ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-275/95-08
50-323/95-08

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 (DCPP), Units 1 and 2

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

Inspection Conducted: April 2 through May 13, 1995

Inspectors: M. Tschiltz, Senior Resident Inspector
G. Johnston, Senior Project Inspector

Approved: D. D. Chamberlain, Acting Chief, Project Branch E — 21 JUNE, 1995 Date

Inspection Summary

Areas Inspected (Units 1 and 2): Routine announced inspection of operational safety verification, plant maintenance, surveillance observations, onsite engineering, plant support activities, and in-office review of licensee event reports (LERs).

Results (Units 1 and 2):

Operations:

- Required testing of the Unit 2 containment emergency airlock door seals was not performed following verification of emergency airlock door interlocks. Reviews of the completed procedure by both the Shift Technical Advisor and the Shift Foreman failed to identify this discrepancy. This was identified as a noncited violation (Section 4.3).

Maintenance:

- A violation was identified because preplanning, procedures, and work instructions for repair of pyrocrete failed to adequately consider the effect on emergency diesel generator (EDG) radiator exhaust air flow. Corrective actions implemented as a result of the partial blockage of

radiator exhaust air flow on Unit 1 failed to prevent a similar problem when pyrocrete repairs were performed on Unit 2 (Section 3.1).

Engineering:

- An operability evaluation of Safety Injection (SI) Pump 2-2 did not consider a known pump failure mechanism. The degradation of pump performance was subsequently attributed to the loosening of the impeller locknuts. This problem had previously occurred at Diablo Canyon and had resulted in an SI pump seizing during operation (Section 5.1.1).

- Inservice valve stroke time testing was not performed in a manner which measured the as-found condition of the valve. Several instances were noted where valve cycling occurred prior to stroke timing tests (Section 5.2).

- Chemical and volume control system (CVCS) valve seat leakage was previously identified as effecting emergency core cooling system (ECCS) flow balance. A formal evaluation of the valve leakage was not performed until over 6 months later when the leakage affected the performance of routine surveillance testing (Section 5.4).

Plant Support:

- The questioning by an Independent Safety Engineering Group (ISEG) engineer of the blockage of EDG radiator exhaust air flow caused by scaffolding and associated tenting installed in EDG radiator exhaust rooms is considered strong performance. As a result, the amount of scaffolding and tenting was limited in order to ensure adequate airflow (Section 3.1.1).

- Contrary to management expectations, the results of a surface contamination area (SCA) survey performed to allow maintenance without the use of protective clothing was not documented (Section 6.1).

Summary of Inspection Findings:

- Violation 275/9508-01 was identified (Section 3.1.5).

- A noncited violation was identified (Section 4.3.3).

- LERs 275/95-02, Revision 0, and 323/94-013, Revision 0, were closed (Section 7).

Attachments:

- Attachment 1 - Persons Contacted and Exit Meeting

- Attachment 2 - Acronyms

DETAILS

1 PLANT STATUS (71707)

1.1 Unit 1

Unit 1 began the report period at 100 percent power. On April 21, 1995, power was reduced to 50 percent to perform scraping of marine growth from the circulating water system conduits. The unit returned to 100 percent power on April 24, 1995, following completion of the tunnel scraping and operated at 100 percent for the remainder of the report period.

1.2 Unit 2

Unit 2 began the report period at 100 percent power. On May 8, 1995, power was reduced for 8 hours to approximately 60 percent at the request of the system dispatcher. During the period that power was reduced, corrective maintenance was performed on Inverter P2000, which supplies power to the main turbine digital electrohydraulic control system. Unit 2 operated at 100 percent for the remainder of the report period.

1.3 Request for Notice of Enforcement Discretion (NOED) Due to Expiration of Reactor Coolant System Heatup and Cooldown Limits

Background The licensee's reactor coolant heatup and cooldown limitations were developed based on a projected fluence equivalent to 8 effective full power years (EFPYs). On April 11, 1995, the licensee discovered a calculational error in the EFPY calculation which revealed that Unit 1 exceeded 8 EFPYs of operation on April 8, 1995, 11 days before the previously predicted date. Technical Specification (TS) 3/4.4.9.1, "Reactor Coolant System - Pressure/Temperature Limits," Figures 3.4-2, "Reactor Coolant System Heatup Limitations - Applicable Up to 8 EFPY," and 3-4.3, "Reactor Coolant System Cooldown Limitations - Applicable Up to 8 EFPY," were no longer applicable when Unit 1 exceeded 8 EFPYs.

The licensee had previously submitted License Amendment Request (LAR) 94-09 to revise TS 3/4.4.9.1 applicability beyond 8 EFPYs, but the LAR submittal had not been approved by the NRC. On April 12, 1995, the licensee performed an operability evaluation which determined that the existing heatup and cooldown limits specified in TS 3/4.4.9.1 were applicable up to 12 EFPYs. The licensee then requested enforcement discretion until 1200 PDT on April 21, 1995, not to enforce compliance with TS 3/4.4.9.1 and to allow continued use of the current TS figures until revised figures were approved as a part of LAR 94-09.

1.3.1 EFPY Calculation Error

Plant Engineering Procedure R-5, Revision 0, "Burnup Tracking," is used to calculate effective full power days (EFPDs) and is normally performed on a monthly basis. Using the data from this procedure Reactor Engineering had

projected that 8 EFPYs would be exceeded on April 19, 1995. The cumulative calculation had, in error, not included 12 days of coastdown at the end of Unit 1's Cycle 5, which added another 10 EFPDs to the total. When the 10 EFPDs were included in the EFPY calculation on April 11, 1995, it was noted that Unit 1 had exceeded 8 EFPYs of operation on April 8, 1995.

1.3.2 NRC Review

The NRC evaluated the licensee's safety justification assertions as a part of the review of LAR 94-09 and concluded that the use of the existing heatup and cooldown figures was acceptable until termination of the Notice of Enforcement Discretion (NOED). The NRC granted the enforcement discretion verbally on April 12, 1995, at 2:58 p.m. EST. On April 13, 1995, at 4:35 a.m. EST, LAR 94-09 was issued approving the licensee's submittal. The licensee formally exited the NOED on April 14, 1995, at 9:08 a.m. PDT after receiving a copy of the approval.

1.3.3 Safety Significance

Due to fast neutron irradiation of the reactor vessel beltline, the nil-ductility-transition temperature changes over the life of the reactor vessel. Due to implementation of very low leakage core loading patterns, the reactor vessel peak flux had been reduced. Reactor vessel neutron irradiation measurements, which utilized two surveillance capsules, confirmed irradiation levels to be less than projected. As a result, the nil-ductility-transition temperature projections for 12 EFPYs were lower than those previously submitted for 8 EFPYs. The licensee performed an analysis which established that the heatup and cooldown limitations applicable up to 8 EFPYs were applicable and conservative through 12 EFPYs. This NOED involved no violations of regulatory requirements.

1.3.4 Conclusion

The NRC concluded that the exercise of enforcement discretion was warranted since this action involved no effect on safe plant operation and, as a result, had no adverse impact on public health and safety.

2 OPERATIONAL SAFETY VERIFICATION (71707)

2.1 Auxiliary Feedwater (AFW) Safety System Walkdown

During a routine walkdown of portions of the AFW system, the inspector noted that a pipe cap installed on a vent installed on the steam supply to the steam driven AFW pump was different from the type of pipe cap typically used on steam lines. The connection appeared to have a swagelock type test connection fitting installed on the cap.

2.1.1 AFW System Configuration Requirements

After the inspector identified this configuration to the licensee, it was determined that the reference piping Drawing 063930, "Vents, Drains, and Test Connections, Two Inches and Smaller," Revision 7, contained the applicable requirements and did not allow for the installed configuration. The licensee initiated an action request (AR) to document the problem. The inspector had noted several similar deficiencies with other systems during the previous inspection period. The licensee had acknowledged the inspector's observations, but had not fully implemented actions to identify additional areas that may have this problem.

2.1.2 Safety Significance

The licensee concluded that this configuration resulted in no operability concerns since the cap was installed downstream of the code break boundary. The licensee's evaluation appeared to have considered the appropriate factors.

2.1.3 Conclusion

The installed pipe cap was not in accordance with the applicable drawing requirements. The licensee has initiated actions to resolve this and other discrepancies of this nature. The licensee's evaluation indicated that, although this installation was not specifically authorized by drawing, it was acceptable. The licensee is revising the drawing to allow this type of cap to be used and plans to further investigate the cause of this configuration control problem. The licensee's actions to investigate and resolve this issue appear to be adequate.

3 PLANT MAINTENANCE (62703)

During the inspection period, the inspector 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/quality control 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:

<u>Unit 1</u>

- AFW Pump 1-1; Repair FW-1-115 leak
- Battery Charger 1-2 Capacitor Change-out
- Replace Coupling Hub on Spent Fuel Pool Pump 1-1
- EDG 1-1 Starting Air Compressor Maintenance
- Repair of Pyrocrete in EDG Radiator Exhaust Area

Unit 2

- Repair of Pyrocrete in EDG Radiator Exhaust Area

3.1 Pyrocrete Repairs in EDG Radiator Exhaust Rooms

Background Pyrocrete fire barrier material installed in the common exhaust plenum of the EDG radiator fan exhaust area, for both Units 1 and 2, was noted to have been damaged following a recent storm. The damage was evaluated by the licensee to potentially effect the design function of the pyrocrete and, therefore, required repair. A roving firewatch was in effect for the areas with the damaged pyrocrete at the time the water damage was discovered. The licensee concluded that no additional compensatory actions were required for the degraded fire barriers. Prior to commencing the repairs, the pyrocrete was sampled and determined to contain asbestos. The installation of scaffolding and tenting was required for the removal of pyrocrete containing asbestos.

3.1.1 Evaluation of Unit 1 Scaffolding and Tenting Installation

On March 8, 1995, prior to installation of the scaffolding and tenting, System Engineering was requested to evaluate its effect on EDG air flow. During EDG operation, radiator exhaust air discharges through separate fan rooms on the 107 foot elevation and into a common discharge room open down to the 85 foot elevation. The common discharge room opens to the outside through screened and louvered vents in the side of the turbine building. System Engineering initially provided verbal assurance, followed later by a written response that the installation of the scaffolding would not significantly reduce the EDG radiator exhaust air flow. After a portion of the work was completed, the tenting was removed and the scaffolding was left installed for the remaining repair work.

The basis for System Engineering's evaluation was questioned by an ISEG engineer. As a result of the ISEG engineer's questions, System Engineering and Nuclear Engineering Services performed further reviews of the installed scaffolding and determined that there was a potential for a significant reduction of EDG radiator exhaust air flow. As a result, the amount of scaffold planking was limited to three planks. This required removal of five planks since, at the time, there were eight planks installed on the scaffolding. The basis for the decision to reduce the amount of planking was engineering judgement. At that time, a detailed analysis had not been performed.

Subsequently, the licensee conducted a meeting to discuss the EDG air flow concerns. During the meeting, the licensee identified that there was margin for radiator cooling based on ambient temperature, but there was no margin in the EDG radiator air flow. At this point, the licensee removed the remaining planks from the scaffolding until a detailed analysis could be performed to evaluate the effect of the scaffolding and tenting on EDG radiator exhaust air

flow. Analysis results revealed that, with the existing ambient temperature and wind conditions during the period, the scaffolding and tenting were installed such that the EDGs would not have overheated. In the calculations for determining operability, the outside ambient temperature was required to be less than 69°F for the EDGs to have been considered operable.

3.1.2 Unit 2 Pyrocrete Repairs

Following the repairs to the Unit 1 pyrocrete, similar repair work was commenced in Unit 2. In order to ensure that Unit 2 EDGs remained operable during the repairs, a calculation was performed prior to commencing the work to determine limitations for the scaffolding and tenting. The scaffold planking was limited to three planks (49 square feet). The tented area used in the analysis was 25 square feet. The tented area of 25 square feet was not included as a limitation in the work package.

Initially, during preparation for the pyrocrete repairs, the scaffolding and tenting were installed within the limits determined by the engineering calculation. Later, additional tenting was installed which blocked approximately 85 percent of the entire area for EDG 2-2 air flow to the lower vents. This configuration was observed by the EDG system engineer who questioned the blockage of EDG radiator exhaust air flow. During a review of the installed scaffolding and tenting, it was noted that the tented area exceeded the 25 square feet included in the calculation. At that point, the licensee removed the additional tenting.

3.1.3 Procedural Controls for Scaffolding Installation

The procedure which describes the methods for requesting and controlling the staging, erection, dismantling, and modification of elevated work structures is Procedure AD7.ID5, Revision 0, "Elevated Work Structures." The procedure was designed to minimize the potential for damage to safety-related equipment caused by falling structures and interference with the operation of such equipment caused by the structure during normal conditions and seismic events. The precautions and the instructions require review of the scaffolding installation for seismic interactions which could possibly render safety-related equipment inoperable and a check for interferences which could prevent access for operation of components.

The inspector reviewed the elevated work structure requests which were used to authorize the installation of the scaffolding and the work orders for the pyrocrete repairs. The inspector noted that these documents did not contain instructions to limit the amount of tenting or scaffold planking. The specific size of the scaffolding structure was listed; however, the option to modify the structure without additional Engineering concurrence was allowed.

3.1.4 Safety Significance

The licensee performed calculations to determine the operability of EDGs during the periods that EDG radiator exhaust flow was obstructed. The results

indicated that the EDGs were never inoperable due to the scaffolding and tenting restricting air flow through the radiators. Due to the lack of proper planning and adequate work instructions, the potential existed under certain elevated outside temperatures and adverse wind conditions for the EDGs to have been inoperable.

3.1.5 Conclusion

The failure to adequately evaluate the impact of the pyrocrete repairs on EDG operability when preplanning the work and the failure to provide written procedures and documented instructions which limited the obstruction of EDG radiator exhaust air flow is a weakness. TS 6.8.1, states, in part, that written procedures shall be established, implemented, and maintained covering applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, dated February 1978. Appendix A of Regulatory Guide 1.33, Revision 2, recommends that procedures for performing maintenance which can affect the performance of safety-related equipment should be properly preplanned and performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstance. Contrary to these requirements, during the period of March 3 through April 5, 1995, for Unit 1, and April 26 though May 2, 1995, for Unit 2, pyrocrete repairs were performed which affected the performance of the EDGs without adequate preplanning and without procedures and documented work instructions which were appropriate to the circumstance. This was identified as a violation of TS 6.8.1 (275/9508-01).

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:

<u>Unit 1</u>

- Surveillance Test Procedure (STP) P-AFW-11, "Routine Surveillance Test of Turbine Driven Auxiliary Feedwater Pump 1-1"
- STP SP S-312S, "Security System Emergency Power Source and Load Transferring System Test"
- STP I-38-A.1, "SSPS Train A Actuation Logic Test in Modes 1, 2, 3, or 4"

Unit 2

- STP I-36-S4EPT, "Protection Set IV Eagle 21 Partial Trip Board Actuation Test"

4.1 AFW Pump 1-1 Surveillance

Background The surveillance accomplished a remote manual warm start of turbine-driven AFW Pump 1-1.

4.1.1 Equipment Observations

Steam traps were verified to be properly aligned and appeared to be functioning properly. A minor packing leak was noted on a valve associated with one of the steam traps. An AR was written to document the leakage. The surveillance verified operation of the steam admission trip throttle valve. The trip lever, trip mechanism, and associated linkage were noted to operate freely. After remotely starting the turbine, the as-found speed was slightly greater than the reference speed but within that allowed by the surveillance. The steam supply valves (FCV-37 and FCV-38) were stroked one at a time and verified not to affect the turbine speed (i.e., adequate steam flow through one supply line was verified). Steam generator AFW control valve operation was also verified during the surveillance.

4.1.2 Conclusion

The surveillance test verified the capability to perform a remote manual warm start of turbine-driven AFW Pump 1-1. Operators closely followed procedural requirements.

4.2 Security System Emergency Power Source and Load Transferring System Test

Background On April 28, 1995, the inspector observed the monthly test of the security diesel generator in accordance with STP SP S-312S, Revision 7C, "Security System Emergency Power Source and Load Transferring System Test." The inspector attended the pretest briefing and accompanied operators to the diesel generator room to observe the performance of the test.

4.2.1 Security Inverter Display Panel Deficiency

While observing the operators verify the system alignment for STP SP S-312S, the inspector noted that, during Step 11.3.2.g, the operators stopped to obtain direction from the shift foreman prior to continuing with the procedure. The step required that the security inverter panel display indicate that the maintenance bypass switch is normal (i.e., the associated alarm message LED is off). This step could not be completed as written since the display panel had been previously noted not to illuminate when the maintenance switch was placed in the bypass position. This problem had been documented on an AR. After the discussion with the shift foreman, the

operators verified the position of the maintenance bypass switch. The operators then annotated the procedure to indicate the actions taken. These actions appeared to be appropriate and in keeping with management expectations.

The inspector questioned the operators as to how Step 11.3.1 had been performed, which required verifying that all display messages were functioning. The maintenance LED had been covered in March 1995, when a nameplate was installed which referenced the AR written on the display panel deficiency. The operators acknowledged that the maintenance bypass LED could not be verified as required by Step 11.3.1. Contrary to management expectations, the operators did not stop to evaluate their inability to perform this procedure step as written.

4.2.2 Safety Significance

The operators were able to adequately verify that the maintenance bypass switch was in the proper position for testing the security diesel generator with the display panel deficiency. The security diesel started and operated within the specified limits of the procedure.

4.2.3 Conclusions

The security inverter panel display deficiency had existed for over 6 months. The surveillance procedure had not been revised to provide instructions on how to accomplish the test with the deficiency. Each time the surveillance was performed, operators were left to determine the appropriate actions. While performing this surveillance, the operators were slow to exhibit a questioning attitude when they could not strictly adhere to the STP. The licensee has since issued a change to the procedure which provides more specific instructions regarding the verification of display panel indications. The licensee's ultimate actions, while not particularly timely, appear to have resolved the procedural work around created by the status panel deficiency.

4.3 Emergency Airlock Interlock Verification

Background STP M-8E2, "Emergency Airlock Door Interlock Verification," was performed for Unit 2 on May 4, 1995. Following performance of the interlock verification, the emergency airlock door seals are required to be demonstrated operable within 72 hours. On May 10, 1995, during a review of STP M-8E2 test results, the licensee determined that the testing of the door seals had not been accomplished.

The interlock verification procedure, STP M-8E2, contained three specific steps, 11.2.16, 11.2.17, and 11.2.18, which referred to the testing of the airlock seals. These steps had been signed as complete. No other documentation existed that showed that the test had been completed. STP M-8E2, Step 11.2.16, requires that Engineering be notified to complete testing of the door seals within 24 hours of closing the doors, or prior to mode 4. Step 11.2.17 requires that a Plant Information Management System TS tracking

sheet be initiated for the Unit 2 emergency airlock door seal test. Step 11.2.18 requires verification that the emergency airlock door seals have been tested by STP M-8G. The licensee subsequently discovered that the individual performing the test signed off Steps 11.2.16, -17 and -18 as being complete without performing any of the specified actions. The administrative reviews of the surveillance by both the shift technical advisor and the shift foreman did not provide verification that all of the steps had actually been performed.

4.3.1 Licensee Actions Upon Discovery of Missed Surveillance

After discovering that the testing of the emergency airlock door seals had not been accomplished, the licensee performed STP M-8G, Revision 2, "Leak Rate Testing of the Emergency Airlock Seals." The test results were within specification and demonstrated the operability of the seals.

The licensee investigation found that the individual, who had been in containment during the performance of the test, signed off the procedure steps after he left containment and signed off more steps than were performed due to his inattention to detail. The licensee counseled the individual according to their disciplinary program.

4.3.2 Safety Significance

There is no safety significance associated with this problem since the testing performed following the discovery of the problem demonstrated that the emergency airlock door seals were operable even though they had not been tested within the timeframe required by TS.

4.3.3 Conclusions

The failure to test the emergency air lock door seals, as required by STP M-8E2, Revision 1, "Emergency Interlock Verification Test," is a violation of TS 4.6.1.3.a which states, in part, that each containment air lock shall be demonstrated operable by verifying the seal leakage. Contrary to the requirements, operators failed to perform the required actions of STP M-8E2, which required testing the emergency air lock door seals following opening of the air lock doors. This violation was identified by the licensee. Following the discovery of the missed surveillance, the test was performed which verified the operability of the door seals. A nonconformance report was initiated on this problem. Based upon the licensee's actions, this violation is not being cited.

5 ONSITE ENGINEERING (37551)

5.1 SI Pump 2-2 Operability Evaluation

Background SI Pump 2-2 was replaced during the last inspection period. Replacement of the pump was performed following a period of degraded pump performance. The decision to replace the pump was made after it failed to

produce the required total developed head (TDH) during periodic surveillance testing. Prior to failing the surveillance test, Engineering performed an analysis of the pump performance data and investigated potential mechanisms for the degradation of performance in order to evaluate pump operability.

5.1.1 SI Pump 2-2 Failure Mode Effects Analysis

The failure mode effects analysis performed as a part of SI Pump 2-2 operability evaluation prior to pump replacement, determined that there were two plausible failure mechanisms which could cause the noted symptoms of degraded performance. The mechanisms included failure of the O-ring seals, which provide a static seal between the pump stage diffusers and the pump casing, and the degradation of wear rings, which seal between each impeller stage and it's associated stationary diffuser. These failure mechanisms were considered plausible as the expected and observed symptoms of degradation matched. Other failure mechanisms considered and evaluated as not being plausible included: impeller wear, boundary valve leakage, pump motor degradation, and inadequate suction pressure.

The SI Pump 2-2 operability evaluation stated that additional data was required to identify a conclusive trend of pump degradation or a degradation rate. The licensee stated they had not performed more frequent testing of the pump to determine the degradation rate because the ASME Code Section XI alert value of 90 percent of the reference pump differential pressure (dP) had not been achieved. The inspector noted that the dP could and did go below the TS required value prior to the licensee establishing more frequent monitoring. The inspector reviewed the previous surveillance test results and noted that there had been a degrading trend toward the TS value.

The licensee replaced the impeller and shaft (rotating assembly) with a new rotating assembly that had been procured from another utility. The licensee, therefore, had not verified that the impeller locknuts had been coated with Loctite. Following the replacement of SI Pump 2-2, disassembly of the degraded pump revealed loosening of the impeller locknuts located at each end of the shaft outboard of the impeller. Loosening of the locknuts allowed for axial movement of the impeller which caused reduced developed head. Industry experience indicated that this failure mechanism had, in certain instances, resulted in the pump seizing during operation. The loosening of the impeller locknuts had not been considered as a potential failure mechanism in the licensee's operability evaluation.

Investigation of component history records revealed that an SI pump had previously seized due to loosening of the impeller locknuts at DCPP. Further investigation of industry experience revealed that 6 of 24 similar model pumps were known to have failed due to the loosening of the impeller locknuts. In response to the failures, the pump vendor revised the vendor manual maintenance procedure to require the application of Loctite to the impeller nut threads during pump assembly. Upon disassembly there was no evidence that the degraded pump had Loctite applied to the impeller locknuts. The licensee noted that they had previously incorporated the revision to the vendor manuals

and revised maintenance procedures to ensure the application of Loctite to the impeller locknuts as a corrective action to the previous SI pump failure.

5.1.2 Operability of the Replacement SI Pump 2-2

After determining SI Pump 2-2 degraded pump performance was due to the loosening of the impeller locknuts, the licensee attempted to determine if Loctite had been applied by the vendor on the locknuts of the replacement pump by reviewing procurement records. Based upon available evidence, the licensee concluded that Loctite had not been applied on the locknuts of the replacement pump. The licensee performed a review of maintenance records for the remaining three installed pumps for Units 1 and 2 and confirmed that Loctite had been applied on the impeller locknuts of all three remaining pumps during pump assembly.

The licensee performed an operability evaluation for the replacement pump due to the potential mechanism for loosening of the locknuts. Due to the increased potential for degraded pump performance, the licensee instituted compensatory actions associated with SI Pump 2-2 operation. The compensatory actions were necessary to ensure that the conclusions in the operability evaluation remained valid. The actions required that additional pump performance data be obtained during surveillance testing and that the SI pump be monitored for reverse shaft rotation during operation of the opposite train SI pump. The vendor has identified reverse rotation of the pump shaft as the mechanism for locknut loosening. These actions appear to be prudent and necessary to ensure early detection of SI Pump 2-2 impeller locknut loosening. In reference to the monitoring for reverse shaft rotation, the inspectors noted that the only concern was that a leak in the discharge check valve of an idle SI pump could allow backflow and subsequent reverse rotation of the idle SI pump during operation of the opposite train SI pump. Since such an event had never occurred at Diablo Canyon, the inspectors considered the licensee's actions to be precautionary.

5.1.3 Safety Significance

SI Pump 2-2 was replaced when surveillance testing indicated the pump TDH to be less than the specified value. The replacement SI pump has subsequently been identified as being potentially susceptible to the same type of degradation. The licensee has increased the monitoring of the pump to ensure early detection of any significant changes in pump performance during routine surveillance testing.

5.1.4 Conclusion

The licensee's initial operability evaluation of the degraded SI pump performance failed to consider the potential for the loosening of the impeller locknuts, a known mechanism for pump failure based on DCPP and industry experience. As a result, the potential for the pump seizing during operation was not considered in the evaluation.

The operability evaluation of the replacement SI pump, which addressed additional concerns regarding the performance of the replacement pump, appeared thorough. The evaluation provided the licensee with a formal method for assessment of additional pump operating parameters.

5.2 SI Pump 2-2 Performance Test Instrumentation

Background During the performance of the SI Pump 2-2 routine surveillance test, prior to pump replacement, the inspector questioned the acceptability of the range of the digital instruments installed for the test. The system engineer incorrectly responded that the digital instruments met the code requirements. Subsequent to the inspector questioning the range of the digital instruments, an AR was written to document that the digital instruments installed to monitor the SI pump discharge pressure and dP did not meet the ASME Code pump requirements. According to the licensee, this AR was written independent of the inspector's questioning.

The licensee is in the process of implementing the new requirements of ASME Operation and Maintenance (OM) Standard OM-1987, with addenda through OMa-1988. During the transition period, the licensee committed to revise pump and valve STPs to the new inservice test requirements. Upon revision of the surveillance procedures, the new requirements were to be placed in effect. STP P-SIP-22, "Routine Surveillance Test of SI Pump 2-2," had been revised and, therefore, was required to comply with the new inservice testing requirements.

ASME Section XI Part 6 Section 4.6.1.2(b) of OMa-1988 requires that digital instruments shall be selected such that the reference value shall not exceed 70 percent of the calibrated range of the instrument. For the SI Pump 2-2 surveillance, the expected or reference value for the discharge pressure reading was approximately 1500 psig, which was greater than 70 percent of the calibrated range of the 0-2000 psig range discharge pressure digital instrument. Similarly the reference pump dP exceeded 70 percent of the range of the dP digital instruments installed for the test.

5.2.1 Licensee Corrective Actions

The licensee issued a change to STP P-SIP-22 to install test instrumentation for measuring the pump discharge pressure which was in compliance with the ASME code requirement. The licensee has performed a review of other pump surveillance procedures which were required to be in compliance with the new ASME OM standard requirements. The review identified several other pump surveillance procedures where the same discrepancy existed. Revisions to the effected procedures have been issued. The licensee has written a quality evaluation on this problem.

5.2.2 Safety Significance

Since the implementation of revised pump surveillance procedures, the only ASME Section XI required surveillance test performed with incorrect instrumentation installed was the surveillance for SI Pump 2-2. The

surveillance test was reperformed using the correct range digital instrument following the procedure being changed to identify the required instrument range. That test confirmed that the replacement SI pump met TS requirements for TDH.

Prior to the implementation of the new ASME OM standard requirements, there was no specific requirement for limiting the reference value of digital instrumentation to 70 percent of the calibrated range. Surveillance testing performed prior to the implementation of the new requirements utilized digital instrumentation which exceeded the 70 percent limitation. Digital instrument calibration was performed for these tests which verified the accuracy of the instrumentation prior to and after the test in the range in which the instrument was used. Based upon the licensees actions, the accuracy of previous test results is not in question.

5.2.3 Conclusion

During the transition to the new requirements of the ASME OM standard, the licensee did not properly implement the requirements for the use of digital instrumentation in pump surveillance procedures. Initially, licensee personnel appeared not to exhibit a questioning attitude with respect to the inspector's questioning on proper test equipment. The licensee's subsequent actions to resolve this issue appeared appropriate.

5.3 Inservice Valve Stroke Time Testing

Background During the inservice stroke time testing of Unit 1 Valves FCV-37 and FCV-38, the motor-operated steam supply isolation valves for AFW Pump 1-1, the inspector noted that the valves had been operated just prior to the stroke time testing during the performance of slave relay testing. The inspector questioned the sequence of testing since operation of valves prior to their inservice stroke time testing did not appear to meet the intent of testing in the as-found condition. NUREG 1482, "Guidelines for Inservice Testing at Nuclear Power Plants," describes the condition of the valve to be as-found, without prestroking or maintenance.

The ASME Code does not specifically require testing to be performed for components in the as-found condition, except for safety and relief valves. However, if as-found testing is not performed, degradation mechanisms may not be identified.

5.3.1 Licensee Procedures for Valve Stroke Time Testing

The licensee's general procedure governing the exercising of safety-related valves is STP V-3, "Exercising Safety Related Valves General Procedure." STP V-3 required that the first stroke of the valve, in the test direction, be recorded as the official test. A separate detailed procedure is written for each valve to be exercised. The individual procedures for performance of valve stroke timing listed STP V-3 as a reference but did not include requirements for the operator to refer to STP V-3 and comply with the

requirement for timing the first stroke of the valve. In discussing stroke time testing with the Operations Director, the inspector noted that it was not management's expectation for operators to read STP V-3 prior to performing individual valve stroke time tests.

STP M-16N, Revision 11A, "Operation of Trains A and B Slave Relays K632 and K634," contained a procedural note which allowed the operator the option of performing the stroke timing of Valves FCV-37 and FCV-38 after the valves have been operated during the performance of the slave relay test. The sequencing of the slave relay surveillance and the stroke timing tests did not meet the licensee's procedural requirement for timing the first stroke of the valve in the test direction. In addition, the stroke time test procedure, STP V-3R6, Revision 4, "Exercising Steam Supply FCV-37 and FCV-38 Stroke Time Test," was written with the assumption that Valve FCV-37 and FCV-38 were in the open position at the start of the test. As a result, when performing the test of Valve FCV-37 as sequenced in accordance with STP M-16N, the operator was required to open the valve without a specific step in the procedure in order to perform the stroke time test in the closed direction.

Based upon the inspector's concerns for inservice valve stroke time testing, the surveillance test group reviewed this issue and determined that procedural changes were necessary to avoid the possibility of cycling valves prior to performing stroke time testing.

5.3.2 Safety Significance

The licensee conducted a review to determine the number of times that valve cycling occurred prior to inservice stroke time testing in the past. The results of the review indicated that stroking of a valve prior to inservice testing had previously occurred on at least one other occasion. Based upon the results of the review, the cycling of valves prior to valve stroke time testing does not appear to be a programmatic problem.

5.3.3 Conclusion

The inspector observed that, in certain instances, the licensee is not performing the inservice stroke timing of valves during the first stroke in the test direction. The licensee is revising surveillance test procedures to ensure that inservice valve stroke time testing is performed during the first stroke of a valve wherever practical. The licensee's response to the inspector's concern for the preconditioning of valves prior to performing the periodic inservice stroke time test appeared adequate.

5.4 Centrifugal Charging (CC) Pump 1-2 Bypass Valve Seat Leakage

Background During the performance of the Unit 1 reactor coolant pump (RCP) seal flow measurement surveillance, CC Pump 1-2 Bypass Valve CVCS-1-8387C, was noted to be leaking past its seat. A flow measuring instrument (controlatron) was attached to the piping, which confirmed that there was flow past the shut valve.

CVCS-1-8387C seat leakage during the ECCS flow balance testing would effect the flow balance results. Since the point in time that CVCS-1-8387C seat leakage started is unknown, it is possible that the seat leakage occurred during the most recent ECCS flow balance test. During the ECCS flow balance testing, actual charging flow to the RCP seals is secured. Charging flow to the RCP seals is simulated by establishing 80 gpm charging header flow as read on the charging pump discharge header flow indication. CVCS-1-8387C seat leakage provides a parallel flow path during the ECCS flow balance, which bypasses the charging pump discharge header flow element. As a result, CVCS-1-8387C seat leakage would not have been included in ECCS flow balance measurements.

5.4.1 Evaluation of CVCS-1-8387C Impact on ECCS Flow Balance

Unit 1 ECCS flow balance testing was most recently completed during the previous refueling outage (1R6). CVCS-1-8387C seat leakage had subsequently been noted and documented in an AR on October 5, 1994. At that time, an evaluation was performed by engineering to determine the effect of the valve seat leakage on the CC pump, RCP seal injection, and other surveillances for acceptability. The evaluation documented that the next performance of STP V-15, "ECCS Flow Balance Test," may not meet the test acceptance criteria with the existing CVCS-1-8387C seat leakage. A prompt operability assessment of the leakage on ECCS flow rates was not performed at that time.

On April 21, 1995, during the performance of STP M-54, "Measurement of Reactor Coolant Pump Seal Injection Flow," CVCS-1-8387C was again noted to be leaking. A more detailed evaluation of the effect of leakage on ECCS flow balance was performed. The evaluation revealed that the valve seat leakage had the potential to cause the total flow for CC Pump 1-1 to exceed pump runout limitations. To address this concern, an in-depth analysis of the effects of the valve seat leakage on each portion of the ECCS flow balance was performed. The evaluation required a detailed engineering evaluation to assure operability. Specific parameters which were evaluated included: total cold leg injection flow rate, line-to-line flow imbalances, the sum of the three lowest injection flow rates, and total CC pump flow. ECCS CC pump flow requirements were determined by the licensee to be within the TS limits only after instrument error uncertainties were removed from the analysis through review of the posttest instrument calibration data.

5.4.2 Safety Significance

The detailed analysis performed by the licensee which considered the effect of CVCS-1-8387C seat leakage indicated that ECCS flow rates were within TS allowed limits.

5.4.3 Conclusion

The inspector noted that the initial evaluation of CVCS-1-8387C seat leakage failed to adequately consider the impact of valve leakage on ECCS flow rates. Subsequently, over 6 months later, after failing to meet RCP seal injection

flow requirements due to the effect of CVCS-1-8783C seat leakage on measured seal injection flow, a detailed evaluation was required to assure that TS requirements were met.

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 Spent Fuel Pit (SFP) Pump 1-1 SCA Surveys

Background On May 12th the inspector observed maintenance being performed on SFP Pump 1-1. The area in which the maintenance personnel were working was within an area marked with radiological tape normally used to denote an SCA boundary. The inspector noted that the mechanics were not wearing anticontamination clothing and questioned the mechanics as to whether a survey had been performed to allow working in the area without SCA controls. The mechanics indicated that a radiation protection (RP) technician had performed a survey of the work area the previous day and had determined that it was not contaminated. The workers noted that the tape had not been removed due to the concern that the paint on the floor would be marred when the tape was removed.

When exiting the RCA, the inspector reviewed the latest survey of the SFP Pump 1-1 work area. The survey indicated that only the pump shaft had been surveyed and not the foundation area under the pump shaft. The inspector questioned whether the proper radiological work practices were being followed for the work on SFP Pump 1-1. After raising this concern, RP personnel performed a survey of the area underneath the pump shaft which showed that there was no contamination in the area. Further investigation by the licensee indicated that an RP technician had performed a survey of the area the previous day and had failed to document the survey results.

6.1.1 Survey Documentation Requirements

The requirements for recording survey results are contained in procedure RCP D-500, Revision 11A, "Radiation and Contamination Procedures." Paragraph 7.4.1 of the procedure states that, "Survey results should be recorded in red ink on the sketch portion of the appropriate Radiation and Contamination Form." Licensee procedure AD1.ID2, "Procedural Use and Adherence," specifies that "The word "should" is used to denote a recommendation and is NPG management's preference."

6.1.2 Licensee Corrective Actions

Discussions with the RP Director revealed that management expectations for documentation of surveys should be more clearly communicated to the RP technicians. The practice of not documenting the performance of certain radiological surveys was not uncommon, even though the procedure covering radiation and contamination surveys specified that surveys should be

documented. The RP staff has been briefed on this situation and the RP Director plans to revise the procedure to more precisely communicate management's expectation for the documentation of surveys. The RP Director has noted that it is appropriate and expected to document a survey which reflects a significant change in radiological conditions. The actions appear to appropriately address the inspector's concerns.

6.1.3 Conclusion

In this particular circumstance, the failure to document the performance of a survey which reflected the change in radiological conditions is considered a poor radiological work practice.

7 IN OFFICE REVIEW OF LERs (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 are closed:

- 275/95-002, Revision 0, Access/Egress for the Plant Significantly Hampered by the Closure of All Access Roads Due to Mud Slides and Flooding

- 323/94-013, Revision 0, Containment Spray Pump 4 kV Breaker Closing Spring Failed to Charge Following Misalignment of Charging Solenoid Due to Personnel Error

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
M. J. Angus, Manager, Regulatory and Design Services
*H. R. Arnold, Senior Engineer, Predictive Maintenance Engineering
T. R. Baldwin, Senior Engineer, NSSS Systems Engineering
*J. R. Becker, Director, Operations
*J. E. Bonner, Quality Control Specialist, Nuclear Quality Services
*M. Burgess, Senior Engineer, Secondary Systems Engineering
*K. W. Brungs, Director, Outage Maintenance Support Processes
E. Chaloupka, Engineer, Secondary Systems Engineering
M. G. Coward, Engineer, Secondary Systems Engineering
*W. G. Crockett, Manager, Engineering Services
*R. N. Curb, Manager, Outage Services
*T. F. Fetterman, Director, Electrical and Instrumentation and Control Systems Engineering
J. H. Galle, Engineer, NSSS Systems Engineering
*R. D. Glynn, Senior Engineer, Quality Assurance
T. L. Grebel, Supervisor, NRC Regulatory Support
*C. D. Harbor, Engineer, Regulatory Support
*D. B. Miklush, Manager, Operations Services
*J. E. Molden, Manager, Maintenance Services
P. T. Nugent, Engineer, Regulatory Support
D. H. Oatley, Director, Mechanical Maintenance
L. M. Parker, Engineer, Independent Safety Engineering
H. J. Phillips, Director, Technical Maintenance
J. L. Portney, Senior Engineer, Balance of Plant Systems Engineering
*J. A. Shoulders, Director, Engineering Services
D. W. Spencer, Engineer, Secondary Systems Engineering
*D. A. Vosburg, Director, NSSS Systems Engineering
*R. A. Waltos, Director, Balance of Plant Engineering
*J. C. Young, Director, Quality Assurance

1.2 NRC Personnel

*M. D. Tschiltz, Senior Resident Inspector
G. W. Johnston, Senior Project Inspector

*Denotes those attending the exit meeting on May 18, 1995.

In addition to the personnel listed above, the inspectors contacted other personnel during this inspection period.

2 EXIT MEETING

An exit meeting was conducted on May 18, 1995. During this meeting, the resident 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.

ATTACHMENT 2

ACRONYMS

AFW	auxiliary feedwater
AR	action request
ASME	American Society of Mechanical Engineers
AFW	auxiliary feedwater
CC	centrifugal charging
CVCS	chemical and volume control system
DCPP	Diablo Canyon Power Plant
dP	differential pressure
ECCS	emergency core cooling system
EDG	emergency diesel generator
EFPD	effective full power day
EFPY	effective full power year
FCV	flow control valve
ISEG	Independent Safety Engineering Group
kV	kilovolt
LAR	license amendment request
LER	licensee event report
NPG	Nuclear Power Generation
NOED	Notice of Enforcement Discretion
OM	operation and maintenance
RCP	reactor coolant pump
RP	radiation protection
SCA	surface contamination area
SFP	spent fuel pit
SI	safety injection
STP	surveillance test procedure
TDH	total developed head
TS	Technical Specification