintenance crew masked one of the auxiliary feedwater pumps for painting while the redundant train was removed from service for motor overhaul. One of the fire detectors was also masked. In response to the inspector's finding, the licensee committed to develop a comprehensive procedure to control painting activities on or near safety related equipment.

During this inspection, the licensee developed Maintenance Procedure SO123-I-1.11 "Site Painting Procedure" to assure that the control room is informed before painting begins on equipment. Furthermore, this procedure also established cautions to ensure that safety functions are not impaired by painting activities. The inspector reviewed this procedure and found it to be satisfactory. Thus, this item is closed.

c. <u>(Closed) Followup Item (50-362/87-15-01), "HPSI Cold Leg Flow Indicator"</u>

As a result of a reactor trip on June 21, 1987 (Unit 3), a high pressure safety injection actuation occurred. During the licensee's post trip review for this event, it was determined that the high pressure safety injection (HPSI) flow indicator in one of the four cold leg injection lines did not indicate flow. Subsequent investigation indicated that a zero shift in the flow transmitter's calibration existed. In addition, this type of failure occurred previously.

For corrective action, the licensee installed a new transmitter in the 3FT-0341-2 location and verified that this transmitter read correctly (as expected within 25 gpm). The root cause of the malfunction was determined to be premature wear-out of the component, resulting in decalibration of the flow transmitter. The inspector noted that the root cause analysis techniques currently applied to failures such as this was not in place in 1987. With the current root cause analysis techniques in place, repeated common cause failures should be effectively eliminated. The inspector considered that the licensee's actions on this matter were appropriate. Therefore, this item is closed.

d. (Closed) Followup Item (50-362/89-06-01), "Technical Specification Violation And Failure To Report"

On August 15, 1988, the licensee conducted CEA drop time testing. A new test method was used which measured the elapsed time from when the trip signal initiated to when the CEA was 90% inserted. The old method calculated the time from when the breaker was de-energized to when the CEA was 90% inserted. As a result of the change, the new test method revealed an additional 0.4 second delay due to the time it took the electromagnetic decay of multiple CEA coils tied together when the reactor trip breakers were opened. The licensee anticipated this problem and proposed a TS amendment to raise the CEA drop time requirements from 3.0 to 3.2 seconds. However, the licensee did not reevaluate the CEA drop times from previous fuel cycles taking this 0.4 second delay into account. Further evaluation revealed a CEA which did violate the old TS limit. In addition, the licensee failed to report this to the NRC within 30 days as required.

The licensee realized that the failure to report the control rod drop times as a TS violation was a judgement error in determining the reportability of this item. On August 10, 1988, License Amendment Numbers 65 and 54 for Units 2 and 3, respectively, increased the drop times from 3.0 to 3.2 seconds. Cognizant personnel believed that the reportability of the CEA drop times need only be viewed in the context of the then current (i.e., August 18, 1988) TS. As a result of this problem, the licensee instructed the staff to report events based on the rules in place at the time of discovery even if modifications to those rules existed at the time of the report. Full compliance was achieved when LER 2-88-031 was submitted to the NRC. The inspector considered the licensee's efforts appeared acceptable on this matter. This item is closed.

e. (Closed) Followup Item (50-362/89-06-02), "Fire Protection Door Impairment"

On March 29,1989, the inspector identified three Technical Specification fire doors that were left open at the 8 foot level in the Safety Equipment Building. However, no fire impairment compensatory actions had been established. The three doors were recently transferred to the fire barrier seal list and fire door signs were attached to the doors.

In a response to the Notice of Violation dated July 12, 1989, the licensee indicated that they were unable to determine who left the doors open and how long they had been open. Also in that response, the licensee disagreed with the NRR interpretation that the action statement is invoked at the time of the discovery. They believed that they should have been allowed the opportunity (one hour per TS) to correct the condition before it was declared a violation and did not consider that this incident constituted a TS violation. Notwithstanding, the licensee considered that fire doors were an important safeguard and implemented the following measures as of March 29, 1989:

- Fire Doors are checked daily.
- Annual training stresses the importance of fire doors.
- The Station Manager issued a letter stressing the importance of keeping fire doors closed.
- Fire door signs were moved from a position next to the door to being attached directly on the door.
- Fire doors were painted red to highlight their importance.

The inspector concluded that these corrective actions were acceptable, although the NRC still considers this to have been a violation. Based upon the licensee's corrective actions, this item is closed.

f. (Closed) Followup Item (50-361/87-13-01), "Calibration Of Nuclear Instrument Startup Rate Circuits (Units 2&3)"

The item discussed the inspector's examination of the licensee's procedures for conducting calibration of startup rate circuits associated with the nuclear instruments in Units 2 and 3. The inspector noted that the licensee performed single point calibrations as recommended by the vendor's calibration procedure. The inspector considered that standard industry practice required a five point calibration check for other types of circuits and requested the licensee to provide a basis for performing only a one point calibration check of the startup rate circuit.

Calibration of the start-up rate circuits was detailed in procedures SO23-II-5.1, 5.2, 5.3, and 5.4 for the four safety channels. The calibration method was extracted directly from General Atomic Vendor Information (Reference Specification ATP-152). The one point calibration check ensures the correct starting points, ending points, and linearity of the circuits. Verification of this circuit was made by placing the channel in the calibrate position generating a ramp of 0-3.50 VDC for a 60 second period. This check was also performed according to vendor instructions.

The inspector noted that the standard industry practice of performing five point calibration checks applied to components such as gauges and dP cells and not to circuits such as rate circuits.

The licensee evaluated this condition concluded that to perform any other checks would constitute a departure from the vendor instructions and would be inappropriate. Further, the licensee has not found any reason to question the calibration and test methods supplied by General Atomic.

The inspector considered that the licensee's evaluation was acceptable. This item is closed.

g. <u>(Closed) Followup Item (50-361/88-13-02), "Review Of Validation Program And Independent Verification Of The EOI's"</u>

This item concerned the fact that Emergency Operating Instructions (EOI's) were developed and implemented as a result of the TMI-2 accident and the subsequent NUREG-0899, "Guidelines for the Preparation of Emergency Operating Procedures," 1982. The NUREG required that EOI's were to undergo a process of validation/verification to ensure that the procedures were adequate for the intended task. The licensee's Author's Guide, OP-SO23-0-39, outlined how validation/verification process was to be accomplished at San Onofre. Nevertheless, an inspection team noted instances where modifications were made to the plant or control room that the applicable EOI's did not reflect. The inspection team also noted in a simulator scenario that the plant could be in a condition where a safety function could not be met, and yet the EOI could send an operator back to trip recovery if reactor power was less than 10^{-4}%, (which was already being met).

The licensee corrected the Unit 2 and 3 EOI's to reflect the discrepancies identified by the team. These corrections were in place as of May 5, 1989. The inspector considered that the licensee's intended efforts appeared acceptable. This item is closed.

h. The inspector discussed the status of the Unit 1 items below with the licensee. The following items were not ready for closure:

86-25-06	88-10-05	88-10-07	88-10-08
88-10-12	88-10-14	89-01-01	

The status of the following Unit 1 items was being reviewed by the licensee:

88-10-01	88-10-18	85-22-03	85-27-01
87-20-01	88-13-01	88-14-01	89-07-01
89-17-01	88-12-01	89-09-01	89-07-10
89-07-11	89-07-05	89-14-05	

The status of these items will be reviewed in the future.

12. <u>Exit Meeting</u> (30703)

On September 8, 1989, 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.

The licensee committed to perform ground checks of the ESFAS and RPS. These systems will be checked in Unit 2 prior to startup from the current refueling outage. These systems will be checked in Unit 3 while on-line if feasible or during the next outage of sufficient duration for those components that cannot be checked on-line.