APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-275/94-30
50-323/94-30

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: November 27, 1994, through January 7, 1995

Inspectors: M. Miller, Senior Resident Inspector
M. Tschiltz, Resident Inspector
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D. Solorio, Resident Inspector

Approved: D. F. Kirsch, Chief, Reactor Project Branch E — Date: 1/31/95

Inspection Summary

Areas Inspected (Units 1 and 2): Routine, announced inspection of operational safety verification, plant maintenance, surveillance observations, plant support activities, onsite engineering, online maintenance (TI 2515/126), in-office review of licensee event reports (LERs), and followup maintenance.

Results (Units 1 and 2):

Operations:

- Management's decision to maintain Unit 2 shutdown while investigating the seismic qualification of diesel fuel oil (DFO) transfer piping demonstrated a conservative, safety conscious attitude. Restart of Unit 2 was delayed until calculations verified the operability of the piping following a seismic event.

- During periods of increased condenser fouling, the trending of condenser differential pressures was effectively utilized to make timely decisions regarding Unit curtailments.

- Operations personnel performing a surveillance test (emergency core cooling systems (ECCS) venting) did not perform the venting in accordance with the sequence specified in the procedure.

- Operator response to the several plant transients and a manual Unit 2 reactor trip, as a result of the condenser fouling, demonstrated good safety awareness.

- An operator improperly paralleled Emergency Diesel Generator (EDG) 1-3 with startup power without matching voltages which caused EDG 1-3 voltage regulator damage. EDG 1-3 was inoperable during subsequent troubleshooting and repair.

Maintenance:

- Investigations of discrepancies with 4 kilovolt (kV) breakers were thorough and performed in a timely manner. Decisions involving the breaker inspections appeared to be appropriately based upon critical evaluation of potential failure mechanisms and their impact on plant safety.

- Investigation of the reactor trip bypass breaker undervoltage trip attachment failure was comprehensive and thorough. The potential for common mode failure was given appropriate consideration.

- Procedures were not adequate for verifying system tubing integrity after disassembly of tubing fittings for calibration of process variable sensing transmitters.

Plant Support:

- Review of Foreign Material Exclusion (FME) logs for the Units 1 and 2 spent fuel pools indicated that supervisory reviews were not being performed in accordance with procedure.

- Procedures for issuance of security photo-identification (ID) badges did not require verification of identity prior to picture taking for the site ID photo. This resulted in issuing a site security photo-ID to a visiting NRC inspector without verifying the identity of the individual.

Summary of Inspection Findings:

- Noncited Violation 275/9430-01 was identified (Section 2.2).

- Noncited Violation 323/9430-02 was identified (Section 3.1.3).
- Noncited Violation 275/9430-03 was identified (Section 4.1).
- Noncited Violation 275/9430-04 was identified (Section 6.1.3).
- Inspection Followup Item 275/9430-05 was identified (Section 1.3).
- Unresolved Item 275/9101-04 was closed (Section 8.1).
- LERs 275/94-016, Revision 0; 275/94-19, Revision 0; 275/94-022, Revision 0; 323/94-009, Revision 0; and 323/94-008, Revision 0 were closed (Section 9).
- Violation 323/9418-01 was closed (Section 10).

Attachments:

- Attachment 1 - Persons Contacted and Exit Meeting
- Attachment 2 - Acronyms

DETAILS

1 PLANT STATUS (71707)

1.1 Unit 1

Unit 1 started the inspection period at 100 percent power. On December 14, 1994, an automatic reactor trip occurred due to a reactor coolant pump (RCP) undervoltage condition which was caused by a grid disturbance. On December 17, 1994, the unit entered Mode 1 and was paralleled to the grid. The unit returned to 100 percent power on December 20, 1994. On January 4, 1995, an increase in condenser differential pressure, due to fouling of the condenser tubesheet, forced a curtailment to 50 percent power for condenser cleaning. The unit returned to 100 percent power on January 5, 1995, and remained at 100 percent for the remainder of the inspection period.

1.2 Unit 2

Unit 2 started the inspection period at 100 percent power. On December 14, 1994, an automatic reactor trip occurred due to an RCP undervoltage condition which was caused by a grid disturbance. On December 15, 1994, the unit entered Mode 1 and was paralleled to the grid. On December 18, 1994, the unit returned to 100 percent power. On December 19, 1994, the unit was manually tripped due to impending loss of circulating water (CW) flow to the condensers as a result of condenser fouling and kelp buildup on the traveling screens due to high seas. Following condenser cleaning and resolution of restart issues, the licensee management maintained the unit in Mode 3 for an additional day pending the resolution of the seismic qualification of DFO piping. Unit 2 entered Mode 1 and was paralleled with the grid on December 24, 1994. The unit returned to 100 percent power on December 27, 1994. On January 5, 1995, power was reduced to 50 percent due to increased condenser differential pressure caused by sea grass, resulting from high seas, fouling the condenser tubesheet. Following condenser cleaning, power ascension from 50 percent to 100 percent was commenced. The unit returned to 100 percent power on January 7, 1995.

1.3 Units 1 and 2 Reactor Trips Due to Grid Disturbance

On December 14, 1994, at 12:26 a.m., PST, a disturbance on the 500-kV distribution system resulted in Units 1 and 2 reactor trips. The reactor trips were caused by an undervoltage condition sensed on the RCP 12 kV busses. The RCPs for both units remained in operation since a sustained undervoltage condition of the magnitude required to trip the pumps, did not occur. The source of the system disturbance was determined to have been a fault on the distribution system which originated in the Pacific Northwest. The isolation of that fault created a load imbalance on the Western Systems Coordinating Council power distribution network. The load imbalance resulted in a transient voltage collapse throughout the system. Following the reactor and turbine trips, both Units 1 and 2 automatically realigned to the startup

(230-kV) power source. After verifying that the disturbance on the auxiliary (500-kV) system had cleared, both Units 1 and 2 were realigned to receive power from the auxiliary (500-kV) power source.

At the time of the reactor trips EDG 1-3 was in operation for performance of routine surveillance testing and was supplying 4 kV Bus F in Unit 1. After the reactor trip, when plant conditions were stable, EDG 1-3 was paralleled with startup power to transfer loads. After closing the startup feeder breaker, EDG load immediately decreased to 0 KW and the EDG output breaker tripped. Investigation by the licensee revealed that the EDG output breaker tripped on a phase "A" overcurrent condition. EDG 1-3 was declared inoperable. EDG 1-3 troubleshooting revealed that the voltage regulator had been damaged. The licensee replaced the voltage regulator, performed testing and returned EDG 1-3 to operable status.

Unit 1 Reactor Coolant System (RCS) Cooldown

Review of the Unit 1 plant parameters revealed that pressurizer level decreased to 5 percent following the reactor trip. The decrease in pressurizer level was attributed to the effect of RCS contraction due to the RCS temperature decrease to 520°F. The major contribution to the cooldown was the addition of auxiliary feedwater (AFW) to the steam generators (SGs) at the maximum flow rate. Review of the RCS temperatures following the reactor trip showed a rapid drop in temperature, immediately following the trip, followed by a period of relatively stable temperatures for the next minute. Operators initially evaluated RCS temperature as stable when performing Step 1 of the procedure for response to a reactor trip (E-0.1). RCS temperature then continued to decrease due to the effect of the AFW addition to the SGs. Additional RCS cooldown occurred due to auxiliary steam loads which continued to draw steam following the reactor trip. These loads were supplied by Unit 1 to both units. Operators throttled AFW flow during the performance of Step 2 of E-0.1. When pressurizer level decreased to approximately 7.5 percent, a centrifugal charging (CC) pump was started to restore pressurizer level.

Chemical and Volume Control System Alignment

The positive displacement (PD) pump was in service for both units at the time of the reactor trips. The PD pump has a constant volume flow rate independent of RCS pressure, in comparison to the CC pump flow rate which increases with decreasing RCS pressure. Due to the PD pump providing less flow than a CC pump at reduced RCS pressure, a larger decrease in pressurizer level occurred with the PD pump operating than would have occurred had the CC pump been in service.

Training Weakness

Normal operating practice, at the time of the reactor trips, was to maintain the PD pump in operation. Prior to the installation of pulsation dampeners in the chemical and volume control systems, the normal practice was to maintain a CC pump in operation. Simulator scenarios were written for CC pump operation and had not been modified to reflect the change in normal charging pump

operation. In addition, the licensee's simulator instructors generally terminated the training scenarios by stopping the simulator shortly after a reactor trip, before the effect of the AFW cooldown was noted. This practice had the effect of depriving the operators of the opportunity to observe the full effect of the maximum AFW flowrate on the plant temperature and pressurizer level, and the opportunity to deal with the resulting situations. The licensee intends to provide operators more diverse training by including modified simulator training initiated with the PD pump in service and more opportunities to observe and resolve the effects of high AFW flowrate additions on RCS temperature and pressurizer level.

EDG Operations

The paralleling of EDG 1-3 with the startup bus was performed without properly matching power source voltages prior to closing EDG 1-3 output breaker. The difference in voltage resulted in the instantaneous overcurrent trip of the EDG output breaker. Although the operator verified voltages and noted a voltage difference of several volts, instead of matched bus voltages, the difference was evaluated as being acceptable prior to closing the breaker. Results of the licensee's preliminary investigation indicate that mismatch of the voltages during the paralleling evolution resulted in damage to the voltage regulator. The failure to properly match voltages is considered to be an isolated occurrence by the licensee. The licensee was including this problem in periodic operator training and was considering a revision to the procedure.

Conclusion Several training weaknesses were noted during the investigation of the unit trips. First, simulator scenarios had not been modified to reflect normal plant configuration. As a result, operators had not received training which demonstrated the effect of the reduced charging flow following a reactor trip with a PD pump in operation. Secondly, simulator training had not been conducted in a manner to make operators fully aware of the full effect of maximum flowrate AFW addition on RCS cooldown following a reactor trip. These issues are considered to be an inspector followup item (275/9430-05).

In addition, the failure to match voltages during the EDG paralleling operation represents a personnel performance problem in that it is axiomatic knowledge in the industry that voltages must be matched prior to paralleling two electrical sources.

1.4 Unit 2 Manual Reactor Trip Due to Condenser Fouling

On December 19, 1994, Unit 2 reactor was manually tripped from 50 percent power due to an impending loss of main condenser CW flow and vacuum as a result of kelp intrusion on the intake screens and in the main condenser waterboxes.

While operating at 100 percent power, operators observed higher than normal condenser differential pressures and commenced a power reduction to 50 percent power to secure a CW pump and clean the associated condenser portions. After reaching 50 percent power, CW Pump 2-2 was secured. Subsequent to securing CW

Pump 2-2, a rapid buildup of kelp on the traveling screens associated with CW Pump 2-1 occurred, and two of the three screens became overloaded with kelp, causing the drive assembly shear pins to break. Control room operators observed fluctuation of CW Pump 2-1 motor amperage and indication of pump cavitation, at which point operators properly initiated a manual reactor trip, shutdown CW Pump 2-1, and eliminated condenser vacuum.

Following the loss of CW flow, the SG 10 percent atmospheric dump valves were relied upon for removal of decay heat. The ten percent atmospheric steam dump valve for SG 2-4 (Pressure Control Valve (PCV)-22) did not properly control SG pressure, which allowed pressure to increase above the setpoint of 1035 psig. SG 2-4 pressure increased to approximately 1060 psig, at which point the SG code safety valve opened. The SG 2-4 code safety remained open for approximately 30 seconds and then reseated. Operators manually adjusted the 10 percent atmospheric dump valve controls to maintain SG pressures at 1005 psig. Subsequent troubleshooting of PCV-22 isolated the problem to the valve controller. The valve controller for PCV-22 was replaced.

Conclusion Operators' actions were prompt in reaction to the impending loss of CW flow to the condenser. Subsequent resolution of equipment problems prior to restart appeared to be properly controlled.

2 OPERATIONAL SAFETY VERIFICATION (71707)

2.1 Housekeeping and Potential Seismic Interactions

During tours of the facility on several different occasions, the inspector noted storage of temporary equipment and materials which created potential seismic interactions with equipment required for safe shutdown during a seismic event. After the inspector identified these concerns, the licensee promptly moved the temporary equipment and materials.

Procedure AD4.ID3, Revision 1, "Seismically Induced System Interaction Program (SISIP) Review of Housekeeping Activities," defined the responsibilities and requirements for ensuring potential seismically induced systems interactions are not created during maintenance, modification, or testing. The stated intent of Procedure AD4.ID3 is to assure that temporary equipment is positioned or restrained such that it will not detrimentally impact sensitive or vulnerable safety-related targets in the event of an earthquake.

Conclusion The inspector has observed an increase in the number of instances at the facility where temporary equipment and materials storage practices did not meet the intent of AD4.ID3. Specifically, temporary equipment was not being positioned or restrained to prevent the potential for interaction with vulnerable safety-related targets in the event of an earthquake. The licensee performed a case study on the inspector's findings, which has been distributed to increase employee knowledge and awareness of the seismically induced system interaction program. The licensee's actions in response to the inspector's findings appeared to be appropriate.

2.2 FME

On November 28, 1994, during a tour of the Units 1 and 2 spent fuel pool areas, the inspector noted that periodic reviews of the FME accountability logs had not been performed as required by plant Procedure AD4.ID6, Revision 1, "Foreign Material Exclusion Program." The spent fuel pool FME plan, Appendix 7.4 of AD4.ID6, Paragraph 4.4.1.a, states that the "FME supervisor or his designee shall perform a weekly walkdown of the FME area and the adjacent storage and staging area to evaluate area housekeeping and the integrity of the boundary barrier." In addition, Paragraph 4.4.1.b. requires that the FME supervisor or his designee review the personnel entry and material accountability logs monthly.

Contrary to Procedure AD4.ID6 requirements, Units 1 and 2 weekly housekeeping and barrier integrity inspections were not performed during the week of November 20, 1994. Monthly material accountability log reviews were not performed for Unit 1 during the months of July and August 1994. Upon notification of the deficiencies the licensee initiated action to perform reviews and initiated an action request (AR) to document these deficiencies. Spent fuel pool FME log review requirements were added to the Radiation Protection (RP) section survey checklist to ensure the performance of reviews at the specified intervals.

Safety Significance Although the supervisory reviews had not been regularly performed at the specified intervals, there was no evidence of a loss of control of material stored within the FME areas.

Conclusion Reviews of FME records were not consistently being performed in accordance with the AD4.ID6. This appeared to be due to the lack of a method for tracking review requirements. The licensee's action in response to this issue appeared appropriate. The failure to conduct: (1) periodic housekeeping and barrier integrity inspections, and (2) supervisory reviews of personnel entry and material accountability logs is a violation of 10 CFR Part 50, Appendix B, Criterion V, which requires that procedures be followed. Since this violation is of low safety significance and since the inspector considers the corrective actions to be adequate, in accordance with Section VII.B.(2) of the Enforcement Policy, this violation was not cited (275/9430-01).

2.3 Unit 1 Reactor Startup and Unit 2 Power Ascension

On December 17, 1994, the inspector observed backshift activities of the Unit 1 startup operations and Unit 2 power ascension. The operators appropriately followed the procedures applicable to routine unit startup and power increase operations. The shift management was involved with oversight of the shift operations, and the licensed operators gave clear, concise directions to operators performing valve manipulations in the plant. All observed operators ensured clear understanding of the instructions to be performed by answering with specific repeat-backs of instructions. Response to each of the many routine startup alarms involved operator reference to software tools to determine the precise circuit that was in alarm, as well as

reference to the alarm response procedure to identify the required response to the alarm. Operators were familiar with procedures and maintained strict attention to performance of steps in sequence.

Conclusion The startup and power increase on each unit was performed with attention to detail, excellent communication, and in accordance with applicable procedures.

3 PLANT MAINTENANCE (62703)

During the inspection period, the inspector observed and reviewed selected documentation associated with 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 witnessed portions of the following maintenance activities:

Unit 1

- Residual Heat Removal (RHR) Pump 1-1 4 kV Breaker (52HG8) Troubleshooting

Unit 2

- Volume Control Tank (VCT) Pressure Transmitter Calibration (document review)
- Reactor Trip Bypass Breaker Undervoltage Trip Attachment Troubleshooting and Replacement
- 4 kV (General Electric Magne-Blast) Circuit Breaker Inspections

3.1 VCT Pressure Instrument Transmitter (PT-139) Calibration

3.1.1 Description of Work

On January 3, 1995, an instrumentation and control (I&C) technician performed the calibration of the Unit 2 VCT pressure instrument transmitter (PT-139). After initially connecting test equipment to the associated instrument tubing, the technician was unable to draw a vacuum on the assembly. The technician contacted the I&C supervisor who directed that the test equipment be connected directly to the pressure transmitter. Connection of the test equipment to the pressure transmitter required disassembly of additional tubing fittings. Following completion of the transmitter calibration, the test equipment was removed, the tubing fittings reassembled, and the isolation valve opened to realign the pressure transmitter to the VCT. After opening the isolation valve, the technician did not perform an operational check; therefore, he failed to identify a tubing leak which occurred as a result of the work. The

procedure for the transmitter calibrations did not require an operational check to assure fitting integrity after reassembly.

3.1.2 Radiological Effects of Instrument Tubing Leak

When attempting to exit the radiologically controlled area the I&C technician, who had performed the VCT pressure instrument transmitter calibration, was found to be contaminated. A RP technician returned to the job site to evaluate radiological conditions and found dose rates had significantly increased in the hallway adjacent to the PT-139 instrument panel and on contact with the panel door. Upon opening the panel door, the RP technician observed that radiation levels immediately decreased. Subsequent surveys of the panel indicated radiation levels of 400 mr/hr on contact and 200 mr/hr at 12 inches from the panel. After opening the panel door a second time, radiation levels significantly decreased; however, contact radiation readings inside the instrument panel were as high as 2.5 R/hr. The RP technician closed and posted the instrument panel as a High High Radiation Area and posted an area surrounding the panel as a High Radiation Area. Air samples in the hallway indicated a noble gas derived air concentration of 7.99. The licensee examined the panel to locate and isolate the source of the noble gas, and the tubing leak was discovered and isolated. The actions taken by RP personnel in response to the radiological conditions caused by the instrument fitting leak appeared appropriate.

3.1.3 I&C Work Practices

The calibration of the VCT pressure transmitter resulted in an instrument tubing leak which was not detected when realigning the instrument to the VCT. The licensee's procedure, MP I-2.24-4, Revision 2A, "Pressure Testing of Instrument Tubing," did not require testing of previously installed compression fittings. MP I-2.24-4 only recommended that a visual check for system integrity be performed following reassembly. An I&C maintenance engineer and I&C general foreman indicated that the technician was expected to perform an operational check of remade fittings following reassembly even though the procedure did not require the check. In this regard, the I&C maintenance procedure did not reflect management expectations.

The portion of the instrument tubing noted to be leaking would not normally be checked by the I&C technicians since it was not normally disassembled during the pressure transmitter calibration. However, the disassembly and reassembly of adjacent fittings had resulted in the leak. The I&C general foreman indicated that it was not unusual to realign an instrument without performing an operational check of fittings at the time.

The licensee was revising MP I-2.24-4 to require an operational check of instrument tubing fittings which are disassembled as well as those which were potentially disturbed during the maintenance. The licensee has conducted tailboards on this event with I&C and RP personnel and has issued a case study. Additionally, the licensee has initiated a nonconformance report on this event.

Safety Significance The change in radiological conditions caused by the leaking instrument fitting were significant in that the leak created a High High Radiation Area in the panel, a High Radiation Area adjacent to the panel, surface contamination in both the panel and the adjoining hallway, a high airborne concentration of noble gasses, and a monitored but uncontrolled release of noble gasses. Prompt identification and isolation of the source of radioactivity minimized the consequences of the leak.

Conclusion The I&C technicians appeared to have followed the existing procedural requirements for the pressure instrument transmitter calibration; however, existing I&C maintenance procedures were not appropriate to the circumstance in that the maintenance created instrument tubing leaks which were not identified when realigning the transmitter for service. The failure to establish adequate I&C maintenance procedures of a type appropriate to the circumstances and that they be followed, is a violation of 10 CFR Part 50, Appendix B, Criterion V. Since the violation is of relatively low safety significance and since the inspectors consider the corrective actions to be adequate, in accordance with Section VII.B.(2) of the Enforcement Policy, this violation was not cited (323/9430-02).

4 SURVEILLANCE OBSERVATIONS (61726)

Selected surveillance tests required to be performed by the Technical Specifications (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

- Surveillance Test Procedure (STP) M-89, Revision 17A, ECCS Venting

Unit 2

- STP P-8B, Revision 28A, Routine Surveillance Test of CCW Pump 2-2

4.1 STP M-89, ECCS Venting

On December 13, 1994, the inspector observed Unit 1 plant equipment operators perform Surveillance Procedure STP M-89, Revision 17A, "ECCS System Venting." During the surveillance, the inspector observed the operators inappropriately deviate from the procedure specified sequence. Specifically, operators performed Step 12.18, then Steps 12.20 and parts of Step 12.21 before performing Step 12.19. Generally, all these steps involved venting pumps or

system piping at various locations and elevations. The inspector noted that this surveillance was required to demonstrate operability of ECCS subsystems monthly while in Modes 1 - 4.

The inspector reviewed the licensee's program describing use of procedures and discussed this observation with operations management. Operations management stated that the operators should not have deviated from the procedure without prior approval from the shift foreman. The inspector noted that the licensee's program for use of procedures, which was outlined in Procedure AD2.ID1, Revision 3A, "Procedure Use and Adherence," did not specifically include provisions outlining that the shift foreman could approve deviations from surveillance procedures. In addition, the inspector reviewed Procedure AD2, Revision 0, "Procedure Use and Adherence," and noted that personnel were expected to follow the sequence of procedure steps unless otherwise provided for within the specific procedure or authorized by applicable higher level procedures. The inspector reviewed the surveillance procedure for ECCS venting and did not identify any provisions allowing steps to be performed out of sequence. Subsequent discussions with the Operations Director indicated that the foreman could not authorize deviating from the procedure and that a change to the procedure was required if it was necessary to change the sequence of the venting.

The licensee initiated an AR to document this occurrence. Additionally, the licensee counseled the involved individuals and initiated a case study concerning inadequate performance of the surveillance.

Safety Significance The inspector concluded that in this case there was no safety significance and that the performance of steps out of the specified sequence did not impact the accomplishment of the TS 4.5.2.b.1 requirement to verify that the Emergency Core Cooling piping was full of liquid water.

Conclusion The failure to perform the Surveillance STP M-89 in accordance with the procedure is a violation of TS 6.8.1, which 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 procedures covering surveillance testing; preventative maintenance; and startup, operation, and shutdown of safety-related systems. Contrary to this requirement, on December 14, 1994, the inspector observed operators perform the procedural steps of STP M-89 out of the required sequence. Since the violation is of very low safety significance and since the inspectors are satisfied with the adequacy of the corrective actions, in accordance with Section VII.B.(1) of the Enforcement Policy, this violation was not cited (275/9430-03).

5 ONSITE ENGINEERING (37551)

5.1 DFO Piping Seismic Qualification

5.1.1 DFO System Design Review

The DFO system supplies fuel oil from two 40,000 gallon storage tanks to the six EDGs and is comprised of two trains which include two storage tanks, two transfer pumps, and associated piping. The system is designed to remain operable following a design or Hosgri earthquake.

During a design review, associated with the upgrade of the DFO storage tanks, the licensee identified an unreviewed piping configuration. The unreviewed configuration was introduced in 1979 when piping anchors were installed in the DFO pump vaults. The piping anchors were installed for the seismic qualification of the piping in the pump vaults for the Hosgri earthquake. The installation of piping anchors resulted in the connecting piping between the pump vaults and the storage tanks becoming more rigid. The effects of the increase in rigidity on the DFO pump suction and recirculation piping outside of the pump vaults was not analyzed.

Upon discovery of the unreviewed piping configuration the licensee promptly initiated an engineering evaluation. Preliminary calculations concluded the piping was operable, but more detailed calculations were required to confirm the actual stresses on the piping and supports.

5.1.2 DFO Design Calculation Results

The licensee performed a design analysis to determine if the relative motion between the DFO tanks and the pump vaults would result in the overstressing of the connected piping and supports. The analysis indicated that all portions of the system did not meet design basis criteria; however, the pressure boundary of the DFO system would remain intact and operable following a seismic event.

The analysis revealed three locations where design basis criteria were not met. The locations include: the pipe elbow immediately above the DFO Tank 0-2, the hold down bolts for the suction line strainers (STR-67 and STR-68), and the pipe supports for the lines in the vaults (20-87A, 20-89A, 20-94A, 20-85R and 20-90R).

5.1.3 DFO System Operability

On December 23, 1994, the inspector, the Plant Manager, and a shift foreman walked down both trains of DFO piping. The piping supports were found in the configurations described by the operability evaluation, and the equipment appeared to have been properly labeled and maintained. Additionally, the inspector observed the Plant Staff Review Committee (PSRC) meeting which was held on December 23, 1994, to assess the DFO operability evaluation. A conservative questioning attitude was observed in the PSRC. For example, a PSRC member questioned if the additional conservatism of ensuring that the EDG

Fuel Oil Day Tanks were full could be performed. After discussion, the PSRC agreed to accomplish this measure. Additional actions were also accomplished. The licensee tested the operability of a portable DFO transfer pump and associated hoses. The portable DFO transfer pump storage location has been relocated to ensure that the pump is available following a seismic event. Additionally, the licensee has purchased a second portable DFO transfer pump to provide additional assurance of portable DFO pumping capability. At the conclusion of the meeting the NRC inspector questioned several of the assumptions of the operability evaluation, such as the applicable seismic spectra, forces acting on the piping supports, tank fuel volumes, emergency procedure requirements, and other areas. The inspector found that all areas questioned had been appropriately and conservatively addressed. After the conclusion of the meeting and discussions with the inspector, the PSRC concluded that Unit 2 would be allowed to transition from Mode 3 to 100 percent power operation without further restriction.

Safety Significance The discovery of the unanalyzed DFO configuration and subsequent analysis revealed several conditions which did not satisfy design criteria but did, however, satisfy operability criteria. The licensee applied the guidance of Generic Letter (GL) 91-18, "Resolution of Degraded and Nonconforming Conditions," as the basis for continued operation with the existing DFO system configuration.

Conclusion The licensee's actions upon discovery of this issue appeared to have been both timely and focused on safety. The response included significant engineering analysis, compensatory measures, and a conservative operating decision to maintain Unit 2 shutdown until the conclusion of the analysis.

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 Security

6.1.1 NRC Personnel Access Authorization

On December 12, 1994, the licensee approved unescorted access and issued a security badge to an NRC inspector without first verifying the identity of the inspector.

The inspector reviewed relevant licensee procedures and practices, and interviewed access authorization and security supervisory personnel. NRC personnel were provided access in accordance with Procedures SP413, Revision 6, "Access Authorization for Nuclear Regulatory Commission Personnel," and SP409, Revision 17, "Authorization of Status and Shift For Unescorted Access." The inspector reviewed these procedures and determined that there were no requirements to ensure that an individual's identity was verified with photo-ID prior to issuing a security badge. The inspector

concluded this was a programmatic weakness. In addition, the inspector determined that access authorization clerks did not require NRC personnel to present photo-ID because NRC personnel were expected to arrive onsite on a certain date and time and provide all necessary information verbally. The current access authorization supervisor stated that the former access authorization supervisor routinely verified the identification of NRC personnel by requesting photo-ID. However, because the current access authorization process supervisor was not aware of this previous practice, and because he assumed that the access authorization clerks were performing this function, the inspector was not asked to provide photo-ID.

6.1.2 Non-NRC Personnel Access Authorization

Based on a concern for adequate control of access, the inspector reviewed the licensee's access program for non-NRC personnel, and identified a similar procedural weakness. The licensee's program for access authorization was controlled by Station Procedure OM11.DC1, Revision 3, "Process for Unescorted Security Access Authorization." The inspector noted that the licensee's procedure did require that personnel requesting unescorted access provide photo-ID at one stage of the access authorization process. However, the inspector noted that the procedure did not require verification of identity before taking a photograph which would be used for the unescorted security access badge (Step 6.10 of OM11.DC1, Revision 3). The inspector considered this a potential problem because the licensee's process normally took several days to complete the background investigations. Once the investigations were completed the employee would then be called back to the plant to complete the access process. If the photograph had not been previously taken, (interviews with access authorization personnel revealed that the picture did not need to be taken on the first visit) it would be taken at that time. Because photo-ID was not required prior to being photographed, the inspector concluded the potential existed for individuals to be provided unescorted access without positive verification that the individual presenting himself or herself was the same individual previously approved for unescorted access.

In response to the inspectors observations, as outlined above, the licensee initiated an AR. Access control working procedures have been revised to require that photo-ID verification of an individual's identity be performed at the time an individual is photographed.

6.1.3 Access Authorization Requirements

TS 6.8.1 requires written procedures and instructions including applicable check-off lists be established, implemented, and maintained for implementation of the Security Plan. The Physical Security Plan, paragraph 1.4.1, implements 10 CFR 73.56, which requires in Section (b)(2)(i), that the unescorted access authorization program include verification of an individual's true identity.

Conclusion The inspector concluded that the procedures and instructions in place did not implement the intent of the Security Plan, in that they did not ensure that personnel granted unescorted access to the protected area were positively identified. This is a violation of TS 6.8.1. Since the violation

is of very low safety significance and since the inspectors are satisfied with the adequacy of the corrective actions, in accordance with Section VII.B.(1) of the Enforcement Policy, this violation was not cited (275/9430-04).

7 EVALUATION OF ONLINE MAINTENANCE (TI 2515/126)

7.1 Background Information

During recent visits to several nuclear plants in the nation by several NRC senior managers, it was noted that some licensees are increasing both the amount and frequency of maintenance during power operation. An expansion of online maintenance without thoroughly considering the safety (risk) aspects raised significant concerns.

When evaluating online maintenance activities, consideration of the impact of the maintenance activities on event probability is one way to assess the risk associated with those activities. The purpose of performing this temporary instruction was to review and record the licensee's program for scheduling online maintenance activities and to determine if the licensee's program appropriately considers the risk factors.

7.2 Overview of the Current Planning and Scheduling Program at Diablo Canyon

Procedure AD7.ID4, Revision 0, "Online Maintenance Scheduling," is Diablo Canyon's procedure to schedule daily preventative maintenance (PM), corrective maintenance, and STP work. According to the procedure, the goal is for all disciplines to work a component or system during the same maintenance window, thus minimizing equipment and system downtime. Scheduling at Diablo Canyon is developed from various guidelines which include:

(1) Scheduling of work for safety-related components based on a 12-week rolling matrix schedule

(2) Scheduling of balance-of-plant activities based on PM frequency

(3) Scheduling of collective maintenance activities based on the effect of the degradation on the system and on the plant.

The underlying principle of the licensee's program is to perform online maintenance only if it increases or maintains the reliability of the equipment. It was also noted that safety-related equipment outages, that require entry into an Limiting Condition for Operation (LCO), are limited by the licensee's procedure to one half of the LCO action statement time limit.

Integrated with the scheduling procedure are a 12-week rolling matrix schedule based on STP requirements for safety-related equipment and a Mode One Integrated Daily Schedule (MOIDS). The MOIDS is developed based on the 12-week rolling matrix schedule. The MOIDS incorporates specific work activities for safety-related equipment based on the potential opportunity for maintenance as outlined in the 12-week rolling matrix schedule. In addition to scheduling the detailed activities to be performed on safety equipment, the

MOIDS also outlines major activities for nonsafety-related equipment. The Planning and Scheduling group at Diablo Canyon employs one full time, licensed Reactor Operator who provides guidance on minimizing risk by considering the safety aspect of removing single and multiple equipment or components from service to perform maintenance or surveillance activities. In addition, the planners and schedulers meet on Tuesday and Thursday of each week at a MOIDS meeting which, includes the plant Operations Shift Supervisor, who provides the final decision on scheduling of online maintenance and testing.

7.3 Consideration of Risk in the Scheduling of Online Maintenance Activities

The 12-week rolling schedule is one of the basic components of the licensee's scheduling process. The licensee has performed a formal probabilistic risk assessment (PRA) calculation for the safety-related components listed on the 12-week rolling matrix. For example, the licensee's PRA group determined that removal of AFW Pump 3 in conjunction with the removal of CCW Pump 1, one of the sets of work activities which the matrix allows to be worked concurrently results in an order of magnitude increase in core damage frequency (CDF). The licensee considers this risk impact to be of moderate intensity. The licensee does not allow work for activities which would cause a greater than moderate risk impact. The licensee did not calculate the additional safety risk contributed by work activities on nonsafety components when deriving the risk potential. However, an informal qualitative perspective on risk is provided when work activity planning is finalized at the MOIDS meetings. The Operations Shift Supervisor has the final approval at these meetings. For example, according to the licensee, the Operations Shift Supervisor would likely suspend work activities in the switch yard when a diesel generator is out of service for maintenance.

The formal calculations to estimate risk associated with online maintenance were performed only for safety-related equipment listed in the 12-week rolling matrix windows. Although the probability of an initiating event can often be attributed to the failure of nonsafety equipment, online maintenance of nonsafety equipment was not considered in the licensee's formal calculations to quantify risk.

According to the licensee's PRA group, safety-related equipment which would have only a minor influence in the calculation of increased CDF was also excluded from the calculations for the 12-week rolling matrix. For example, in order to maintain containment integrity, only one to two containment fan cooling units (CFCUs) need to be operable (depending upon accident scenario). Since each unit has five CFCUs, the increase in CDF from a single CFCU being inoperable is minor and thus excluded from the formal calculations for online maintenance risk.

Maintenance and testing activities which are not considered in the formal calculations to estimate the increase in the risk of CDF are at least considered on an informal qualitative basis. A full time reactor operator is assigned to the planning and scheduling group. The reactor operator provides an overview of schedules, looking at both safety and non-safety activities, to qualitatively assess potential CDF risk associated with removal of equipment

and components for maintenance and testing activities. Furthermore, the Operations Shift Supervisor and a Senior Reactor Operator attend the twice weekly MOIDS meetings. The final overview of online maintenance scheduling occurs at the MOIDS meetings. The Operations Shift Supervisor provides the final view on potential risk and has the final approval authority for the scheduling of online activities.

7.4 Additional Notes Concerning the Estimate of Risk with Online Maintenance

The inspectors questioned the licensee regarding the accuracy of the PRA information used in the Individual Plant Examination for Diablo Canyon. In response, the PRA group presented the results of a recently performed study comparing actual outage times with those assumed in the PRA. The study looked at the availability of three critical safety systems, the CC pumps, safety injection, and auxiliary saltwater, over the period of the last 3 years. For these systems, the licensee found that the duration of system unavailability assumed in the PRA analysis was 20 percent to 60 percent greater than the actual system unavailability. Therefore, it can be concluded, for these systems, that the assumptions in the Diablo Canyon PRA for system availability were conservative.

7.5 Future Plans for Scheduling Online Maintenance at Diablo Canyon

The licensee had spent considerable time developing a revised online maintenance scheduling program, which, if fully implemented, would provide substantial refinements over the current scheduling program. The licensee planned to begin implementation and testing of their new online maintenance scheduling program about February or March of 1995 and anticipated that, if all goes well, the program would be fully implemented by the end of 1995. Some highlights of the new program are described below.

The new program proposes a long-term schedule shell, of approximately 1 year in duration, encompassing both nonsafety- and safety-related work. The 12-week rolling matrix will no longer be the basic scheduling component but will be incorporated into the overall schedule shell. Each week of the schedule will be assigned an individual planner and undergo a 5-week planning and development cycle, a work execution week, and a postweek summary. The individual planner is solely responsible for the schedule of the week and any changes to it. A key component of the scheduling process will be an assessment of risk significance. Since nonsafety-related work is also included in the assessment, the new program would effectively include the consideration of those initiating events in the assessment of risk. This is not to imply that a formal process will always be used in the assessment, but does allow for alternative evaluations, which, according to the licensee, could include the use of Online Safety Function Assessment Trees (similar in format to the flow diagrams used in the licensee's Functional Recovery Procedures), PRA analysis, or system functional analysis by system experts.

In the new scheduling program, allowed outage times for online work on safety-related equipment would continue to be limited to one half of the LCO action statement time limit. However, further restrictions would also apply. For

example, maintenance activities with an LCO of 24 hours or less are not allowed to be scheduled. Any work outside of the scheduling program guidelines would require sponsorship at the management level of Director or above.

Also of note, with the implementation of the new procedure the licensee will create a small multidisciplined group of seven to eight engineers and technicians who will be responsible for completing emergent work such as might arise from AR. The underlying goal of establishing this team will be to free the other work teams from unplanned work and to reduce the maintenance backlog.

8 FOLLOWUP - PLANT SUPPORT (92904)

8.1 (Closed) Unresolved Item 275/9101-04: Deviations from Approved Fire Protection Program

8.1.1 Background

This unresolved item concerned deviations from the approved fire protection program for Diablo Canyon. Some of the consoles in the control room were not provided with smoke detectors. This may have been contrary to a previous licensee commitment to install smoke detectors in control room cabinets which contain cables from both divisions and ". . . other cabinets in the control room . . ." In addition to the issue of smoke detectors in the control room consoles, this unresolved item referred to preexisting deviations from the licensee's approved fire protection program. With regard to the pre-existing deviations, NRC Inspection Report 50-275/89-33; 50-323/89-33 noted that the deviations from the approved program could be evaluated according to the requirements of 10 CFR 50.59; and where a deviation did not conform to the criteria of 10 CFR 50.59, the corresponding evaluation should be submitted to the NRC staff for review.

8.1.2 Smoke Detectors in the Control Room Consoles

This part of the unresolved item involved the issue that the licensee had not completed their evaluation of this apparent deviation from a commitment to install smoke detectors in all of the control room cabinets, that the deviation was not identified in the Final Safety Analysis Report (FSAR), and that detection of a fire in one of these cabinets could be difficult. In an NRC letter to the licensee, dated December 9, 1977, the NRC requested information about control room cabinets which contain safety related cables from both divisions. In written responses to this request, the licensee committed to install smoke detectors in these cabinets and ". . . other cabinets in the control room also . . ."

The inspectors verified that the licensee had identified the deviations from their approved program in the Diablo Canyon Updated FSAR. Pertinent portions of the Updated FSAR which identify the deviations from the approved fire protection program are: Page 9.5 B41, Table B-1, "Comparison of Diablo Canyon

Power Plant to Appendix A of NRC Branch Technical Position APCSB 9.5-1," and page 9.5A - 376, Section 4.0, "Safe Shutdown Functions."

The licensee identified eight cabinets in the control room which did not have smoke detectors. The licensee performed Fire Hazards Appendix R Evaluation (FHARE) 93 and a 10 CFR 50.59 evaluation for those cabinets:

Unit 1

RODFW1	Digital Feedwater System Flow Control (nonsafety-related)
RODFW2	Digital Feedwater System Flow Control (nonsafety-related)
	Heating, Ventilation, and Air Conditioning (HVAC) Control (safety-related)
POV2	Auxiliary Building and Fuel Handling Building HVAC Control (safety-related)

Unit 2

RODFW1	Digital Feedwater System Flow Control (nonsafety-related)
RODFW2	Digital Feedwater System Flow Control (nonsafety-related)
POV1	Auxiliary Building and Fuel Handling Building HVAC Control (safety-related)
POV2	Auxiliary Building and Fuel Handling Building HVAC Control (safety-related)

The evaluation pointed out several considerations. The combustible loading presented by these cabinets is small, and the presence of transient combustibles adjacent to these cabinets is strictly controlled. Any fire in these cabinets would be slow burning, smoldering, and smoke generating. The fire would be contained by the metal cabinets. A fire would be detected by the continuously manned control room staff. Although the detection would likely be slower than that provided by smoke detectors, the odor and probable erratic indications and/or alarms of abnormal plant parameters associated with the damaged circuitry would likely alert the control room staff to the source before it could spread to other cabinets.

Regarding detection, the inspectors noted a concern that during the incipient stages, opening the cabinets to search for the source of the odor might be enough to spread the gaseous combustion products and make the search difficult. The inspectors walked down these panels in the control room and noted that, due to their limited number and location, they could easily be checked at the first sign of odor or smoke and that opening cabinets in search of the odor would likely not spread the gaseous combustion products except for

opening the door of the panel with the fire. Further, a sufficient number of portable fire extinguishes are provided around the control room, to extinguish the fire in a timely manner.

The licensee's 10 CFR 50.59 evaluation of the control room cabinets without smoke detectors noted that a loss of function of any of the eight cabinets would not affect safe shutdown, since none of the eight cabinets was credited in the safety analysis for safe shutdown. It was also noted that should the control room become uninhabitable, safe shutdown capabilities remain available at an alternate location outside of the control room. The licensee's FHARE evaluations concluded that ". . . For the cabinets in the control room which are not provided with smoke detection, the functions that are lost due to the fire would be mitigated using existing procedures and would not prevent a safe shutdown."

The licensee's 10 CFR 50.59 evaluation noted that the lack of smoke detectors in the eight cabinets did not compromise the approved Diablo Canyon fire protection program, plant safety, or shutdown capabilities. The evaluation concluded ". . . that an unreviewed safety question is not involved. Further, a change to the Diablo Canyon Power Plant's TS is not involved." The inspectors agreed and considered this issue of lack of smoke detectors in the eight control room cabinets to be closed.

8.1.3 Pre-existing Deviations from the Approved Fire Protection Program

In response to GL 86-10, "Implementation of Fire Protection Requirements," the licensee had prepared FHAREs to address deviations from Diablo Canyon's approved fire protection program. The FHAREs addressed differences which had been implemented after approval of the licensee's fire protection program, as well as differences which had already existed at the time the program was approved. NRC inspectors agreed that the FHAREs appropriately addressed the program deviations which occurred subsequent to the approved program. However, this unresolved item was concerned that the FHAREs were not the appropriate means to resolve the pre-existing deviations from the licensee's approved program. (The concern that the licensee had not appropriately resolved pre-existing differences was first identified in Open Item 275/8727-04 which was closed when this unresolved item was opened.) In an earlier NRC inspection report which addressed this issue (refer to NRC Inspection Report 50-275/89-33; 50-323/89-33), the inspectors and the licensee agreed that, although the FHAREs appeared to contain the technical information that would be used to address a 10 CFR 50.59 evaluation, a formal 10 CFR 50.59 evaluation should be performed and any changes that did not conform to the criteria of 10 CFR 50.59 should be submitted to the NRC staff for review and approval.

On April 16, 1994, the licensee informed the NRC by letter (refer to PG&E letter DCL-90-102) that the 10 CFR 50.59 evaluations had been completed and were being sent to the NRC under separate cover. The letter noted that the results of the 10 CFR 50.59 evaluations showed that ". . . the differences were determined not to reduce the level of fire protection as described in the

NRC-approved Fire Protection Program or prevent the plant from achieving safe shutdown during a design basis fire, or to present an unreviewed safety question."

By addressing the pre-existing deviations in the manner described above, the inspectors considered that the licensee appeared to have used a comprehensive and appropriate approach to evaluate the deviations from their approved fire protection program. Because the 10 CFR 50.59 evaluations for all of the deviations concluded that there was no reduction in the level of fire protection as described in the approved program and that there were no unreviewed safety questions, this unresolved item is closed.

9 INOFFICE REVIEW OF LERs (90712)

The inspectors performed 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:

- 275/94-016, Revision 0, Diesel Generators Started as Designed Upon De-Energization of Startup Bus Due to Offsite Wildfire
- 275/94-019, Revision 0, Inadequate Containment Overcurrent Protection Due to Personnel Error
- 275/94-022, Revision 0, TS 3.8.4 Not Met When a Containment Penetration With Inadequate Overcurrent Protection was Re-energized Due to Personnel Error
- 323/94-008, Revision 0, Momentary Loss of RHR Flow Due to Personnel Error
- 323/94-009, Revision 0, Unplanned Diesel Generator Start (Engineered Safety Features Actuation) During Transfer From Auxiliary Power to Standby Power Due to Slow Bus Voltage Decay During a Scheduled Surveillance Test

10 FOLLOWUP MAINTENANCE (92902)

10.1 <u>(Closed) Violation 323/9418-01: Failure to Perform Full-Stroke Tests of Unit 2 RHR Pump Discharge Check Valves and RHR Heat Exchanger Discharge Check Valves</u>

This issue involved the licensee's failure to perform required ASME Section XI In-service testing (IST) for RHR check Valves 8730A, 8730B, 8742A, and 8742B during a cold shutdown period. Following the licensee's discovery of this deficiency, enforcement discretion was requested to provide temporary relief from the cold shutdown full-stroke test requirement for these valves. The temporary relief was granted by the NRC until the next Unit 2 cold shutdown.

The licensee revised the procedure for cold shutdown RHR check valve testing to specify the proper flow through the valves during testing. Full-stroke testing of the valves was conducted during Outage 2R6 which substantiated that the valves were operable. The licensee has conducted a comprehensive review of all other STPs and determined the guidance of GL 89-04, "Guidance on Developing Acceptable IST Programs," was, in all other instances, being followed. Additionally, the licensee is conducting the required 10-year update of the IST program. Based on the above, this item is closed.

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
*R. P. Powers, Manager, Nuclear Quality Services
*J. R. Becker, Director, Operations
D. H. Behnke, Senior Engineer, Regulatory Compliance
W. G. Crockett, Manager, Engineering Services
S. J. Foat, Electrical Engineer, Electrical Maintenance
S. R. Fridley, Director, Scheduling and Outage Planning
*R. Gray, Director, Radiation Protection
T. L. Grebel, Supervisor, NRC Regulatory Support
*J. J. Griffin, Director, Learning Services
*J. R. Hinds, Director, Nuclear Safety Engineering
*K. A. Hubbard, Engineer, Regulatory Compliance
*T. L. Irving, General Foreman, Radiation Protection
*N. Jahangir, Lead Engineer, Onsite Nuclear Engineering Services
*R. L. Jett, Simulator Operator
J. L. Johnson, Supervisor, Work Scheduling Center
M. S. Lemke, Shift Supervisor, Operations
D. B. Miklush, Manager, Operations Services
*J. E. Molden, Manager, Maintenance Services
*T. A. Moulia, Assistant to the Vice President and Plant Manager
A. L. Nicholson, Nuclear Regulatory Engineer, Operations Licensing
*D. H. Oatley, Director, Mechanical Maintenance
*H. J. Phillips, Director, Technical Maintenance
D. L. Ricca, Maintenance Engineer, Electrical and Instrument Maintenance
*W. F. Ryan, Supervisor, Access and Fitness for Duty
J. E. Shellooe, Scheduling Engineer, Work Scheduling
J. A. Shoulders, Director, Support Engineering
*R. G. Todoro, Director, Security
D. A. Vosburg, Director, NSSS Systems Engineering
C. A. Wetter, Supervisor, Work Scheduling Center
*J. C. Young, Director, Onsite Quality Assurance

1.2 NRC Personnel

M. H. Miller, Senior Resident Inspector
*D. F. Kirsch, Branch Chief
*M. D. Tschiltz, Resident Inspector
D. E. Corporandy, Project Inspector
D. L. Solorio, Resident Inspector

*Denotes those attending the exit meeting on January 11, 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 January 11, 1995. During this meeting, the resident inspector 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
CC	centrifugal charging
CDF	core damage frequency
CFCU	containment fan cooling unit
CW	circulating water
DFO	diesel fuel oil
ECCS	emergency core cooling system
EDG	emergency diesel generator
FHARE	Fire Hazards 10 CFR 50 Appendix R Evaluation
FME	foreign material exclusion
FSAR	final safety analysis report
GL	generic letter
HVAC	heating, ventilation, and air conditioning
I&C	instrumentation and control
IST	in-service test
kV	kilovolt
LCO	limiting condition for operation
LER	licensee event report
MOIDS	mode one integrated daily schedule
PCV	pressure control valve
photo-ID	photo-identification
PD	positive displacement
PRA	probabilistic risk assessment
PSRC	Plant Safety Review Committee
RCP	reactor coolant pump
RCS	reactor coolant system
RHR	residual heat removal
RP	radiation protection
SG	steam generator
STP	surveillance test procedure
TS	Technical Specification
VCT	volume control tank