U.S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos. 50-206/85-38, 50-361/85-36, 50-362/85-36

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: November 15, 1985 through January 10, 1986

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

for J. P. Stewart, Resident Inspector — 2/6/86 Date Signed

for A. D'Angelo, Resident Inspector — 2/6/86 Date Signed

for J. E. Tatum, Resident Inspector — 2/6/86 Date Signed

for R. C. Tang, Resident Inspector — 2/6/86 Date Signed

Approved By: P. H. Johnson, Chief
Reactor Projects Section 3 — 2/6/86 Date Signed

Inspection Summary

Inspection on November 15, 1985 through January 10, 1986 (Report Nos. 50-206/85-38, 50-361/85-36, 50-362/85-36)

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 January 10, 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.

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, refueling activities, independent inspection, licensee event report review, and follow-up of previously identified items. This inspection involved 588 inspection hours on Unit 1, 232 inspection hours on Unit 2 and 216 inspection hours on Unit 3 for a total of 1036 inspection hours by five NRC inspectors including 88 hours of backshift or weekend inspection activities. Inspection Procedures 93702, 71707, 60705, 73755, 92700, 62700, 62703, 61726, 60710, 92701, 93702, 61729, 71710, 37702, 71711, 61707, 61708, 61709, 61710, 37701, 30703 and 73753 were covered.

Results: No violations or deviations were identified.

a. Initial Criticality After Refueling (Unit 3)

On January 7, 1986, an inspector observed control room operations to take Unit 3 reactor critical following the first refueling outage. Although the operation was delayed approximately six hours as a result of Control Element Drive Control System equipment problems, criticality was achieved without any other complications.

On January 7, 1986, the inspector toured the Unit 3 charging pump rooms and noted the following conditions in the pump room for charging pump 3P-191:

(1) The room was full of tools and debris left over from overhaul work done during the refueling outage. Tools were lying on the floor, on the pump (which was in service and operating) and in the overhead area near the pump.

(2) Cans of paint were left stored in the room.

(3) A flashlight was improperly stored in the manual operating mechanism for pump discharge valve MU-070.

(4) The cover was unfastened and loose on electrical junction box 3XP-1RZ-TB158.

These conditions had previously been identified by the licensee, and actions were being taken to correct these material deficiencies. The inspector emphasized with the licensee the importance of verifying the adequacy of material plant conditions prior to returning equipment to service following maintenance activities.

b. Unit 2 and 3 Heat Trace System

The inspector reviewed the status of the heat trace system associated with Unit 2 and 3 boration flow paths. On January 7, 1986, the inspector reviewed the following concerns with the licensee.

(1) Several heat trace circuits were in an over- or under-temperature alarm condition. Although this condition by itself is not necessarily a problem, these low temperature signals result in a continuous heat trace trouble alarm in the control room. Since the control room heat trace trouble alarm does not have reflash capability, a valid under temperature or circuit failure alarm condition on a boration flow path circuit would not be alarmed in the control room. This undesirable operating condition could result in a serious degradation of required boration flow path capability unless conscientious compensatory measures are implemented by station operations personnel. The risk associated with this mode of operation was further increased by the lengthy outages of boron makeup pumps 2P174 and 3P175.

(2) The alarm response procedure associated with the heat trace trouble alarm required shiftly observation of all required heat trace circuits for proper operation and temperature. Station operators stated that they make routine shiftly tours of all heat trace panels associated with boration flow paths; however, discussions with different shift supervisors and operators indicated that no specific compensatory measures were being taken or documented with regard to heat trace circuits associated with boration flow paths during periods when the heat trace trouble alarm is locked in.

Based on the above concerns, the licensee identified that the following corrective actions were being taken:

(1) The current configuration for the heat trace trouble alarm was being reviewed to determine if the continuous alarm condition could be eliminated.

(2) The compensatory actions associated with heat trace trouble alarms were being reviewed to ensure adequate attention to operability verification of technical specification required systems.

(3) Return to service of inoperable boron makeup pumps would be expedited.

This is an open item (50-361/85-36-01).

3. <u>Evaluation of Plant Trips and Events</u>

a. <u>Reactor Trip and Water Hammer Event on November 21, 1985 (Unit 1)</u>

On November 21, 1985, at 0450, while at 60% power, the reactor was manually tripped when auxiliary transformer "C" was automatically isolated due to differential relay protective actions. Auxiliary transformer "C" is normally powered from offsite sources, and is used to supply power to the safety related 4KV electrical busses. A 100% ground had been traced to the "C" transformer, the plant was placed in an abnormal electrical line up, and troubleshooting was in progress when the transformer was automatically isolated. The reactor was manually tripped to place the plant in a safe configuration following the loss of the "C" auxiliary transformer. When the reactor was tripped, generator electrical output was lost and approximately four minutes elapsed before electrical power was restored to Unit 1 via offsite power sources. The emergency diesel generators started, but were not loaded since offsite electrical power was available.

Shortly after the reactor tripped, a severe water hammer occurred in the feedwater piping to the "B" steam generator (SG), causing a steam leak and significant damage to the feedwater piping and supports. The licensee declared an Unusual Event shortly after 0500, the reactor coolant system (RCS) was cooled down and depressurized, and the residual heat removal (RHR) system was placed in service at 0940. The licensee terminated the Unusual Event, and at 1045 the steam leak in the "B" SG feedwater line was isolated. The unit entered Mode 5 at 1508. The Unit 1 refueling outage, which was originally scheduled to begin November 29, was started November 22, 1985.

A Confirmatory Action Letter (CAL) was issued to SCE on the day of the event which precluded any work in progress or planned on equipment that malfunctioned during the incident until SCE and the NRC have completed their investigation and evaluation of the event. The CAL also confirmed that San Onofre Unit 1 would remain in a shutdown condition until SCE receives concurrence from the NRC to return to power.

An NRC Headquarters Incident Investigation Team (IIT) arrived at the site on November 22, 1985, to conduct an independent investigation of the event. The IIT completed its onsite investigation on January 3, 1986 and the IIT report on its evaluations and findings regarding the event was expected to be available on or about January 20, 1986. At the close of this report period, Unit 1 was in Mode 6 preparing for refueling.

b. Reactor Trip and Safety Injection Actuation on December 10, 1985 (Unit 2)

On December 10, 1985, at 1824, while at 100% power, the reactor tripped due to a low water level in steam generator E-089. The low steam generator water level resulted when maintenance associated with E-089 feedwater isolation valve (FWIV) 2HV-4052 caused the valve to go shut. (See paragraph 8b for additional details regarding this maintenance activity). The auxiliary feedwater system actuated as designed at 25% narrow range level in E-089 (concurrent with reactor trip) and restored steam generator level to approximately 45%. Due to the large amount of cold auxiliary feedwater that was subsequently added to steam generator E-089, the reactor coolant system (RCS) was cooled down to approximately 533^{o}F and pressurizer pressure dropped to approximately 1762 psia. At 1806 psia pressurizer pressure, both trains of safety injection were actuated and the two operable charging pumps injected borated water into the RCS for approximately 7 minutes. The third charging pump was cleared for maintenance, and pressurizer pressure did not decrease far enough to allow the high pressure safety injection pumps to inject borated water into the RCS. During the course of the transient, pressurizer level dropped to approximately 5%, RCS cold leg temperature dropped to approximately 533^{o}F and pressurizer pressure dropped to 1762 psia. This transient was being evaluated by the licensee to ensure that it was bounded by the accident analysis in Chapter 15 of the FSAR (Open Item 50-361/85-36-02).

c. Reactor Trip on January 9, 1986 (Unit 2)

On January 9, 1986, at 0859 while at 100% power, the reactor was manually tripped as a result of a loss of feedwater to Steam Generator (SG) E-088. The loss of feedwater occurred as a result of the closure of 2HV-4047, the downstream isolation valve for SG E-088 main feedwater regulating valve 2FV-1121. Valve 2HV-4047 had closed due to failure of the solenoid associated with the 2HV-4047 Marotta valve. The Marotta valve opened, dumping the hydraulic fluid which was providing the force to hold valve 2HV-4047 in the open position. Plant systems performed as required following the trip. A safety injection did not result as was the case following the December 10 event above, apparently because the operators (1) manually tripped the reactor in anticipation of an automatic trip and (2) throttled auxiliary feedwater flow to limit plant cooldown. The solenoid was replaced and the unit returned to service at 1530 on January 11, 1986.

d. <u>Excessive Cooldown Rate on December 24, 1985 (Unit 3)</u>

On December 24, 1985, while the unit was in Mode 5 at 181^{o}F, a cooldown in excess of the 30^{o}F per hour Technical Specification limit occurred. The unit was being cooled down in order to replace the upper thrust bearing and thrust collar on reactor coolant pump 3MP002. The unit was cooled down 44^{o}F in one hour when the shutdown cooling system was placed in service and the low pressure safety injection pump was started with the shutdown cooling heat exchanger discharge throttle valves (3HV-8150 and 3HV-8151) slightly open. These valves are supplied with Limitorque operators with a jogging type control circuit, with open and closed position indicating lights in the control room. When shutdown cooling was initiated, the valves indicated closed in the control room even though they were slightly open. The control operator recognized the rapid cooldown of the reactor coolant system approximately 20 minutes after initiating shutdown cooling flow, but the cause of the excessive cooldown rate was not identified until approximately 60 minutes after shutdown cooling flow was initiated. At that time, the control operator held the control switches for valves 3HV-8150 and 3HV-8151 in the closed position. The valves went to the full closed position as evidenced by the temperature difference across the shutdown cooling heat exchangers. The reactor coolant system temperature had gone from 181^{o}F to 135^{o}F in 70 minutes. Based on an analysis conducted by Combustion Engineering, the licensee determined that this transient did not affect the reactor coolant system pressure boundary.

During the 1985 refueling outage, the limit switch that bypasses the closing torque switch in the valve actuator for valves 3HV-8150 and 3HV-8151 was adjusted from the 2% valve open position to the 16% valve open position. The licensee stated that these adjustments were made in accordance with the recommendations of Limitorque and the Institute of Nuclear Power Operations (INPO). However, it was not recognized that this adjustment also affected the control room position indication. This item remains open pending a more detailed review of the circumstances which led to this event.
(50-362/85-36-01)

The activities discussed in this section involved apparent or potential violation of NRC requirements identified by the licensee for which appropriate licensee actions were taken or initiated. Consistent with Section IV.A of the NRC Enforcement Policy, enforcement action was not initiated by Region V.

e. Mode 2 Entry on January 10, 1986 (Unit 3)

On January 10, 1986 at 0540 the unit entered Mode 2 so that repairs could be made to the #1 overspeed trip mechanism on the main turbine. The unit had just completed low power physics testing following the first refueling outage and the reactor was at 6% power prior to the mode decrease. The trip mechanism had failed to trip the turbine during surveillance testing that was conducted prior to entering the power ascension test program. Repair efforts were in progress at the end of this report period.

No violations or deviations were identified.

4. Monthly Surveillance Activities

a. Unit 2 Monthly Surveillances

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

SO23-V-12.10.1	Qualified Safety Parameter Display System Channel A Test
SO23-V-1.20	Reactor Coolant System Calorimetric Flow Measurements
SO2-3-3.35	Post Accident Monitor Instrumentation Monthly Surveillance

The inspector noted that the above surveillances were conducted in accordance with the procedures and no deficiencies were identified.

b. Testing of Uninterrupted Power Supply (UPS) to Station Security Computer Following Loss of Preferred AC Power (Unit 3)

On December 2, 1985, the inspector observed portions of the Unit 3 integrated ESF relay test which is required under Unit 3 Technical Specifications to be performed once per 18 months during cold shutdown. The completed work package was being reviewed by the inspector at the conclusion of this report period. One of the test objectives, as stated in the station test procedure SO23-3-3.12 (TCN No. 9SU1), was to "verify that security computer power supply can be transferred from its preferred AC power source to its battery and transferred back to its AC power source without interruption." This test objective was satisfied in that the security computer power source was transferred (i.e. simulated loss of preferred AC power) without an interruption of power to the security computer.

No violations or deviations were identified.

5. Monthly Maintenance Activities

a. Unit 1

Following the Unit 1 reactor trip and feedwater transient on November 21, 1985, the inspector observed disassembly and inspection of the "B" steam generator feedwater regulating valve (FWS-457), feedwater check valve (FWS-346) and bypass check valve (FWS-378). These activities were conducted in accordance with the approved procedures.

b. Unit 2

Refer to paragraph 8.b for review of Unit 2 maintenance activities.

c. Unit 3

While making preparations for Mode 4 entry following the unit refueling outage, the licensee discovered some pinhole leaks in the charging pump common suction piping. The leaks were found in the heat affected zone where a support had been welded to the common suction piping. The inspector monitored the repair efforts which included replacement of a short length of the existing schedule 10 stainless steel piping with schedule 40 stainless steel piping. When the piping was subsequently hydrostatically tested, additional leaks were found in the vicinity of another welded support. The inspector observed the repair efforts to replace additional schedule 10 stainless steel piping with schedule 40 piping.

No violations or deviations were identified.

6. Engineered Safety Feature Walkdown

a. Unit 2 Auxiliary Feedwater

On January 2, 1986, the inspector walked down the valve and electrical lineup for the Unit 2 auxiliary feedwater system. All valves and breakers were in their required position to support Mode 1 operation. The inspector reviewed the condition of the pump bearing lubrication system and found no deficiencies. The general material condition of all components in the auxiliary feedwater room was good and was noted to be a significant improvement over deficient conditions previously noted in inspection report 50-361/85-32.

The inspector also walked down the steam lines from the main steam headers to the turbine on the steam driven auxiliary feedwater pump (2P140). During this walkdown the inspector noted that snubber S2-ST-017-H-009 on this steam line was not properly installed. Specifically, the snubber clevis pin was backed out of its clevis and the snubber paddle was disengaged from the clevis. This deficient condition was reported to the control room and the following actions were taken by the licensee:

(1) The technical specification action statement applicable to the inoperable snubber was initiated.

(2) It was confirmed that the last maintenance on this snubber was performed in December 1984, at which time the proper installation of the snubber, including proper installation of the clevis pin and pin retainers, was verified and documented.

(3) The deficient snubber was examined and it was determined that the snubber (rated at 1/2 KIP) had been damaged by a hydraulic transient. The licensee concluded that the hydraulic transient also resulted in the dislocation of the clevis pin.

(4) All other snubbers on the steam line were examined and one other deficient snubber attributable to hydraulic transient damage was found.

(5) An analysis was performed which confirmed that failure of the above snubbers in their as found condition would not have rendered the steam line inoperable under design seismic conditions.

(6) The failed snubbers were replaced.

The licensee was unable to define the transient which resulted in snubber damage. To preclude recurrence of undetected snubber damage, the licensee established a requirement to inspect and stroke test auxiliary feedwater pump steam line snubbers following every start of the steam driven auxiliary feedwater pump.

b. Unit 3 Auxiliary Feedwater

On January 3-6, 1986, the inspector performed the post refueling walkdown inspection of the Unit 3 Auxiliary Feedwater System (AFS). All the AFS flow valves were in the required position. The inspector noted minor housekeeping deficiencies in each of the following areas: condensate storage tank area, refueling water storage tank area, and piping tunnel to the AFS containment penetrations. The inspector also noted that the local valve position indicator for 3HV-4713 was missing. The licensee immediately initiated corrective action for the above deficiencies.

No violations or deviations were identified.

7. Refueling Activities

a. Containment Inspection (Unit 3)

On January 2, 1986, an inspector performed a general inspection of Unit 3 containment prior to the securing of containment following the Unit 3 refueling outage. A minor body to bonnet leak was noted on an auxiliary feedwater vent valve (V-284) which was non-isolable from the steam generator. The licensee repaired the valve prior to plant heat up. No other deficiencies were noted.

No violations or deviations were identified.

b. Post Refueling Startup Testing (Unit 3)

During this inspection period, Unit 3 completed low power physics testing and entered Mode 1 on January 9, 1986. The first refueling outage was completed at 2137 on January 11, 1986, when the generator was synchronized to the grid. The inspector observed portions of the following physics tests:

SO23-V-1.0.1	Criticality Following Refueling
SO23-V-1.0.2	Boron Endpoint Determination
SO23-V-1.0.3	Isothermal Temperature Coefficient Measurement at Hot, Zero Power
SO23-V-1.0.6	Control Element Assembly Worth by Exchange
SO23-3-3.29	Actual Shutdown Margin Calculation with Reactor Subcritical (Checkoff List 3)

No violations or deviations were identified.

8. Independent Inspection

a. During the refueling outage on Unit 3, an inspector observed DCP work for replacement of the start-up detectors with environmentally qualified fission detectors. The inspector observed that QC coverage was not required for installation of the fission detectors and associated wiring integral to the detectors inside containment. This observation was discussed with the licensee. The licensee's QA organization subsequently conducted an audit of the DCP and found that the fission detectors had not been tested for leakage as required by the Technical Specifications. The detectors were subsequently tested for leakage as required and no leakage was found. The licensee also identified that the detectors installed in Unit 2 during implementation of the DCP were not tested for leakage. The Technical Specification could not be satisfied for Unit 2 since the unit had operated at power and the detectors were therefore highly radioactive. These circumstances were discussed in the licensee's LER No. 361/85-37.

The activities discussed in this section involved apparent or potential violation of NRC requirements identified by the licensee for which appropriate licensee actions were taken or initiated. Consistent with Section IV.A of the NRC Enforcement Policy, enforcement action was not initiated by Region V.

b. On December 10, 1985, the licensee initiated a Shift Superintendent's Accelerated Maintenance (SSAM) to investigate an annunciator ground alarm on Unit 2. Subsequent repair efforts caused the unit to trip from 100% power as discussed in paragraph 3a of this report. The inspector reviewed the maintenance activity which resulted in the reactor trip and subsequent safety injection actuation, and determined that the following did occur:

(1) The Shift Superintendent declared a SSAM to investigate an annunciator ground alarm. The ground was traced to the two pressure switches which monitor nitrogen pressure being supplied to the two Marotta valves for main feedwater isolation valve (MFIV) 2HV-4052. The Marotta valves are held closed by the nitrogen pressure, but when the nitrogen is vented to the atmosphere by a solenoid valve which is integral with the Marotta valve, the Marotta valve opens and dumps the hydraulic fluid from the MFIV actuator and allows the MFIV to go shut. The MFIV will shut when either of the two Marotta valves opens. This arrangement is illustrated on P&ID S02-40156D.

(2) The control operator gave the I&C technician verbal authorization to isolate the pressure switches (2PSL-4052A and 2PSL-4052B) and remove them for repair or replacement. The control operator did not review the system drawing to verify that the pressure switches could be isolated, and the work activity was not discussed with the senior reactor operator prior to issuing the verbal approval to do work as required by the work authorization procedures.

(3) The I&C technician closed valves 1305-MU-777 and 1305-MU-779 to isolate the pressure switches and removed them for maintenance. The I&C technician thought that he was closing the instrument isolation valves, but the pressure switches did not have instrument isolation valves and the I&C technician actually isolated the nitrogen supply to the pressure switches as well as to the Marotta valves. The I&C technician did not recognize that the valves he had operated were not instrument isolation valves and should only be closed by a qualified equipment operator.

(4) By approximately 45 minutes after the I&C technician isolated the nitrogen supply to the Marotta valves, leakage allowed the existing nitrogen pressure to decrease to the point where the Marotta valves opened, causing the FWIV to shut.

This improperly controlled maintenance activity ultimately led to the Unit 2 reactor trip and subsequent safety injection actuation. Specifically:

(1) The maintenance activity did not receive an independent review by the senior reactor operator as specified by procedures.

(2) The control operator did not verify the system configuration prior to issuing the verbal authorization to do work.

(3) The I&C technician operated valves other than instrument isolation valves, which is prohibited by procedure.

(4) A procedure was not prepared for conducting the maintenance activity prior to starting work, as required by the Technical Specifications.

Corrective actions initiated by the licensee were discussed in LER No. 361/85-58. These corrective actions will be reviewed during future inspections.

No violations or deviations were identified.

9. Review of Licensee Event Reports

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

Unit 1

85-16	Generator Hydrogen Seal Oil Fire Protection Deluge system Air Flow Test Failure

Unit 2

82-01	Control Room Emergency Air Cleanup System (CREACUS) Fire Protection System Modification to a Manual System (Rev. 1)
82-12	CREACUS Found Inoperable During Surveillance Testing
82-15	Overspeed Trip of Diesel Generator 2G003 During Monthly Operability Test
82-23	Uncontrolled Actuation of Cable Tunnel Auto Deluge Valve
82-29	Failed Limit Switch on Auxiliary Feedwater System Valve 2HV4714
82-37	Remote Shutdown Boronometer Inoperable
82-43	CREACUS Emergency Chilled Water Pump Would Not Start Due to Wrong Fuse Size
82-56	Failure of One Level Instrument on Each Steam Generator
82-78	Departure from Nucleate Boiling Ratio (DNBR) Monitor Channel "A" Failed Channel Check Test
82-125	Level Control Switch 2LSH-6498 Out of Calibration
82-177	Surveillance Test SO23-XIII-49 for Fire Doors not Being Done
85-18	Reactor Trip - Invalid Penalty Factors
85-39	Toxic Gas Isolation System (TGIS) Hydrocarbon Analyzer Malfunction (Rev. 1)
85-43	Toxic Gas Isolation System (TGIS) Actuation due to Ammonia Channel Failure
85-46	Reactor Trip Caused by a Generator Exciter Fire (Rev. 1)
85-47	Toxic Gas Isolation System (TGIS) Spurious Actuation of Ammonia Channel
85-50	Reactor Trip - Moisture Separator Reheater Drain Tank Hi Level
85-51	Reactor Trip - Axial Shape Index
85-52	Toxic Gas Isolation System (TGIS) Train "B" Spurious Actuation
85-53	Incorrect Gaseous Effluent Monitor Setpoint During Containment Venting
85-55	Fuel Handling Isolation System (FHIS) Train "A" Actuation Due to Instrument Failure
85-56	Containment Purge Isolation System (CPIS) Spurious Actuations

85-60 Reactor Trip - Axial Shape Index

Unit 3

85-06	Special Report - Emergency Core Cooling System (ECCS) Actuation
85-19	Spurious Fuel Handling Isolation System (FHIS) Actuations (Rev. 1)
85-26	Fuel Handling Without Required Monitor
85-31	Fuel Handling Isolation System (FHIS) Actuations
85-32	Fuel Handling Isolation System (FHIS) Actuations
85-34	Inadvertent Fuel Handling Isolation System (FHIS) Actuations
85-35	Containment Purge Isolation System (CPIS) Actuations

No violations or deviations were identified.

10. Follow-Up of Allegation or Concern

ATS No.: RV-85-A-031

a. Characterization

The alleger reported that the Units 2 and 3 I&C Supervisor was trying to cover up an incident concerning lifted leads. The alleger reported that the temporary modification form controlled by procedure SO123-II-15.3 had been altered by the licensee in that an additional terminal was added to the form as having its leads lifted on or after March 18, 1985, thereby falsely indicating that the responsible mechanic had failed to reterminate the leads on terminal 3PSH0103B1 on February 28, 1985. The alleger also reported that the licensee may have performed a surveillance on or about March 10, 1985, which should have identified the lifted leads.

b. Implied Safety Significance to Operation

The implied safety significance based on the inspector's investigation of the importance of the lead to 3PSH0103B1 which was found lifted is minor. The lifted leads (wires 3+ and 3-) on terminal 3PSH0103B1 normally allow the Safety Injection Tank (SIT) valves to the Reactor Coolant System (RCS), 3HV9350 (SIT #2) and 3HV9360 (SIT #3), to be closed from the control room when reactor coolant system pressure was above 395 psi. Another relay would automatically open the valves when RCS pressure reached 515 psi. Therefore, having the valves capable of being shut below 515 psi has no major safety significance. Additionally, the lifted leads would not cause the valves to be in a position not directed by the reactor operator. The related controls allowed the operator the capability of shutting the valve between 395 to 515 psi without going to "Bypass". Also, the valve position is controlled by a procedure which directs the operator to open the valve and lock open the valve's motor-operator breaker before pressurizing the RCS. Therefore, at normal operating conditions it is physically impossible to close the valve for two reasons, (1) Power is removed from the valve operator and (2) if power were available to the valve operator the 515 psi interlock would automatically keep the valve open.

c. Assessment of Safety Significance

Based upon interviews and documentation review, the inspector determined the following:

(1) The I & C Supervisor did not attempt to cover up the lifted lead event which occurred from February 27, to March 17, 1985. Several people observed and numerous others were aware of the event including quality control and station operations personnel. Additionally, the I&C Supervisor had all personnel involved in the event document the history of their involvement and the event was then summarized per maintenance department guideline No. 104.

(2) The licensee had performed a leak rate surveillance in accordance with procedure SO23-3-3.31.1 check off list 10 and 11 on March 2 to March 7, 1985, which is the surveillance the alleger referred to as having been performed on or about March 10, 1985. The performance of this surveillance would not normally identify this lifted lead problem since the operator would normally bypass the 395 psi interlock to operate the valve.

(3) The inspector examined the temporary modification form and found no indication that the form had been altered in that no additional entries lifting these leads were made after February 27, 1985.

As a result of the inspection activities, the inspector noted that the procedure which controls the temporary modification form did not require the restoration and verification of restoration dates to be documented. The licensee issued Temporary Change Notice 2-1, which corrected this deficiency with a new form 335, Rev. 1.

d. Staff Position

The allegation that the I&C supervisor was covering up the lifted lead incident was not substantiated. The allegation that the temporary modification form was altered, showing that the alleger had failed to reterminate the lifted leads, was not substantiated. The statement that a surveillance was performed on or about March 10, 1985 was correct, although the allegaton that the surveillance should have identified the lifted leads prior to their actual identification on March 17, 1985, was not substantiated.

e. Action Required

Based on the inspection findings, the allegations were not substantiated and no additional action is required. This allegation is closed.

11. Follow-Up of Previously Identified Items

a. (Closed) Open Item (50-361/81-20-01) Protective Covers on Containment Air Lock Doors

During the construction of Unit 2, prior to initial fuel loading, it was identified that containment personnel air lock door seals and mating surfaces had no protective coverings. Based on observations of containment air lock door seal protection when being used, and the satisfactory leak rate tests of the personnel air lock doors the inspector determined that the licensee's corrective action was adequate. This item is closed.

b. (Closed) Open Item (50-361/81-20-02) Time Response Test Procedure Instrumentation Problem

During the performance of startup test 2PE-358-01, "Plant Protection System Time Response", problems were observed to have been encountered with the test instrumentation. The licensee had subsequently resolved the test equipment problem during Unit 2 startup testing. This item is closed.

c. (Closed) Open Item (50-361/84-35-01) Evaluate Effluent Radiation Monitoring and Forced Ventilation of Containment When Containment Open

The inspector had requested that the licensee evaluate current technical specification requirements for containment purge and the sequencing of maintenance of plant effluent radiation monitors when containment integrity is not required. The licensee evaluated the existing technical specifications and determined that the basis for the monitors to be operable in Mode 6 is to ensure they are available in the event of a fuel handling accident. The licensee's evaluation noted that if no fuel handling, or crane movement over the reactor vessel with the vessel head removed is in progress that there is no technical basis to prevent the equipment hatch being open without purging the containment. This item is closed.

d. (Closed) Open Item (50-361/84-35-02) Health Physics Technicians not Fully Cognizant of Status of Radiological Conditions and Equipment

During tours of radiation restricted areas the inspectors noted several deficiencies in the licensee's health physics program implementation. The licensee took the following actions to correct the deficiencies:

- Installed new functional test record cards on airborne samplers

- Routinely picked up yellow/magenta bags when full
- Included proper methods for reading dosimeters in practical factors training, which is required annually of red badge workers
- Included in shift turnover information activity levels under the reactor vessel head

Based upon the review of the licensee's actions this item is closed.

e. <u>(Closed) Open Item (50-361/84-35-04) Technical Surveillance (T.S.) 4.9.8.2 Does not Require that Two Trains of Shutdown Cooling be Verified</u>

The licensee determined that T.S. 3/4.9.8.2 is consistent with the Combustion Engineering-standard technical specifications and the similar Mode 5 specification and that the operability of the nonoperating shutdown cooling train is determined in accordance with T.S. 4.0.5/ASME Code Section XI. This item is closed.

f. <u>(Closed) Open Item (50-361/85-01-02) Locking Device on Locked Valves Inadequate</u>

The inspectors had previously identified inadequate locking devices and control of locked valves in inspection reports Nos. 85-01 and 85-27. The licensee has completed the installation of new locking devices and color coding of safety related valves specified in their locked valve program. The licensee implemented the new administrative program for the control of locked valves with the issuance of TCN 10-2 of Procedure SO23-0-17 on January 3, 1986. Plant tours by the inspectors during the inspection period identified no deficiencies in the licensee's control of locked valves. This item is closed.

g. <u>(Closed) Open Item (50-361/85-09-02) Transmission of Chemistry Data to Operations Personnel</u>

It was noted that the chemistry reports from the chemical supervisor to the shift superintendent do not contain acceptance criteria or trending data, and it had been concluded that the shift superintendent is unable to evaluate the chemistry data report adequately. The licensee evaluated this concern and determined that no action was required as plant chemistry personnel provide the data required and perform trending, and keep the shift superintendent informed of the trends in chemistry data. Based on routine interviews with the Unit 2 and 3 shift superintendents it appears the licensee's actions are appropriate. This item is closed.

h. <u>(Closed) Open Item (50-361/85-09-05) HPSI Lineup Initiated Prior to Drawing a Steam Bubble in Pressurizer</u>

Procedure SO23-5-3.1 Revision 11 "Plant Startup from Cold Shutdown to Hot Standby" had a procedural inconsistency between steps 6.3 and 6.14. A step 6.14 note permitted the performance of the HPSI system alignment only after a bubble had been formed in the pressurizer. This "Note" was inconsistent with a preceding step, step 6.3, which allowed the HPSI system to be completely aligned prior to encountering the precondition of step 6.14. The licensee eliminated the above deficiency by revising procedure SO23-5-3.1. This item is closed.

i. <u>(Closed) Open Item (50-361/85-09-11) Brown Boveri HK Circuit Breaker Problems Not Acted On</u>

The licensee had not completed action on Brown Boveri circuit breaker problems discussed in IE Bulletin 83-03, relating to the overtravel of a control device lever, due to the location of the lever stop, which affects the closing function of the circuit breaker. The licensee revised Procedure SO23-I-4.5, step 6.4.4 on March 5, 1985. The change to the maintenance procedure for the 4.16 KV air circuit breakers implemented the IB83-03 adjustments. This item is closed.

j. <u>(Closed) Violation (50-361/85-13-03) Failure to Perform Battery Discharge Test</u>

The licensee had failed to perform the 18 month battery discharge test required by the technical specifications on Unit 2 batteries 2B007 and 2B008 within the 18 month requirement. No licensee response was requested as the tests were subsequently performed and the cause of the failure to perform was identified and corrected. This item is closed.

k. <u>(Closed) Violation (50-362/83-13-01), Procedures for AFW Electrical Alignment and Fire Protection Valve Alignment Were Inadequate</u>

The inspector reviewed procedure SO23-2-4 (TCN 8-14) and determined that sufficient detail was provided such that a qualified operator could complete the AFW electrical alignment. Procedure SO23-7-1 (TCN 9-10) was reviewed and the inspector determined that the valve alignment was changed to require valves to be locked open as required by the Fire Hazards Analysis. This item is closed.

l. <u>(Closed) Violation (50-362/84-14-01), Failure to Declare an Unusual Event as Required by EPIP</u>

The aspect of this item which remained open was verification of operator training. Based on records review, the inspector determined that the operators have received preliminary training during preshift briefings. Additionally, this topic has been included in the operator requalification training program. This item is closed.

12. <u>Exit Meeting</u>

On January 10, 1985, 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.