U.S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos. 50-206/89-07, 50-361/89-07, 50-362/89-07

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: April 2 through April 30, 1989

Inspectors: C. Caldwell, Acting Senior Resident Inspector
Units 1, 2 and 3

J. E. Tatum, Resident Inspector

A. L. Hon, Resident Inspector

N. K. Trehan, NRR (March 27 - 30, 1989)

Approved By: P H Johnson 6/6/89
P. H. Johnson, Chief
Reactor Projects Section 3
Date Signed

Inspection Summary

Inspection on April 2 through April 30, 1989 (Report Nos. 50-206/89-07, 50-361/89-07, and 50-362/89-07)

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, refueling activities, independent inspection, licensee events report review, resolution of Unit 1 restart issues, and follow-up of previously identified items. Inspection procedures 30703, 37700, 37828, 61726, 62703, 64704, 71707, 71710, 72701, 90712, 92700, 92701, 92703, 93702 were utilized.

Safety Issues Management System (SIMS) Items: None

Results:

General Conclusions and Specific Findings:

a. Paragraph 8.j discusses an observed weakness in surveillance testing requirements.

b. Paragraphs 8.e and 8.j discuss a number of observations which indicate continuing weakness in the performance of engineering work.

Significant Safety Matters:

Paragraph 8 discusses licensee resolution of a number of Unit 1 design deficiencies that were identified during the cycle 10 refueling outage.

Summary of Violations: None

Open Items Summary:

During this report period, 11 new followup items were opened and 12 were closed; 2 were examined and left open.

DETAILS

Part 1 -- Resident Inspectors

1. Persons Contacted

Southern California Edison Company

*C. McCarthy, Vice President and Site Manager
*H. Morgan, Station Manager
D. Herbst, Quality Assurance Manager
D. Stonecipher, Quality Control Manager
*R. Krieger, Operations Manager
*D. Shull, Maintenance Manager
J. Reilly, Technical Manager
C. Chiu, Assistant Technical Manager
P. Knapp, Health Physics Manager
D. Peacor, Emergency Preparedness Manager
P. Eller, Security Manager
*J. Schramm, Operations Superintendent, Unit 1
V. Fisher, Operations Superintendent, Units 2/3
L. Cash, Maintenance Manager, Unit 1
R. Santosuosso, Maintenance Manager, Units 2/3
*R. Plappert, Compliance Manager
R. Baker, Compliance Engineer

*Denotes those attending the exit meeting on April 28, 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

The unit remained shutdown during this report period, as work continued during the cycle 10 refueling outage and preparations for reactor startup were being completed. On April 24, 1989, at 12:55 p.m., the unit entered Mode 4. On April 28, at 9:32 p.m., the unit entered Mode 3, but returned to Mode 4 at 2:28 a.m. on April 29 to resolve surveillance problems with the south auxiliary feedwater pump (G10S). On April 29, at 10:37 p.m., the unit returned to Mode 3. At the end of the inspection period the unit had completed 154 days of the cycle 10 refueling outage activities (originally scheduled to last 98 days).

Unit 2

During this inspection period, the unit operated at full power.

Unit 3

On April 7, 1989, the unit tripped from 100% power after 88 days of continuous operation. A control element drive mechanism (CEDM) bus undervoltage (UV) condition initiated a turbine trip which in turn caused the reactor trip on loss of load. All systems responded properly after the trip. The licensee found that undervoltage relays which initiated the turbine trip had a setpoint lower than the worst case bus UV condition. This condition was evaluated and corrected.

The Unit was returned to Mode 2 on April 17, 1989 and was synchronized to the grid shortly thereafter. The unit operated at full power for the balance of the inspection period.

3. Operational Safety Verification (71707)

The inspectors performed several plant tours and verified the operability of selected emergency systems, reviewed the tagout 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. Atmospheric Dump Valve (ADV) Operation

During the Unit 3 outage on April 7, 1989, the licensee tested the ADVs when the unit was in mode 3. The purpose of the test was to verify the proper operation of the ADVs in light of a recent problem with similar valves at Palo Verde. The valves at both SONGS and Palo Verde were supplied by Control Components Incorporated (CCI), although the SONGS valves are a different size and configuration. The ADVs at Palo Verde failed to open upon demand. This failure was attributed to excessive bonnet pressure caused by abnormally high leakage past the main valve plug piston ring (beyond the pilot valve venting capacity), such that the actuator was unable to overcome the excessive bonnet pressure and open the ADV. Similar problems were also experienced at other facilities using similar valves supplied by CCI. The NRC issued Information Notice 89-38 on April 5, 1989, to inform the industry of the potential generic problem.

When ADV 3HV8421 was tested from the control room with 15% demand, it was observed that the ADV's stem moved about 5% and the pilot vent valve opened immediately. However, the stem did not continue to open the main valve plug in response to the increased demand to 75% until about 90 seconds later. The licensee recalibrated the signal converter and the valve positioner. The ADV was retested without significant improvement in response. The licensee

instrumented the valve actuator and found that the specified pressure was applied to the actuator almost immediately upon demand and concluded that the actuator performed properly. The licensee then tested ADV 3HV8419 and it opened promptly and smoothly in response to the demand signal from the control room. The licensee concluded that the slow response of 3HV8421 was attributed to the increased leakage of steam through the piston ring, requiring additional time for the valve bonnet pressure to be vented by the pilot valve. Nevertheless, the licensee considered the valve to be operable per the FSAR description.

After discussion with the NRC, the licensee performed a 10 CFR 50.59 Safety Evaluation of the ADV Design for SONGS 2&3 as an interim disposition for Nonconformance Report (NCR) G-949. The recommended actions, which were implemented by the licensee, are summarized as follows:

* Increase the setting of the actuator supply pressure from 60 psig to the vendor recommended value of 80 psig.

* Test all Unit 2&3 ADVs bi-weekly as part of the routine surveillance program. The main valve must open within 120 seconds to be considered operable. The actual stroke time will be recorded and trended for evaluation by Station Technical and the test frequency will be adjusted accordingly.

* Revise procedure SO23-3-2.18.1, "Atmospheric Dump Valve Operation", to include abnormal operation instructions for excessive bonnet pressure.

* Conduct enhanced operator training on the operation of the ADV, including manual operation (which was already part of the remote shutdown operations training per 10CFR50 Appendix R). Visual aids were posted near the ADVs to instruct the operators regarding proper local manual operation.

In addition, the licensee concluded that the problem at Palo Verde did not apply directly to SONGS due to the following differences:

	SONGS	Palo Verde
ADV size	8"	10"
Bonnet drain	yes	none
ADV block valve	yes	none
Pneumatic control volume booster	yes	none

SONGS has not experienced difficulties with the ADVs in the past, except one anomaly due to a maintenance error during valve

reassembly. In addition, when the other ADV on Unit 3 (3HV-8419) was tested and both ADVs on Unit 2 were tested (2HV8419 and 2HV8421) from April 8 - 14, 1989, they all stroked smoothly and promptly upon demand. The licensee planned to modify the ADVs to incorporate improved piston ring design (to limit bonnet leakage) and enlarged pilot valves (to increase the bonnet venting capacity). The licensee also planned to propose a Technical Specification change to address the ADV operation. Presently, only the closure time is specified for containment isolation.

The inspector reviewed the licensee's 50.59 evaluation, interim resolution of NCR-G949, revised operating procedure, and operator training. The inspector also observed the stroking of the ADVs both remotely from the control room and manually at 3HV8421 by the handwheel. After confirming that the ADVs operated properly, the licensee restarted Unit 3 on April 15, 1989.

b. Motor Operated Valve Failure

During the restart of Unit 3 on April 7, 1989, a plant operator attempted to open the Safety Injection Tank (SIT) discharge valve (3HV-9350) in order to place the SIT in service. The valve experienced difficulty in responding to the control signal. The licensee inspected the Limitorque valve actuator and discovered that the key which locked the motor shaft and pinion gear had moved and allowed the motor to spin freely. The setscrew securing the key was found to be loose and it was not staked per the current maintenance procedure S0123-I-6.8, "Actuators - Limitorque Models SMB-0 through SMB-4 and SB-0 through SB-4 Disassembly, Inspection, Repair and Assembly". As a precaution, the licensee inspected the other three SIT discharge valves and did not find any loose set-screws on the motor pinion gears, though they were not staked.

The licensee stated that these MOVs were placed in service before the staking requirements were implemented. Of the approximately 270 safety related MOVs at SONGS, all were tested with the MOVATS technique. About 125 of them had the motor pinion gear setscrew inspected and staked per S0123-I-6.8 during maintenance activities which required motor removal. The licensee intended to stake the remaining MOV setscrews during the next maintenance activity requiring motor removal.

In response to the concern raised by the NRC, the licensee committed to inspect and stake the motor pinion setscrews of the uninspected MOVs at the rate of 15% per year, or during the next maintenance activity requiring motor removal. The inspector will review the preliminary results of these inspections following the next Unit 2 refueling outage which is currently scheduled to begin in October, 1989. This is an open item (361/89-07-01).

No violations or deviations were identified.

4. Evaluation of Plant Trips and Events (93702)

a. Unusual Event on April 7, 1989 (Units 1, 2 and 3)

On April 7, 1989, at 1:23 p.m., the licensee declared an Unusual Event (UE) due to seismic activity. A magnitude 4.6R earthquake centered at Newport Beach experienced at 1:08 p.m. was annunciated in the Unit 1 control room. Unit 1 was in Mode 5 and Unit 3 was in Mode 3, while Unit 2 was in Mode 1 at 100% power. The licensee verified that damage did not occur to safety systems, in accordance with station procedures, and the UE was terminated at 3:30 p.m..

b. Unit 3 Trip on Turbine Trip

On April 7, 1989, at 5:55 a.m. (PDT), the unit tripped from 100% power. The operator implemented the standard post-trip actions and verified proper plant response. Based on the evaluation of the sequence-of-events recorder and the operators' recollection, the licensee determined the output breaker of one of the two motor-generator (MG) sets had opened and caused a low voltage condition on the control element drive mechanism control system (CEDMCS) bus. Although the low bus voltage was able to hold the control element assemblies, two of the four undervoltage (UV) relays on the bus dropped out (anticipating a reactor trip condition) and signaled the turbine to trip. The turbine trip then initiated a reactor trip.

The licensee initiated a root cause evaluation to address the two observed anomalies: why the MG set output breaker opened and why the redundant MG set did not maintain the bus voltage as designed.

Spurious opening of an MG output breaker had occurred four times previously at SONGS 2&3. In addition, at the time of the April 7 event, one of the Unit 2 breakers was instrumented for trouble-shooting. In each instance, the redundant MG set was able to carry the load without causing a turbine trip. The licensee was unable to repeat the spurious breaker opening during troubleshooting, as was the case during previous efforts. The breaker was instrumented to monitor its performance continuously.

During troubleshooting of the UV relays that prematurely dropped out, the licensee found that the UV relays were set at 223 volts. This setting was established during the recent refueling outage based on the midpoint of the vendor's recommended range. The nominal bus voltage was 240 volts and the worst case transient voltage was less than 225 volts when the output breaker of one MG set was opened. Thus, it appeared that the MG set output voltage was set too low. The licensee reevaluated the setpoint and specified the nominal bus voltage to be set at 245 +/- 5 volt. Furthermore, the licensee specified that the UV relays be set at 214 volts, similar to Unit 2, based on the low end of the vendor's recommended range.

The unit was restarted and returned to power on April 17, 1989, without further problems related to the CEDMCS.

No violations or deviations were identified.

5. Monthly Surveillance Activities (61726)

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

a. Observation of Routine Surveillance Activities (Unit 1)

SO1-12.8-5 (TCN 2-1)	Cold Operability Test of the Containment Spray Actuation System
SO1-12.8-22 (TCN 0-3)	RCS Vent Valve Test

b. Observation of Routine Surveillance Activities (Unit 2)

SO23-3-2.18.1	Atmospheric Dump Valve Operation
SO23-3-3.25	Power Distribution and Burnup Log

c. Observation of Routine Surveillance Activities (Unit 3)

SO23-3-2.18.1	Atmospheric Dump Valve Operation

d. Steam Generator Tube Inspection Surveillance Interval (Unit 1)

Unit 1 Technical Specification 4.16 state that inservice inspection of steam generator tubes shall be conducted not less than 10 nor more than 24 calendar months after the previous inspection. Although not explicitly stated, the inspector considered that the 25% extension normally available for completing surveillance requirements was not applicable in this case. This interpretation appeared consistent with the discussion provided in RG 1.83. The inspector discussed this observation with the licensee and noted that the licensee had intended to apply the 25% extension to the steam generator tube inspection surveillance interval, which would extend the inspection from March to September, 1990. The next refueling outage for Unit 1 would occur in November, 1990, and the licensee had intended to get a Technical Specification exemption to permit operation from September until the refueling outage in November before conducting the next steam generator tube inspection. The licensee stated that the steam generator tube inspection frequency requirement would be reevaluated. This is an open item pending completion of licensee action (206/89-07-01).

6. Monthly Maintenance Activities (62703)

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

a. Observation of Routine Maintenance Activities (Unit 1)

M089031907	Feedwater Pump B Breaker Maintenance (S1-152-11C04)
M089041549	Reactor Trip Test - Post Maintenance Testing
M088120352	Annunciator Failed to Alarm (S1-MIS-UA-ELE-02)

b. Observation of Routine Maintenance Activities (Unit 2)

M089031241	Containment Post-LOCA Hydrogen Monitor Calibration

c. Observation of Routine Maintenance Activities (Unit 3)

M089040617	Main Steam ADV Calibration
M089042695	Troubleshooting Core Protection Calculator (CPC) Channel D

No violations or deviations were identified.

7. Engineered Safety Feature Walkdown (71710)

During the cycle 10 refueling outage on Unit 1, the inspector walked down portions of the following systems:

Auxiliary Feedwater	P&ID 5178220, 5178221 and 5178222
Main Feedwater	P&ID 5178205
Component Cooling Water	P&ID 5178310, 5178311 and 5178312
Safety Injection	P&ID 5178115

These system walkdowns were conducted in conjunction with modification activities being completed by the licensee, as further described in paragraph 8 of this inspection report.

No violations or deviations were identified .

8. Plant Modification and Refueling Activities (37700, 37828, 92703)

As discussed in paragraph 8.d of NRC Inspection Report 206/89-01, a number of technical issues were identified in a confirmatory action letter (CAL) dated January 31 and in a followup letter dated February 8, 1989, for licensee resolution prior to Unit 1 restart from the Cycle X refueling outage. The inspectors reviewed design change packages, observed work, and verified installation of plant modifications relative to these technical issues and other issues that were identified during the current Unit 1 outage. Although one unresolved item and a number of open items were identified relative to the Unit 1 restart issues, these items did not directly affect plant operation and resolution of these

items was not considered necessary prior to Unit 1 return to service. The licensee's actions to address the restart issues appeared to be acceptable for Unit 1 startup and continued operation. The inspectors made the following specific observations:

a. Electrical Overload Due to Swing Bus Alignment (LER 1-88-19)

The licensee identified that a failure of the Train B safeguards load sequencing system (SLSS #2) would result in a failure to trip the feeder breaker for 480V bus #3, which could cause the Train A diesel to be overloaded during an event.

During the current outage, the licensee corrected this deficiency by changing SLSS #1 (Train A) to include a trip signal for feeder breaker 11C11 upon initiation of a safety injection signal (SIS) or safety injection signal with concurrent loss of power (SIS/LOP). The licensee committed to implement administrative controls for operation of tie breakers 52-1103, 52-1203 and 52-1303, and to install caution tags to prevent inadvertent manual operation of these breakers which could tie Train A and Train B together. The inspector reviewed DCP 5113.4 for changing the control logic for circuit breaker 11C11 and observed post-modification testing relative to this design change. The inspector also verified that caution tags were hung on circuit breakers 52-1103 and 52-1203. The licensee concluded that additional administrative controls were not warranted since these circuit breakers are normally operated remotely from the control room, and specific instructions did not exist for manual operation. The licensee's resolution of this item was considered to be acceptable.

b. Steam Generator Wide Range Level Instrumentation (LER 1-88-20)

On January 23, 1989, the licensee identified that steam generator wide range (SGWR) level indicators LI-450A, LI-451A and LI-452A were not powered by a vital bus. This was contrary to the licensee's commitment for addressing post-TMI Action Plan Item II.E.1.2. The licensee further identified that the SGWR level indicators were not environmentally qualified.

The licensee issued Revisions 2 and 4 to Design Change Package (DCP) 3364.00TJZ to correct this deficiency. The DCP converted existing narrow range steam generator level transmitters LT-2400A, B, and C (Train A) and LT-3400A, B and C (Train B) to wide range, environmentally qualified level indicators. In addition, the power supplies for level indicators LI-450A, LI-451A and LI-452A were changed from plant lighting panels to vital buses. Current-limiting fuses were used for isolation purposes. The licensee's resolution of this item appeared to be acceptable. However, the inspector requested that the licensee confirm the appropriate use of current-limiting fuses with NRR. This item remains open pending completion of licensee action and post-modification testing during power escalation (206/89-07-02).

c. Charging Pump Motor G-8B Rewind Qualification (NCR S01-P-6764)

During a review of pump motor maintenance history for charging pump G-8B, the licensee identified a memo to file which indicated that the charging pump motor had been rewound in 1972. This repair activity was not identified previously when environmental qualification (EQ) was established for the charging pump motor, and sufficient documentation of this repair was not available to satisfy EQ requirements.

The licensee's justification for continued operation (JCO) for this condition, dated December 29, 1988, was reviewed and accepted by NRR for Unit 1 restart. The acceptability of continued operation until the next scheduled refueling outage with this condition was pending additional NRR review and will be the subject of separate licensing correspondence.

The licensee's identification of this poorly documented maintenance activity placed some uncertainty on the current status of equipment qualification. In order to address this concern, the licensee conducted an extensive search of NCRs and operators' logs to identify any additional maintenance activities that could place equipment qualification status in question. The licensee did not find any additional EQ deficiencies during this records search. The inspector questioned the amount of confidence that could be placed in this review to establish equipment maintenance histories, and specifically questioned the completeness of operators' logs during plant outages. The inspector noted that the licensee did not conduct an extensive review of memos written to file (how the charging pump motor discrepancy was originally identified) or of deficiency logs. This is an open item pending licensee action to address the inspector's concern (206/89-07-03).

d. Residual Heat Removal Piping Wall Thickness (NCR S01-P-6896)

During in-service inspection, the licensee identified that the residual heat removal (RHR) suction piping (line RCS-5002-8") was Schedule 120 instead of Schedule 160 as specified by the system design documents.

The licensee provided additional information to the Region V office regarding this NCR during a telephone call on March 29, 1989. The licensee stated that the installation of Schedule 120 pipe in this location was acceptable per the original Westinghouse "E" Specifications and a related field change notice. The licensee stated that they had performed thickness measurements on samples of similar piping in the RHR and reactor coolant systems and had found no other indications of improper piping schedule. Based on the information provided, the NRC concluded that the licensee had taken acceptable actions for unit restart. The associated enforcement item (50-206/89-03-02) remains open, however, pending verification of completed licensee corrective actions.

e. CCW Flow to RHR Heat Exchanger Temperature Control Valve -- Potential Single Failure (LER 1-89-03)

As a result of evaluating the instrument air system in response to Generic Letter 88-14, the licensee identified that during certain failure scenarios, the component cooling water (CCW) throttle valves (TCV-601A & B) for the residual heat removal (RHR)/letdown heat exchangers could fail open and allow the CCW pumps to exceed run-out limits and divert flow from the recirculation heat exchangers.

The licensee's resolution of this problem was to isolate CCW to one train of RHR heat exchangers and to limit the maximum flow to the in-service RHR heat exchanger to 500 gpm by limiting the stroke on valves TCV-601A & B (PFC 89-008). The licensee contracted Stone and Webster Engineering Corporation to determine the minimum CCW system flow requirements for the in-service RHR heat exchanger (to verify that 500 gpm was adequate), and to determine whether the proposed resolution would satisfy RHR heat removal requirements and resolve CCW pump run-out concerns. The inspector reviewed the Stone and Webster calculations and the safety evaluation contained in the PFC, and made the following observations:

(1) A clear definition of the design bases, including system parameter requirements, for the RHR and CCW systems was not included in the analysis. The basis for Technical Specification limiting condition for operation (LCO) 3.1.2 stated that a single RHR train provides sufficient capability for removing decay heat in Modes 4 and 5. The Updated Final Safety Analysis Report (UFSAR) stated that the RHR system is placed in operation approximately four hours after reactor shutdown. The licensee's safety evaluation did not address the effect of reducing CCW flow through the RHR heat exchangers on these design bases.

The licensee acknowledged the inspector's concerns and performed additional calculations to demonstrate that CCW was still capable of removing the maximum decay heat load during reactor shutdown. The licensee stated that the safety evaluation would be revised to reflect these results and to more clearly state the design bases of the system. The licensee further stated that the ability to cool down the reactor coolant system (RCS) within 20 hours as stated in the UFSAR was not critical and was a statement of the functional capability of the system as originally designed rather than a design basis for the system. With regard to steam generator tube rupture considerations, the licensee stated that any release to the atmosphere would be terminated shortly after the RHR system was placed into service and that the only critical parameter was the ability of the RHR system to handle the maximum decay heat load following the reactor shutdown. The licensee's actions to address the inspector's concerns were considered to be acceptable. This item remains open pending

licensee action to properly document and address the system design basis in the safety evaluation.

(2) The accuracies of the analyses, including consideration for assumptions that were made, were not documented. This is an open item pending licensee resolution.

(3) The analysis (Stone and Webster Calculation 18872-NP(B)-002) stated that the RHR heat exchanger inlet temperature could reach 550 degrees F during a load rejection, but the design data sheet stated that the RHR heat exchanger was only designed for 400 degrees F. This condition was not evaluated. The licensee stated that at least one load rejection had occurred (in 1981) and no indication of heat exchanger degradation was identified during the 10-year inservice inspection that was conducted during the current outage. The licensee further concluded that this condition was not a problem because the letdown flow through the RHR heat exchanger was less than one tenth of the design flow, and preliminary stress calculations indicated that this condition was acceptable. The licensee's actions to address this item were considered to be acceptable for Unit 1 restart. However, this item remains open pending licensee completion of a formal evaluation of this condition, including vendor concurrence.

(4) The analysis concluded that the onset of cavitation could occur in the operating pump during post-LOCA recirculation operation, and it was judged that this condition would be acceptable for approximately 30 days without resulting in pump failure. The licensee tested the CCW pump under worst-case flow conditions for several hours and confirmed that the pump did not exhibit any fluctuations in flow, discharge pressure or running current, although the cognizant engineer noted minor indications of void collapse noises at the pump discharge. The inspector noted that the licensee had not obtained vendor concurrence with the conclusion that long term pump operation with marginal cavitation was acceptable. This item remains open pending licensee action to obtain vendor confirmation.

Items (1) through (4) above will be tracked as followup item 206/89-07-04.

f. <u>Containment Spray Flow Diversion (LER 1-89-08)</u>

During follow-up review of the CCW single failure problem discussed in paragraph 8.e of this report, the licensee identified that containment sphere fire loop spray valve CV-92 could fail open and divert flow from the sphere spray header.

The licensee resolved this problem by implementing proposed facility change (PFC) 1-89-011, which installed a set of contacts in series with the control switch for CV-92 solenoid valve SV-116. The

inspector reviewed the PFC and verified that control switch modifications for CV-92 were as described. The licensee's resolution of this item was considered to be acceptable.

g. Steam Generator Tube Sleeve Discrepancies (LER 1-88-018)

In February 1988, during the mid-cycle outage that was conducted following the cycle 9 refueling outage, the licensee performed eddy current testing of steam generator tubes and identified that the upper rolled expansion joint did not exist on five tube sleeves and that the lower expansion joint did not exist on one tube sleeve. The licensee documented this condition on NCR SO1-P-6419, and performed a safety evaluation to address this condition. The licensee plugged all leaking tube sleeves and concluded that continued operation of the unit was acceptable without the rolled expansion joints until the cycle 10 refueling outage. Westinghouse Electric Corporation (WEC) reviewed the licensee's safety evaluation and provided comments in a letter dated May 9, 1988. On December 12, 1988, following a phone notification from WEC, the licensee determined that operation of the steam generators without the tube sleeve upper rolled expansion joints was outside the design assumptions for the tube sleeves, and that the affected steam generator tubes had inadequate structural integrity. The licensee's Onsite Review Committee concluded that this condition was a potential nuclear safety hazard. This condition was reported to the NRC in LER 206/88-18, which stated in part, "Analysis has shown that during certain postulated accidents (e.g., main steam line break), sleeved tubes without roll expansions may not provide sufficient load-carrying capability to preclude tube pullout. The pullout of one or more tubes could result in primary-to-secondary leakage sufficient to exceed allowable offsite dose limits." Unit 1 was shut down on November 28, 1988, for the current (Cycle 10) refueling outage.

The licensee reviewed eddy current test data for the Unit 1 steam generators, conducted additional eddy current examinations, and concluded that 156 tube sleeves did not have proper indication of rolled expansion joints. As corrective action, the licensee removed these steam generator tubes from service by plugging and provided the details of the steam generator tube evaluation to the NRC for review in a letter dated February 6, 1989. In a letter to the licensee dated February 23, 1989, NRR concluded that the licensee's actions to resolve this issue were acceptable.

The inspector reviewed NCR SO1-P-6419, which documented the licensee's safety evaluation supporting Unit 1 startup from the cycle 9 midcycle outage. The inspector also reviewed the WEC letter dated May 9, 1988, which provided comments relative to the licensee's safety evaluation. The inspector observed that the WEC letter stated in part, "An assessment of the thermal hydraulic response of a sleeved tube without a roll expansion would be required to address the consequences of a (steam line break) SLB." The inspector noted that the licensee did not complete this

assessment until after Unit 1 was returned to service and subsequently shut down for the cycle 10 refueling outage. Upon completion of this assessment, the licensee concluded that missing rolled expansion joints in steam generator tube sleeves were an unreviewed safety question and a potential nuclear safety hazard. This is an unresolved item pending additional NRC review (206/89-07-05).

h. Diesel Generator Bearing Rotation Problems (NCR SO1-P-6921)

In 1982, the licensee identified that the connecting rod bearing shells for bearings #5 and #8 on the #1 diesel generator were rotating backwards approximately 220 degrees during engine shutdown. The licensee performed extensive testing and evaluation during the current outage to determine the cause for this anomaly, and discussed the root cause of this deficiency in a letter to the docket file dated March 30, 1989. The licensee concluded that the cause of bearing rotation resulted from high spots on the bearing journals. The high spots were hand-stoned to fair in with the journal diameter and additional indications of bearing shell rotation have not recurred. The licensee will continue to periodically monitor for this condition. The licensee's actions relative to this issue are considered to be acceptable.

i. Refueling Water Pump G27S Jumper (LER 1-88-16)

While conducting circuit testing relative to refueling water pump (RWP) G27S, the licensee identified that an unauthorized jumper was located in the pump control circuit. The jumper could have prevented the automatic start of G27S upon receipt of a containment spray actuation signal (CSAS) during certain postulated conditions.

The inspector reviewed NCR SO1-P-6774 and maintenance order (MO) 88110214, which implemented the NCR disposition. The MO documented that the control circuit for pump G27S was restored to the design configuration, and that functional testing was completed to verify the final configuration. The licensee's actions to resolve this item were considered to be acceptable.

j. Safety Injection Miniflow Valve Logic (LER 1-89-11)

During stroke testing, the licensee identified that main feedwater pump (MFP) condensate miniflow valves CV-36 and CV-37 did not stroke within the 9 seconds assumed in the safety analysis (NCR SO1-P-6751). In pursuing this deficiency, the licensee identified that the limit switches for MFP safety injection miniflow valves CV-875 A&B were not wired in accordance with Load Sequencer Drawings 5149179 and 5149182. CV-36 and CV-37 should receive a signal to close from the "not fully closed" limit switches on CV-875 A&B during a safety injection actuation signal (SIAS). Instead, the closing relays for CV-36 and CV-37 were wired to the open limit switches on CV-875 A&B, which caused a 12 second delay in closing the condensate miniflow valves.

The inspector reviewed NCR SO1-P-6751 (Rev.4) which stated that the limit switch wiring configuration specified by the Load Sequencer Drawings for mini-flow valves CV-875A & B was different from the field configuration and the configuration that was specified by the elementary drawing (5149858 Rev.11), with the configuration specified on the load sequencer drawings being correct. The inspector observed that no corrective action was specified on the NCR to determine why the inconsistency existed and to verify the accuracy of other field installations and elementary diagrams relative to the load sequencer drawings. This is an open item pending licensee resolution (206/89-07-06).

After the limit switches on CV-875A & B were rewired for the design configuration, CV-36 and CV-37 were tested to verify proper operation. As a result of this testing, the licensee wrote NCR SO1-P-7159 which stated that the response times specified on the load sequencer drawings for CV-36 and CV-37 to receive a close signal were in error. The inspector reviewed the NCR and noted that the load sequencer drawings specified a response time of less than one second, but during testing the actual response time was greater than two seconds (the licensee safety analysis indicated that response within 6 seconds is acceptable). The inspector observed that no corrective action was specified on the NCR to determine the cause of this discrepancy and to verify the accuracy of any additional design data contained on the load sequencer drawings. This is an open item pending licensee resolution (206/89-07-07).

At the exit meeting discussed in paragraph 11 of this inspection report, the inspector noted that this item was indicative of a poorly defined surveillance program. This issue was identified as a concern previously, and additional follow-up inspection relative to this item will be documented under NRC Open Item 206/89-06-07.

k. Potential Cracking of Steam Generator Tube Plugs (NRC Information Notice 89-33)

NRC Information Notice 89-33, dated March 23, 1989, identified that certain steam generator tube plugs supplied by Westinghouse Electric Corporation (WEC) may be susceptible to intergranular cracking. In a letter dated April 4, 1989, WEC notified the licensee that 50 mechanical steam generator tube plugs were installed at SONGS Unit 1 that may be susceptible to intergranular cracking. The licensee issued NCR SO1-P-7166 to address this concern.

The inspector reviewed the licensee's interim NCR disposition which stated that the plugs in question have approximately 713 EFPD available before failure could occur (per WEC letter #SCE-89-553 dated April 17, 1989), and cycle 10 operation would only use approximately 461 EFPD. On this basis, the licensee concluded that operation of Unit 1 during fuel cycle 10 with this condition was acceptable. Final resolution of this item by the licensee is pending further analysis by WEC. The licensee's actions relative to this item were considered to be acceptable.

l. MOV-358 Uninteruptible Power Supply (PFC-1-88-3501.03)

Recirculation valve MOV-358 (Loop C) originally received power from motor control center (MCC) 3, which was normally powered by Train A. In order to provide for electrical independence, the licensee issued Proposed Facility Change (PFC) 1-88-3501.03 to power MOV 358 from the uninteruptible power supply (UPS) for loop C safety injection valve MOV-850C. As discussed in the enclosure 2 inspection report, the licensee experienced difficulty with the UPS upon completion of this modification. The licensee subsequently determined that the UPS battery was inadequate, and resolved the problem by using the security battery for the UPS. The PFC was revised to account for this change and post-modification testing was conducted to verify that the installation was adequate. The inspector reviewed the PFC and observed that the security battery was disconnected from all other loads and that it was upgraded for Class 1E service and seismic application. The licensee's actions to resolve this item were considered to be acceptable.

m. Overpressure Protection System (NCR SO1-P-7160)

The licensee identified that the maximum relief pressure setpoint of 500 psig allowed by Technical Specification 3.20 for the overpressure protection system was nonconservative. The overpressure protection system setpoint was based on the reactor vessel heatup and cooldown curves (Technical Specification 3.1.3) for 16 effective full power years (EFPY), and the 500 psig set point was arrived at by design calculation DC-1562 dated February 10, 1984. When the reactor vessel heatup and cooldown curves were revised on May 21, 1986, DC-1562 was not revised to reflect new pressure set point requirements for the power operated relief valves (PORVs).

The licensee dispositioned NCR SO1-P-7160 to reset the PORVs to relieve at 420 psig, which was in accordance with revised design calculation DC-1562. The licensee discussed this problem with the SONGS Unit 1 Project Manager and agreed to submit a Proposed Technical Specification Change Request to address this problem within 90 days following Unit 1 return to service. The inspector reviewed the following procedures relative to this issue:

SO1-3-1 (TCN5-5)	Plant Startup From Cold Shutdown to Hot Standby
SO1-3-5 (TCN5-4)	Plant Shutdown From Hot Standby to Cold Shutdown
SO1-3-10 (TCNO-5)	Plant Operations During Cold Shutdown
SO1-II-1.250.1 (TCNO-6)	Surveillance Requirement -- Overpressure Mitigation System Power-Operated Relief Valve (PORV) PORVs CV-545 and CV-546 Channel Test (31-Day Interval)

The inspector observed that procedures SO1-3-10 and SO1-II-1.250.1 had not been revised to reflect the lower PORV pressure setpoint of 420 psig. It was not clear how the licensee satisfied the surveillance requirement after the PORV lift pressure was lowered to 420 psig, and what the licensee's intentions are relative to cold shutdown operations. This is an open item pending resolution by the licensee (206/89-07-08).

n. Intake Structure Inspection and Repair (PFC 1-88-3440)

LER 206/84-08 dated September 5, 1984, reported that excessive rebar corrosion was found in the Unit 1 intake structure during inspections. The licensee installed strap plates over the concrete surface where rebar corrosion existed (PFC 1-84-060), and implemented a surveillance program to inspect the intake structure during subsequent refueling outages. During the current refueling outage surveillance inspection, the licensee identified additional rebar corrosion and installed strap plates in the affected areas in accordance with PFC 1-88-3440 requirements. The inspector viewed the video tape that was taken of the surveillance inspection and observed that underwater clarity was poor and that hydrolazing to clean the concrete surfaces did not appear to be very effective. The inspector also noted that the licensee's surveillance procedure did not require torque verification of the strap plate bolts to verify structural integrity. This item remains open pending further NRC review of the licensee's intake structure surveillance requirements (206/89-07-09).

o. Diesel Generator Slow Start Modifications (PFC 1-88-3481)

The inspector discussed this modification with the licensee and reviewed proposed facility change (PFC) 1-88-3481, Revision 0, that was the controlling document for the change. This modification provides for a slow start of the D/Gs whenever a manual start is required (the D/G still fast starts on an automatic signal). The PFC was translated into design change package 3481.00 TE and subsequent functional testing was performed in accordance with SO1-XXVI-3481.00. The slow start feature limits fuel rack opening so that speed will increase to 430 rpm in 34 seconds. At approximately 32 seconds into the start sequence, the field flash circuit will energize for approximately 4 seconds. The licensee indicated that the fast start capability is tested every 18 months by surveillance procedure.

The inspector reviewed the PFC and noted that the appropriate reviews and approvals had been performed. The inspector also noted that an adequate 10 CFR 50.59 evaluation was performed for this modification. The inspector considered that the licensee's control and implementation of this modification were adequate.

p. Root Cause Of Spurious Number 2 Diesel Generator Starts (LER 1-89-05)

The inspector discussed the root cause of spurious starts on the number 2 diesel generator (D/G) for Unit 1 with the licensee. During these discussions, Edison personnel indicated that the D/G had started spuriously on 4 separate occasions. The first time was in 1981, the second time was in 1986, and the most recent times were on February 20 and March 17, 1989. The data for the first two spurious starts were sketchy, but the data for the most recent starts were fairly conclusive as to the root cause. In particular, the two recent starts occurred when an equipment operator had an occasion to open up 4KV panel 12C03 which contains the breaker and control circuit for one of the circulating water pumps. The back of panel door 12C03 contains the loss of bus voltage relay, 127-12X to the sequencer for number 2 D/G. Edison functionally tested and shake tested the relay in place, and performed continuity checks on the wiring, but no spurious D/G starts occurred. The licensee's investigation narrowed the cause down to this component, however. As a result, relay 127-12X along with relay 127-10X (which has several wires that are an integral part of relay 12X) were replaced. In addition, the licensee replaced the cases that these relays were housed in. This had not been done previously. The circuits and relays were functionally tested and found to be satisfactory. The parts that were removed will be sent to the laboratory for additional testing. The inspector considered that the licensee's actions were adequate and that this item was 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

89-04	Diesel Generator Load Sequencers Undervoltage Logic Design Deficiency
89-07	Reactor Protection System Outside of the Design Basis as the Result of Single Failure Susceptibilities
89-08	Containment Spray Flow Diversion Due to Single Failure Susceptibility of a Containment Fire Suppression System Control Valve
89-09	Delinquent Effluent Dose Determinations Due to Procedure Deficiency
89-11	Safety Injection Alignment Delay Contrary to Safety Analysis

Unit 2

88-25 R1 Spurious CRIS Train A Due to Relay Failure

89-03 CRIS Train B Spurious Actuation Due to Switch Failure

Unit 3

89-03 Delinquent Fire Watch Posting for Inoperable Fire Detectors Due to Programmatic Oversight

No violations or deviations were identified.

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

a. (Open) Open Item (206/87-27-02), ESF Single Failure Problems

The licensee identified several engineered safety features (ESF) single failure problems prior to the Cycle 10 refueling outage, and implemented administrative measures to justify continued operation until design changes could be completed during the Cycle 10 refueling outage. As discussed in paragraph 8 of this report, the licensee implemented a number of design changes to resolve the single failure problems that were identified and the administrative controls that were initially established are no longer required. However, as a result of the design changes, new administrative control requirements were imposed on the plant operators. The licensee was making an assessment of the impact that these administrative requirements will have on plant operation and defining measures to reduce operator action requirements. This item remains open pending licensee action to resolve this issue.

b. (Closed) Open Item (206/87-29-05), Failure of MOV-1202

The licensee conducted a review of Unit 1 motor operated valves to verify that the thermal overloads for other valves used in safety related applications were bypassed. The results of this review were documented in a memo to file dated June 7, 1988. The licensee also established an action plan to incorporate the requirements of Regulatory Guide 1.106 relative to thermal overloads into the Unit 1 design criteria.

The licensee's interim root cause of MOV-1202 failure to stroke, which was documented in NCR S01-P-6253, concluded that the operating speeds within the motor were such that the grease was forced from the gears which resulted in excessive frictional forces. The licensee changed the lubricant from Exxon Nebula EP-1 to Exxon Nebula EP-0, and required the gear boxes to be filled 100%. The licensee will continue to monitor the performance of MOV-1202 during Cycle 10 operation to verify satisfactory resolution of this problem. The licensee's actions to resolve this problem appeared to be acceptable. This item is closed.

c. (Closed) Open Item (206/89-06-05), Excessive Stroke Time for PORV CV-546

The inspector reviewed the licensee's evaluation of this problem, as documented on NCR SO1-P-7119. DCP 3341.0TE added a redundant solenoid valve for operating CV-546 from the dedicated safe shutdown (DSD) panel. The DCP piped the outlet port for the redundant solenoid valve to the vent of the existing solenoid valve (used during normal operation) which was contrary to the design requirements for ASCO solenoid valve Model #NP8316E35E. This piping arrangement accounted for the slow stroke time that was observed for CV-546. The NCR stated that CV-546 continued to operate normally from the control room and that the original accident assumptions were still met. The NCR also stated that operation of the PORV from the DSD panel was not credited by the accident analysis for mitigation of an overpressure transient, and that the slower stroke time still provided the ability to control reactor coolant system pressure from the DSD panel. The licensee planed to correct this problem during the cycle 11 refueling outage. The licensee's actions to address this item appeared to be acceptable. This item is closed.

d. (Open) Open Item (206/89-06-07), Component Surveillance and Post-modification Testing Requirements

The inspector observed that the licensee's program for conducting post-modification testing and surveillance testing was not well defined in that the functional requirements for plant equipment were not very well established and included in program development. Another example of this weakness was discussed in paragraph 8.j of this report. This item remains open pending licensee definition of testing requirements as a function of the design basis review effort.

e. (Closed) Open Item (362/88-08-01), Implementation of Vendor Manual Requirements

After additional discussion with the licensee following the previous inspection, the inspector determined that the licensee's program to implement vendor requirement appeared to be acceptable. This item is closed.

f. (Closed) Open Item (361/88-08-02), Control of Thread Sealant

In response to the previous inspection, the licensee issued TCN 2-3 to Maintenance Procedure SO123-I-1.7, "Maintenance Order Preparation, use and Scheduling". Section 6.13.3.3 was revised to clarify the control of consumables such as thread sealant. The inspector reviewed this procedure and found it addressed the concern. Thus, this item is closed.

g. (Closed) Open Item (362/88-08-02), Component Maintenance and Surveillance Requirements

The licensee initiated changes to applicable procedures to include the following:

* inspect the oil filter high dp indicator flag during the quarterly In Service Testing (IST);

* Overhaul the hydraulic relief valve at every third refueling outage.

These proposed actions were concurred in by the vendor, Paul Monroe. The inspector considered the licensee action to be satisfactory. This item is closed.

11. Exit Meeting (30703)

On April 28, 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.

REPORT DETAILS

Part 2 -- N. K. Trehan, NRR

1. Persons Contacted

Licensee Employees

*H. E. Morgan, Station Manager
R. Krieger, Operations Manager
*M. Merlo, Manager, Nuclear Engineering Design
*W. Strom, Supervisor, Nuclear Engineering
*D. Brevig, Supervisor, Onsite Nuclear Licensing
*J. Shipwash, Supervisor, Compliance
*S. Khamamkar, Electrical Engineer
*T. Graham, Electrical Engineer
*A. Thiel, Engineer
*G. Holloway, Nuclear Construction
*T. Garven, Quality Assurance Engineer
*C. Couser, Compliance Engineer
*R. Baker, Compliance Engineer
*J. Winter, Engineer

U. S. Nuclear Regulatory Commission
*F. R. Huey, Senior Resident Inspector
*J. E. Tatum, Resident Inspector

*Attended exit interview at the San Onofre Station on March 30, 1989.

2. Diesel Generator Sequencer Operation

During a loss-of-coolant accident (LOCA) with a concurrent loss of off-site power (LOP), the safeguards load sequencing system (SLSS) generates a (safety injection system) SIS/LOP sequencer signal. The SIS/LOP signal initially sends start signals to both diesel generators. Both diesel generators should start, reach their rated speed and voltage and load onto their respective 4kV buses simultaneously. However, during testing it was discovered that both diesel generators are not loaded simultaneously. Closing of one diesel generator breaker to its respective ESF bus will remove the undervoltage condition on the sequencer input and will prevent the unconnected diesel generator from automatically closing its breaker to the ESF bus and sequencing the loads. Consequently, if one diesel generator starts and energizes its bus in a shorter period of time than the redundant diesel generator, the LOP signal will clear and the output breaker for the lagging diesel generator will not close. Based upon the data associated with the actuation time of the bus undervoltage relays, it is necessary for the output breaker of the lagging diesel generator to close within approximately 0.8 seconds of the leading diesel generator. If this does not occur during a postulated SIS/LOP scenario, the automatic response capability of one of the two trains of safety related components may be lost. In the event of a single failure of the ESF train which receives power from the loaded diesel generator, both ESF trains would be unavailable.

As corrective action for this problem, the licensee installed time delay relays in the circuits of 4kV inputs to the sequencer for monitoring loss of power conditions. The relay will drop out instantaneously upon receipt of an undervoltage signal and will pick up 12 seconds after restoration of bus voltage. The 12-second time delay will ensure that both diesel generator breakers close before reset of the opposite train undervoltage signal to each sequencer occurs.

The licensee's actions appeared to be appropriate for Unit 1 restart. However, discussions were held with the licensee regarding the possibiity of eventual removal of the loss of power (LOP) signal in the diesel generator circuitry (with start of each diesel generator to be initiated by undervoltage on its associated bus). It appeared that this would make the starting circuitry more reliable. The licensee stated that this would be reviewed. (206/89-07-10)

3. Potential Overloading of 480V Bus Breakers, Transformers and Cables

During a newly postulated scenario of a line break in the pressurizer vapor space, the peak loading on 480V switchgear 1 and 2 could exceed the continuous current rating of their main feeder breakers following a safety injection actuation and starting and operating of the safety and non-safety loads. The design of San Onofre Unit 1 is such that the safety and non-safety buses are not segregated, except for the buses which supply the reactor coolant pumps. On the occurrence of a safety injection or loss of power signal, safety as well as non-safety loads are loaded onto switchgear 1 & 2. On the occurrence of a SIS/LOP, non-safety loads are shed. Calculation results indicated that the peak loads on 480V switchgear 1 and 2 could exceed the continuous current rating of their main breakers (52-1102 and 52-1202) during a SIS without LOP because the non safety loads would not be shed. The subject breakers (Westinghouse Model DB-50) are rated at 1600 amps continuous, and the load currents for the bus breakers are conservatively calculated to be 1896 and 1640 amperes (at 480V) respectively. These conditions would result in breaker heatup which eventually could result in breaker degradation and potential loss of power to both trains of the 480V buses.

As a result of this condition, the station service transformer rating and the power cable ampacities passing through the fire protection zone would be exceeded. This problem did not exist following a SIS actuation with a concurrent loss of offsite power, because the non-safety loads are automatically shed, thus eliminating the overload condition.

The non-safety loads involved under the new postulated scenario are:

* Instrument Air Compressor
* Pressurizer heaters
* Screen Wash Pump heaters
* Exhaust fans

The licensee performed a test on an equivalent DB-50 breaker and determined that under the worst-case conditions, some temperatures recommended in ANSI C37.50, "Test Procedures for Low-Voltage AC Circuit Breakers Used

in Enclosures," would be exceeded. However, the additional temperature rise allowed by ANSI for 4-hour breaker emergency overload conditions would not be exceeded. The licensee also performed a review of station service transformer rating and power cable ampacities. According to the licensee, based on the 4-hour limits prescribed in ANSI C57.92, the transformer overload condition (133% of 1400kVA OA rating at 65C rise) would result in a negligible loss of transformer life, even without crediting the transformer forced air fans. Overloading of the station service transformer therefore did not appear to be a short-term, or Unit 1 restart, concern; however, longer-term resolution of this issue is the subject of additional NRR review.

The main power cables feeding 480V switchgear #1 are routed through a 34-inch fire barrier. The licensee had reworked the fire barrier to preclude the thermal effects of power cables and has provided a minimum 10" separation as required; therefore, this concern is resolved.

The licensee had tested the breakers and concluded that the temperature rise allowed by ANSI for 4-hour breaker emergency overload conditions would not be exceeded. Moreover, the plant has operated for almost 20 years without any degradation. Therefore, plant operation with these breakers for one additional operating cycle was determined to be acceptable. The licensee committed to find a viable solution from one of the following alternatives for subsequent operation:

a. Rerate the breakers to 1900 amps.

b. Replace the DB-50 breakers with newer Westinghouse breakers type DS-420.

c. Shed non-safety loads on a safety injection signal.

This item remains open pending licensee action (206/89-07-11).

4. <u>480V Swing Bus No. 3</u>

480V bus #3 is a swing bus normally powered from 4kV bus 1C (Train A) through station service transformer SST #3 and breaker 1303. In case the feed from SST #3 is unavailable, the swing bus can be fed either from 480V switchgear bus 1 (Train A) by closing the breaker 1103 or from 480V switchgear bus 2 by closing the breaker 1203. These breakers are electrically interlocked so that the independence of both the trains is maintained. A potential to lose the independence of both the trains exists, however, when the swing bus is being powered from Train A through breaker 1303 and the tie breaker 1203 powered from Train B is manually closed. General Design Criterion 17, "Electric Power Systems," requires, in part, that the onsite electric power supplies including the onsite electric distribution system have sufficient independence to perform their safety functions assuming a single failure.

Visual inspection of the tie breakers revealed the following:

a. A trip button and trip indication exist on the breaker.

b. A close mechanism on the breaker exists but the handle for manually closing is located at the tool rack about 15 feet away.

To prevent these two buses from being tied together while both are energized, the licensee committed to provide adequate administrative controls for the operation of tie breakers 1103, 1203 and 1303 and to install "Caution Tags" before restart of Unit 1 (for further discussion, see paragraph 8.a of Report Details, Part 1).

5. Diesel Generator #2 Spurious Starts

Diesel generator No. 2 started spuriously on two occasions on the receipt of an undervoltage signal. The undervoltage relay 127-12X is mounted on the door of the cubicle of the cooling water pump. On both occasions, the operator opened the cubicle door of the breaker for one of the circulating water pumps, and in doing so actuated the 127-12X relay, which started the diesel generator on undervoltage.

The licensee had tried to duplicate the event of starting the diesel generator by opening and closing the door of the circulating water pump cubicle but could not repeat it. As a precaution, the licensee replaced the existing seismically qualified 127-12X relay and relay 127-10X with similar relays, and installed new wiring. The removed relays were being sent to the laboratory for a shaker test. The licensee had taken appropriate action to resolve this problem and therefore, this item is closed.

6. Installation of Uninterruptible Power Supply (UPS) For MOV 358

Correct operation of the recirculation system loop 'C' was not assured in that motor operated valve MOV 850C was powered from an uninterruptible power supply, but MOV 358 (emergency core cooling recirculation flow to loop 'C') was supplied from Train A which supplies power to loop 'A'. Train 'A' powered the safety system of loop 'A' as well as MCC 3 which in turn powered MOV 358 of loop 'C'. On the failure of Train 'A', the potential of losing both loops 'A' and 'C' existed. Therefore, the licensee had changed the power supply for MOV 358 from motor control center No. 3 to the uninterruptible power supply of loop 'C'. However, the licensee also discovered that when operating MOV 358 on the UPS, the voltage drops from 125V dc to 110V dc which is not enough to stroke the valves. The licensee was taking corrective action to resolve this problem.

By switching the power supply of MOV 358 from motor control center 3 to the UPS, correct operation of the recirculation system loop 'C' is assured by the operability of the UPS for MOV 850C which also supplies MOV 358. Therefore, this design change was considered acceptable.

The UPS design basis load profile duration prior to the refueling outage was 100 seconds and MOV 850C was started successfully with a battery terminal voltage of 116V dc. With the addition of MOV 358 on the UPS and an initial battery voltage of 114V dc, the load profile is extended to 32 minutes, which would impair the ability of MOV 850C and MOV 358 to

perform their intended design function. The battery does not maintain 105V dc at the inverter input during stroking of MOV 850C with an initial battery voltage of 114V dc. This condition causes the inverter to shut down prematurely on dc undervoltage.

The licensee had changed silicon controlled rectifiers (SCRs) and performed testing/troubleshooting to gather additional data and to test possible circuit modifications to resolve this problem. The licensee had also issued a nonconformance report SCI-P-7146 and committed to resolve this problem with the UPS before the restart of Unit 1 (for further discussion, see paragraph 8.1 of Report Details, Part 1)..

7. Interlocks Associated With the Feedwater Pumps

Under normal conditions, system interlocks should assure that the injection of feedwater to the reactor by the safety injection system cannot occur. These interlocks include:

a. Actuation of the safety injection relay which deenergizes the condensate and heater drain pumps and closes the flow path for condensate, thereby preventing injection of feedwater into the coolant system.

b. Interlocks between the condensate isolation valves at the feedwater pump suction and the safety injection header isolation valves at the pump discharge which prevent the opening of one valve unless the other is closed.

It is necessary to prevent intrusion of feedwater into the reactor coolant system. Injection of feedwater has the potential to dilute the system and create a potential for a reactivity excursion. The design should be such that on the receipt of safety injection signal, the miniflow valve HV 875A for the safety injection valve HV 851 should open and the miniflow valve CV 36 for the feedwater system HV 852 should close immediately. The licensee discovered that HV 852 was not closing immediately but staying open for another 12 seconds.

The licensee determined that the design as installed had incorrectly used Limit Switch 1 (full open indication) of valve HV 875 in the control of valve CV 36, thus allowing CV 36 to stay open for 12 seconds which is the stroke time of valve HV 875. The licensee had revised the drawings to provide control of valves CV 36 and CV 37 by limit switches LS-2 (not fully closed) instead of LS-1. With this revised circuitry, valves CV-36 and CV 37 begin to close instantaneously on the receipt of an actuation signal and, therefore, this change is acceptable.

8. Summary

The licensee identified four design deficiencies: (1) diesel generator sequencer operation on safety injection/loss of offsite power signal allowing one diesel generator breaker to close automatically and remove the loss of power signal before the other diesel generator breaker could close; (2) potential overloading of 480V bus breakers, transformers and

cables; (3) installation of uninterruptible power supplies for MOV 358 and (4) interlocks associated with feedwater pumps. The licensee had corrected the design deficiency of diesel generator sequencer operation by installing time delay relays to ensure closure of both diesel generator breakers. The licensee also committed to evaluate a design modification to the diesel generator circuitry as a long term solution. Regarding item (2), the licensee had taken corrective actions for potential overloading of cables and had performed tests which demonstrate that additional temperature rise allowed by ANSI for 4-hour breaker emergency overload conditions would not be exceeded for the new scenario postulated. Therefore, operation of these breakers for one refueling cycle appeared appropriate. However, the licensee committed to find a long term solution for the potential overloading of these breakers. The licensee had taken corrective actions for powering MOV 358 from loop 'C' UPS and for providing interlocks associated with feedwater pumps. The licensee committed to resolve the problem with the inverter of UPS before restart of Unit 1.

Regarding diesel generator No. 2 spurious starts, the licensee had taken appropriate actions and, therefore, this item is closed.

Regarding 480V swing bus No. 3, the licensee committed to provide administrative controls for breakers 1103, 1203 and 1303 and to install "Caution Tags" before restart of Unit 1.

9. Exit Meeting

The inspector met with licensee personnel (denoted in paragraph 1) on March 30, 1989. The inspector summarized the inspection findings.

At no time during this inspection was written material given to the licensee.