Enclosure (2)

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket Nos:	50-275, 50-323
License Nos:	DPR-80, DPR-82
Report No:	50-275/96006, 50-323/96006
Licensee:	Pacific Gas and Electric Company (PG&E)
Facility:	Diablo Canyon Power Plant, Units 1 and 2
Location:	Avila Beach, California 93424
Dates:	March 3 - April 13, 1996
Inspectors:	M. D. Tschiltz, Senior Resident Inspector S. A. Boynton, Resident Inspector J. A. Sloan, Senior Resident Inspector, San Onofre Nuclear Generating Station
Approved by:	H. J. Wong, Chief, Reactor Projects Branch E Division of Reactor Projects

EXECUTIVE SUMMARY

Diablo Canyon Power Plant, Units 1 & 2
NRC Inspection Report 50-275/96006, 50-323/96006

This report covers a 6-week period of resident inspection, which incorporated operational safety verification, maintenance observations, surveillance observations, onsite engineering, and plant support activities.

Operations:

- The inspectors identified the failure to perform an adequate channel check of a cold calibrated pressurizer level, an indication which is located at the dedicated shutdown panel, but not required by Technical Specification (TS) (Section M1.2.2).

- The inspectors identified a noncited violation involving the in-use Axial Flux Distribution (AFD) Limits Figure posted on the Unit 1 control panel which exceeded its issued-for-use period of 30 days without having been reverified (Section O1.4).

- The inspectors identified a violation for operators failing to follow procedural requirements by raising Unit 1 reactor power above 20 percent (220 MWe) without completing the required procedural steps and prerequisites (Section O1.3).

- Operators promptly identified and stopped valve packing leakage in excess of 7 gallons per minute within the time allowed in the TS. A prompt operability assessment was performed which thoroughly addressed relevant operability issues (Section O1.2).

Maintenance:

- Both an inadequate surveillance procedure and ineffective reviews of the completed surveillance, resulted in the improper performance of the surveillance of the reactor coolant system (RCS) hot leg and cold leg temperature indications at the dedicated shutdown panel in January 1996. This was identified as a violation (Section M1.2.2).

Engineering:

- Inaccuracies and inconsistencies within the UFSAR associated with the component cooling water system, remote shutdown instrumentation, 4 kV power and the emergency diesel generators were noted. This was identified as an unresolved item (Sections E7.1).

- Continued problems were noted with the source range nuclear instruments startup rate meters sticking on their low peg. An Inspection Followup

Item was opened to track the licensee's long-term corrective actions for this problem (Section E1.2).

- The licensee's corrective actions in response to a previous violation (275/95014-01) failed to identify the need to reset the emergency diesel generators' (EDG) lube oil low temperature alarm setpoint (Section E2.1).

- The licensee has conducted full-core offloads routinely without having performed a safety evaluation and as a consequence licensee procedures did not ensure that the spent fuel pool temperature and the time to offload the core were within the licensing bases. This was identified as an unresolved item (Section E2.2).

Report Details

Summary of Plant Status

Unit 1 began this inspection period at 100 percent power. On March 14, the unit was placed in Mode 3 to facilitate the installation of Auxiliary Transformer 1-1. Following installation, Unit 1 was returned to full power on March 20, and remained at full power for the balance of the inspection period.

Unit 2 began this inspection period at 100 percent power. On March 12, the unit was curtailed to 85 percent power for approximately 5 hours at the request of the system dispatcher. On April 6, Unit 2 was shut down for its seventh refueling outage. The unit was in Mode 6 at the end of the inspection period.

I. Operations

01 Conduct of Operations

01.1 General Comments

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below.

01.2 Reactor Coolant System (RCS) Leakage (Unit 1)

a. Inspection Scope (71707)

The inspector reviewed the licensee's actions regarding elevated RCS leakage identified in Unit 1 on March 4.

b. Observations and Findings

On March 4, at 6:07 a.m., Unit 1 operators observed level decreasing in the volume control tank. The leakage was estimated to be between 5-7 gpm. The licensee promptly investigated and determined that the leakage was from the packing gland of the centrifugal charging Pumps 1-1 and 1-2 flow control Valve (FCV) CVCS-1-FCV-128. Operators opened valves in the bypass line and closed Valve CVCS-1-FCV-128. At 8:14 a.m., operators isolated the FCV. They then performed a RCS leak rate calculation and confirmed that the leak had been isolated. As a compensatory action, an operator was stationed near the centrifugal charging pump in order to restore recirculation flow in the event it had become necessary to start the second pump.

The licensee initiated Action Request (AR) A0394938 to document the event and the licensee's prompt operability assessment (POA) and to initiate corrective maintenance. The inspectors reviewed the POA and determined that it appropriately addressed the relevant TS requirements. The inspectors determined that TS requirements were met while the FCV was isolated and the bypass line was in service.

c. Conclusions

Operations appropriately identified and stopped the leakage within the time allowed in the TS. The POA was thorough in addressing all relevant operability issues.

01.3 Startup Observations Unit 1

a. Inspection Scope (71707)

The inspectors observed startup activities in the Unit 1 control room on March 17 and 18. The inspectors observed the use of portions of the following procedures:

- OP L-3, Revision 15, "Secondary Plant Startup"
- OP L-4, Revision 33, "Normal Operation at Power"
- OP L-0, Revision 34, "Mode Transition Checklists"
- OP C-3:II, Revision 17, "Main Unit Turbine Startup"

b. Observations and Findings

The secondary plant startup observed on March 17 was well controlled by the Senior Control Operator. Communications were clear and the evolution proceeded with caution. Operators questioned indications and were observed to use self-verification techniques.

During the secondary plant startup, the operators noted several weaknesses with the procedures. Although these problems did not appear to have any safety consequence, several procedural steps were written to require an exact value rather than a range of acceptable values. Following the evolution operators submitted several pages of comments which identified areas where procedural improvements could be made.

Procedure OP L-3 provides instructions for raising reactor power from 0 to 20 percent (approximately 220 MWe). Procedure OP L-4 provides instructions for power changes between 20 percent and 100 percent power. OP L-3, Step 6.37 required operators to proceed to OP L-4 after all of the steps of OP L-3 were complete. The inspectors noted that the operators had raised power to 29 percent the morning of March 18 without completing the required steps in OP L-3. The steps that had not been completed were for the alignment of the feedwater and condensate system for operation at power levels of greater than 50 percent. Although there was no safety consequence for not performing the steps at that point in time, the inspectors were concerned that operators did not note their actions were contrary to procedures. Additionally, the prerequisites of Procedure OP L-4 had not been completed prior to beginning some of the steps.

c. Conclusions

The secondary plant startup was well controlled and operators provided numerous comments for procedural improvements. Operators failed to follow procedures for raising reactor power. Oversight and direction of the evolution by the shift foreman did not prevent this from occurring. The failure to complete all of the requirements for transition from Procedure OP L-3 to OP L-4 is a violation of TS 6.8.1 (VIO 50-323/96006-01).

01.4 Axial Flux Distribution (AFD) Limits Curve

a. Inspection Scope (71707)

On April 1, the inspectors conducted a walkdown of the Unit 1 control panel to verify operation in accordance with TS requirements and licensee procedures.

b. Observations and Findings

The AFD Limits Figure posted on the control panel was noted to have exceeded the issued-for-use period of 30 days without having been reverified. Administrative Procedure AD2.ID1, "Procedure Use and Adherence," Step 5.1.1.b specifies a maximum in-use period for procedures of 30 days and requires that procedures in use for longer than 30 days be verified to be the current revision and remarked. After the inspectors noted the problem the figure was verified to be up to date. Normally this matter would be considered a minor issue of low safety significance and therefore would not be discussed in an inspection report; however, this was a recurring problem which the inspectors had raised in the previous inspection period.

c. Conclusions

The failure to verify the in-use AFD Limits Figure posted at the Unit 1 control panel every 30 days as required by Administrative Procedure AD2.ID1 was identified as a noncited violation of TS 6.8.1. This failure constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy (NCV 50-275/96006-02).

02 Operational Status of Facilities and Equipment

02.1 Engineered Safety Feature System Walkdowns

a. Inspection Scope (71707)

The inspectors used Inspection Procedure 71707 to perform a detailed walkdown of accessible portions of the control room ventilation system (CRVS). The inspectors also reviewed the applicable portions of the

licensee's Updated Final Safety Analysis Report (UFSAR) associated with the CRVS and design criteria memorandum (DCM) S-23F, Revision 0, Change 11, "Control Room Heating, Ventilation, and Air Conditioning System."

b. Observations and Findings

The inspectors noted on April 8 that the material condition of system components and area housekeeping of the accessible portions of the CRVS were generally good. A detailed walkdown of the system configuration and its components found no discrepancies with the current as-built mechanical drawings.

The inspectors reviewed the applicable portions of the licensee's UFSAR and the system DCM and found several discrepancies where the documents did not reflect current design and operation. Table 9.4-1 of the UFSAR describes the design parameters of the CRVS filter train including an 85 percent removal efficiency by the charcoal filter beds for methyl iodine, an organic form of iodine. This appears to be a typographical error. The 85 percent value is inconsistent with the listing in Table 9.4-2 for removal efficiency, the licensee's analysis for determining postaccident doses to control room personnel, and the acceptance criteria in the associated surveillance procedure. Additionally, Table 9.4-2 referenced information contained in Table 9.4-3; however, Table 9.4-3 had been deleted from the UFSAR.

Review of the DCM for the system revealed that it had not been updated to reflect the impact of the installation of the third emergency diesel generator (EDG) on Unit 2. In addition, 11 interim design criteria memorandum changes had been made to the DCM since its original issuance in 1992. However, these interim design criteria memorandums had not been incorporated into the body of the DCM and only existed as pen-and-ink attachments, making it difficult to extract technical information. The licensee has identified problems with maintenance of the DCMs through its own self-assessment program.

c. Conclusions

The configuration of the CRVS was in accordance with the licensee's UFSAR and the as-built mechanical drawings. Material condition of the system was generally good. The discrepancies identified in the UFSAR and DCM were considered to be of low safety consequence; however, they were indicative of a less-than-effective program to review and update these documents. These failures to update the UFSAR are considered additional examples of the problem described in Section E7.1 and will be included in the Unresolved Item (URI 50-275/96006-06).

08 Miscellaneous Operations Issues (92700)

08.1 (Open) Violation 50-275/9428-01: Failure to follow EDG test procedure.

Following the inadvertent loss of residual heat remover during 1R6 testing, the NRC issued a violation. In order to track and develop corrective actions in the response to the violation the licensee issued a nonconformance report (NCR). The licensee's response to the violation dated December 9, 1994, detailed corrective actions which included:

1. Review and revision of programs that place tags on main control boards to prevent information from being obscured on in-service equipment.

2. Revision of Administrative Procedure OP1.DC12, "Conduct of Routine Operations" to:

a. require that, during refueling outages where significant outage activities are in progress, a dedicated licensed operator will be in the control room with no assigned duties other than monitoring overall plant conditions;

b. define the threshold of operating evolutions where it is expected that the shift foreman be in the control room directly supervising the evolution; and,

c. change the attachment that describes tailboard briefings to place more emphasis on the "big picture" discussion.

The licensee had indicated that the first corrective action review would be complete by April 1, 1995, and OP1.DC12 would be revised by February 1, 1995.

The inspectors reviewed the changes to the procedures discussed in the response to the violation. Discussions with the Operations Director revealed that the corrective actions associated with the first action had not been completed. The programs that place tags on main control boards had not been revised and there was no ongoing effort to do so. The NCR had been closed without completing all of the actions discussed in the licensee's response to the violation.

The remaining actions were subsequently completed; however, they had not been completed within the time frame indicated by the licensee. The last revision to OP1.DC12 was completed in October 1995, over 8 months after the date indicated by the licensee.

The inspectors concluded that the licensee had failed to take all of the actions described in the response to the Notice of Violation. The failure to complete these corrective actions is of particular concern since they were initiated in response to an incident that involved the

inadvertent loss of core cooling. Violation 50-275/9428-01 remains open pending further review of corrective actions taken by the licensee.

08.2 (Closed) VIO 50-275/95016-01: (A) failure to follow procedure during reactor vessel draindown to half-loop operation; (B) failure to follow procedure during operational checks of the source range nuclear instruments.

The inspectors reviewed the licensee's response to the Notice of Violation, dated February 15, 1996, and discussed with the licensee the corrective actions taken in response to Part A of the violation. The inspectors also verified that the licensee had completed the long-term corrective actions as stated in its response.

Associated with this violation, the inspectors noted in NRC Inspection Report 50-275/95016 that a potential root cause of the violation was an ineffective preevolution tailboard. The licensee justified the shortened tailboard observed by the inspectors based upon discussions held between the operators prior to the tailboard. The licensee concluded that the prerequisites, precautions and limitations had been reviewed in these discussions. However, discussions of this type did not meet the licensee's expectations for conduct of a tailboard. The operations director agreed that informal discussions are appropriate for augmenting operator knowledge, but should not be relied upon in lieu of conducting a tailboard.

The inspectors concluded that the actions taken by the licensee to prevent recurrence of the violation appeared adequate to address the root causes.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Maintenance Observations

a. Inspection Scope (62703)

The inspectors observed all or portions of the following work activities:

- C0142927 Radiography of CVCS-1-RV-8116 Inlet Piping
- C0142601 Install/Remove Ground Buggy @ 52HF13
- C0142875 Radiography of RCP 1-2 diffuser
- TP TD-9607 Providing Vital 125-Vdc Power From SD21 to SD22 Vital Loads
- C0143460 Replace Eagle 21 Analog Input Board

b. Observations and Findings

The inspectors found the work performed under these activities to be professional and thorough. All work observed was performed with the work package present and in active use. Technicians were experienced and knowledgeable of their assigned tasks. The inspectors frequently observed supervisors and system engineers monitoring job progress, and quality control personnel were present whenever required by the procedure. When applicable, appropriate radiation control measures were in place.

In addition, selected maintenance observations are discussed below.

M1.1.1 Repacking of FCV CVCS-1-FCV-128 (Unit 1)

a. Inspection Scope (62703)

The inspectors observed portions of the performance of Work Order (WO) C0142940, which directed unpacking and repacking the above valve per Mechanical Maintenance Procedure (MP) M-51.23, Revision 3A. This work was required due to valve packing failure that resulted in significant system leakage (see Section O1.1).

b. Observations and Findings

The WO directed careful examination of the packing upon removal to attempt to determine the cause of the failure. The WO also directed engineering personnel to be present during the unpacking and repacking. The licensee determined that the lower rings of packing material were substantially missing, but that the upper rings were intact.

The sequence of steps in Procedure MP M-51.23 was to first install all the packing rings and then consolidate the packing. However, maintenance and engineering personnel performed consolidation after installation of the lower two rings. Procedure MP M-51.23 allowed the engineer to alter the sequence based on job requirements.

During the maintenance activity, the licensee identified a small bolt in the drain line for Valve CVCS-1-FCV-128, and documented the condition in AR A039468. The licensee initiated an investigation of the potential origin of the bolt.

c. Conclusions

There was good engineering involvement during unpacking, inspection, and repacking of the valve and procedures were followed.

M1.2 Surveillance Observations

a. Inspection Scope (61726)

Selected surveillance tests required to be performed by the TS were reviewed on a sampling basis to verify that: (1) the surveillance tests were correctly included on the facility schedule; (2) a technically adequate procedure existed for the performance of the surveillance tests; (3) the surveillance tests had been performed at a frequency specified in the TS; and (4) test results satisfied acceptance criteria or were properly dispositioned.

The inspectors observed all or portions of the following surveillances:

- STP R-1B, Revision 15, "Rod Drop Measurement"
- STP I-36-S3TTD, Revision 1, "Protection Set Time Delay"
- STP P-AFW-11, Revision 1A, "Routine Surveillance Test of Turbine-Driven Auxiliary Feedwater (AFW) Pump 1-1
- STP V-3P1, Revision 13, "Exercising Main Feedwater Regulating Valves and Bypass Valves"
- STP V-3P2, Revision 7, "Exercising Main Feedwater Isolation Valves FCV-438, 439, 440 and 441"

b. Observations and Findings

The surveillances reviewed and/or observed by the inspectors were scheduled and performed at the required frequency. The surveillance test procedures were technically adequate and personnel were knowledgeable. The inspectors also noted that test results were appropriately dispositioned.

In addition, see specific discussion of other surveillances observed by the inspectors under Sections M1.2.1, M1.2.2, M1.2.3, and M1.2.4.

M1.2.1 Nuclear Power Range Incore/Excore Calibration

a. Inspection Scope (61726)

The inspectors observed partial performance of Surveillance Test Procedure (STP) STP I-2D, Revision 39, "Nuclear Power Range Incore/Excore Calibration," on Channel D in Unit 1. The inspectors reviewed qualification records for the test performer, and discussed the procedural guidance with maintenance supervision.

b.. Observations and Findings

The test performer conducted on-the-job training with two less experienced technicians. The test performer appeared to be very knowledgeable of the nuclear instrumentation system and test procedure.

In preparation for taking data for Table SC-I-2D-A1, Attachment 4.4 (T4), the test performer advised the trainees to first set the coarse adjustment for the highest test point so that the fine adjustment potentiometer would be near the middle of its range to allow for maximum flexibility for subsequent instrument adjustments. This guidance was not specified in the surveillance procedure and the highest test point was listed in the middle of the data table.

The inspectors discussed this with the test performer and with a maintenance general foreman. The discussion revealed that the test procedure would work as written, but may not be efficient and may not leave the fine adjustment in the middle of its range. However, operators only need approximately 20 percent of the range for their use during operations.

The nuclear instrumentation channel was removed from service for this test. The qualification records of the test performer were appropriate for surveillances on the nuclear instrumentation system.

c. Conclusions

The test performer was appropriately qualified. The test procedure was acceptable.

M1.2.2 TS Monthly Surveillances

a. Inspection Scope (61726)

The inspectors observed operators perform portions of Procedure STP I-1D, Revision 26, "Routine Monthly Checks Required by Licenses." Procedure STP I-1D is utilized by the licensee to satisfy various surveillances required by plant TS, including system alignment verifications and instrument channel checks. The inspectors also reviewed previous records of the performance of Procedure STP I-1D.

b. Observations and Findings

The inspectors reviewed the licensee's documentation of the performance of Procedure STP I-1D for Unit 2 in January 1996. Channel checks of the RCS Loop 1 hot leg and cold leg temperature indications at the dedicated shutdown panel were not performed. A design change had been implemented which changed the temperature elements (TE) for RCS Loop 1 from those specified by Procedure STP I-1D. The operator noted this discrepancy in the remarks section of the procedure checklist without performing a channel check on the Loop 1 hot leg and cold leg temperatures (from TE-414C and TE-411B respectively). Several levels of review failed to identify this as a missed surveillance. Following the inspectors' identification of this missed surveillance, the licensee reviewed additional documentation and found that these channel checks were successfully performed in December 1995 and February 1996. As a result

of the inspectors' findings, the licensee revised Procedure STP I-D to reflect the appropriate sensor inputs to be checked for RCS Loop 1 hot and cold leg temperatures. The inspectors noted that the design change had been implemented in July 1995.

Steps 3.e. and 3.h. of Attachment 11.1 to Procedure STP I-1D directed the operator to verify the status of Valves FCV-360 and 366, the component cooling water (CCW) header B and header A return valves from the containment fan cooler units (CFCUs). However, the valves were identified in the control room to be abandoned in place. The CO explained that a design change had been implemented rendering them inoperable and leaving the valves fully open. Surveillance Engineering personnel explained that these valves were abandoned in place with air isolated to the valve actuator in September 1992 (air inlet valves closed and sealed) and that it was unnecessary to periodically verify their position. The licensee indicated that the procedure would be revised to delete the requirement to verify the position of these valves.

During the CO's channel check of the RCS subcooled margin monitor (SCMM), the RCS Loop 1 hot leg temperature input to the SCMM indicated approximately 25°F less than the hot leg temperature inputs from Loops 2, 3, and 4. The problem was not documented and the inspectors questioned the CO on its acceptability. The CO rechecked the parameter reading and concurred with the inspectors' observation. The CO subsequently initiated an AR to investigate the discrepancy with the Loop 1 temperature input. The low Loop 1 hot leg temperature input did not impact the operability of the SCMM. Valid temperatures from several core exit thermocouples and from the other three loops provided adequate inputs to the instrument for determining subcooled margin.

The inspectors also observed an NO perform those portions of Procedure STP I-1D associated with comparisons of control room instrument readings with the indications at the dedicated shutdown panel. The NO did not have a control room reading for cold-calibrated pressurizer level (not a TS required instrument). The inspectors inquired about how a channel check was accomplished The inspectors discussed that an alternate indication of this parameter was available in the control room of which the NO was unaware. The inspectors raised a concern for the channel check of the instrument to the shift foreman (SFM) and the shift technical advisor. The SFM and shift technical advisor concurred with the inspectors' conclusion and a valid channel check was subsequently performed.

c. Conclusions

Both an inadequate procedure and an ineffective review of the surveillance, resulted in an improperly performed surveillance of the RCS hot leg and cold leg temperature indications at the dedicated

shutdown panel in January 1996. This is a violation of TS 6.8.1 (VIO 50-323/96006-03).

M1.2.3 AFW Pump Full Flow Test

a. Inspection Scope (61726)

The inspectors observed routine full flow testing of the turbine-driven AFW pump on March 18. The inspectors observed the use of portions of the following procedures:

- STP P-AFW-11, Rev. 1A, "Routine Surveillance Test of Turbine-Driven AFW Pump 1-1"
- AD13.DC2, Rev. 0A, "Dealing With Gauge Oscillations During the Performance of Tests on Safety Related Pumps"

b. Observations and Findings

The AFW pump testing was accomplished in accordance with the licensee's requirement to perform full flow testing following each Mode 3 entry. The inspectors observed the pretest tailboard and portions of the pretest system alignment verification.

During the AFW pump test, the inspectors noted a steam leak on the turbine cross-over line. The licensee had previously identified the leak and had written an AR to document and evaluate the impact of the deficiency on operability. Although the steam leak did not appear to impact current operability, it should be monitored and evaluated during periodic pump surveillance testing. Adjustment of the governor was needed to achieve the AFW pump differential pressure specified by the procedure.

c. Conclusions

The testing verified that the turbine-driven AFW pump was operable. The operators demonstrated adequate system knowledge during the performance of the test.

M1.2.4 Main Feedwater Valve Testing

a. Inspection Scope (61726)

The inspectors observed the exercising of main feedwater regulating and bypass and isolation valves performed in accordance with the following procedures:

- STP V-3P1, Rev. 13, "Exercising Main Feedwater Regulating Valves and Bypass Valves"

- STP V-3P2, Rev. 7, "Exercising Main Feedwater Isolation Valves FCV-438, 439, 440 and 441"

b. Observations and Findings

The inspectors noted that the testing was well controlled and coordinated. Operators involved with the testing were knowledgeable of the testing requirements. The procedure did not provide for restoration of the monitor light test switch, thus leaving the switch in the test position at the end of the surveillance. The inspectors questioned this and the SFM directed the operators to document the problem so that the procedure could be revised prior to future performance.

c. Conclusions

Operators were knowledgeable of test requirements and performed the testing in accordance with TS requirements. The SFM appropriately dispositioned an error in the procedure.

III. Engineering

E1 Conduct of Engineering

E1.1 Rod Drop Testing (Unit 1)

a. Inspection Scope (37551 & 71707)

On March 16, during the Unit 1 1T8 outage, the licensee conducted control rod drop testing in response to NRC Bulletin 96-01, "Control Rod Insertion Problems." The inspectors reviewed STP R-1B, Revision 15, "Rod Drop Measurement," AR A0395504, and NRC Bulletin 96-01, observed portions of the test, and reviewed the test results.

b. Observations and Findings

Interactions between the system engineer and the CO were both formal and clear. During rod withdrawal, the CO remained focused on power indications. During the test, the control console startup rate (SUR) meter for source range instrument NI-32 stuck on its bottom peg on several occasions. This required the CO to tap on the meter face to restore free movement of the meter and was a distraction to the CO. The CO appropriately stopped rod withdrawal each time to correct the problem. The operators did not consider the SUR meter to be inoperable. The inspectors agreed with their assessment.

Following the rod drop testing, an AR (A0396189) was initiated to investigate and repair the SUR meter. Historical ARs revealed that

similar problems were observed with this meter in November 1995 (A0386028). The corrective action taken in response to A0386028 was the replacement of the meter housing. A similar problem was also noted in NRC Inspection Report 95-16 where an intermediate range meter was found to be sticking during a reactor startup. The licensee has incorporated the repair of the SUR meter into the scope of the next Unit 1 refueling outage scheduled for May 1997. The nuclear instrumentation system engineer pointed out that the SUR meter received limited use and that it provides no protective trip, permissive or interlock signals.

The review of the test data indicated that all control assemblies fully inserted into the core within the 2.7 seconds required by TS. Comparison with the data and traces obtained from previous testing indicated that there were no significant changes in rod drop responses. The average rod drop time was 1.38 seconds during the testing performed during the 1T8 outage and 1.39 seconds from the testing performed during the last Unit 1 refueling outage, 1R7.

c. Conclusions

The rod drop testing was well controlled and in accordance with the licensee's surveillance procedure. Test results indicated that rod drop times had not significantly changed since 1R7.

Although the control console SUR meters provide no protective trip, interlock or permissive signals, they are relied upon by operators to provide accurate indication of reactivity changes in the nuclear source range. Their continued reliability is essential for the safe conduct of evolutions involving positive reactivity additions such as the approach to criticality. The licensee's actions to correct the identified problems with the SUR meters will be tracked as Inspection Followup Item (IFI 50-275/96006-04).

E2 Engineering Support of Facilities and Equipment

E2.1 Diesel Generator Lube Oil Low Temperature Alarm

a. Inspection Scope (37551)

On April 10, the licensee declared EDG 2-1 inoperable based upon low lube oil temperature. The inspectors reviewed the event with the on-shift operators and discussed the lube oil temperature requirements with EDG system engineer. The inspectors also reviewed the licensee's corrective actions in response to NRC Violation 50-275/95014-01.

b. Observations and Findings

On April 10, the licensee was performing scheduled maintenance on EDG 2-3 and its associated 4kV and 480V vital buses. The clearance of these buses resulted in an expected loss of power to the 'B' contactor

panel for EDG 2-1. The 'B' contactor panel provides power to the EDG 2-1 lube oil heaters. The lube oil heaters are designed to maintain diesel lube oil temperature between 90-120°F. The loss of power to the heaters caused lube oil temperature to fall below 90°F. This condition was identified by the turbine building auxiliary operator during shift rounds. The immediate corrective action taken by the licensee was to operate EDG 2-1 to raise lube oil temperature. The licensee subsequently installed a temporary jumper to provide power to the lube oil heaters while maintenance continued on EDG 2-3 and its associated buses. EDG 2-2 was operable during this event; therefore, operability of EDG 2-1 was not required by TS.

The on-shift operators stated that a low lube oil temperature alarm was not received in the control room. Further inquiry revealed that the EDG low lube oil temperature alarm setpoint for each of the diesels was less than 90°F.

NRC Inspection Report 50-275/95014 documented a violation for failure to test the EDGs at ambient conditions as required by TS. In response to the violation, the licensee revised the governing STP to require initial jacket water and lube oil temperatures to be between 90-120°F. Prior to this, the operability threshold for lube oil temperature was 70°F. The licensee's reply to the Notice of Violation, dated November 27, 1995, and associated NCR did not address raising the lube oil low temperature alarm setpoints.

c. Conclusions

Licensee actions to restore operability of EDG 2-1 were prompt and effective. The failure to adjust the low temperature setpoint for the EDG lube oil low temperature alarm when the lube oil temperature for operability was increased from 70°F to 90°F was considered to be a weakness.

E2.2 Core Offload Practices and Spent Fuel Pool Controls

a. Inspection Scope (92903)

The inspectors reviewed the licensee's procedures and past practices for core offload during refueling outages. The inspectors reviewed the following documents:

- Diablo Canyon UFSAR
- NRC Information Notice 95-54: Decay Heat Management Practices During Refueling Outages
- NUREG-0800, USNRC Standard Review Plan, Section 9.1.3, "Spent Fuel Pool Cooling and Cleanup Systems"
- Diablo Canyon TS

- Diablo Canyon License Amendment (LA) 22/21 (Expansion of Spent Fuel Pool Storage Capacity Units 1 and 2) and the associated Safety Evaluation Report (SER)

b. Observations and Findings

UFSAR, Section 9.1.4.2.3, describes a one-third core offload. However, the licensee has conducted a full-core offload during each refueling outage since the start of commercial operation of the units. Further, a safety evaluation has not been performed, as required by 10 CFR 50.59 prior to the licensee's departure from performing core offloads as described in the UFSAR.

The SER, which approved LA 22 and 21 for Units 1 and 2 respectively, concluded, in part, that the spent fuel pool temperature would not exceed 140°F for normal offload conditions (i.e., unloading of 76 assemblies) and 212°F for abnormal offload conditions (i.e., full-core offload). The licensee's thermal-hydraulic analysis supported these conclusions and demonstrated that the spent fuel pool temperature would not exceed 140°F during a one-third core offload and 175°F for a full-core offload.

The inspectors questioned whether the 140°F temperature limit should apply as the licensing basis for full-core offloads since they had become the routine, or normal method of refueling. The licensee concluded that the 140°F temperature limit was applicable to full-core offloads. The licensee had not previously implemented controls to ensure the spent fuel pool temperature would not exceed 140°F following full-core offloads. Further investigation by the licensee, after being questioned by the inspectors, revealed other inconsistencies with temperatures used in analyses and associated controls. The inconsistencies are described below:

- The criticality analysis of record assumed a maximum normal temperature of the spent fuel pool of 150°F; however, the Equipment Control Guideline allowed up to 175°F.

- The licensee noted on April 2, 1996, that the Unit 2 spent fuel pool temperature decreased to 66°F which was below the 68°F minimum temperature assumed in the criticality analysis. The licensee initiated actions to reduce CCW flow which had little impact on the spent fuel pool temperature. Subsequently, the licensee performed a criticality analysis that demonstrated that the reactivity in the spent fuel pool would be below the regulatory limit for a pool temperature as low as 32°F.

Section 9.1.3.1 of the UFSAR notes that the spent fuel pool cooling analysis is based upon a full-core offload completed in no less than 148 hours following shutdown. During the 2R6 refueling outage a

full-core offload had been completed 146 hours after shutdown. The licensee's refueling procedures did not incorporate controls to ensure that core offload would not be completed in less than the 148 hours.

The licensee's disposition of Information Notice (IN) 95-54 by the independent safety evaluation group (ISEG) did not identify any problems with the processes or activities related to decay heat management. The ISEG review noted that "core offload practices and thermal design limitations are well documented and conservative such that actual operating practices are bounded and considered adequate." The failure of ISEG to identify problems associated with the licensee's decay heat management practices during refueling outages was a missed opportunity to identify and correct these problems.

The licensee implemented corrective actions for the above deficiencies prior to the Unit 2 refueling outage (2R7). The corrective actions included:

- performing a 10 CFR 50.59 safety evaluation for the normal conduct of a full-core offload,
- establishing administrative controls to ensure spent fuel pool temperature is maintained within the licensing basis and the assumptions of the supporting analyses,
- establishing administrative controls to ensure that the core is not offloaded at a rate faster than that assumed in the supporting thermal-hydraulic analysis, and
- revising the UFSAR description of the refueling procedure.

c. Conclusions

The licensee's failure to perform a safety evaluation prior to performing full-core offload is an unresolved item pending NRC review (URI 50-275,323/96006-05). This caused the licensee's failure to implement administrative controls for the reload process (spent fuel pool temperature and time for full-core offload).

E4 Engineering Staff Knowledge and Performance

E4.1 Review of Design Change Package (DCP) J-050216

a. Inspection Scope (37551)

The inspectors reviewed DCP J-050216, including the safety evaluation, technical description and drawings, and the proposed change to the UFSAR. This DCP replaced the input to Loop 2-1 reactor coolant system cold leg wide range TE (TE-413B) with an alternate available sensor (TE-411B) in order to provide the TS required indication at the dedicated shutdown panel in Unit 2. The inspectors discussed the

changes with the licensee's staff and walked down the dedicated shutdown panels in both units.

b. Observations and Findings

The change was implemented in July 1995 as an "install and remove" change. The DCP indicated that the configuration would be restored during the "next suitable" Unit 2 outage. The next Unit 2 refueling outage was scheduled for April 1996.

The DCP included a proposed UFSAR change which was submitted to the licensee's licensing organization. The proposed UFSAR change inappropriately included a change to Table 9.5G-2, page 10, which was for Unit 1 only.

Some sections of the Fire Hazards Analysis (including some not affected by the UFSAR change for this DCP) failed to identify with which unit the various components were associated. An example of an unclear section was Fire Area TB-7, Fire Zone 19-A (beginning on page 9.5A-561).

The DCP included extensive documentation of the implications of the change. The inspectors noted that the DCP package did not explicitly state in the first several pages which unit was affected by the change. However, consistent with licensee practice, the DCP had an even number, which implied that the change was for Unit 2.

c. Conclusions

The DCP was thorough in addressing most aspects of the change with some minor discrepancies noted. Weaknesses in the completeness of engineering work were evident.

E7 Quality Assurance In Engineering Activities

E7.1 Review of LAs and Their Impact on the UFSAR

a. Inspection Scope (37551)

The inspectors reviewed a sample of 6 approved LAs to determine their impact, if any, on the facility UFSAR. Specifically, the inspectors reviewed the applicable portions of the UFSAR to evaluate the consistency and accuracy of the UFSAR with the approved changes in the LAs.

b. Observations and Findings

The inspectors reviewed LAs 94 and 93 for Units 1 and 2, respectively. These amendments revised the TS requirements for remote shutdown instrumentation to be consistent with the Westinghouse Standardized TSs (NUREG 1431). The licensee concluded that indication of the RCS hot and

cold leg temperatures was required for remote shutdown of the plant. The licensee also concluded that indication of emergency boration flow was not required for remote shutdown. Although the revised TS reflected these conclusions, the licensee's UFSAR did not. Specifically, Section 7.4.1.1 of the UFSAR listed emergency boration flow as a required indication for shutdown of the plant outside the control room while it remained silent on the requirement for RCS temperature indication.

The inspectors reviewed LAs 89 and 88. These amendments revised the TS to reduce the minimum required CCW flow to each of the CFCUs from 2000 gpm to 1650 gpm during normal operation. The licensee's post-loss of coolant accident containment performance analysis in the UFSAR assumes a design basis CCW flow of 2000 gpm to at least two of the CFCUs. The licensee's safety analysis accompanying the LA request justified the difference between the minimum CCW flow in TS and the design basis CCW flow in the UFSAR analysis based upon the automatic isolation of the nonvital CCW header in response to a loss of coolant accident. The isolation of the nonvital header under accident conditions would redirect sufficient flow to the vital CCW headers to provide a minimum of 2000 gpm to the CFCUs.

Although the UFSAR had been revised by the licensee to reflect these LAs, the revisions were incomplete and, as a result, the UFSAR was both inconsistent with the LA and internally inconsistent. Specifically, Section 9.2.2.2.7 of the UFSAR states that during normal operations, flow through the fan coolers is throttled to pass the design basis accident flows. It further states that full flow is assured through each CFCU under accident conditions without any automatic or operator action. This contradicts the LA safety analysis which assumed normal flow rates less than the 2000 gpm design basis and required the automatic isolation of the nonvital CCW header to achieve full flow through the CFCUs. In addition, both Section 9.2.2.2.7 and Table 6.2-26 of the UFSAR define normal CCW flow through the CFCUs as 2000 gpm while Table 9.2-5 defines normal CCW flow to all of the CFCUs as 8,250 gpm (1650 gpm per unit).

The table incorporated into Section 9.2.2.2.7 of the UFSAR stated that the design CCW inlet temperature for the CFCUs during normal operation was 95°F. In contrast, Table 6.2-26 of the UFSAR lists the design inlet temperature during normal operation as 90°F.

The licensee failed to revise Section 8.3.1.1.9 of the UFSAR from 3.6kV to 3.8kV when implementing the increase in setpoint of the secondary undervoltage relay to 3785 VAC authorized by LA 85/86. In addition, the licensee failed to revise the 4kV bus nominal voltages listed in Appendix 8.3A after raising the secondary undervoltage relay setting. The inspectors determined that the licensee had also recently noted these deficiencies during a UFSAR review.

The licensee has issued an NCR to address the UFSAR inaccuracies and, as a part of the corrective actions, the licensee initiated a review by system engineers of the entire UFSAR. The initial review efforts were done to gain a quick assessment of the UFSAR's accuracy.

c. Conclusions

The deficiencies identified in the UFSAR are continuing to be evaluated. However, the number of deficiencies in the relatively small sample is indicative of weaknesses in this program to review and update the UFSAR in response to LAs and therefore is of regulatory concern. These deficiencies, the examples discussed in Section O2.1, and those being identified by the licensee in their UFSAR review process are being tracked as an unresolved item (URI 50-275/96006-06) pending further NRC review.

E8 Miscellaneous Engineering Issues

E8.1 Review of UFSAR Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures, and/or parameters to the UFSAR description. During the inspection period, the inspectors reviewed the applicable sections of the UFSAR related to the inspection areas discussed in this report. The following inconsistencies were noted between the wording of the UFSAR and the plant practices, procedures, and/or parameters observed by the inspectors. The deficiencies are discussed in the sections in the report that are referenced below:

- O2.1 UFSAR inconsistency with referenced charcoal bed methyl iodide removal efficiency
- E2.2 Core offload practices did not coincide with actual licensee practice
- E4.1 Inaccuracies in UFSAR revision written for DCP J-050216
- E7.1 incomplete UFSAR revisions written for LAs (several examples noted)

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of the licensee management at the conclusion of the inspection on April 18, 1996. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. R. Becker, Director, Operations
D. H. Behnke, Senior Engineer, Regulatory Services
E. Chaloupka, Engineer, Surveillance Engineering
S. G. Chestnut, Senior Engineer, Primary Systems Engineering
T. L. Grebel, Director, Regulatory Services
C. D. Harbor, Engineer, Regulatory Services
R. L. Johnson, Supervisor, Regulatory Services
D. B. Miklush, Manager, Enineering Services
R. P. Powers, Manager, Operations

NRC

M. D. Tschiltz, Senior Resident Inspector
S. A. Boynton, Resident Inspector
J. A. Sloan, Senior Resident Inspector, San Onofre Nuclear Generating Station

INSPECTION PROCEDURES USED

IP 37551: Onsite Engineering
IP 61726: Surveillance Observations
IP 62703: Maintenance Observations
IP 71707: Plant Operations
IP 71750: Plant Support Activities
IP 92700: Followup - Operations
IP 92903: Followup - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-275/96006-01	VIO	failure to follow Operations Procedures OP L-3 and L-4
50-275/96006-02	NCV	failure to follow Administrative Procedure AD2.ID1
50-275/96006-03	VIO	failure to perform channel check of remote shutdown instrument
50-275/96006-04	IFI	licensee long-term corrective actions to improve source range instrument reliability
50-323/96006-05	URI	failure to perform a 10 CFR 50.59 evaluation for full-core offload
50-275/96006-06 50-323/96006-06	URI	failure to adequately review and update the UFSAR

Closed

50-275/95016-01	VIO	failure to follow procedure during vessel draindown; failure to follow procedure for source range operational checks

Discussed

50-275/94028-01	VIO	failure to follow EDG test procedure

LIST OF ACRONYMS USED

1R7	Unit 1 Seventh Refueling Outage
1T8	Unit 1, Cycle 8, Transformer Outage
AFD	Axial Flux Distribution
AFW	auxiliary feedwater
AR	action request
CCW	component cooling water
CFCU	containment fan cooler unit
CO	control operator
CRVS	control room ventilation system
CVCS	chemical and volume control system
DCM	design criteria memorandum
DCP	design change package
EDG	emergency diesel generator
FCV	flow control valve
ISEG	Independent Safety Evaluation Group
LA	license amendment
MP	maintenance procedure
NCR	nonconformance report
NI	nuclear instrument
NO	nuclear operator
OP	operating procedure
POA	prompt operability assessment
RCS	reactor coolant system
SCMM	subcooled margin monitor
SER	Safety Evaluation Report
SFM	shift foreman
STP	surveillance test procedure
SUR	start-up rate
TE	temperature element
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
WO	work order