U.S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos.	50-206/92-20, 50-361/92-20, 50-362/92-20
Docket Nos.	50-206, 50-361, 50-362
License Nos.	DPR-13, NPF-10, NPF-15
Licensee:	Southern California Edison Company Irvine Operations Center 23 Parker Street Irvine, California 92718
Facility Name:	San Onofre Units 1, 2 and 3
Inspection at:	San Onofre, San Clemente, California
Inspection conducted:	June 4, 1992 through July 16, 1992
Inspectors:	C. W. Caldwell, Senior Resident Inspector D. L. Solorio, Resident Inspector C. D. Townsend, Resident Inspector T. Sundsmo, Project Inspector

Approved By: H. J. Wong, Chief, Reactor Projects Section 2 — 8-13-92 Date Signed

Inspection Summary

Inspection on June 4, 1992 through July 16, 1992 (Report Nos. 50-206/92-20, 50-361/92-20, 50-362/92-20).

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, independent inspection, licensee event report review, electrical maintenance, design basis document review, emergency preparedness drill, training, and followup of previously identified items and items of non-compliance. Inspection procedures 37700, 41701, 60710, 61726, 62703, 62705, 71707, 71710, 82301, 90712, 92700, 92701, 92702 and 93702 were utilized.

Safety Issues Management System (SIMS) Items: None

Results:

General Conclusions and Specific Findings:

Strengths

A new site record of 236 days of continuous operation was set by Unit 1 on July 12, 1992. The inspector considered that this record was achieved through the diligence and attention to detail on the part of all personnel involved with the operation and maintenance of the Unit (Paragraph 2).

The inspector considered that the licensee's efforts to understand and propose corrective actions for weaknesses in the maintenance process, and to reduce the backlog of maintenance items to be extensive. The implementation and effectiveness of these efforts will be reviewed further as part of the routine inspection effort (Paragraph 9.d).

Weaknesses

The inspector noted two events that were indicative of a weakness in the interface between Station Technical and Operations to maintain configuration control of plant equipment during surveillance activities.

In the first instance, the inspector observed that Station Technical (STEC) personnel did not obtain approval from the Senior Reactor Operator (SRO) Operations Superintendent to perform an inservice test of a Unit 2 auxiliary feedwater pump. As a result, the SRO was not involved to the level required by both Operations and Engineering procedures (Paragraph 5.b).

In the second instance, a Unit 2 salt water cooling (SWC) pump became inoperable due to a misaligned valve. The event was detailed in licensee event report (LER) 2-92-009. In that case, Operations personnel failed to recognize that the Engineering procedure did not comply with procedural requirements to provide for an Operations sign-off and an independent verification of equipment manipulation. Thus, proper configuration control was not maintained.

As a result of these two events, the inspector was concerned that additional licensee attention was necessary to strengthen the STEC/Operations interface.

Significant Safety Matters:
Summary of Violations:

One violation concerning the failure of Station Technical personnel to obtain approval to perform a surveillance on an auxiliary feedwater pump from the SRO Operations Supervisor was identified (Paragraph 5.b).

Open Items Summary:

During this report period, four new followup items were opened and 12 were closed; one was examined and left open.

DETAILS

1. Persons Contacted

Southern California Edison Company

H. Ray, Senior Vice President, Nuclear
*H. Morgan, Vice President and Site Manager
*R. Krieger, Station Manager
J. Reilly, Manager, Nuclear Engineering & Construction
B. Katz, Manager, Nuclear Oversight
*R. Rosenblum, Manager, Nuclear Regulatory Affairs
*K. Slagle, Deputy Station Manager
*R. Waldo, Operations Manager
*L. Cash, Maintenance Manager
*M. Short, Manager, Station Technical
M. Wharton, Manager, Nuclear Design Engineering
P. Knapp, Manager, Health Physics
W. Zintl, Manager, Emergency Preparedness
D. Herbst, Manager, Quality Assurance
C. Chiu, Manager, Quality Engineering
*J. Schramm, Plant Superintendent, Unit 1
V. Fisher, Plant Superintendent, Units 2/3
*D. Brevig, Supervisor, Onsite Nuclear Licensing
*G. Hammond, Supervisor, Onsite Nuclear Licensing
J. Reeder, Manager, Nuclear Training
H. Newton, Manager, Site Support Services
*R. Plappert, Manager, Technical Support and Compliance
*J. Jamerson, Lead Engineer, Onsite Nuclear Licensing
*D. Axline, Engineer, Onsite Nuclear Licensing
*W. Marsh, Assistant Manager, Operations
*S. Paranandi, Supervisor, Quality Assurance
*N. Maringas, Supervisor, Quality Assurance
*J. Rainsberry, Plant Licensing Manager
*J. Fee, Assistant Manager, Health Physics
*S. Hetrick, Supervisor, Computer Engineering, Station Technical
*N. Quigley, Engineering Supervisor, Station Technical
*D. Roberts, Safety Injection Cognitive Engineer
*W. Conklin, Compliance Engineer, Station Technical
*R. Nielsen, Cognitive Engineer, Station Technical

San Diego Gas and Electric Company

*R. Lacy, Manager, Nuclear Department
*R. Erickson, Site Representative

*Denotes those attending the exit meeting on July 16, 1992.

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

Unit 1 operated at power the entire inspection period and established a new site record (236) days for continuous operation on July 12, 1992.

Unit 2

Unit 2 operated at power for the entire inspection period.

Unit 3

Unit 3 operated at power for the entire inspection period.

3. Operational Safety Verification (71707)

The inspectors performed several plant tours and verified the operability of selected emergency systems, reviewed the tag out log and verified proper return to service of affected components. Particular attention was given to housekeeping, examination for potential fire hazards, fluid leaks, excessive vibration, and verification that maintenance requests had been initiated for equipment in need of maintenance. The inspectors also observed selected activities by licensee radiological protection and security personnel to confirm proper implementation of and conformance with facility policies and procedures in these areas.

Several minor discrepancies were noted and discussed with the Shift Superintendents for resolution. In addition, the following issue was noted as discussed below.

Unit 1 Turbine Building

On June 4, 1992, the inspector noted that a pipe draining into a floor drain was splashing water onto the floor around the drain in the Unit 1 Turbine Building. Because the drain was labeled potentially contaminated, the inspector contacted health physics (HP) supervision to determine if the water splashing onto the floor was spreading contamination.

In response to the inspector's question, HP performed a survey of the drain and the floor around it. Contamination was found in the drain, but not on the surrounding floor. The draining pipe provided waste drainage from the secondary plant chemistry lab. Initially, HP installed one end of a plastic wrap around the pipe and the other end to the floor around the drain. This was done to prevent water from splashing out from the drain onto the surrounding floor. However, with the plastic secured to the floor, it was not clear to the inspector that the drain would have functioned properly.

The inspector questioned HP management as to whether they were defeating the purpose of the drain by this modification. HP management responded that they did not know but would find out. A few days later the inspector observed that the plastic had been removed from the floor around the drain. In fact, the plastic had been re-secured to the inside of the drain.

The inspector noted that the drain in question was located near the 4160 VAC (4KV) and 480V switchgear rooms. The inspector observed other floor drains in the same area, but was unable to determine if they were functioning properly. The inspector will evaluate the consequences and significance of the temporary drain modification as part of the routine inspection effort.

4. Evaluation of Plant Trips and Events (93702)

a. Temporary Waiver of Compliance From Technical Specification 3.3.1 For Safety Injection Valve HV852B - Unit 1

On May 18, 1992, the licensee was granted a Temporary Waiver of Compliance (TWOC) from TS 3.3.1, "Safety Injection and Containment Spray Systems Operating Status," to allow repairs of safety injection (SI) hydraulic valve (HV) HV852B. The duration of the TWOC was for 24 hours and was initiated on May 19, 1992. At 11:09 p.m. on May 19, 1992, HV852B was restored to service, establishing compliance with TS 3.3.1.

The waiver was requested to allow for the replacement of the HV852B accumulator nitrogen addition valves (schrader valves), which had been identified to be leaking nitrogen. The nitrogen leakage had resulted in a recharging frequency of the accumulators of approximately once every three days.

Hydraulic valve 852B is opened with a pneumatic-hydraulic pump, and closed by two nitrogen-hydraulic fluid accumulators connected at their hydraulic discharge to the valve actuator. The nitrogen in the accumulators is separated from the hydraulic fluid by a piston with seal rings. The nitrogen in the accumulators provides the motive force necessary to displace the hydraulic fluid from the accumulator which is used to move the valve to its closed SI position. Nitrogen is added to the accumulators by connecting a nitrogen high pressure cylinder to accumulator schrader valves with a charging manifold.

On May 19, 1992, HV852B was removed from service to replace the schrader valves on both accumulators. Initially the accumulators were ultrasonically tested to determine the locations of the pistons. However, measurements of piston positions were indeterminate. Upon removal of the schrader valves from the top of the accumulators, the position of the pistons were measured visually using reach rods. The pistons were found to be misaligned. One accumulator piston was found at its uppermost possible location with the maximum volume of hydraulic fluid and minimum volume of nitrogen gas. The other piston was found at its lowest possible location with the minimum volume of hydraulic fluid and maximum volume of nitrogen gas.

As corrective action, the schrader valves were replaced, the accumulators were recharged with nitrogen, and the pistons were evenly aligned. After measuring the piston locations with the rods, STEC considered the operability of the valve to be indeterminate and initiated an evaluation after completion of the corrective maintenance.

On June 17, 1992, a nonconformance report (NCR) was issued to document the degraded condition of HV852B as found on May 19, 1992. Station compliance determined that the degraded condition of HV852B was reportable under 10 CFR Part 50.73, which required SCE to submit a licensee event report (LER) within 30 days. On June 23, 1992, the valve vendor and STEC concluded that HV852B had been inoperable prior to its repair on May 19, 1992.

Based on the events associated with HV852B, the inspector had the following concerns:

- The accumulators were modified in 1986 to use the pistons to isolate the hydraulic fluid from the nitrogen. Up to two weeks prior to replacement of the schrader valves, it was not recognized that leaks from the accumulators could result in piston misalignment. (The most severe consequence of the misalignment was the valve becoming inoperable). Evidence of this is supported by the absence of a program to monitor the piston locations concurrent with or independent of accumulator recharging evolutions.

- Ultrasonic testing of the other HV accumulators following the discovery of HV852B piston misalignment would have identified the ongoing degradation of HV851A prior to June 17, 1992 when the licensee requested a TWOC (reference section 4.b for discussion).

- The NCR documenting the inoperable condition of HV852B was initiated approximately one month after the valve was found in its inoperable condition.

This is an unresolved item pending review of the licensee's assessment of the condition as documented in their LER (50-206/92-20-01).

b. <u>Temporary Waiver of Compliance From Technical Specification 3.3.1 For Safety Injection Valve HV851A - Unit 1</u>

On June 17, 1992, the licensee requested a TWOC from the requirements of sections A(1) and A(3) of Technical Specification (TS) 3.3.1, "Safety Injection System - Containment Spray Systems -

Operating Status." This was necessary for a period of 24 hours in order to facilitate repairs to safety injection (SI) valve HV851A. This request was granted verbally by the NRC on June 17, 1992 and formally documented in a June 18, 1992 letter to the NRC. At 11:48 a.m. on June 18, 1992, HV851A was restored to service, establishing compliance with TS 3.3.1.

The SI valve, HV851A, is a double disc gate valve, with a pneumatic-hydraulic actuator which is similar in configuration to HV852B as discussed above. The only major difference is that HV851A has one accumulator instead of two.

The actuator associated with SI discharge isolation valve HV851A experienced minor hydraulic fluid leakage on the accumulator side. The leakage had been monitored by STEC. The licensee assumed that a significant loss of hydraulic fluid could limit the capability of the valve to stroke to the fully open position upon demand. An evaluation was initiated, which included the use of ultrasonic testing (UT) to determine the position of the accumulator piston. The conclusion from the evaluation was that a loss of hydraulic fluid had occurred which would prevent the valve from opening beyond approximately 85% of full stroke. The licensee stated that in this condition the valve would still perform its required safety function since analyses had recently been completed which demonstrated that the required SI flow would occur with HV851A 50% open. However, the licensee requested the TWOC to remove HV851A from service to recharge the accumulator hydraulic side in order to regain the full stroke capability of the valve.

Because the accumulator oil leak was not repaired, (repairs would have required valve disassembly), the licensee committed to implement measures that would assure continued operability of HV851A. Those measures were to trend the frequency of accumulator nitrogen recharging and perform periodic piston location measurements using the UT method developed previously.

Because there were questions as to the positions of the other HV accumulator pistons, the licensee committed to perform UT measurements on them (with the exception of HV852B, which had been ultrasonically tested approximately two weeks prior and left with pistons in their optimum position).

On July 1, 1992, the remaining HVs (851B, 854B, 853B, 852A, 853A, 854A) were ultrasonically tested. All of the HVs were found to be in an optimum condition except for HV854A. The accumulator pistons for HV854A were found to be misaligned greater than the ¼" limit that station engineering had determined was the optimum configuration for dual accumulator valves. However, the valve was determined to be operable. The licensee subsequently realigned the pistons by recharging the accumulators with nitrogen.

No violations or deviations were identified.

5. Bi-Monthly Surveillance Activities (61726)

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

a. Observation of Routine Surveillance Activities (Unit 1)

S01-V-2.14.1	"Auxiliary Feedwater Pump, S1-AFW-G10, Inservice Pump Test."
S01-II-1.6.20	"Surveillance Requirement Intermediate Range Channels NIY-1203 and NIY-1204 Neutron Flux Channel Test."
S01-12.4-2	"Operations In-Service Valve Testing."
S01-II-1.1.2	"Surveillance Requirement Pressurizer Level and Pressurizer Pressure Channel Test."
S01-V-3.9	"Isothermal Temperature Coefficient."

b. Observation of Routine Surveillance Activities (Unit 2)

S023-I-2.72	"Fire Detection-Surveillance Testing Of Actuation Detectors Outside Unit 2 Containment."
S023-V-3.4.1	"Auxiliary Feedwater Inservice Pump Test Monthly Surveillance 2P140."

On July 1, 1992, the inspector observed surveillance testing on the Unit 2 and Unit 3 auxiliary feedwater (AFW) pumps, 2P140 and 3P141, required by surveillance procedure S023-V-3.4.1. During the Unit 2 surveillance of 2P140, the inspector noticed that approval to conduct the test had been received from the Control Operator (CO), but the procedure directed that approval be from the SRO Operations Superintendent. The inspector discussed this observation with the on-shift SRO and determined that he knew the test would be performed that day, but had not actually discussed it with engineering personnel.

Step 3.2 of S023-V-3.4.1 stated; "Obtain the SRO Operations Supervisor approval to conduct the test. Operations should release pump 2(3)1305MP140 to the Cognizant Engineer for testing at this point under a verbal approval." The inspector noted that the signature block allowed the engineer to document who was informed including the date and time the individual was contacted. The engineer had filled the signature block indicating approval from the CO. When this was discussed with the engineers involved, they indicated that it was appropriate to gain approval from the CO and had utilized the CO for approvals previously. However, their supervisor indicated that the procedure should be adhered to and that the SRO should have reviewed the scope of the surveillance before it was performed.

Further inspection revealed that section 6.11, "Plant Manipulations Using Other Division Procedures" of operations procedure SO123-0-20, "Use Of Procedures," stated, in part, that it is acceptable to use other division procedures to manipulate the plant provided the procedure is reviewed and approved by a SRO Operations Supervisor (prior to performing work). The procedure also stated that the Control Room Supervisor is responsible for overall plant safety and can suspend test activities at any time.

The inspector discussed this issue with licensee management who agreed that the surveillance procedure was not properly followed. It is important to consider that there was little safety significance to this issue as the plant was operating at steady state with no other related safety equipment out of service and the surveillance was run successfully and in accordance with other procedures. However, as shown by the missed procedural requirements (as identified above), there appeared to be a weakness in configuration control since the SRO operations supervisor was not involved to the level required by both the operations and engineering procedures. Failure to follow procedures SO23-V-3.4.1 and SO123-0-20 is a violation, (50-361/92-20-02).

The inspector was concerned with the interface between Operations and STEC and the impact on configuration control of plant equipment during the performance of STEC procedures. In addition to the concern identified above, a Unit 2 salt water cooling (SWC) pump became inoperable in May 1992, due to a misaligned emergency seal water supply valve. The event was detailed in LER 2-92-009. In that case, the Station Technical surveillance procedure, SO23-V-3.5.4, "Inservice Testing Of Check Valves," was used to perform a quarterly test of SWC check valves. A step in the procedure was signed by the test engineer indicating that he had requested Operations to open the emergency seal water supply valve. However, flow data suggest that the valve may have been inadvertently left closed following the check valve test. Operations personnel failed to recognize that Engineering procedure SO23-V-3.5.4 did not comply with the requirements in Operations procedure SO123-0-20 prior to authorizing the test engineer to perform the check valve test. In particular, the requirements for an Operations sign-off and independent verification of equipment manipulation were not contained in the Engineering procedure.

As a result of these two events, the inspector was concerned that additional licensee attention was necessary to resolve STEC/Operations interface weaknesses to ensure that plant configuration control is properly maintained.

c. Observation of Routine Surveillance Activities (Unit 3)

S023-I-2.73	"Fire Detection Surveillance Testing Of Actuation Detectors Outside Unit 3 Containment."
S023-V-3.4.1	"Auxiliary Feedwater Inservice Pump Test Monthly Surveillance 3P141."
S023-3-3.27.2	"Weekly Electrical Bus Surveillance."

One violation was identified in this area.

6. Monthly Maintenance Activities (62703)

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

a. Observation of Routine Maintenance Activities (Unit 1)

92051545000	"Intermediate Range Drawer Channel 1203, S1-NIS-NIY-1203, Channel Test."
92060339001	"Several Relays Have Caused The 'Start Up Rate Reactor Trips Active' Permissive To Illuminate Upon Relay Failure."
92061088000	"Bank A Instrument Air/N2 Header Relief Valve, S1-GNI-PSV-301, Is Leaking Through, Resulting In Lowering Pressure On The Backup Nitrogen Banks For HV851A."
92061958000	"Readjustment of the Dual Accumulator Pistons. East Accumulator Piston Is At A Higher Level Than The West Accumulator Piston."
92061860000	"Support STEC/QC In UT Inspection Of The Accumulator For HV-851B."
92061867000	"Support STEC/QC In UT Inspection Of The Accumulator For HV-854B."
92061964000	"Excessive Leakage On Outboard Seal of North Component Cooling Water Pump. A Small Stream Approximately 12 Ounces Per Minute."

b. Observation of Routine Maintenance Activities (Unit 2)

92060333000	"Main Steam Relief Valve To Atmosphere, 2P5V8407, Water Leak Where Relief Valves Downstream Piping Connects to the Stand Pipe."

92060334000	"Main Steam Relief Valve To Atmosphere, 2P5V8408, 30 Drips A Minute Leak Where Relief Valve Downstream Piping Connects To The Stand Pipe."
92060019000	"Steam Generator, 2E088, Blowdown Vent Valve, S21301MR800, Has Body Leak Of Steam That Is Getting Worse."
92010602000	"Diesel Generator, 2G002, Fire Protection Pre-Action Actuating Detector Surveillance Testing."
90050432000	"High Pressure Safety Injection Pump, S21204MP019, Train B - P3 - Inspect Each Cyclone Separator To Ensure Their O-Rings Are In Place. If The O-Rings Are Missing Replace With Qualified In-Kind Parts."

c. Observation of Routine Maintenance Activities (Unit 3)

92051337000	"Diesel Generator, 3G002, Fire Protection Pre-Action Actuating Detector Surveillance Testing."
92070060001	"General Isolation PH Bus Potential Transformer, S31802EPXP1, Cross-tie Generator Potential Transformer Channel B To A To Provide For Voltage Regulating, Per TFM 3-92-MAA-002, Revision 0."
92070942000	"125VDC Station Battery 3D1, S31806E6007, Cell #14 Voltage is 2.066 VDC, Allowable Limit Is 2.07 VDC. Jumper Out Cell #14, Jumper In Cell #53."
92060813000	"125VDC Station Battery 3D1, S31806EB007, Perform A Bank Equalize Charge."
92070965000	"125VDC Station Battery 3D1, S31806EB007, Perform Single Cell Charge On Cell #53, Cell Voltage Is 1.208VDC."

The inspector observed the licensee's actions to jumper out failed cell #14 and replace it with cell #53 in battery 3D1. Failure of cell #14 resulted in the Unit entering a 2 hour Technical Specification (TS) action statement to restore the battery to operable status or to shut down the Unit. As a result of the licensee's activities, the inspector had a number of questions related to the performance of the surveillance test that identified the failed cell and the adequacy of the replacement cell. The inspector will further evaluate the licensee's actions related to this matter as followup item (50-362/92-20-03).

No violations or deviations were identified.

7. Independent Inspection (62705, 37700, 41701, 82301)

a. Electrical Maintenance (62705)

The inspector observed that cell 58 of Class 1E battery 3D3, was being charged by a non-Class 1E portable single cell battery charger.

The inspector noted that the use of non-Class 1E individual cell chargers to charge Class 1E batteries has generally been accepted when a licensee has demonstrated that adequate equalization of cell voltages cannot be maintained using a full capacity charger and when administrative controls have been maintained. Administrative controls would be required to preclude the masking of data which would indicate a potentially failing cell. These administrative controls would typically limit any cell to the following:

- Perform only one individual cell equalization charge a year.
- Limit the equalization charge rate to the battery manufacturer's limits.
- Recheck cell parameters two weeks after the charge.
- Ensure that a 10 CFR 50.59 evaluation had been accomplished to verify that a fault on the non-1E charger would not degrade the 1E battery.
- Provide criteria to demonstrate that adequate equalization of cell voltages could not be maintained using a full capacity charger.

The inspector reviewed the following licensee documents concerning the batteries:

- Procedure SO123-I-9.301, Revision 1, Temporary Change 6, "Battery - Spare and Single Battery Cell Inspection and Testing"
- SO123-I-2.3, Revision 1, "Quarterly Battery Inspection"
- A June 11, 1992, 10 CFR 50.59 evaluation for use of the individual battery charger
- Current and previous data for cell 58 and for battery 3D3

As a result of the review of the data for the cell 58, the inspector concluded that cell 58 was not continually failing surveillances and being individually recharged. Based on this data, the inspector concluded that there was no immediate operability question for cell

58 in battery 3D3.

However, based on a review of Procedure SO123-I-9.301, the inspector concluded that administrative controls for individual cell charging were not in place to preclude use of the individual cell charger to mask a failing cell.

In response to the inspector's concern, the licensee stated that maintenance supervisors make the decision on when an individual cell charge will be performed based on the number of cells which require charging. The licensee stated that engineering personnel review Class 1E cell data outside the normal performance characteristics. As a result of these controls, the licensee stated that no changes to add additional administrative controls for individual Class 1E cell charging were planned.

In addition, based on a review of Procedures SO123-I-9.301 and SO123-I-2.3, the inspector concluded that the licensee's battery procedures did not contain a method for demonstrating that they only use the single cell charger if the licensee can't maintain voltage using the full capacity charger.

The inspector noted that the June 11, 1992, 10 CFR 50.59 evaluation for use of the individual battery charger concluded that the charger was an isolation device as defined in IEEE STANDARD 384, "Criteria for Independence of Class 1E Equipment and Circuits," because it was a current limiting device. The evaluation was based on a Ratelco Constant Voltage Charger, Type FF8504, Model 102-3617.00. The evaluation concluded that the charging rate was limited to 80 amps, based on output fuses in the charger. The evaluation also concluded that an 89 amp charging rate would not damage the battery.

Based on a review of the licensee's 10 CFR 50.59 evaluation and Procedure SO123-I-9.301, the inspector concluded that the licensee's individual cell charger 10 CFR 50.59 evaluation was inconsistent with Procedure SO123-I-9.301. A charging current limit of 80 amps assumed in the 50.59 evaluation was not contained in the procedure. In fact, a note after Step 6.3.7, Procedure SO123-I-9.301, directed that the craft person performing the charge monitor the charging operation hourly for charging currents over 100 amps. The inspector also concluded that the licensee's evaluation that a battery charger was a current limiting device was generally acceptable in accordance with IEEE STD 384.

The inspector provided the conclusions discussed above to the licensee. The licensee agreed that the note after Step 6.3.7 did not match the 10 CFR 50.59 evaluation. As a result, the licensee committed to revise the note to match the 10 CFR 50.59 review and the actual equipment being used.

In addition to the concerns discussed above, the inspector also questioned the effect of using the single cell charger on the seismic qualification of the vital batteries. The inspector will further evaluate the licensee's controls for use of the single cell charger as followup item (50-362/92-20-04).

b. Design Bases Documentation Review (37700)

A Region V inspector performed an informal review of the licensee's design bases documentation (DBD) program during the weeks of May 18 to 21 and June 8 to 11, 1992. This review primarily focused on inspection of plant systems to ensure that these systems actually exhibited selected safety significant design characteristics documented by the DBD program. The inspector reviewed each system's DBD, identified several verifiable safety significant characteristics for each system, and then inspected each system to verify the characteristics. The inspection was conducted in Unit 2, and included the following systems:

SYSTEM	DBD DOCUMENT NO.
Class 1E 125 Volt DC	DBD-S023-140, Revision 0
Component Cooling Water	DBD-S023-400, Revision 0
Saltwater Cooling	DBD-S023-410, Revision 0
Instrument Air/Dedicated Backup Nitrogen	DBD-S023-540, Revision 0
Emergency Chilled Water	DBD-S023-800, Revision 0

Results of the plant system DBDs inspected during this review indicated that these documents appeared adequate. Inspection of additional plant systems will periodically be conducted by Region V and documented in inspections reports as additional DBD documents are developed by the licensee.

c. Observation of Emergency Preparedness Drill (41701, 82301)

On June 10, 1992, the inspectors observed an emergency preparedness (EP) drill being conducted by the licensee for training purposes. The drill involved a steam generator tube rupture (SGTR) and a sequential loss of all feedwater on Unit 2. These events required

the operators to perform emergency operating instructions (EOIs) for reactor trip, SGTR, and finally transition into the functional recovery procedures (FRPs).

During the drill, the inspector had the following observations:

1) Control room evaluators (controllers) were not prepared to evaluate operator actions during the drill. The prepared

scenario summary emphasized EP actions, but excluded operator actions except for event classifications. For example, an inspector informed the lead control room evaluator (operations department) that the operators were performing actions that were not contained in the EOI that was being performed (functional recovery success path HR-2). The evaluator stated that he had not reviewed this procedure lately and wasn't sure if it prescribed the observed operator actions or not. Because the evaluators were not conscious of required operator actions, they were not objectively critical of those actions.

The inspector considered that emergency drills are a good opportunity to perform operator evaluations. This was discussed with the licensee who indicated that they would evaluate the inspector's observation.

2) Operators used the EOIs as guidance in certain instances, rather than as procedures for the scenario given. In particular, actions taken by the operators to cross-connect Unit 3 condensate to Unit 2 were not directed by the EOIs; these actions were improvised on the spot by the operators without identification that they were deviating from the prescribed course of action in the EOIs. However, the EOIs directed use of the (Unit 2) condensate transfer system. Even though the operator's actions had merit, there was no indication that the course of action prescribed by the EOIs would have been unsuccessful when the operators decided to deviate from the EOIs. The operators continued with prescribed EOI actions when the improvised actions were unsuccessful.

The inspector noted that the EOIs do not incorporate directions to cross-connect systems between units in order to mitigate an accident. The observed drill identified the need for cross-connecting condensate upon a loss of all feedwater event, and the lack of a procedure to implement it.

The ability to cross-connect Unit 2 and Unit 3 systems during an emergency was discussed with the licensee after the drill. The licensee indicated that they had a "desk top" procedure for cross-connecting electrical systems between Units 2 and 3, but did not have an emergency procedure to cross-connect condensate systems. They indicated that the "desk top" procedure was not an official procedure since it could not pass a 10 CFR 50.59 evaluation. However, the licensee indicated that this would only be used when they were in an accident scenario that was beyond the design basis event and not adequately covered by the FRPs. In addition, it would be a conscious management decision to implement it.

The inspector will review use of this "desk top" procedure further. In particular, the inspector questioned if the "desk top" procedure should undergo the formal review and approval process, and if it was consistent with current methodology for complementing the EOI. Followup item (50-361/92-20-05).

No violations or deviations were identified.

8. 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

91-07, Revision 0	"Large Break LOCA Analysis Nonconservative Due To Incorrect RCS Volumes."
91-07, Revision 1	"Large Break LOCA Analysis Nonconservative Due To Incorrect RCS Volumes."

On March 28, 1991, with Unit 1 operating at 20% reactor power, it was determined that the value for the reactor vessel refill volume used in the Large Break Loss of Coolant Accident (LBLOCA) analysis performed by Westinghouse was underestimated by approximately 182 cubic feet. A supplement to this LER providing a complete discussion of the event, causes, corrective actions, and safety assessment was to be submitted by May 10, 1991.

LER 91-07, Revision 1, was issued on June 14, 1991. This LER contained a discussion of the event, causes, corrective actions, and safety assessment associated with the volume underestimation in the LBLOCA analysis performed by Westinghouse.

Immediate corrective actions as stated in LER 91-07, Revision 1, included:

1) immediately restricting reactor power level to 75%, and

2) administratively restricting Incore Axial Offset (IAO) to allow for full power operation.

Planned Corrective Actions were to submit an amendment application to the NRC by June 18, 1991. The amendment was to request a change to Technical Specification (TS) 3.11, "Continuous Power Distribution Monitoring," reflecting the current administratively imposed IAO values and also to change the basis of TS 3.5.2, "Control Rod Insertion Limits," for the new values of specific power and peaking factors.

On June 18, 1991, the licensee submitted Amendment Application No. 196, which consisted of the Proposed Change No. 245, to the Provisional Operating License, DPR-13, for SONGS, Unit 1. Proposed Change No. 245 was a request to revise Appendix A, TS Section 3.5.2, "Control Rod Insertion Limits," and Section 3.11, "Continuous Power Distribution

Monitoring." The proposed change was to impose more restrictive limits on core axial offset than those specified in the current Technical Specifications.

On July 8, 1992 the licensee requested that the NRC postpone issuance of Proposed Change No. 245 and make it contingent on Unit 1 operating beyond its current cycle, Cycle XI. Currently, Unit 1 is scheduled to be decommissioned at the end of Cycle XI.

The inspector verified the implementation of administrative controls restricting IAO to allow for full power operation and also changes to the values of specific power and peaking factors as identified in LER 91-07, Revision 1. These administrative controls were implemented by reactor engineering procedures SO1-V-1.6, "Incore Flux Mapping", and SO1-V-1.16, "Axial Offset Correlation." The inspector concluded that no further followup action is required. This item is closed.

Unit 2

92-006, Revision 0 "Reactor Shutdown To Test Safety Injection Pump Miniflows."

No violations or deviations were identified.

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

a. (Open) Followup Item (50-361-362/91-29-02), "IN-88-73, 'Direction Dependent Leak Characteristics of Containment Purge Valves.'"

Paragraph 4 of Inspection Report 91-29, dated November 6, 1991, concerned a followup to NRC Information Notice (IN) 88-73, "Direction-Dependent Leak Characteristics of Containment Purge Valves." The IN provided guidance regarding the testing of Fisher Model 9200 valves used for containment isolation. In particular, it had been observed that these valves, which have tapered seats, had a direction-dependent leakage characteristic. The valves could seal in both directions but a test in the preferred direction did not always verify sealing in the non-preferred direction.

The licensee's Independent Safety Engineering Group (ISEG) completed a review of IN 88-73 in October 1988, as documented in report 88-ISEG-152. The ISEG review determined that Southern California Edison's (SCE) containment penetration testing practices were acceptable. However, the inspector learned from the ISEG Supervisor that 88-ISEG-152 was not accurate. A design change, in response to IN 88-73 had occurred, reversing the seating direction of the Units 2 and 3 inside-containment 8-inch purge valves. Further, the licensee had committed to review other plant valves which had leakage limits, to determine if the recommendations of Information Notice 88-73 also applied. In addition, the licensee also committed to revise 88-ISEG-152 to include this information.

For followup, on May 28, 1992, "Request for Action: NRC Information Notice 88-73 (Amended Evaluation), 'Direction-Dependent Leak Characteristics of Containment Purge Valves' RCTS No. 9205022" was prepared by the ISEG Supervisor with the action request to "determine administrative or design changes necessary to resolve direction-dependent leakage of Fisher Series 9200 valves". On June 5, 1992, a Regulatory Commitment Tracking System (RCTS) E-mail commitment was received by the ISEG Supervisor accepting these commitments and proposing a due date of June 1, 1993.

The inspector will monitor the licensee's efforts to resolve this issue. Therefore, this item will remain open.

b. (Closed) Followup Item (50-206/91-13-03), "NCR Not Written For Failed Sequencer Test."

Following a monthly surveillance test, troubleshooting and a retest of the Unit 1 sequencer were performed as a result of varying and conflicting results. The inspector questioned why an NCR had not been generated for the test failure. At the time there was some difference of opinion as to whether or not NCR procedure SO123-XV-5, "Nonconforming Material, Parts, or Components," was clear in its direction to generate an NCR for the failed surveillance. The licensee agreed to review the procedure and make enhancements where necessary as a result of the inspector's concern.

For followup to this issue, the licensee revised procedure SO123-XV-5 on January 29, 1992, to give more detailed information as to when an NCR would be required. This revision included specific details that indicated that when results of a surveillance test fail to meet acceptance criteria, an NCR shall be written. The procedure also indicated that an NCR shall be written when a component is determined to have a failure rate significantly higher than the industry average as determined by existing programs. Based on these revisions, the inspector considered that the licensee's actions were appropriate. Therefore, this item is closed.

c. (Closed) Followup Item (50-206/91-13-04), "Maintenance Program Implementation For Corroded Fasteners."

The inspector observed several components in the plant with fasteners which were corroded to some degree (as discussed in inspection report 206/91-13) and also noted that there was no program to specifically evaluate the condition of fasteners in many systems. As a result of the inspector's concern, the licensee stated that they would evaluate the need for a program to inspect fasteners. In order to do this they would have to gather data during the Unit 2 refueling outage in the fall of 1991.

As a result of the licensee's assessment on this matter, it was determined that levels of fastener degradation, resulting from corrosion, varied from cosmetic to severe. However, most findings were cosmetic in nature and of the large sample taken (536 maintenance orders), only 32 maintenance orders (MOs) were identified as having potentially corroded fasteners. And of those, six MOs were found to have corroded fasteners warranting further inspection.

The licensee tested fifteen fasteners from the six MOs and one failure was found. The licensee therefore concluded that although the number of failures was small, more attention should be given to routine inspection and preservation of fasteners in plant systems.

The licensee has planned a number of actions with regard to this matter. For example the licensee would do the following:

- Enhance training for personnel who walk down systems
- Include fastener corrosion identification in the SONGS preservation program
- Include incidents observed of fastener corrosion with the weekly active leak report
- Expand the thermography program to cover insulated high energy systems on a sampling basis
- Develop a procedure for inspection and further corrective actions as warranted

The inspector considered that the licensee's efforts and planned corrective actions appeared adequate. However, the inspector will continue to monitor the licensee's implantation of corrective actions as part of the routine inspection effort. This item is closed.

d. <u>(Closed) Followup Item (50-361/91-13-02), "Material Condition Of The Units - MO Backlog."</u>

As discussed in inspection report 50-361/91-13, the inspector noted numerous deficiency tags on equipment in all three units. Although most of the items appeared to be of relatively low safety significance, many dated back a few years (to 1987 or 1988). It was noted that the backlog of outstanding maintenance items appeared to have been increasing in recent months, with most items being low priority (non-safety related). (A backlog is considered as corrective maintenance items that are safety or non-safety related that have been in existence for more than 120 days that are awaiting work that can be done on-line.) The inspector had noted the slowly increasing backlog of items awaiting repair and questioned whether they were being properly prioritized and effectively dealt with.

Discussions with the licensee revealed that they were aware of the backlog and had provided a method of tracking and trending these items. The licensee also indicated that a Work Authorization Task Force (WATF) had been formed to review the situation and recommend a course of action.

The inspector reviewed the licensee's WATF efforts and noted that a number of recommendations were made. Recommendations included the implementation of work window managers, a dedicated operator to interface between Maintenance and Operations for the issuance of work orders, and a revised prioritization scheme. The inspector also noted that the licensee's Nuclear Oversight Department (NOD) also performed an organizational assessment that introduced a number of recommendations.

The inspector noted that the licensee was in the process of implementing a Work Process Management Team consisting of the Operations and Maintenance Superintendents in Units 2 and 3. They will be responsible for setting a charter and a schedule to further enhance the maintenance process and implement remaining WATF and NOD recommendations. The licensee also was very close to implementing procedures that streamline and enhance the maintenance process by incorporating all work group responsibilities into a single set of procedures.

With regard to the maintenance order backlog, the licensee just recently dedicated significant resources to reduce it. The inspector noted that some progress has been made, although there was a long way to go. Discussions with the licensee indicated that they believed the backlog reduction rate would increase as maintenance efforts get fully implemented.

The goals for maintenance items were less than 500 items per unit in Units 2 and 3. Discussions with the Maintenance Manager indicated that Unit 1 currently met the backlog goal. However for Units 2 and 3, the level of items was approximately 650 items per unit at the end of the inspection period.

The inspector noted that some maintenance items were being resolved by the minor maintenance effort. This process as defined in procedure SO123-XX-3, "Minor Maintenance Program," consisted of less paperwork and planning needed to execute the work activity. Minor maintenance is done on equipment if it meets a number of requirements (e.g., it is within the skill of the craft, no written work plan is necessary, it does not involve the disposition of an NCR, and it does not require any operability testing). The procedure also provided examples of work activities that would fit in the minor maintenance category.

The inspector considered the licensee's efforts to understand and correct weaknesses in the maintenance process to be extensive. The effectiveness of these actions and the licensee's efforts to reduce the backlog of maintenance items including work performed under minor maintenance procedures, will be reviewed as part of the routine inspection effort. This item is closed.

e. (Closed) Information Notice (50-206/IN-86-99), Supplement 1, "'Degradation Of Steel Containments' - Inspector Followup On Licensee ISEG Evaluation For Potential Applicability To Unit 1."

NRC IN 86-99, Supplement 1, "Degradation Of Steel Containments," was issued in response to the discovery of significant corrosion on the external surface of the carbon steel drywell in the sand bed region of the Oyster Creek plant.

On August 26, 1991, the licensee's ISEG organization issued its evaluation of NRC IN 86-99. The inspector noted that the evaluation stated that the SONGS Unit 1 containment is a 140 ft. diameter steel sphere which extends 40 ft. below grade. It is continuously supported by a concrete cradle between the steel shell and the undisturbed soil. The free-standing steel shell contains a concrete structure which provides support and shielding for the equipment. Loads from this structure are transmitted through the sphere shell and the exterior concrete cradle to the soil. The exterior surface of the sphere, below grade, is protected from corrosion by an epoxy coating and by cathodic protection. The cathodic protection system is the impressed current type.

The method of verification for containment integrity is an Integrated Leak Rate Test (ILRT) per 10 CFR 50, Appendix J. The licensee stated that, as of the date of the ISEG evaluation, no ILRT data had been obtained that would indicate that containment integrity had deteriorated.

The inspector considered the evaluation adequate and that no further followup action is required. Therefore, this item is closed.

f. (Closed) Information Notice (50-361, 362/IN-91-13), "Inadequate Testing Of EDGs - Applies To 2nd And 3rd Units At Multi-Unit Sites."

This IN was intended to alert licensees to inadequacies in the testing of emergency diesel generators (EDGs) at nuclear power plants. In particular, some EDG testing had not adequately verified the capability of the EDG to carry its maximum expected loads and other tests had failed to properly verify the operation of the load shedding logic for the EDG. More specifically, it was noted that there was no requirement to test the EDG at its reactive load limit or to compensate for ambient temperature effects.

The inspector reviewed the licensee's evaluation of the conditions as applicable to SONGS. The inspector noted that the licensee concluded, after discussions with the vendor, that a requirement to compensate for ambient temperature variations was not necessary since the EDG would only be affected by temperatures well above the design maximum of 100 degrees in the diesel generator buildings.

The inspector also noted that the licensee revised procedure SO23-3-3.12, "Diesel Generator Monthly Test," to include testing the EDGs at reactive loads of 3000 to 3200 KVAR which is greater than the worst case reactive load calculated at 2614 KVAR.

The inspector considered that the licensee's evaluation of this IN was adequate. Therefore, this item is closed.

No violations or deviations were identified.

10. <u>Follow-Up On Items Of Non-Compliance</u> (92702)

a. <u>(Closed) Violation (206/91-36-01), "Inoperable Halon System In The 4KV Switchgear Room."</u>

This item identified that the Unit 1 4160 VAC (4KV) room Halon system was inoperable without a continuous fire watch being available for certain periods of time as required by Technical Specifications (TS).

The licensee implemented a number of corrective actions following the inoperability of this event. Those actions included properly configuring the Halon system, revising procedures to include drawings and instructions for the system actuation lines, and plans to provide specific training on proper configuration of the Halon system. The inspector considered the licensee's actions (both implemented and planned) to be appropriate. Therefore, this item is closed.

b. <u>(Closed) Violation (206/91-36-02), "Inadequate Licensee Report Concerning The Inoperable Halon System In The 4KV Switchgear Room."</u>

This item identified a statement in an LER which was inaccurate. The inaccurate statement was that a design basis fire in the 4KV room would not have prevented the Unit from achieving and maintaining safe shutdown.

For corrective actions on this issue, the licensee revised the LER to properly reflect plant conditions at the time of the event, discussed with LER writers the need to ensure that safety assessments consider all plant conditions, and had all management personnel review the response to the NOV to ensure that they were aware of the need for LERs to be complete and accurate. Based upon these actions, this item is closed.

c. <u>(Closed) Violation (206/91-36-03), "Inadequate Halon System Testing."</u>

This item identified that the licensee's test program did not include testing to demonstrate operability of the Halon bottle slave cylinders.

For corrective actions to this item, the licensee revised the Halon bottle surveillance procedures to include drawings of the system actuation configuration and to include the fire protection system manuals in the Vendor Interface Program to ensure that vendor information is properly incorporated into fire protection procedures. The inspector considered the licensee's actions appropriate. This item is closed.

d. <u>(Closed) Violation (50-361/91-13-04), "Followup Of Corrective Actions Described In Licensee Civil Penalty Response Dated 2/2/91."</u>

As discussed in inspection report 50-361/91-13, three corrective actions remained to be completed concerning two violations first referenced in inspection report 50-361/90-37. These violations involved an auxiliary feedwater pump being inoperable due to a misaligned steam trap (Unit 2), and the ECCS and containment spray subsystem being inoperable due to a misaligned emergency sump outlet valve (Unit 3).

The corrective actions that remained to be implemented from the licensee's February 2, 1991, response to the Notice of Violation were the following:

- Install audible annunciator for engineered safety feature (ESF) valves when in abnormal positions.
- Review the administrative workload assigned to operators to reduce non-operational duties.
- Perform an AFW pump/turbine overspeed trip analysis to determine optimum setting.

As of this inspection period, the licensee completed a review of the administrative workload assigned to the operators. This resulted in a number of changes to reduce the administrative burdens including the assignment of a designated operator to interface with maintenance in the preparation of work authorizations.

The inspector noted that the licensee formulated a work schedule to install the audible annunciator for ESF valves during the Cycle VIII refueling outages for Units 2 and 3. This commitment was entered in the licensee's regulatory commitment tracking system (RCTS) to ensure completion of the commitment.

The inspector noted that the licensee formulated a schedule to perform the AFW pump turbine overspeed trip analysis during the upcoming Cycle VII refueling outages for Units 2 and 3. This action was also entered in the licensee's RCTS system to ensure completion of the required action.

The inspector considered that the licensee's proposed and completed corrective actions were conservative measures and appeared adequate to minimize the potential for similar errors. Implementation of remaining actions will be reviewed as part of the routine inspection effort. Therefore, this item is closed.

No violations or deviations were identified.

11. Unresolved Items

Unresolved items are matters about which more information is required to determine whether they are acceptable items, violations or deviations. An unresolved item addressed during this inspection is discussed in paragraph 4 of this report.

12. Exit Meeting

On July 16, 1992, 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.