ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket Nos.:	50-275 50-323
License Nos.:	DPR-80 DPR-82
Report No.:	50-275/98-18 50-323/98-18
Licensee:	Pacific Gas and Electric Company
Facility:	Diablo Canyon Nuclear Power Plant, Units 1 and 2
Location:	7 ½ miles NW of Avila Beach Avila Beach, California
Dates:	October 25 through December 5, 1998
Inspector(s):	David L. Proulx, Senior Resident Inspector Dyle G. Acker, Resident Inspector Cliff A. Clark, Reactor Inspector
Approved By:	Linda J. Smith, Chief, Project Branch E

ATTACHMENT: Supplemental Information

EXECUTIVE SUMMARY

Diablo Canyon Nuclear Power Plant, Units 1 and 2
NRC Inspection Report 50-275/98-18; 50-323/98-18

This inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 6-week period of resident inspection.

Operations

- Operators controlled power decreases and increases in a careful manner in response to equipment problems and high kelp loading on the traveling screens (Section O1.1).

Maintenance

- Overall, the licensee provided effective operator training, planning, and execution of the Diesel Engine Generator (DEG) 1-1 cylinder head replacement (Section M1.1).

- Licensee planning, preparations, and contingencies, including previous simulator training, for the Unit 1 startup transformer insulator coating and Component Cooling Water Pump 1-1 seal replacement were conservative, thorough, and executed properly (Sections M1.2 and M1.3).

- The licensee properly measured and evaluated as-found containment spray pump shaft axial displacement (Section M1.4).

- A noncited violation of Technical Specification 6.8.1.a was identified for failure to properly implement a procedure for calibration of a component cooling water system flow transmitter, consistent with Section VII.B.1 of the Enforcement Policy. Technical maintenance personnel performed work on the wrong unit because of a lack of self-verification (Section M1.5).

Engineering

- The inspectors concluded that the loss of startup power to the site and subsequent starting of all diesel generators on both units was caused by inadequate relay setpoint design review and inadequate testing during installation of the new startup transformers in 1997. The licensee's immediate corrective actions for this nonsafety-related design deficiency were satisfactory (Section E2.1).

Plant Support

- Housekeeping was excellent throughout safety-related areas (Section O2.1).

- The inspectors identified that portable fire extinguishers located in vital areas were routinely not being inspected annually to the timeliness criteria contained in Procedure M-18.2. However, the fire extinguishers met their performance criteria when tested and the licensee implemented the appropriate corrective actions to correct the deficiency (Section F1.1).

Report Details

Summary of Plant Status

Unit 1 began this inspection period at 100 percent power. On October 27, 1998, Unit 1 operators reduced power to 71 percent to repair the discharge throttle valve for Heater Drip Pump 1-2. Following these repairs, Unit 1 was returned to 100 percent power on October 28. On December 1, Unit 1 operators curtailed power to 50 percent because of high kelp loading on the traveling screens. Later, on December 1, operators further reduced power to 40 percent because of minor intake structure flooding caused by failure of a nonsafety-related expansion joint. On December 2 reactor power was increased to 97 percent. Subsequently, operators reduced power to 50 percent because an expansion joint leaked on a line that provided cooling to Circulating Water Pump 1-2. Operator response to these events will be discussed in NRC Inspection Report 50-275; 323/98-20. Upon improved weather conditions and after replacement of several expansion joints, operators returned Unit 1 to 100 percent power on December 5. Unit 1 operated at essentially 100 percent power until the end of this inspection period.

Unit 2 began this inspection period at 100 percent power. On November 28, Unit 2 operators reduced power to 50 percent for the cleaning of the main condenser and returned to 100 percent power on November 29. Unit 2 operators manually tripped the plant on December 1 because of high kelp loading on the traveling screens. Operator response to this event was discussed in NRC Inspection Report 50-323/98-21. Following improved weather conditions and repairs on balance-of-plant equipment, Unit 2 entered Mode 2 for restart on December 5. Unit 2 was at 8 percent power at the end of this inspection period.

I. Operations

O1 Conduct of Operations (Units 1 and 2)

O1.1 General Comments (71707, 93702)

The inspectors visited the control room and toured the plant on a frequent basis when on site, including periodic backshift inspections. In general, the performance of plant operators reflected a focus on safety. Operators performed self-checking, peer-checking, and strong pre-evolution briefings. The licensee reduced power to 50 percent on both units several times during this inspection period. The inspectors noted that these evolutions were conducted in accordance with procedures in a careful manner.

O2 Operational Status of Facilities and Equipment (Units 1 and 2)

O2.1 Housekeeping (71707)

General Comments

During tours of the facility, the inspectors observed housekeeping practices to assess their impact on safety. The inspectors concluded that, except for minor items (such as

loose tools) that were brought to the shift supervisor's attention and immediately corrected, housekeeping was excellent throughout safety-related areas.

O8 Miscellaneous Operations Issues (92901)

O8.1 (Closed) Violation 50-275; 323/97001-01: failure to follow procedures related to respiratory protection.

This violation involved a failure by the licensee to maintain prescription lenses for control room licensed operators' respirators. Subsequent review of corrective actions during NRC Inspection Report 50-275; 323/97-22 verified that the licensee had completed necessary actions to close the above violation.

O8.2 (Closed) Inspection Followup Item 50-275; 323/97006-05: untimely operating experience reviews.

The inspectors had previously identified that the licensee had not performed timely evaluations of NRC and industry communications to determine if the items applied to their facility. At that time the licensee had nine items up to 2 years old that had not been evaluated. The inspectors concluded that the licensee had not placed sufficient priority or resources to address NRC or industry generic issues.

Since issuance of this inspection followup item, the licensee established a program to address the operating experience backlog. During this inspection, the inspectors reviewed the backlog of the operating experience program. Eleven items were in the evaluation stage and the average age of these items was 40 days. The inspectors noted that the oldest item still requiring review was 138 days. Issues entered into the program were addressed within times appropriate to the safety significance. Because of the progress made in improving timeliness of the operating experience program, the inspectors concluded that the licensee has taken sufficient action to address this issue.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Replacement of DEG 1-1 Cylinder Heads (Unit 1)

a. Inspection Scope (62707)

The inspectors witnessed the training, pre-evolution briefing, and execution of the replacement of several DEG 1-1 cylinder heads. The inspectors evaluated Procedures TP TO-9808, "Diesel Generator Head Replacement," Revision 0, and STP M-81A, "Diesel Engine Generator Inspections," Revision 13, which mechanics used to implement the maintenance.

b. Observations and Findings

On October 27, 1998, the licensee commenced replacing several DEG 1-1 cylinder heads because the vendor had identified a design flaw in the air exhaust manifold that could affect the long-term operation of the engine. The licensee performed this work online in order to ensure more resources could be focused on proper execution of the activities.

In preparation for the cylinder head replacements, operations conducted simulator training of the applicable crews. The simulator training included responses to loss of offsite power events with DEG 1-1 inoperable. In addition, maintenance personnel conducted a pre-evolution briefing of the operations staff so that operators understood the anticipated maintenance outage scope and window.

The inspectors reviewed the probabilistic safety assessment for the DEG 1-1 outage. The licensee stated that, because of the availability of other required safety equipment, the length of time that DEG 1-1 would be inoperable, and the contingency actions in place, the on-line replacement of the DEG 1-1 cylinder heads was not considered risk significant. An NRC Senior Reactor Analyst reviewed the probabilistic safety assessment and determined that it was reasonable. The inspectors witnessed the actual cylinder head replacements, inspections, and postmaintenance testing. The inspectors concluded that the work was performed carefully in accordance with procedures.

During postmaintenance testing with DEG 1-1 operating, the system engineer identified that the cylinder temperatures and differential pressures for several cylinder heads were out of specification as specified in the vendor manual. Mechanics adjusted the fuel injectors to bring the temperatures into specification. One cylinder head still had a higher than recommended differential pressure during a subsequent test run. The licensee consulted with the vendor who stated that elevated cylinder head differential pressures could have a long-term effect on DEG 1-1 performance; however, operability of DEG 1-1 would not be affected if not corrected until Refueling Outage 1R9, scheduled to begin in February 1999. Based on this vendor information, the licensee completed surveillance testing and declared DEG 1-1 operable.

As part of an effort to minimize the effect of having DEG 1-1 inoperable, the licensee deferred any planned maintenance on offsite power sources. On October 30, as DEG 1-1 maintenance neared completion, offsite maintenance personnel notified control room personnel that they needed to take one of three 500 kV lines to the site (Diablo Canyon to Midway 3 line) out of service for cold washing of insulators.

The inspectors noted from review of control room logs that operators placed DEG 1-1 in service (6:36 a.m.) prior to the 500 kV line being de-energized (7:13 a.m.). Upon further questioning, the licensee determined that the 500 kV line had been disconnected at the Midway end of the line 5 minutes prior to operators declaring DEG 1-1 operable (6:31 a.m.).

The licensee stated that, because the line was forced out of service, the requirement in the DEG maintenance procedure to prohibit planned line outages could not be implemented in this situation. The inspectors concurred; however, the inspectors determined that the control room was not specifically aware of the condition of the line until 7:13 a.m. Since the procedure for main generator operation required different voltage specifications for different kinds of line configurations, the inspectors determined that control room personnel should know the specific condition of the lines. Consequently, the inspectors determined that the communications between the control room and the offsite system operator were weak since control room personnel were not aware of the condition of the offsite power sources to the site.

c. Conclusions

Overall, the licensee provided effective operator training, planning, and execution of the DEG 1-1 cylinder head replacement. As an exception, communications between the control room and the offsite system operator were weak.

M1.2 Maintenance Observations For Startup Transformer 1-1 Sylgard Coating Repair (Unit 1)

a. Inspection Scope (62707)

The inspectors observed the preparations for the work and portions of the insulator coating and painting performed in accordance with Work Orders C0159109, "Startup Transformer 1-1 & Switch 211-1; Repair Sylgard/Apply Grease," and R0187727, "Startup Transformer 1-1 Clearance Areas; Coating Maintenance."

b. Observations and Findings

The licensee de-energized Unit 1 Startup Transformer 1-1 on November 16, 1998, in preparation for repairing damaged Sylgard coating installed on the various insulators associated with Startup Transformer 1-1 and 230 kV line side, no-load Disconnect Switch 211-1. In addition to the Sylgard coating repair, painting was scheduled for Startup Transformer 1-1 and its associated bus ducting and fire deluge system. After applying the Sylgard coating, personnel applied a silicone grease coating to the insulators to prevent insulator electric arcing.

The inspectors observed that the pre-evolution briefing was thorough in that the evolution, contingencies, and past problems were discussed.

The risk assessment for a short Startup Transformer 1-1 outage indicated only a small increase in risk, based on no other concurrent outages for other safety-related equipment in Unit 1. The inspectors observed that the Startup Transformer 1-1 outage was the only work scheduled in the work area, that the initial weather was clear, and that the offsite grid was stable. The licensee accomplished the Sylgard coating repair and application of silicone grease in a satisfactory manner and minimized the outage time. The inspectors concluded that the training and work were performed in a conservative manner.

During the switching process to energize Startup Transformer 1-1 for return to service, a differential current trip occurred, which tripped the startup power supply to both units. All six DEGs started on undervoltage, which is discussed in Section E.2.1 of this report.

c. Conclusions

Licensee planning, preparations, and contingencies for the Unit 1 startup transformer repair work was conservative, thorough, and executed properly.

M1.3 Maintenance Observations For Component Cooling Water Pump 1-1 Seal Replacement. (Unit 1)

a. Inspection Scope (62707)

The licensee initiated work to replace the inboard mechanical seal on Component Cooling Water Pump 1-1 on November 18, 1998. The inspectors observed preparations for and portions of the actual work performed in accordance with Work Order C0156605, "Component Cooling Water Pump 1 Replace Inboard Mechanical Seal, Repair Oil Leaks."

b. Observations and Findings

The risk assessment for a short Component Cooling Water Pump 1-1 outage indicated only a small increase in risk, based on no other concurrent outages for other safety-related equipment in Unit 1. The inspectors observed that the Component Cooling Water Pump 1-1 outage was the only major safety-related equipment work scheduled in Unit 1 for the period of the outage. A member of the maintenance team had designed and fabricated special tooling to facilitate removal of the original mechanical seal assembly and the cleaning/polishing of the exposed pump shaft surfaces after the seal assembly was removed. As a result of the use of the special tooling and good mockup training, the licensee accomplished the replacement of the Component Cooling Water Pump 1-1 inboard mechanical seal in a satisfactory manner, minimizing the outage time. The inspectors concluded that the training and work were performed in a conservative manner.

c. Conclusions

Licensee planning, preparations, and contingencies for replacement of the inboard mechanical seal on Component Cooling Water Pump 1-1 work was conservative, thorough, and executed properly.

M1.4 Investigation of Containment Spray Pump 2-1 Axial Shaft Movement (Unit 2)

a. Inspection Scope (61726, 62707)

The inspectors observed portions of a Containment Spray Pump 2-1 surveillance performed on November 18, 1998, to verify that the surveillance was performed in accordance with the applicable procedure and to observe the actions implemented to

measure the as-found pump shaft axial displacement. The inspectors noted that, on November 3, an operator had documented on Action Request (AR) A0471139 that the. Containment Spray Pump 2-1 pump shaft appeared to have approximately 0.125 inch axial movement.

b. Observations and Findings

On November 3, the licensee had satisfactorily completed the pump surveillance and confirmed all vibration readings were within specification. However, during performance of Procedure STP P-CSP-21, "Routine Surveillance Test Containment Spray Pump 2-1," Revision 6, an operator had noted that the Containment Spray Pump 2-1 pump shaft appeared to have approximately 0.125 inch of axial movement. The licensee generated AR A0471139 to investigate: (1) the source of observed pump shaft axial movement, (2) whether axial movement of the pump shaft was noted when a similar test was performed on Unit 1 Containment Spray Pump 1-1, and (3) whether the surveillance of Containment Spray Pump 2-1 should be performed again with mechanics present to observe actual pump shaft axial movement.

On November 18, the inspectors observed that the surveillance was performed in accordance with Procedure STP P-CSP-21. Engineering, maintenance, operations, quality assurance, and management personnel witnessed the surveillance and the as-found pump shaft axial displacement measurements. Initial shaft axial displacement was observed using a strobe light with the pump running and estimated to range up to 0.0156 inch. Once the pump was secured, shaft axial displacement was measured using a dial indicator while moving the shaft manually. With the pump secured, maximum pump shaft displacement was measured as 0.009 inch, which was within the vendor tolerances for pump thrust. Based on the measured displacement, the inspectors concurred with the licensee that the axial movement was acceptable.

c. Conclusions

The licensee properly measured and evaluated as-found containment spray pump shaft axial displacement.

M1.5 Component Cooling Water Gage Calibration on Wrong Unit (Units 1 and 2)

a. Inspection Scope (62707, 92902)

On November 25, 1998, the inspectors evaluated the resolution of AR A0472057 to determine if the corrective actions were commensurate with the potential safety significance.

b. Observations and Findings

On November 25, the Unit 2 control room operators received an annunciator indicating low flow in the component cooling water system. The operators checked the pressures and pump flow rates in the system and determined that these parameters remained normal. Additionally, the operators noted that no planned work was in progress on

Unit 2 concerning the component cooling water system. The Unit 2 shift foreman made a public address communication for any personnel working on the component cooling water system to contact the control room. Subsequently, technical maintenance personnel contacted the control room and informed the shift foreman that they had just commenced calibration of a flow transmitter. Control room operators recognized that the gage calibration had been approved for Unit 1, and the maintenance personnel had initiated work on the transmitter in the wrong unit. After the maintenance personnel returned the Unit 2 pressure transmitter to service, the component cooling water low flow annunciator cleared.

The shift supervisor initiated AR A0472057 to ensure that the corrective action program would address this deficiency. Upon review of the AR, the licensee elevated this deficiency to quality evaluation (Q0012087). The licensee determined that Procedure MP I-14-F68, "Component Cooling Water Supply Header A Flow Channel FT-68," Revision 1, clearly indicated the proper flow transmitter and isolation valves such that no confusion existed in the procedure as to which nuclear unit the procedure applied. In addition, walkdowns of the area revealed that the components on both units were clearly labeled and properly illuminated. The inspectors reviewed the procedure, toured both units, and agreed with the conclusions.

The licensee interviewed the individual who revealed that he had failed to use methods of self-verification or peer-checking to ensure that the proper components were manipulated. This failure is similar to an incident that involved mechanics draining the oil from an incorrect auxiliary feedwater pump on Unit 1 (wrong train - refer to NRC Inspection Report 50-275; 323/98-10) since both incidents involved individual personnel errors. During the first event, the individual performing the work did not have the work order in hand in order to perform a self-check and did not closely coordinate with his peers; whereas, during the second event, the individual did not perform an adequate self-check. The inspectors reviewed the circumstances related to each personnel error and determined that the specifics of the first incident differed from the second such that the corrective actions could not have prevented the second incident.

For corrective actions, the licensee returned the incorrect flow transmitter to service, calibrated the proper instrument, and counseled the individual on the need to implement management expectations for self- and peer-checking. Failure to implement Procedure MP I-14-F68 is a violation of Technical Specification 6.8.1.a. However, this nonrepetitive, licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section VII.B.I of the Enforcement Policy (50-275/98018-01).

c. Conclusions

A noncited violation of Technical Specification 6.8.1.a was identified for failure to properly implement a procedure for calibration of a component cooling water system flow transmitter, consistent with Section VII.B.1 of the Enforcement Policy. Technical maintenance personnel performed work on the wrong unit because of a lack of self-verification.

M2 Maintenance and Materiel Condition of Facilities and Equipment

M2.1 Observations from Walkdowns (Units 1 and 2)

a. Inspection Scope (62707)

The inspectors performed in-plant walkdowns to verify the materiel condition of equipment after the completion of maintenance activities. Walkdowns were performed in both Units 1 and 2 to examine the external material condition of portions of the following systems and other components in the adjacent plant areas:

- Feedwater
- Component Cooling Water
- 125 Vdc (vital and nonvital)
- 480 V (vital)
- Auxiliary Feedwater
- Safety Injection
- Containment Isolation Valves
- Residual Heat Removal
- 4 kV (vital)
- 12 kV
- 230 kV
- Civil Structures associated with the above systems

b. Observations and Findings

The inspectors found that the structures, systems, and components observed were visually free of corrosion. There were some minor oil and water leaks; however, based on their external condition, the structures, systems, and components were well maintained.

c. Conclusions

In general, the material condition of the plant areas toured by the inspectors was good.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) Violation 50-275; 323/96014-03: Failure to remove AR tags from the control boards.

This violation involved the failure to implement procedures that required removal of AR tags from the control boards following corrective maintenance. For corrective actions, the licensee: (1) removed the out-of-date AR tags, (2) performed an audit of the control boards to ensure the procedures were followed, (3) reprogrammed the plant work control computer to include a block verifying removal of AR tags, (4) revised the implementing procedures for control of AR tags, and (5) established management expectations for accountability sessions for failure to follow these procedures.

During a previous inspection (NRC Inspection Report 50-275; 323/98-07), the inspectors reviewed the effectiveness of these corrective actions. The inspectors found several additional examples of failure to control AR tags. Therefore, this item was left open for further review to establish licensee effectiveness in identifying corrective actions.

However, during this inspection period, the inspector noted improved implementation of control room AR tag procedural requirements. No problems were identified during board walkdowns, and the licensee added an expectation for frequent walkdowns of the control boards to ensure that the AR tags were kept up-to-date. Based on this additional information, this item is closed.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Operation of Startup Transformers and Loss of Startup Power (Units 1 and 2)

a. Inspection Scope (37551)

The inspectors evaluated the loss of startup power that occurred twice on November 20, 1998, while operators restored Startup Transformer 1-1 to service after completing the insulator coating that began on November 16. On November 20, work was completed and the incoming 230 kV lines were reconnected. The inspectors reviewed the licensee actions for maintaining design control associated with this work.

b. Observations and Findings

During 1997, the licensee had installed new startup transformers, which provided the only immediate source of power to the site upon loss of unit power. In addition, the licensee also installed separate disconnect switches on the incoming 230 kV lines to each transformer. Prior to the installation of the disconnect switches, a single circuit breaker in the 230 kV switchyard provided power to both Startup Transformers 1-1 and 2-1. These transformers could be paralleled on the 12 kV side so that one transformer could supply power to both units upon loss of an individual transformer. However, the single supply circuit breaker arrangement required the licensee to de-energize startup power to both units any time work was to be performed on either transformer.

Parallel Operation of Startup Transformers 1-1 and 2-1

The plan for completing the work on the Startup Transformer 1-1 insulators started with paralleling both transformers on the 12 kV side, then opening the disconnect switch on the 230 kV side of Startup Transformer 1-1. Because the licensee planned to work on the insulators on the 230 kV side of the startup transformer, the 230 kV line was disconnected while energized. During the preparations for this evolution, the inspectors questioned whether the busses and circuit breakers on the 12 kV side of the startup transformers had short circuit ratings high enough to sustain a bolted fault (worst case short circuit) during the time that both startup transformers were paralleled. The

licensee determined that the busses had sufficient rating but that selected 12 kV and 4 kV circuit breakers were not rated to interrupt a bolted fault when Startup Transformers 1-1 and 2-1 were paralleled. The licensee stated that they were aware of this design limitation and had procedures in place to minimize the time that the startup transformers were paralleled. The inspectors verified that Procedure J-2:III, "Startup Bank Shutdown and Clearing," Revision 7, directed that parallel operation of the startup transformers be minimized. On November 16, the inspectors noted that the two startup transformers were paralleled for less than 1 minute. The inspectors concluded that the licensee established satisfactory administrative controls to minimize the design limitations.

Loss of Startup Power

On November 20, after refurbishing the insulators and restoring the disconnected 230 kV lines, the licensee attempted to energize Startup Transformer 1-1, while unloaded, by closing the 230 kV disconnect switch. At this time Startup Transformer 2-1 was supplying the loads in both units. The supply circuit breaker in the 230 kV switchyard subsequently tripped, causing loss of all startup power. All six diesel generators started upon loss of startup power, as designed. The licensee reset the lock out relay, reopened the disconnect switch for Startup Transformer 1-1, reclosed the 230 kV switchyard circuit breaker, and restored startup power to both units using Startup Transformer 2-1.

The licensee determined that a Phase A transformer differential relay had tripped. The primary side of the relay monitored the 230 kV current, while the secondary side monitored the 12 kV current. Since Startup Transformer 1-1 was unloaded on the 12 kV side, the relay functioned as a time overcurrent relay by quickly tripping the supply breaker since a high differential current was sensed. The relay was a Type IAC with Very-Inverse-Time characteristics (i.e., the higher the current differential the shorter the period before the protective function actuates). This relay functioned to protect the transformer from internal faults. The licensee performed electrical and oil tests on Startup Transformer 1-1 and did not find any indications of a transformer fault. The licensee tested the differential relay and determined that it had been properly set.

After the licensee instrumented the relay, the licensee attempted to energize Startup Transformer 1-1 with Startup Transformer 2-1 supplying plant loads. When the primary side disconnect switch was closed, the 230 kV switchyard circuit breaker again tripped. Operations personnel responded quickly to this trip and restored startup power to both units using Startup Transformer 2-1.

After further review, the licensee decided to restore startup power by the method used prior to 1997. The licensee de-energized all startup power to the site by opening the 230 kV switchyard supply circuit breaker, closing the disconnect switch on Startup Transformer 1-1 and, with both startup transformers unloaded, energizing both transformers at the same time by closing the 230 kV switchyard supply circuit breaker. The licensee monitored Startup Transformer 1-1 no load current and voltage and determined that they remained normal. The licensee subsequently loaded the transformer with normal plant loads.

The licensee issued a nonconformance report to evaluate the cause of the trip. The instrumentation from the second trip indicated that the relay had actuated on a real-current signal of sufficient magnitude and time to cause the relay to trip. The licensee found that Calculation 154C-DC, Revision 0, dated March 18, 1991, which set the relay, was performed when the old model startup transformers were installed. For the old model startup transformers, there were no disconnect switches on the primary side of the transformers, so both transformers were energized together. Thus, for the present circumstance, the inspectors concluded that the contribution of energized Startup Transformer 2-1 to the initial no-load energization current for Startup Transformer 1-1 was not considered.

The licensee stated that Calculation 154C-DC was reviewed during preparation for the installation of the new startup transformers in 1997; however, no change was considered necessary. The licensee concluded that the failure to update this calculation with a new relay setpoint allowed the relay to trip during a normal energization, which challenged a Technical Specification required power source. In addition, the licensee determined that they had not tested the ability to energize Startup Transformer 1-1 with Startup Transformer 2-1 already energized, during postinstallation testing. The licensee stated that the calculation would be reperformed as part of the actions for Nonconformance Report N0002077 and that both transformers would be energized together until the relay setting calculation was reperformed.

The inspectors determined that the licensee had not performed an adequate review of Calculation 154C-DC during the installation of the new startup transformers in 1997 to ensure that the relay setpoints would protect the transformers but not interfere with normal energization sequences. The inspectors also determined that adequate testing had not been performed to verify the relay setpoints. The inspector noted that review of Calculation 154C-DC in 1997 was informal, in that the design change did not provide any documentation to ensure that the calculation had been reviewed and did not provide any reasons for concluding that the calculation remained valid for the new startup transformer configuration.

c. Conclusions

The inspectors concluded that the loss of startup power to the site and subsequent starting of all diesel generators on both units was caused by inadequate relay setpoint design review and inadequate testing during installation of the new startup transformers in 1997. The licensee's immediate corrective actions for this nonsafety-related design deficiency were satisfactory.

E8 Miscellaneous Engineering Issues (92700, 92903)

E8.1 (Closed) Unresolved Item 50-275; 323/97201-01: licensee commercial grade procurement of 4 kV breakers did not meet industry codes.

This item was discussed in NRC Inspection Report 99900912/98-01, and the NRC evaluation of this item was sufficient to address the issues raised; therefore, this item is closed.

E8.2 (Closed) Licensee Event Report 50-275; 323/96-005-01: potential inoperability of component cooling water system because of flashing in containment fan cooler units.

Following NRC notification, the licensee evaluated the possible effects of flashing in the component cooling water system and determined that this potential existed at Diablo Canyon. The NRC followup identified a noncited violation in NRC Inspection Report 50-275; 323/96-23. No further followup is required.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls (Units 1 and 2)

R1.1 General Comments (71750)

The inspectors evaluated radiation protection practices during plant tours and observation of work activities. The inspectors determined that personnel properly donned protective clothing and dosimetry and confirmed that radiological barriers were properly posted.

S1 Conduct of Security and Safeguards Activities (Units 1 and 2)

S1.1 General Comments (71750)

During routine tours, the inspectors observed that the security officers were alert at their posts, security boundaries were being maintained properly, and screening processes at the Primary Access Point were performed well. During backshift inspections, the inspectors noted that the protected area was properly illuminated, especially in areas where temporary equipment was brought in.

F1 Control of Fire Protection Activities

F1.1 Portable Fire Extinguishers (Unit 2)

a. Scope (71750)

The inspectors toured safety-related areas to confirm that fire protection equipment was staged as required.

b. Observations and Findings

The inspectors identified that the portable fire extinguishers in the three DEG rooms in Unit 2 were 2 weeks overdue for an annual service inspection required by Procedure M-18.2, "Service, Tagging, Charging and Hydrostatic Testing of Portable Fire Extinguishers," Revision 9.

The licensee initiated an AR to have the extinguishers inspected and determine the cause for not performing the annual inspections required by Procedure M-18.2. The licensee determined that Procedure M-18.2 had been updated in 1994 to match the requirements of National Fire Code NFPA-10 (1994) and applicable State regulations, which both required the service inspection be conducted within 30 days prior to the service anniversary date. However, associated repetitive work orders, which directed performance of the work were not updated at this time. The repetitive work orders only required that the extinguishers be inspected within the same month as the service anniversary date, which allowed a 30-day grace period after the annual service inspection date. Because of this difference in procedures, the licensee noted that numerous other portable extinguishers had not had their service inspection within the 30 days prior to the service anniversary date. The licensee was unable to determine why the discrepancy between these procedures had not been previously discovered.

The inspectors determined that Procedure STP M-69A, "Monthly Fire Extinguisher Inspection," Revision 26, required review of the annual inspection dates but did not specify any action until the last annual service inspection was greater than 13 months. The inspectors discussed this conclusion concerning Procedure STP M-69A with the licensee. The licensee agreed that the 13 months allowed in Procedure STP M-69A before any action was required contributed to the problem. The licensee issued an AR to have this procedure changed to require action for any extinguishers that had not received their service inspection within 12 months.

The licensee changed all the associated repetitive work orders and completed the annual inspection of the portable extinguishers in the Unit 2 DEG rooms and the portable extinguishers in other locations that had not been inspected within the required 1 year service period. The licensee verified that all of the extinguishers had remained within specifications. The inspectors considered the licensee actions adequate to resolve this item. The inspectors concluded that, although an inadequate procedure resulted in fire extinguishers exceeding their service inspection within the required interval, this item was of minor safety significance and not subject to formal enforcement.

c. Conclusions

The inspectors identified that portable fire extinguishers located in vital areas were routinely not being inspected annually to the timeliness criteria contained in Procedure M-18.2. However, the fire extinguishers met their performance criteria when tested and the licensee implemented the appropriate corrective actions to correct the deficiency.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on December 11, 1998. The licensee acknowledged the findings presented.

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

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

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T. L. Grebel, Director, Regulatory Services
D. B. Miklush, Manager, Engineering Services
J. E. Molden, Manager, Operations Services
D. H. Oatley, Vice President and Plant Manager
L. F. Womack; Vice President, Nuclear Technical Services

INSPECTION PROCEDURES (IP) USED

IP 37551	Onsite Engineering
IP 61726	Surveillance Observations
IP 62707	Maintenance Observation
IP 71707	Plant Operations
IP 71750	Plant Support Activities
IP 92700	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92901	Followup - Operations
IP 92902	Followup - Maintenance
IP 92903	Followup - Engineering
IP 93702	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED AND CLOSED

Opened

None

Closed

50-275; 323/ 97001-01	VIO	Failure to follow procedures related to respiratory protection (Section O8.1)
50-275; 323/ 97006-05	IFI	Untimely operating experience reviews (Section O8.2)
50-275; 323/ 96014-03	VIO	Failure to remove AR tags from the control boards (Section M8.1)
50-275;323/ 97201-01	URI	Licensee commercial grade procurement of 4 kV breakers did not meet industry codes (Section E8.1)
50-275; 323/ 96-005-01	LER	Potential inoperability of Component Cooling Water System because of flashing in Containment Fan Cooler Units (Section E8.2)

Opened and Closed

50-275; 323/ 98018-01	NCV	Performance of work on wrong unit (Section M1.5)

LIST OF ACRONYMS USED

AR	action request
DEG	diesel engine generator
IFI	inspection followup item
IP	inspection procedure
LER	licensee event report
NCV	noncited violation
NRC	Nuclear Regulatory Commission
PDR	Public Document Room
URI	unresolved item
VIO	violation