U.S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos. 50-206/86-04, 50-361/86-05, 50-362/86-05

Docket Nos. 50-206, 50-361, 50-362

License Nos. DPR-13, NPF-10, NPF-15

Licensee: Southern California Edison Company
P. O. Box 800, 2244 Walnut Grove Avenue
Rosemead, California 92770

Facility Name: San Onofre Units 1, 2 and 3

Inspection at: San Onofre, San Clemente, California

Inspection conducted: January 11 through February 14, 1986

Inspectors: PH Johnson 3/6/86
for F. R. Huey, Senior Resident Inspector, Units 1, 2 and 3 — Date Signed

PH Johnson 3/6/86
for J. P. Stewart, Resident Inspector — Date Signed

PH Johnson 3/6/86
for A. D'Angelo, Resident Inspector — Date Signed

PH Johnson 3/6/86
for J. E. Tatum, Resident Inspector — Date Signed

PH Johnson 3/6/86
for R. C. Tang, Resident Inspector — Date Signed

Approved By: PH Johnson 3/6/86
P. H. Johnson, Chief
Reactor Projects Section 3 — Date Signed

Inspection Summary

Inspection on January 11 through February 14, 1986 (Report Nos. 50-206/86-04, 50-361/86-05, 50-362/86-05)

Areas Inspected: Routine resident inspection of Units 1, 2 and 3 Operations Program including the following areas: operational safety verification, evaluation of plant trips and events, monthly surveillance activities, monthly maintenance activities, engineered safety feature walkdown, refueling activities, licensee event reports review, and follow-up of previously identified items. This inspection involved 315 inspection hours on Unit 1, 122 inspection hours on Unit 2 and 152 inspection hours on Unit 3 for a total of 589 inspection hours by five NRC inspectors, including 57 hours of backshift or week-end inspection activities. Inspection Procedures 71707, 92701, 30703, 62703, 60710, 93702, 61726, 37701, 92700, 62700, 37702, 36700, 40700, 71710, and 5-71711 were covered.

Results: No violations or deviations were identified.

DETAILS

1. Persons Contacted

Southern California Edison Company

*H. Ray, Vice President, Site Manager
*G. Morgan, Station Manager
*M. Wharton, Deputy Station Manager
*D. Schone, Quality Assurance Manager
D. Stonecipher, Quality Control Manager
*R. Krieger, Deputy Station Manager
*D. Shull, Maintenance Manager
J. Reilly, Technical Manager
P. Knapp, Health Physics Manager
*B. Zintl, Compliance Manager
J. Wambold, Training Manager
D. Peacor, Emergency Preparedness Manager
P. Eller, Security Manager
*W. Marsh, Operations Superintendent, Units 2/3
*J. Reeder, Operations Superintendent, Unit 1
*V. Fisher, Assistant Operations Superintendent, Units 2/3
*B. Joyce, Maintenance Manager, Units 2/3
H. Merten, Maintenance Manager, Unit 1
*R. Santosuosso, Instrument and Control Supervisor
*T. Mackey, Compliance Supervisor
G. Gibson, Compliance Supervisor
*C. Kergis, Compliance Engineer
*P. King, Quality Assurance Supervisor

San Diego Gas & Electric Company

*R. Erickson, San Diego Gas and Electric

*Denotes those attending the exit meeting on February 14, 1986.

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. Operational Safety Verification

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.

No violations or deviations were noted.

3. Evaluation of Plant Trips and Events

a. Reactor Trip on January 12, 1986 (Unit 3)

On January 12, 1986, at 1735 while increasing reactor power during power ascension testing following the first refueling outage, the reactor tripped at 44% reactor power due to a load rejection signal. The licensee's investigation revealed that the turbine generator load signal was not electrically aligned to the turbine supervisory control system, which gave indication that only the steam bypass control system was available to accept the heat load from the reactor even though the turbine generator was operating and accepting all of the reactor heat load. At the time of the reactor trip, only 3 of the 4 steam bypass control valves were operable, which limited reactor power to 44%. The licensee took actions to electrically align the generator load signal with the turbine supervisory control system and addressed personnel and human factors aspects to prevent a recurrence of the event. Power ascension testing resumed on January 13, 1986.

b. Unit Shutdown to Investigate Leakage into the Containment Sump (Unit 3)

At 1720 on February 12, 1986, a unit shutdown was initiated to allow for containment entry in order to identify the source of leakage into the containment sump. The sump level had been increasing at a rate of 4-5 gallons per minute. The unit entered Mode 3 at 2102, a containment entry was made, and the source of leakage was identified to be from a 3/4" threaded connection in the component cooling water (CCW) supply to Reactor Coolant Pump (RCP) 3P004 lower motor bearing cooling coil. Repairs were completed on February 14, 1986.

No violations or deviations were noted.

4. Monthly Surveillance Activities

a. Surveillance of Seawall Structure (Unit 1)

The licensee conducted an inspection at five locations of the seawall. The seawall consists of rolled sheetpile designed to prevent breaking waves from entering and flooding the Unit 1 site.

The inspections consisted of five excavations at the seawall, dug to the bottom of the sheetpile. Visual observation was made of the members and their connections, with measurements made of the wall thickness of the sheetpile. All measurements indicated adequate wall thickness and visual observation revealed minimal corrosion and pitting of the seawall below grade. One sheetpile connection located near the auxiliary salt water pump pit did have significant corrosion where the connection was not intact. The sheetpile itself had little loss of wall thickness and no indication of similar wastage had occurred at the connection. Licensee engineering personnel stated that the connection in question was not needed to maintain the integrity of the seawall and therefore no repair was needed.

All other locations viewed had little pitting and other connections inspected were found intact. The seawall inspection performed by the licensee was comprehensive and complete.

Prior to backfill of the excavation, the licensee applied a coal tar epoxy protective coating and was considering the installation of a cathodic protection system for the seawall.

b. Unit 2 Monthly Surveillance

During this inspection period, an inspector observed the performance of the following monthly surveillances:

SO23-V-12.2.1	Core Protection Calculator (CPC) Functional Test (monthly)
SO23-3-3.25	Once-a-shift Surveillance (Technical Specification)

The inspector noted that the above surveillances were conducted in accordance with the procedures.

c. Integrated Engineered Safety Features (ESF) Relay Test (Unit 3)

On December 2, 1985, an inspector observed portions of the Unit 3 integrated ESF relay test which is required under Unit 3 technical specifications to be performed once every 18 months during cold shutdown. Areas inspected included procedure and data review, instrument calibration, personnel qualification, conformance with technical specification requirements, and administrative controls. Overall, the inspector determined that the test had been conducted in accordance with test procedure SO23-3-3.12 (TCN No. 9SU1), and that the test objectives as stated in the procedure had been met. However, the review and observation resulted in the following specific comments regarding documentation of test results:

(1) Procedure SO23-0-35, Rev. 2, TCN 2-6 (Use of Procedures) states in part that:

- Changes to or deviation from procedures shall be within the guidelines of Section 6.2 of this procedure (6.1.1.14).

- Changes to or deviation from procedures and/or attachments may be accomplished by use of Temporary Change Notice (TCN), Procedure Modification Permit (PMP), Alternately Controlled (A/C) Notation, etc. provided that the original intent is not altered (6.2.1).

o Discrepancies between the component label nomenclature and procedure nomenclature should be identified using Procedure Revision Request (6.4.2.2).

In the safety injection actuation system (SIAS) pretest lineup portion of the test (page 161), one component identification number was lined out and replaced with a different number. One of the above methods (e.g., PMP) was not used to correct the error.

(2) Procedure SO23-0-35, Rev. 2, TCN 2-6, attachment 1, definitions:

o <u>Verified By</u>: The signature/initials of the individual who attests to the correctness of an operation or step based on first hand observation, by review of records on file, or reports from qualified individuals.

Of the 17 attachments reviewed in the retest data package (SO3-3-3.43, Rev. 0, TCN 0-12), seven contained a verification signature, nine did not have verification signatures, and one did not have the "verified by" blank printed. Based upon discussions with licensee personnel and review of station procedures, it appeared that most people were uncertain as to whether a verification signature was required for this type of procedure. Some took the position that "verification is not needed because it does not involve valve alignment or repositioning." However, no station procedure could be found which addressed this. The decision to sign or not to sign appeared to be left with the Control Operator/Senior Reactor Operator (CO/SRO) responsible for the particular activity. This was identified to the licensee for resolution.

(3) Procedure SO23-0-35, Rev. 2, TCN 2-6, Attachment 1 Definitions:

o <u>Reviewed By</u>: The signature/initials of the SRO Operations Supervisor (shift superintendent or control room supervisor) who performs an <u>independent</u> assessment (emphasis added) of a procedure or activity for completeness and legibility after it is accomplished.

In 3 instances (pages 49, 64, and 186 of SO23-3-3.12), the two blanks ("performed by" and "reviewed by") bore the signatures of the same person; thus the review was not independent as apparently intended.

(4) Procedure SO23-0-35, Rev. 2, TCN 2-6:

Section 6.5.4 stated that the use of alternately controlled notations (A/C) requires review and approval prior to continuing with the activity in progress. This section also stated that the SRO operations supervisor shall review the A/C and its effect on the procedure, and that he shall signify approval by initialing adjacent to the A/C.

On page 163 of Procedure SO23-3-3.12, step 1.13.6 required opening component cooling water from high pressure safety injection (HPSI) pump 3P-017, valve S31203MU013, as part of post-testing HPSI pump 3P-017 lineup on train A. This step was not performed and instead "A/C SO23-3-2.7" was written in the initials blank. However, there was no indication of the SRO's review and approval of the A/C, as might be evidenced by the SRO's initial next to the A/C notation.

(5) One of the test objectives was to verify that on a simulated loss of the diesel generator with offsite power not available, the loads are shed from the emergency buses and that subsequent loading of the diesel generator is in accordance with design requirements. Verification of proper sequencing of the diesel generator was to be accomplished by comparing the measured starting time for various ESF equipment with prescribed acceptable time ranges. The measured starting time for containment spray pump 3P-013 was not included in the completed test package. When inquiring into this, the inspector was told that the starting time was recorded on the visicorder trace and was determined to be within the required time range but was not included on page 47 of the test package due to an apparent oversight. This placed the thoroughness of the test results review in question and was identified to the licensee for followup. (362/86-05-01)

The inspector raised the above concerns with licensee management and requested an evaluation of the potential impact of each item on the overall test result and objectives. The inspector was subsequently informed that such an evaluation had been performed and indicated no adverse impact on the test. Based on this and the inspector's direct observations and test package review, the inspector determined that the test objectives had been met. During discussion of the above issues with the NRC inspector, licensee management committed to reemphasize with cognizant operations personnel the importance of rigorous attention to detail in the performance and review of surveillance procedures.

No violations or deviations were identified.

5. <u>Monthly Maintenance Activities</u>

a. <u>Maintenance Activity on Unit 1 Diesel</u>

During the current refueling outage, the licensee performed a TDI owners' group inspection of the number 1 diesel generator. The inspection included a liquid penetrant examination of all oil holes on the crankshaft. No crack indications were found at the oil holes.

In addition, surface examinations were performed on the engine block surface which mates with the cylinder head. These inspections revealed no crack indications in any of the surfaces examined.

All maintenance activities on the diesel were properly controlled, including personnel access to the area.

b. Unit 2

An inspector observed portions of the charging pump 2P-190 18-month overhaul, which was conducted when the licensee identified that the charging pump was exhibiting low flow during routine operation. The cause of the low flow condition was attributed to improper seating of one of three discharge piston valves in the pump discharge manifold. The overhaul of the pump was conducted in accordance with the approved procedures.

c. Unit 3

An inspector observed the maintenance activities associated with the Shift Supervisor's Accelerated Maintenance (SSAM) on the Containment Sump Level indicator 3LI5853-1, which is a Post Accident Monitoring Indicator. The inspector observed the performance of the activities in accordance with SO23-II-9.245 (GEMS 3600 Series TLI System Modular Transmitter and Indicator Calibration) and noted no deficiencies.

No violations or deviations were identified.

6. Engineered Safety Feature Walkdown

Units 2 and 3

During the inspection period, the inspector walked down the class 1E DC power distribution systems for Units 2 and 3. The bus energization and the overall voltage for the 1E batteries were as required by the unit technical specifications, the Final Safety Analysis Report (FSAR), and applicable station procedures. Records for the weekly technical specifications surveillance for demonstrating the operability of the systems were also reviewed.

No violations or deviations were identified.

7. Refueling Activities

Unit 1

Unit 1 entered Mode 6 on January 11, 1986. The inspector observed activities related to the reactor vessel head lift, which were conducted on January 17, 1986. Surveillances were conducted to certify the heavy lift equipment and preparations for conducting the head lift appeared to be well organized. The licensee experienced no difficulties in removing the reactor vessel head and placing it on the inspection platform.

No violations or deviations were identified.

8. Review of Licensee Event Reports

Through direct observations, discussions with licensee personnel, or review of the records, the following Licensee Event Reports (LER's) were closed:

Unit 3

82-01	Both CREACUS trains inoperable
83-34	Vendor notified of potential failure mode in QSPDS
83-39	Auxiliary feedwater (AFW) pump bearing failed due to improper oil groove machining
83-40	Reactor coolant system (RCS) sampling nozzle loads exceed stress limits
83-43	Train "B" chiller inoperative
83-44	Service air improperly supplied in containment during Mode 3
83-46	Improper valve lineup resulted in inoperable diesel generators
83-73	Charging pumps isolated during reactor coolant system leak isolation attempts
83-87	PMS failure due to moving head disk error in PMS computer
83-91	UV armatures for RTB found in midposition

9. Follow-Up of Previously Identified Items

(Closed) Open Item (50-361/85-36-02) Reactor Trip and Safety Injection Actuation

The licensee had reviewed this event and verified that it was bounded by a loss of steam generator feedwater accident and main steam line break accident, as discussed in Chapter 15 of the FSAR. This item is closed.

(Open) Open Item (50-362/85-36-01) Excessive Cooldown Rate on December 24, 1985

Additional review of the records associated with this event indicated that post-maintenance testing on valves 3HV-8150 and 3HV-8151 had identified the discrepancy between remote (control room) and local position indication. However, this deficiency was not formally addressed by the licensee to ensure that, in addition to using the control room indication, other measures were taken to ensure that the valves were fully closed. The licensee had changed the operating instructions for these valves to require that the operators continue to close valves 3HV-8150 and 3HV-8151 for at least 15 seconds after the control room position indicates closed to ensure that the valves are fully closed. Additionally, the licensee is considering a permanent design change which would provide accurate position indication in the control room for these valves. This will be examined further during a future inspection.

10. Exit Meeting

On February 14, 1986 an exit meeting was conducted with the licensee representatives identified in Paragraph 1. The inspectors summarized the inspection scope and findings as described in this report.