ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-275/96-02
50-323/96-02

Licenses: DPR-80
DPR-82

Licensee: Pacific Gas and Electric Company
77 Beale Street, Room 1451
P.O. Box 770000
San Francisco, California

Facility Name: Diablo Canyon Nuclear Power Plant, Units 1 and 2

Inspection At: Diablo Canyon Site, San Luis Obispo County, California

Inspection Conducted: January 21 through March 2, 1996

Inspectors: M. D. Tschiltz, Senior Resident Inspector
S. A. Boynton, Resident Inspector
D. E. Corporandy, Project Inspector
C. J. Paulk, Reactor Inspector
D. G. Acker, Senior Project Inspector

Approved: [signature] 4/9/96
for H. J. Wong, Reactor Projects Branch E — Date

Inspection Summary

Areas Inspected (Units 1 and 2): Routine, announced inspection of operational safety verification, maintenance observations, surveillance observations, onsite engineering, plant support activities, followup operations, followup engineering, in office review of licensee event reports (LERs), and review of the Updated Final Safety Analysis Report (UFSAR).

Results (Units 1 and 2):

Operations:

- The licensee's procedure for performing monthly channel checks of the incore thermocouple instruments did not ensure the Technical Specification (TS) surveillance requirement was met. As a result, the licensee failed to identify an inoperable incore thermocouple instrument on Unit 2. A violation was identified (Section 2.1).

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- Operations responded promptly and effectively in response to a steam leak on cold reheat drain piping that necessitated an unanticipated reduction of reactor power to perform repair of a cracked weld (Section 2.4).

- Operators failed to identify the potential for spread of contamination during a surveillance test of a containment spray pump when leakage from the pump's mechanical seal sprayed outside of the posted surface contamination area (Section 4.1).

- An operator failed to properly perform a system alignment verification for the performance of TS required surveillance testing. A noncited violation was identified (Section 4.2).

<u>Maintenance</u>:

- Maintenance personnel failed to address a potential seismically induced system interaction when a storage cabinet was allowed to be placed in close proximity to safety-related conduit associated with the Unit 2 diesel generators (Section 2.2).

- The licensee's configuration control program and engineering system walkdowns failed to identify the installation of improperly sized motor bearing oilers on several safety-related pumps (Section 2.3).

- The replacement of Safety Injection (SI) Pump 2-2 was thoroughly planned and well coordinated, enabling the work to be completed within the allowed 72-hour action statement. Briefings conducted for the test were informative and personnel performing testing were knowledgeable of their assigned duties (Section 4.3).

<u>Engineering</u>:

- The thermography program implemented by predictive maintenance was effective in identifying a problem with a containment fan cooler motor controller prior to actual failure (Section 3.1).

- The licensee failed to take timely and appropriate licensing actions to pursue extension of the TS allowed outage time for SI Pump 2-2 replacement, after noting a decrease in pump performance during surveillance testing and concluding that LOKTITE had not been applied to the shaft locknuts (Section 4.3).

- Engineering investigative actions taken in response to concerns regarding centrifugal charging (CC) pump operability failed to fully consider the impact of closing the recirculation isolation valves on accident analyses. As a result, the failure to take prompt and comprehensive corrective actions, a violation was identified (Section 5.1).

Plant Support:

- Periodic fire brigade proficiency training was not completed as required, and resulted in unqualified personnel being assigned as fire brigade members. A violation was identified (Section 6.2).
- A number of minor radiological controls deficiencies were noted, indicating a decline in radiological housekeeping practices and worker awareness of radiological hazards and controls (Section 6.3).

Summary of Inspection Findings:

- Violation 323/9602-01 was opened (Section 2.1).
- Violation 275/9602-02; 323/9602-02 was opened (Section 5.1).
- Violation 275/9602-03; 323/9602-03 was opened (Section 6.2).
- A noncited violation was identified (Section 4.2).
- Violation 275/95015-01 was closed (Section 7.1).
- Inspection Followup Item 275/9334-01 was closed (Section 8.1).
- Unresolved Item 50-275/95014-04 was closed (Section 8.2).
- LERs 275/95-009, Revision 0; 275/95-012, Revision 0; and 275/95-017 Revision 0 were closed (Section 9).

Attachments:

- Persons Contacted and Exit Meeting
- List of Acronyms

DETAILS

1 PLANT STATUS

Unit 1

At the beginning of this inspection period, Unit 1 was in Mode 1 at 100 percent power. On February 17 operators reduced power when a moisture separator reheater stop valve failed to reopen during a surveillance test. The stop valve was reopened within an hour and the unit was returned to 100 percent power. On February 21 power was reduced to approximately 10 percent to allow for a weld repair of a cold reheat drain line. The unit returned to 100 percent power on February 22 and remained there through the end of the inspection period.

Unit 2

At the beginning of this inspection period, Unit 2 was in Mode 1 at 100 percent power. The unit remained at 100 percent power throughout the inspection period. Between February 22-24, the licensee replaced SI Pump 2-2 based upon pump performance concerns identified during the pump's routine surveillance test (Section 4.3).

2 OPERATIONAL SAFETY VERIFICATION (71707)

The inspectors performed this inspection to ensure that the licensee operated the facility safely and in conformance with license and regulatory requirements. The methods used to perform this inspection included direct observation of activities and equipment, observation of control room operations, tours of the facility, interviews and discussions with licensee personnel, independent verification of safety system status and TS limiting conditions for operation, verification of corrective actions, and review of facility records. The Senior Resident Inspector conducted a review of recent INPO evaluations during this inspection period.

2.1 Incore Thermocouple Channel Checks

On February 13 the inspector identified a discrepancy between the incore thermocouple readings on postaccident monitoring system (PAMS) Train A and Train B on Unit 2. Specifically, the average core temperature on the PAMS Train B display was approximately 20°F higher than that on the Train A display. The inspector discussed the temperature variation with the engineering supervisor responsible for the incore temperature monitoring system and requested them to evaluate its impact on the system's operability. As a result, engineering determined that the PAMS Train B temperature indications were erroneous and operations declared the PAMS Train B display inoperable. Train A of the incore thermocouple PAMS continued to provide a sufficient number of operable thermocouples to meet TS requirements.

TS require that the incore thermocouples be calibrated on a refueling frequency and that a channel check be performed monthly when the unit is operating in Modes 1, 2, or 3. The inspector reviewed the work orders, documenting the latest calibrations performed, on Trains A and B to meet TS surveillance requirements. The work orders were complete and no abnormal results were noted. The inspector also reviewed Procedure STP I-1D, Revision 25A, "Routine Monthly Checks Required By Licenses." Procedure STP I-1D is utilized by the licensee to satisfy the TS requirement to perform monthly channel checks of the incore thermocouples. Step 11.s. of Attachment 11.1 to Procedure STP I-1D directs operators to perform a channel check of the incore thermocouples and verify at least four thermocouples operable per core quadrant. The procedure stipulates that the indications may be read locally (at the PAMS panel) or through a graphical interface on the plant process computer (PPC). With no other specific guidance provided for determining the acceptability of the thermocouple indications, the inspector questioned several control operators on how they would evaluate Step 11.s. The inspector determined that, in general, operators would rely upon the incore thermocouple map provided by the PPC and not visually observe the local indications. The inspector considered this to be a contributing factor in the operators' failure to identify the inoperable PAMS Train B display.

Concerned with the acceptability of using the PPC to fulfill the TS required channel check of the incore thermocouples, the inspector discussed this practice with the system engineer, the operations director, and the surveillance engineering group. The operations director and the surveillance engineering group responsible for the maintenance and performance of Procedure STP I-1D agreed that use of the PPC alone would not adequately verify operability of the incore thermocouple accident monitoring instruments. The operations director initiated an action request (AR) for engineering to evaluate this issue and directed the on-shift operators to perform a partial STP I-1D to verify the operability of the local PAMS displays. The results of the partial surveillance were satisfactory.

The inspector noted that the incore thermocouple accident monitoring instruments would be relied upon by operators during an accident to evaluate the core cooling critical safety function criteria. A potential consequence of inadequate surveillances of these instruments is erroneous core temperature indication that could adversely impact the operators' ability to effectively implement the emergency operating procedures. The inspector concluded that Procedure STP I-1D, as written, would not necessarily verify operability of the incore thermocouples in that it did not specifically require operators to observe the local indications. The failure of Procedure STP I-1D to adequately evaluate the operability of the PAMS incore thermocouples is a violation of TS 6.8.1 (Violation 323/9602-01).

2.2 Unit 2 Diesel Generator Air Exhaust Room Material Storage

On February 1, during a plant tour of the Unit 2 turbine building, in the diesel generator exhaust room, the inspector identified a potential seismically induced system interaction (SISI) when he noted that a large,

unrestrained storage container had been placed in close proximity to safety-related electrical conduit. The inspector raised the concern of potential seismic interactions between the container and the conduit with the responsible maintenance supervisor. The supervisor agreed that the placement of the container was inappropriate and the container was moved to a new location and secured.

The inspector discussed his concerns with the system engineer responsible for implementation of the SISI program. The system engineer determined that the conduit was an SISI "target" in that it contained vital circuits for the operation of Emergency Diesel Generator (EDG) 2-3. SISI "targets" are defined in Procedure AD4.ID3, Rev. 1B, "SISI Review of Housekeeping Activities," as those components required for safe shutdown of the plant or for accident mitigation. The system engineer evaluated the potential SISI and determined that it was unlikely the container could have damaged the conduit in a seismic event.

Conclusion: The inspector concluded that the maintenance supervisor failed to identify the potential SISI created by the placement of the storage container and, thus, the appropriate evaluation had not been performed by engineering services. Similar concerns had previously been identified by the inspector and communicated to the licensee for ongoing work in this same area. The actions taken to resolve the issue had not been effective. The inspector considered these problems as a weakness in the implementation of the SISI program during maintenance activities.

2.3 Component Cooling Water (CCW) Pump Motor Bearing Oilers

On January 31, during a plant tour in the Unit 1 auxiliary building, the inspector noted that the size of the motor bearing oilers installed on CCW Pump 1-2 were smaller than that on the other CCW pump motors for Unit 1. The inspector contacted the CCW system engineer to ascertain the reason for the difference and to determine if the oiler's smaller capacity could affect the operability of the pump. In response to the inspector's concerns, the system engineer performed a prompt operability assessment (POA) of CCW Pump 1-2 and reviewed the work order history for the pump motor. The system engineer determined that the installed oilers did not meet design requirements; however, their smaller capacity did not affect the operability of the pump. The licensee's review of the maintenance history on the pump motor could not identify a definitive cause for the installation of improperly sized bearing oilers.

In addition to evaluating the impact of the smaller bearing oilers on CCW Pump 1-2, the licensee visually inspected the other CCW pumps on Units 1 and 2. The licensee identified that an improperly sized bearing oiler had also been installed on CCW Pump 2-1. The inspector followed up this finding by visually inspecting all safety-related pumps and motors in the auxiliary building and identified another improperly sized oiler on the outboard motor bearing of auxiliary feedwater (AFW) Pump 2-3. The inspector noted that an AR had been initiated by the licensee for improper sizing of the motor-bearing

oilers on AFW Pump 2-3 and containment spray (CS) Pump 1-2. The AR for the CS pump included a POA justifying the pump's operability. Although a formal POA was not performed for AFW Pump 2-3, the AR provided technical justification for the acceptability of the smaller sized oiler. The licensee determined that the incorrect oiler was installed due to an error in tne replacement parts evaluation (RPE) associated with the AFW pump motors. The licensee has revised the RPE to reflect the proper oiler size required for the AFW pump motors. The licensee has also initiated actions to replace the incorrect oilers on all four pumps.

Conclusion: The inspector concluded that the installation of improperly sized bearing oilers on the above pumps did not impact the pumps' ability to perform their safety function. The inspector noted that the POAs for the CCW pump motors and the CS pump were technically sound. However, the inspector considered the multiple examples and failure of system engineers to note these problems during system walkdowns to be indicative of a weakness in the licensee's configuration controls during plant maintenance.

2.4 Control Room Observations

On February 21 the inspector observed the conduct of operations in the control room during a reduction in power of Unit 1. The reduction of reactor power was required to establish conditions to perform a weld repair of a cracked weld on a cold reheat steam line drain connection. Prior to reducing reactor power, a preevolution briefing was conducted. The inspector noted that the appropriate procedures were referred to and followed, where applicable, and that the briefing covered the important aspects of the evolution and the applicable precautions.

During shift turnover, the inspector observed the communications and briefings of the control room operators for the oncoming shift. The inspector noted that the information pertinent to the evolution was communicated during the shift turnover. As the reduction in power continued, the inspector observed that the control operator was attentive and responsive to plant parameters and conditions.

The inspector noted that the axial flux difference (AFD) limits figure posted on the control panel had expired three days earlier. The issued-for-use interval of 30 days had been exceeded without the figure having been reverified as current. The inspector discussed the deficiency with the control operator, who initiated actions to obtain a verified copy of the figure. The inspector later determined that the AFD limits figure had not been revised since the figure was previously issued and that the issued-for-use figure was the latest revision.

Conclusion: During the reduction of reactor power level, operators referred to and followed applicable procedures. Crew briefings observed by the inspector covered the important aspects of the evolution and the applicable precautions. The failure of the control operators to verify that control

panel posted are maintained current for a period of over 3 days is indicative of inadequate tracking of issued-for-use procedures.

3 PLANT MAINTENANCE (62703)

During the inspection period the inspectors observed and reviewed selected documentation associated with the maintenance and problem investigation activities, listed below, to verify compliance with regulatory requirements, compliance with administrative and maintenance procedures, required quality assurance department involvement, proper use of safety tags, proper equipment alignment and use of jumpers, personnel qualifications, and proper retesting. Specifically, the inspector reviewed the work documentation or witnessed portions of the following maintenance activities:

Unit 1

- Troubleshooting and repair of containment fan cooler Unit (CFCU) 1-4 motor controller
- CCW System Backflush

Unit 2

- Troubleshoot and repair (Pressure Control Valve) PCV-21 I/P controller (10 percent atmospheric steam dump)
- Replace PCV-106 regulator (air supply to EDG 2-3 air start motors)
- SI Pump 2-2 replacement

Selected observations from the activities witnessed are discussed below.

3.1 Troubleshooting and Repair of Cabling in CFCU Breaker Cubicle

On February 27 and 28 the inspector observed maintenance personnel perform troubleshooting and repair of cabling inside the breaker cubicle for CFCU 1-4. This maintenance was being performed based upon periodic thermal imaging data collected by predictive maintenance. Thermographic imaging of the breaker cubicle had identified an elevated temperature on several cables.

The inspector reviewed the associated work package and referenced procedures and discussed the scope of troubleshooting with the maintenance technicians. The inspector noted that the technicians were knowledgeable on the breaker design and function, and their approach to the troubleshooting was methodical. The troubleshooting resulted in the identification and replacement of several degraded cables. Postmaintenance testing verified that the elevated temperatures had been corrected.

Conclusion - The inspector concluded that the maintenance on the CFCU 1-4 breaker cubicle was performed in accordance with applicable procedures and was effective in identifying the root cause of the elevated temperatures and resolving the deficiency. The inspector also noted that the thermography program implemented by predictive maintenance was effective in identifying the problem before a failure occurred.

3.2 DEG-2-PCV-106 Replacement

On February 15 the inspector observed portions of the work to replace EDG 2-3 air start motor air supply pressure reducing Valve DEG-2-PCV-106. When the inspector arrived at the work site, the valve had already been removed from the system and the workers had taped foreign material exclusion postings over the open piping.

The inspector reviewed the work package and noted that, although the valve had been removed from the system, two of the prerequisites for the work had not been initialed as being completed in the controlling work document. The specific prerequisites that had not been initialed as complete were the verification of the subclearance and hanging of the red tag and the foreman reporting on the clearance. Prior to leaving the work site the maintenance mechanic hung the red tag required by the subclearance. When questioned by the inspector, the mechanic indicated that the foreman had reported on the clearance prior to the start of the work although the step had not been initialed. The inspector later verified that the foreman had, in fact, reported on the clearance prior to the removal of the valve.

The inspector reviewed the licensee's work order procedures and did not find any specific requirement to complete work order prerequisites prior to commencing work. The inspector discussed the observations with the director of mechanical maintenance who indicated that he did not believe the failure to complete work order prerequisites was a violation of procedures; however, it was management's expectations that, prior to commencing work, prerequisites would be completed.

Conclusion - The inspector agreed with the licensee's conclusion that, during the replacement of DEG-2-PCV-106, the maintenance workers performing the work failed to meet management expectations for completion of work order prerequisites.

4 SURVEILLANCE OBSERVATIONS (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 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.

Specifically, portions of the following surveillances were observed by the inspector during this inspection period:

Unit 1

- STP P-CSP-11, Revision 0, Routine Surveillance Test of Containment Spray Pump 1-1
- STP P-12B2, Revision 5, Routine Surveillance Test of Diesel Fuel Oil Transfer Pump 0-2
- STP P-3RV1, Revision 9, Exercising 10 percent Atmospheric Dump Valves PCV-19, 20, 21, 22
- STP I-111A, Revision 5, Functional Test of Steam Generator Blowdown Sample Effluent Liquid Monitor RM-19

Unit 2

- STP P-SIP-22, Revision 7, Routine Surveillance Test of Safety Injection Pump 2-2
- STP M-16D, Revision 13A, Operation of Train B Slave Relay K608 (Safety Injection)

4.1 Containment Spray Pump Performance Test

On February 1 the inspector observed portions of STP P-CSP-11, Revision 0, "Routine Surveillance Test of Containment Spray Pump 1-1." The test is performed on a quarterly frequency to verify continued operability of the pump. The inspector attended the preevolution briefing and observed operator actions in the containment spray pump room. The inspector noted that the briefing appropriately emphasized the precautions and limitations of the surveillance and that the procedure was performed in a controlled, formal manner.

During operation of the pump, the inspector observed leakage from the outboard mechanical seal of the pump at approximately 150 drops/min. Noting that the surveillance acceptance criteria for seal leakage was no leakage or minor dripping, the inspector questioned the operators on the acceptability of the observed leakage. The operators and the shift supervisor agreed that the leakage was greater than anticipated; however, they considered that the leakage would not affect the operability of the pump as it did not exceed the test's criteria for unacceptable leakage (i.e., steady stream or spraying). The inspector discussed the seal leakage with the containment spray system engineer. The system engineer explained that during previous surveillance tests of CS Pump 1-1 the outboard seal leakage had been observed at varying levels and that he believed the leakage observed on February 1 was not indicative of a significant seal degradation.

Following completion of the test, the inspector observed that water had sprayed outside the posted surface contamination area (SCA) around the pump's outboard seal area, and informed the operators. In response, the operators requested a radiation protection technician to survey the area. The results of the survey identified no spread of contamination outside of the SCA.

Conclusion - The inspector concluded that the surveillance test was well controlled and that both operations and engineering appropriately evaluated the impact of the observed seal leakage on the operability of the pump. However, operators failed to take action to address the potential spread of contamination from the seal leakage until prompted by the inspector.

4.2 Diesel Fuel Oil Transfer Pump Surveillance Test

On February 6 the inspector observed portions of STP P-12B2, Revision 5, "Routine Surveillance Test of Diesel Fuel Oil Transfer Pump 0-2." The test is performed on a quarterly frequency to verify the operability of the pump per TS 4.0.5.

During the verification of the system electrical lineup, prior to starting the pump, the inspector noted that the operator failed to perform all of the required actions of Step 12.2.2 prior to proceeding to the next step. Step 12.2.2 requires that the transfer switch in loadcenter 1H is in the "Unit 1" position with Breaker 52-1H-65 closed. During the performance of this step, the operator failed to verify the position of Breaker 52-1H-65. After checking that the step had been completed, and prior to performing the next step, the inspector questioned the operator whether he had verified the breaker position. The operator indicated that he had not and returned to the switchboard and verified that the breaker was in the required position as required by the step.

The inspector observed the remainder of the test and noted that the pump operated within the limits specified in the surveillance procedure and that there were no leaks during pump operation on the portion of the system located within in the vault.

Conclusion: The failure to perform the required actions of a surveillance test constitutes a violation of minor significance. This violation is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy.

4.3 SI Pump 2-2 Surveillance Test

4.3.1 Licensing Actions in Preparation for SI Pump Testing

Background: SI Pump 2-2 was replaced in March 1995 after the pump failed to develop required differential pressure during surveillance testing. Prior to conducting the test, the licensee submitted contingency License Amendment and Notice of Enforcement Discretion (NOED) requests to increase the allowed outage time (AOT) for the pump from 72 hours to 7 days for pump replacement.

The pump was replaced in accordance with 10 CFR 50.59, tested, and returned to an operable status in less than 72 hours. Since the pump was returned to an operable status within the allowed outage time there was no need for NRC approval of the contingent requests and the licensee later formally withdrew them.

In May 1995 the licensee determined that the replacement SI pump did not have documentation that LOKTITE had been applied to the shaft locknuts during assembly. The licensee determined that the absence of LOKTITE made the locknuts susceptible to loosening. This was the same mechanism for degradation that was determined to have caused the decrease in pump performance of the previously installed pump. The licensee performed an operability evaluation (OE) which provided the basis for concluding that the pump was operable and instituted more restrictive performance criteria during periodic pump tests.

During the performance of the quarterly pump test in August 1995, a slamming noise was noted on the pump start as well as a slight decrease in differential pressure. At that point the cause of the noise was indeterminate; however, it was believed to have been caused by a water hammer, due to a void in the piping or check valve slam. A week later the pump was tested again with a slight decease in performance, although no slamming noise was noted. The pump was tested again in November with a continued decrease in differential pressure and the slamming noise. The pump was placed on an "alert" status in accordance with the compensatory measures established by the OE. Placing the pump on "alert," required pump performance testing every 6 weeks as opposed to the normal quarterly frequency. In January 1996 the pump was tested with no change in differential pressure and no slamming noise.

On February 15, 1996, 6 days prior to the next scheduled performance of the pump test, the licensee submitted a license amendment request (LAR) to the NRC requesting an increase in the allowed outage time from 72 hours to 7 days for pump replacement. On February 22 the licensee provided the NRC a draft version of a contingent NOED request to allow the continued operation of Unit 2 with one train of SI system inoperable for up to 7 days, 4 days longer than allowed by TS. Preliminary discussions regarding the basis for the request between the NRC and the licensee revealed that the licensee had known of the pump's degraded condition and the potential need for an extension of the AOT for pump replacement since May 1995. Consequently, sufficient time nad been available for the licensee to process and gain NRC approval of an LAR to increase the pump AOT. Therefore, the condition that resulted in the need for an NOED was considered to have been avoidable. Following the discussion with the NRC the licensee decided not to pursue formal submittal of the NOED request.

4.3.2 SI Pump Testing Resulting in Pump Replacement

On February 22 the inspector observed the performance of STP P-SIP-22, Revision 7, "Routine Surveillance Test of Safety Injection Pump 2-2."

In preparation for the pump test the licensee installed acoustic emission monitoring equipment on several locations on the pump and adjacent piping. A temporary procedure was issued to record investigative data concurrent with the start of the pump. The pump start was initiated by energizing the Train B slave relay at the solid state protection system safeguard test cabinet. Initiating the pump start with the test signal also started the following pumps: CC Pump 2-2, Residual Heat Removal (RHR) Pump 2-1, CCW Pump 2-2. The inspector was in the pump room for the test and heard a loud slamming noise concurrent with the start of the pump.

The licensee's evaluation of the acoustic emission data indicated that the noise emanated from SI Pump 2-2. The pump performance data did not show any further degradation in pump performance since the previous surveillance test; however, since the slamming noise was determined to have come from the pump, the licensee declared the pump inoperable and commenced replacement of the pump. It should be noted that the licensee considered that there was a potential for the slamming noise to have been caused by a water hammer from the start of the RHR pump; however, there were insufficient accelerometers installed on the suction of SI Pump 2-2 to provide the data necessary to further investigate the issue.

4.3.3 Postmaintenance Testing Following SI Pump Replacement

Following replacement of the SI pump, the inspector attended the preevolution briefing and observed the test of the replacement pump. The replacement pump was instrumented to monitor for any unusual noises during the test. The pump was started manually from the control room and developed a differential pressure greater than the minimum required by TS and within the acceptable band of the surveillance. There was no slamming noise noted during the pump start or at any other time during the testing.

4.3.4 Conclusion

The replacement and testing of SI Pump 2-2 was well coordinated, and, as a result, was accomplished in a timely manner within the allowed 72-hour action statement. Briefings conducted for the test were thorough. The testing observed by the inspector was well organized and the personnel involved were knowledgeable of their assigned duties. Following the licensee's conclusion that LOKTITE had not been used during pump assembly and the decrease in pump performance, the licensee failed to take appropriate licensing actions to pursue extension of the TS allowed outage time for pump replacement as opposed to reliance upon an NOED request. The LAR submitted on February 15, 1996, did not allow sufficient time for public comment and NRC review prior to the scheduled performance of the surveillance test.

4.4 <u>Exercising 10 Percent Atmospheric Steam Dump Valves</u>

On February 6 the inspector observed portions of STP V-3R1, Exercising 10 percent Atmospheric Dump Valves PCV 19, 20, 21, 22, which accomplished the quarterly inservice atmospheric steam dump valve stroke timing pursuant to the

requirements of TS 4.0.5. The measured stroke testing of PCV-19 was within the acceptance limits of the procedure. The inspector noted that the first stroke of the valve in the test direction was recorded as the official test and that the appropriate TS action statement was entered during the performance of the test.

During the testing, the inspector noted that the cover to mechanical panel, PM-308, which contains the solenoid valves and control air lines that supply the PCV-19 actuator, was not securely fastened. Closer inspection revealed that a number of the clips that hold the panel cover in place had not been tightened. The inspector questioned the operator about the condition of the panel. The operator opened the panel and noted approximately 1/2 to 1 inch of standing water in the bottom of the panel. The operator then opened Panel PM-309 for PCV-20 and noted approximately 1/8 inch of water in the bottom of the panel. The inspector noted that there were drains installed in each of the panels but the installation did not allow all of the water to drain from the panels. The operator wrote an AR to document the standing water found in the panels. The response to the AR concluded that the water intrusion did not effect the safe operation of the solenoid valves and exposed terminal boards mounted in the panel.

Conclusion: The inspector noted that the test was performed per the procedure and that the valve operated within the acceptable limits of the surveillance. The water in the panels did not appear to have any current impact on valve operability; however, failing to secure the panel cover clips on safety-related panels exposed to the weather was judged to be a poor work practice.

5 ONSITE ENGINEERING (37551)

5.1 <u>Investigation of CC Pump Surveillance Testing</u>

5.1.1 Background

On September 15, 1994, the licensee discovered that closing the CC pumps common recirculation flow path isolation valves (CVCS-8105 or 8106) during periodic pump performance tests potentially impacted the operability of both charging pumps. The concern identified that closing the recirculation valves secured the minimum flow required for internal cooling of the pump to prevent overheating.

5.1.2 Licensee Investigation and Corrective Actions

Following identification of the concern, the licensee's regulatory compliance organization was consulted to determine the reportability of the condition. Since the impact of closing the valves during testing had not been fully evaluated, no reportability determination was made at that time; however, a nonconformance report (NCR) was initiated on September 24, 1994.

The NCR documented that the closure of the CC pump recirculation valves during periodic pump testing was inconsistent with the licensee's response to NRC Bulletin 80-18, "Maintenance of Adequate Minimum Flow Thru Centrifugal Charging Pumps Following Secondary Side High Energy Line Rupture." The NRC bulletin identified the potential for CC pump failure due to loss of recirculation flow under accident conditions where reactor coolant system pressure remained at or near the CC pump shut-off head. The licensee's initial investigation of the issue focused principally upon the impact of the loss of recirculation on the cooling of the pumps. The licensee responded to the concern by revising the surveillance procedure to close a manual isolation valve that secured the recirculation flow only for the pump being tested. After revision of the surveillance the technical review group (TRG) did not close the NCR and did not hold any meetings to discuss the issue for a period of approximately 6 months.

Closing CC pump recirculation isolation valves during testing increases the charging injection flow rate. The TRG failed to evaluate the impact of the increased charging injection flow on the accident analyses until January 19, 1996, when concerns were raised to the TRG by a system engineer.

On February 1, 1996, the licensee determined that closure of recirculation flow path Valves 8105 and 8106 for testing placed the emergency core cooling system in an unanalyzed condition. Following the determination the licensee made 1-hour nonemergency report to the NRC that both units had been previously placed in an unanalyzed condition during CC pump surveillance testing.

From September 1994 to February 1996 the investigative actions taken in response to concerns regarding CC pump operability failed to consider the impact of closing the recirculation isolation valves on the accident analyses. Significant conditions that are adverse to quality are required to be investigated and corrected in a timely manner. The actions initiated by the licensee following identification of concerns with CC pump surveillance testing were not considered to have been either prompt or comprehensive.

5.1.3 Conclusion

10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires that measures shall be established to assure that conditions adverse to quality, such as failures, deficiencies, and deviations are promptly identified and corrected. The licensee's failure to fully consider the effect of closing the CC pump recirculation valves on accident analyses for over 1 year after the initial concerns with the test were identified is a violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Action (Violation 275/9602-02, 323/9602-02).

6 PLANT SUPPORT ACTIVITIES (71750)

The inspectors evaluated plant support activities based on observation of work activities, review of records, and facility tours. The inspectors noted the following during these evaluations.

6.1 Repair of Fire Pump 0-1 Discharge Isolation Valve

On February 7 licensee mechanical maintenance personnel overhauled the discharge isolation valve to fire Pump 0-1. The clearance associated with the maintenance required that several fire water hose reel stations be isolated in the Unit 1 Fuel Handling Building. The inspector discussed with the licensee the compensatory actions implemented to ensure adequate fire fighting capability was maintained in the fuel handling building. The inspector also toured the fuel handling building with a fire brigade member to walk down the temporary fire hoses that had been staged for providing water to the isolated hose reel stations. The inspector noted that the fire brigade member was knowledgeable on the actions they would take in the event of a fire in the affected areas.

The inspector concluded that the licensee had adequately assessed the impact of the maintenance on the in-plant fire protection system and had implemented appropriate compensatory measures. Following completion of the work the inspector observed portions of the surveillance on firewater Pump 0-1 performed in accordance with STP P-13A, Rev. 15 XPR, "Fire Pumps Performance Test."

6.2 Failure to Meet Fire Brigade Training Requirements

6.2.1 Background

On January 19 the licensee noted in AR A0391417 that there were several members of the fire brigade whose qualifications had lapsed because they had not completed all of the requalification requirements. Further investigation by tne inspector revealed that as of January 19, greater than 70 percent of the personnel listed as qualified fire brigade members did not have current qualifications. In order to be able to meet minimum fire brigade manning requirements the licensee administered challenge exams to personnel whose qualifications had lapsed.

Prior to January 19, 1996, the licensee had utilized a computer bulletin board to list all qualified fire brigade members; however, as fire brigade member training lapsed, the bulletin board had not been properly updated. Since the shift watchlists, which designate fire brigade members, had been written utilizing the bulletin board, personnel whose training had lapsed had been assigned to the fire brigade.

6.2.2 Review of Fire Brigade Training

The inspector reviewed the qualification matrix previously used by the licensee to track fire brigade training and noted that in January 1996, the fire brigade qualifications for 79 of the 97 personnel, listed as being qualified fire brigade members, had lapsed. The majority of the individuals had not received the required biennial portable fire extinguisher training since July 1993. In addition, the inspector noted that other fire brigade members' training had lapsed in other areas, including techniques for suppression of electrical and radiological fires.

The inspector reviewed the shift watchlists for December 29, 1995, for the 7 p.m. to 7 a.m. watches. The review found that none of the personnel listed as fire brigade members had current fire brigade qualifications.

6.2.3 Fire Brigade Training and Manning Requirements

TS 6.8.1 requires that written procedures shall be established, implemented, and maintained that cover the implementation of the fire protection program. Fire Brigade training is a part of the fire protection program. Diablo Canyon Procedure TQ1.DC12, Revision 1, "Fire Brigade Training," details the training requirements for fire brigade members. Section 5.3.3.c.3 requires that fire brigade continuing training include a biennial review of the subject matter contained in the initial fire brigade member and leader training courses in each of the subject areas specified in UFSAR Appendix 9.5H. The classroom instruction program described in the UFSAR requires instruction in the proper use of fire fighting equipment and the correct method for fighting various types of fires.

Fire brigade manning requirements are detailed in OP1.DC12, Revision 2, "Conduct of Routine Operations." OP1.DC12 Section 5.9 requires that a site fire brigade of at least five members shall be maintained onsite at all times.

6.2.4 Previous NRC Findings in the Area of Fire Brigade Training

NRC Inspection Report 50-275/95-09; 50-323/95-09, issued on July 7, 1995, contained a Notice of Violation (275/9509-02) that cited a Severity Level IV violation regarding the licensee's failure to ensure that all members of the fire brigade participated in required quarterly fire drills. Following receipt of the violation, the licensee initiated an NCR on the missed fire drills. The inspector discussed the scope of the NCR with the individual assigned as the chairman of the TRG responsible for investigation of the NCR. The individual indicated that although the TRG had questioned whether there were problems in other areas of fire brigade training, no in-depth review had been performed.

Although the initial problem with fire brigade member qualification was identified by the licensee, the issue is considered to be more than a minor violation for several reasons.

- Corrective actions initiated in response to Violation 275/9509-02 failed to identify fire brigade member qualification deficiencies.
- The errors resulted in a significant number of personnel being routinely assigned to the fire brigade without having completed the required training.
- The situation existed over a period of several months.

6.2.5 Conclusion

The failure to complete proficiency training required by TQ1.DC12 and the UFSAR for individuals assigned to the fire brigade is a violation of TS 6.8.1, which requires that written procedures shall be established, implemented, and maintained that cover the implementation of the fire protection program (Violation 275/9602-03,323/9602-03).

6.3 <u>Radiological Work Practices within the Radiologically Controlled Area (RCA)</u>

6.3.1 Observations and Findings

The inspector performed several tours of the RCA to assess the effectiveness of the licensee's radiological controls. As a result, several deficiencies in radiological work practices were identified. During a tour of the RCA on February 5, 1996, the inspector noted poor housekeeping practices associated with ongoing work in the hot shop SCAs located in the fuel handling building (FHB). The inspector noted the following deficiencies which increased the potential for the spread of contamination outside of the SCAs:

- Items were laid across SCA boundaries.
- Tools and trash were on the floor of the SCA.
- Used protective clothing was laying on the floor.
- A hose crossed the SCA boundary without being taped down.
- The radiological posting at the entrance to the SCA was down.

Based upon these observations, the inspector questioned whether it would be prudent to perform a survey of the area to verify that there was no spread of contamination. Personnel performed a survey of the hot shop and determined that there had been no spread of contamination outside of the SCAs. After the inspector voiced concerns over the condition of the SCAs in the hot shop, the licensee stopped all work in these areas until conditions were improved. The actions initiated by the licensee in response to the issues were aggressive and have significantly improved the conditions in the FHB hot shop work area. The inspector considered these actions to be warranted and prudent based upon the conditions noted.

In addition, the inspector noted other conditions within the RCA which raised concerns about the implementation of radiological controls. Observations included the following:

- Dry boric acid crystals in a walkway which had accumulated as a result of a dripping pipe cap. This condition was estimated to have existed for several days. A contamination survey performed indicated the presence of contamination outside of a surface contamination area.
- A radiation area posting that had fallen down ana was no longer effectively posting the area.
- Bags of used potentially contaminated protective clothing were setting in a puddle of rainwater that crossed over an SCA boundary.
- Welding lines that were coiled across the SCA boundary during the SIP-2-2 replacement.
- Disconnected instrument tubing to RHR Pump 2-1 recirculation flow switch was noted to be dripping onto the RHR pump room floor.

6.3.2 Conclusions

The inspector determined that these issues were weaknesses and did not constitute a violation. The observations have, however, furthered a continuing concern about radiological housekeeping practices and worker awareness of radiological hazards and controls. It is also noteworthy that routine supervisor tours of the RCA had not identified and corrected the problems noted by the inspector. The inspector concluded that the observations were indicative of a decline in performance in the area of radiological controls.

7 FOLLOWUP - OPERATIONS (92901)

7.1 <u>(Closed) Violation 50-275/95015-01: Failure to Ensure Adequate Containment Closure During Refueling Operations</u>

The subject violation occurred during Unit 1 refueling operations (core offload) when the licensee discovered that two of the main steam isolation valves (MSIVs) had failed to fully close. This condition, in conjunction with the removal of the steam generator secondary manways, provided a direct pathway from the containment atmosphere to the environment.

The inspector reviewed the licensee's response to the Notice of Violation, dated December 21, 1995, and LER 275/95-012, Revision 0, dated November 10, 1995. The inspector also verified the licensee's installation of gag devices on the MSIVs prior to the subsequent core reload.

The main factor that contributed to the violation was the licensee's failure to implement adequate corrective actions from a similar event that occurred in 1994. The licensee previously identified incomplete closure of the MSIVs during a Unit 2 refueling outage in October 1994. As a result of that event, the licensee planned to revise its operating procedures to require a visual inspection of the actuator position of the MSIVs. However, visual observation of the MSIV actuator position during the subsequent Unit 1 refueling outage was not performed until after the core offload. Licensee corrective actions included replacement of the MSIV actuator pins to reduce frictional binding of the valves and the revision of the library clearance work instruction to require the installation of an MSIV gagging device when the MSIVs are relied upon to provide containment closure. As discussed above, the gagging devices were installed on Unit 1 prior to core reload. In their response to the Notice of Violation, the licensee has also committed to replacing the actuator pins on the Unit 2 MSIVs during its next refueling outage, scheduled for April 1996. The inspector verified that the actions described in the licensee's response letter of December 21, 1995, to be reasonable and appeared to address correction of the circumstances which contributed to the violation.

8 FOLLOWUP ENGINEERING (92903)

8.1 (Closed) Inspection Followup Item 50-275/9334-01: Unexplained Difference Between Calculated and Actual Estimated Critical Position of Control Rods

During a restart on December 31, 1993, following a trip on December 26, 1993, the actual critical position of the control rods was 79 steps less than the calculated estimated critical position. While the difference between the actual and estimated critical positions was the largest experienced by the licensee to that time, it was within TS limits.

The licensee and Westinghouse engineers performed an investigation of the large difference between actual and estimated critical positions. Westinghouse issued its report on June 7, 1994.

The inspector reviewed the licensee's and Westinghouse's evaluations. The inspector found that both concluded that the calculated value provided by the Westinghouse APEX code was in good agreement with the 3D ANC model. Westinghouse concluded that the effects of variations in boron concentrations, measured boron-10 isotopics, and rod positions, collectively, could have caused the difference between the actual and estimated critical positions.

The inspector concluded that, while criticality occurred sooner than expected, the estimated critical position was appropriately calculated and criticality occurred within the allowable range. The inspector also found that a conservative approach was taken by licensee engineers to evaluate this issue and reach an appropriate conclusion.

8.2 (Closed) Unresolved Item 50-275/95014-04: Adequacy of 230 kilovolt (kv) System Corrective Actions and (Open) Licensee Event Report 50-275/95007: 230 kv System Outside 10 CFR Part 50, Appendix A, General Design Criteria 17, in Some Cases

The unresolved item was opened to review the root cause(s) of the degraded 230 kv source of offsite power to the Diablo site. Violation 50-275/95014-03 documented initial failure of the licensee to take corrective actions after they became aware of the degraded 230 kv system. The inspector reviewed the unresolved item and determined that it was now duplicated by LER 50-275/95007, as discussed below. Final NRC review of the acceptability of the licensee's root cause and corrective actions for the degraded 230 kv system will be by further review of the LER.

The inspector reviewed the operability of the 230 kv and 500 kv sources of offsite power during the storm of December 11, 1995. The inspector determined that the 500 kilovolt system remained operable throughout the storm, and that the 230 kilovolt system was properly declared inoperable when two of four power lines supporting the system were lost.

The inspector noted that the problems with the 230 kv system were reported in LER 50-275/95007, Revision 0. This brief LER stated that a revision would be issued to provide a root cause and corrective actions. The inspector determined that an understanding of the licensee's position on the cause(s) of the LER and their planned corrective actions would assist in the review of the LER. The licensee informed the inspector that they planned to issue the revision in the near future. The inspector deferred review of the LER pending the licensee planned revision.

9 IN-OFFICE REVIEW OF LICENSEE EVENT REPORTS (90712)

The inspectors performed a review of the following LERs associated with operating events. Based on the information provided in the report, review of associated documents, and interviews with cognizant licensee personnel, the inspectors concluded that the licensee had met the reporting requirements, addressed root causes, and taken appropriate corrective actions. The following LERs were closed:

9.1 (Closed) LER 275/95-09, Revision 0: Turbine and Reactor Trip Due to Failure of Auto Stop Oil Pilot Valve Seat Material. This event was discussed in Inspection Report 50-275/95-14. No new issues were revealed by the LER.

9.2 (Closed) LER 275/95-012, Revision 0: Technical Specification 3.9.4, Requirement for Containment Closure During Refueling Not Met as a Result of Inadequate Evaluation. This event is discussed in Section 7.1.

9.3 (Closed) LER 275/95-17, Revision 0: Manual Reactor Trip Due to Heavy Debris Loading to Traveling Screens. This event was discussed in NRC Inspection Report 50-275/95-18. No new issues were revealed by the LER.

9.4 (Closed LER 275/95-15, Revision 0: Manual Reactor Trip Due to Loss of Feedwater Due to Design Deficiency. This event was discussed in Inspection Report 50-275/95-16. No new issues were revealed by the LER.

10 REVIEW OF FSAR 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 a portion of the inspection period (February 1 through March 2, 1996), the inspectors reviewed the applicable sections of the UFSAR that related to the inspection areas discussed in this report. The following inconsistency was noted between the wording of the UFSAR and the plant practices, procedures, and/or parameters observed by the inspectors.

10.1 UFSAR Radionuclide Source Term

During a review of the licensee's UFSAR, the inspector identified an apparent discrepancy in the assumptions utilized to determine the plant's radionuclide source term. Specifically, the UFSAR assumed the plant would operate on a 12-month cycle at a capacity factor of 80 percent. Currently, Diablo Canyon Units 1 and 2 are operating on an 18-month cycle and have historically exceeded an 80 percent capacity factor.

In response to the inspector's concerns, the licensee reviewed their source term analyses and determined that calculations had been performed for various operating cycle lengths, including 18 months, and that the 12-month operating cycle effectively bounds the source term. Similarly, capacity factor differences did not affect the source term calculation. The inspector reviewed the analyses and had discussions with licensee and NRC personnel to confirm the licensee's conclusion that the calculations for the 12-month cycle with an 80 percent capacity factor were bounding and reasonable. The licensee has issued an NCR to clarify the FSAR.

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Licensee Personnel

G. M. Rueger, Senior Vice President and General Manager, Nuclear Power Generation Business Unit
W. H. Fujimoto, Vice President and Plant Manager, Diablo Canyon Operations
L. F. Womack, Vice President, Nuclear Technical Services
*S. D. Allen, Supervisor, Balance of Plant Engineering
M. J. Angus, Manager, Regulatory and Design Services
*T. R. Baldwin, Senior Engineer, Nuclear Steam Supply System (NSSS) Engineering
J. R. Becker, Director, Operations
D. H. Behnke, Senior Engineer, Regulatory Services
E. Chaloupka, Engineer, Surveillance Engineering
*D. K. Cosgrove, Supervisor, Safety and Fire Protection
*W. G. Crockett, Manager, Quality Services
M. E. Craig, Shift Foreman, Operations
*R. N. Curb, Manager, Outage Services
J. S. Ellis, Instructor, NPG Training
*T. F. Fetterman, Director, Electrical and Instrumentation and Control Systems Engineering
J. H. Galle, Engineer, NSSS Engineering
*N. Gaudiuso, Supervisor, Procedure Services Team
*W. A. Ginter, Engineer, NSSS Engineering
*T. L. Grebel, Director, Regulatory Support
*C. R. Groff, Director, Secondary Systems Engineering
*L. A. Hagen, Director, Safety, Health and Emergency Services
*C. D. Harbor, Engineer, Regulatory Support
*R. A. Harris, Director, Materials Services
*J. A. Hays, Acting Manager, Operations Services
*J. R. Hinds, Director, Quality Control
M. T. Hug, Supervisor, Emergency Planning
C. E. Johnson, Fire Marshall, Emergency Services
R. L. Johnson, Supervisor, Regulatory Services
*R. J. Magruder, Shift Supervisor, Operations
*D. B. Miklush, Manager, Engineering Services
*J. E. Molden, Manager, Maintenance Services
*E. P. Nelson, Supervisor, Materials Services
P. T. Nugent, Senior Engineer, Regulatory Support
*D. H. Oatley, Director, Mechanical Maintenance
*L. M. Parker, Engineer, Nuclear Safety Engineering
*R. P. Powers, Acting Plant Manager, Diablo Canyon Operations
H. J. Phillips, Director, Technical Maintenance
*M. O. Somerville, Senior Engineer, Radiation Protection
*D. A. Taggart, Director, Nuclear Safety Engineering
*D. A. Vosburg, Director, NSSS Engineering
R. A. Waltos, Director, Balance of Plant Engineering
*J. C. Young, Director, Quality Assurance

1.2 NRC Personnel

*M. Tschiltz, Senior Resident Inspector
*J. Sloan, Senior Resident Inspector, San Onofre Nuclear Generating Station

*Denotes those attending the exit meeting on March 6, 1996.

2 EXIT MEETING

An exit meeting was conducted on March 6, 1996. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee acknowledged the inspection findings documented in this report. The licensee did not identify as proprietary any information provided to, or reviewed by the inspectors.

<u>ATTACHMENT 2</u>

ACRONYMS

AFD	axial flux difference
AFW	auxiliary feedwater
AOT	allowed outage time
AR	action request
CCW	component cooling water
CFCU	containment fan cooler
CS	containment spray
EDG	emergency diesel generator
FHB	fuel handling building
LAR	license amendment request
LER	licensee event report
MSIV	main steam isolation valve
NCR	nonconformance report
NOED	notice of enforcement discretion
NSSS	nuclear steam supply system
OE	operability evaluation
PAMS	post accident monitoring system
PCV	pressure control valve
PDR	public document room
POA	prompt operability assessment
PPC	plant process computer
RHR	residual heat removal
RPE	repair parts evaluation
SCA	surface contamination area
SI	safety injection
SISI	seismically induced system interaction
STP	surveillance test procedure
TRG	technical review group
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report