U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos: 50-275/91-27 and 50-323/91-27

Docket Nos: 50-275 and 50-323

License Nos: DPR-80 and DPR-82

Licensee: Pacific Gas and Electric Company
77 Beale Street, Room 1451
San Francisco, California 94106

Facility Name: Diablo Canyon Units 1 and 2

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

Inspection Conducted: September 2 through October 9, 1991

Inspectors: H. Wong, Acting Senior Resident Inspector
M. Miller, Resident Inspector
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Approved by: P. J. Morrill
P. J. Morrill, Chief, Reactor Projects Section 1 — 11/6/91 Date Signed

Summary:

Inspection from September 2 through October 9, 1991 (Report Nos. 50-275/91-27 and 50-323/91-27)

Areas Inspected: The inspection included routine inspections of plant operations, maintenance and surveillance activities, follow-up of onsite events, open items, and licensee event reports (LERs), as well as selected independent inspection activities. Inspection Procedures 60710, 61726, 62703, 71707, 71710, 90712, and 93702 were used as guidance during this inspection.

Safety Issues Management System (SIMS) Items: None

Results:

General Conclusions on Strength and Weaknesses:

During the Unit 2 outage, licensee management and personnel demonstrated careful planning and execution of activities; particularly noteworthy were the core reload and the startup bus outage. Planning and good coordination enabled these activities to be completed safely and without significant problems.

The inspector noted that there appeared to be a high number of significant events caused by personnel errors in the past two months. Verification methods were not effective in preventing these errors from occurring. While this issue was brought up in General Office Nuclear Plant Review and Audit Committee (GONPRAC) meetings in July and September 1991, only recently had any recommendations been initiated. At the end of the inspection period an overall site strategy had not been developed.

Significant Safety Matters: None.

Summary of Violations and Deviations:

Two non-cited violations were identified and are described in paragraphs 5.a and 5.b. These violations involved: (1) the miscalculation of the reactor coolant system leak rate in Unit 2 when in fact a leak rate above Technical Specifications allowable criteria existed and (2) the removal of power from Unit 2 containment sump recirculation valves and containment spray pumps while in Mode 4.

Open Items Summary: Seventeen items closed; two new items opened.

DETAILS

1. Persons Contacted

*J. D. Townsend, Vice President, Nuclear Power Generation & Plant Manager, Diablo Canyon Power Plant
*D. B. Miklush, Manager, Operations Services
*M. J. Angus, Manager, Technical Services
*B. W. Giffin, Manager, Maintenance Services
W. G. Crockett, Instrumentation and Controls Director
W. D. Barkhuff, Quality Control Director
R. Powers, Mechanical Maintenance Director
*D. A. Taggart, Quality Performance and Assessment Director
T. L. Grebel, Regulatory Compliance Supervisor
H. J. Phillips, Electrical Maintenance Director
J. S. Bard, Work Planning Director
J. A. Shoulders, Onsite Project Engineering Group Manager
M. G. Burgess, System Engineering Director
*S. R. Fridley, Operations Director
R. Gray, Radiation Protection Director
*J. J. Griffin, Senior Engineer, Regulatory Compliance
*J. Bouchard, Regulatory Compliance
R. W. Hess, Assistant Onsite Project Engineer
J. B. Hoch, Manager, Nuclear Safety and Regulatory Affairs
*T. Moulin, Assistant to Vice President Operations
*D. Acker, NRC, Region V

*Denotes those attending the exit interview on October 9, 1991.

The inspectors interviewed several other licensee employees including shift supervisors, shift foremen (SFM), reactor and auxiliary operators, maintenance personnel, plant technicians and engineers, and quality assurance personnel.

2. Operational Status of Diablo Canyon Units 1 and 2

Unit 1 was at 100 % power for essentially the entire reporting period. The only exception was two days during which power was reduced to 50% for condenser tube sheet cleaning. Unit 2 began the reporting period in refueling outage 2R4 and had progressed through the outage to Mode 5 by the end of the reporting period.

An earthquake occured on September 17, 1991 centered approximately 50 miles northwest of the plant. The earthquake measured approximately 5.2 on the Richter scale and was felt by plant personnel, but did not affect plant equipment. An Unusual Event was declared when the earthquake occured and was terminated when the magnitude of the earthquake was determined.

3. Management Changes

A number of PG&E management changes were announced during the inspection period. The changes which affect Diablo Canyon include the retirement of

George Maneatis as President of PG&E and the election of Stanley Skinner to the position of President and Chief Operating Officer. Also announced was the promotion of James Shiffer to Executive Vice President and the selection of Gregory Rueger to become the Senior Vice President and General Manager of the Nuclear Power Generation Business Unit. Mr. Rueger will report to Mr. Shiffer. These changes will be effective November 1, 1991.

4. Notification of Unusual Event Due to an Earthquake (93702)

On September 17, 1991, while Unit 1 was at 50 percent power and Unit 2 was defueled, an earthquake was felt in Diablo Canyon's administration and auxiliary buildings. The site "Terre Tech" detectors alarmed at their 0.01g setpoint. However, the site "Kinemetric" detectors, set at 0.10g, did not alarm. In accordance with the Diablo Canyon Emergency Plan, a Notification of Unusual Event (NUE) was declared and response actions were taken. The required emergency notifications were initiated by the licensee. The licensee verified control room indications and spent fuel pool levels. The post-earthquake checklist surveillances were completed with no abnormalities noted. The control room shift supervisor informed the NRC inspector that: (1) no fuel movement was in progress in Unit 2 during the earthquake and (2) no deleterious effects of the earthquake had been reported or observed in either of the two Units. Subsequent licensee reviews determined that the earthquake was centered approximately 41 to 50 miles from Diablo Canyon, near San Simeon, California, and estimated to be of magnitude of 5.1 to 5.3 on the Richter scale.

The NRC inspector performed a visual walkdown inspection of various areas of the plant to determine any effects of the earthquake. Portions of the turbine building, auxiliary buildings, and emergency diesel generator rooms were inspected. The inspector noted no obvious visible effects of the earthquake on the building structures, piping, components and equipment. However, during the inspection the following items were observed.

a. The Unit 2 turbine and main generator were undergoing overhaul. Various portions of the turbine and main generator, including rotor sections, and large overhaul equipment had been stored on the Unit 2 side of the main turbine floor. The inspector requested the licensee to determine if any evaluations had been performed to determine the effects of a design basis earthquake on the disassembled parts and equipment and any consequential potential effects of movement of the parts and equipment such that they could impact Unit 1 operations or Unit 2 safety systems. The licensee indicated that equipment laydown areas had been determined prior to the outage and coordinated in reviews by the civil engineering department. The licensee also stated that the Seismically Induced System Interactions Manual indicates equipment which would be needed for safe shutdown in the event of an earthquake. The manual showed there was no equipment in the vicinity of the lay down areas of the turbine or main generator rotor which would be needed for safe shutdown in the event of an earthquake. The inspector had no further questions regarding this matter.

b. During inspection of the Unit 1 auxiliary feedwater (AFW) pump rooms, the inspector noted that the common steam supply header for the turbine-driven AFW pump was routed through the common motor-driven AFW pump room and directly above the pumps. The inspector observed that a break in the steam line in the motor-driven AFW pump room could disable all AFW pumps if the equipment were not environmentally qualified for steam. The inspector requested information from the licensee regarding the qualification of equipment in the motor-driven pump room for a steam environment and more specifically, any licensee evaluations or actions related to INPO SOER 91-17 that addressed the same possible condition. The inspector was informed that the issue had been the subject of discussions during the licensing of Diablo Canyon. Reportedly, the NRC staff accepted the design basis that a break was not postulated in that portion of the steam line due to the fact that steam was not in the line during normal operation of the plant. The inspector reviewed Supplemental Safety Evaluation Report number 20, paragraph 4.2.5, which documented the NRC staff's review of this matter. The inspector had no further questions on this matter.

No violations or deviations were identified.

5. <u>Events Caused by Personnel Errors (93702 and 92701)</u>

a. <u>Reactor Coolant System Leak Rate Above Technical Specification Requirements not Identified - Unit 2</u>

On August 13, 1991, at 7:00 a.m., Surveillance Test Procedure (STP) R-10C, Reactor Coolant System Water Inventory Balance, was performed. The results of the STP indicated that reactor coolant system (RCS) leakage was 0.8 gpm; however, this calculation was in error and the actual RCS leakage rate was 1.4 gpm. If leakage is greater than 1.0 gpm, Technical Specifications (TS) require action to be taken to reduce the leakage below the limit. The calculation error was made in subtracting the temperature of the RCS when the STP was started from the temperature of the RCS when the STP was concluded. The change in RCS temperature is used as a component in the leakage calculation to account for the effects of coolant expansion or contraction. The calculation error was not discovered by other personnel (shift technical advisor and shift foreman) who reviewed the results of the STP.

On August 13, 1991, at 5:55 p.m., another RCS leakage determination was performed and the results indicated that a leak rate of 1.2 gpm existed. The licensee entered Action b. of Technical Specifications (TS) 3.4.6.2 and subsequently reduced RCS unidentified leakage below the 1 gpm limit on August 14, 1991, at 12:19 a.m..

On August 16, 1991, engineers reviewed the STP R-10C results and discovered the calculation error. Due to the error, Action b. of TS 3.4.6.2 was exceeded at 5:00 p.m. on August 13, 1991. The licensee's corrective action as a result of this event was to counsel the personnel involved on the need for attention to detail

and self verification. The failure to comply with Action b. of TS 3.4.6.2 constituted a violation of the TS. However, this licensee identified violation is not being cited because the criteria specified in Section V.G.1 of the Enforcement Policy were satisfied (NCV 50-323/91-27-03).

Licensee Event Report 50-323/91-04-00 addressed the failure to meet TS 3.4.6.2 on August 13, 1991, as a result of an error in calculating RCS unidentified leakage. This LER is closed based on the licensee's corrective actions.

Unit 2 was shut down on August 31, 1991, after the RCS unidentified leak rate increased to 0.9 gpm. The licensee subsequently found that the normal charging line check valve closest to the RCS had a body to bonnet leak. Additional details regarding the check valve leak are described in NRC Inspection Report 50-323/91-24 and in paragraph 7.a of this inspection report.

b. Removal of Electrical Power from Containment Sump Recirculation Valves and Containment Spray Pumps - Unit 2

On September 1, 1991, while Unit 2 was in Mode 4 and preparations for entry into Mode 5 were being made, operators removed power from containment sump recirculation valves 8982A and B as well as both containment spray pumps. The licensee's review of these events is documented in NCR DC2-91-OP-N074 and in Licensee Event Report 50-323/91-03-00. The licensee concluded that the cause of the containment sump valves being de-energized was due to procedure OP L-5 being in error in specifying the opening of local breakers to de-energize the valves. The licensee also concluded that the de-energization of the containment spray pumps was due to the inappropriate approval by the shift foreman (senior licensed operator) of the tag out of the pumps. The intention was to pre-approve the tag out, but not to implement it. This was not adequately communicated to the senior control operator nor was this practice considered acceptable by licensee management.

The licensee's corrective actions included: restoration of the correct lineups when the inconsistencies were identified on September 1, 1991; revision of procedure OP L-5; a review of other procedures to determine whether similar problems existed; issuance of an Operations Incident Summary, highlighting proper tag out review processing; and issuance of a memorandum to shift foremen, shift supervisors, and clearance personnel to clarify the intention that shift foreman approval shall take place only immediately before the tag out is processed. The inspector reviewed these corrective actions, discussed the approval process with shift foremen, and concluded that the corrective actions appeared appropriate.

The de-energization of the containment sump valves for approximately six hours and containment spray pumps for approximately 1.5 hours while in Mode 4 appear to be potential violations of Technical Specification requirements. However, the violations are not being

cited because the criteria of the Enforcement Policy (10 CFR Part 2, Appendix C) Section V.G.1 were satisfied. The inspector noted that opportunities existed to prevent the violations had operations personnel carefully considered the actions to de-energize equipment with regard to the existing plant mode. This evaluation would have clearly indicated that the actions being taken in the case of the containment spray pumps were inappropriate (NCV 50-323/91-27-04).

This closes LER 50-323/91-03-00 and Unresolved Item 50-323/91-24-03.

c. Inadvertent Start of Diesel Generator 1-3 - Unit 2

On September 25, 1991, Unit 2 operators inadvertently started diesel generator 1-3 while preparing electrical lineups for maintenance to be done on the 12 KV and 4 KV startup buses. The licensee's preliminary review indicated that the wrong voltage sensing relay was deactivated. It appears that instead of deactivating the undervoltage diesel generator auto start relay, 27HFU, the operators deactivated overvoltage relay, 59HFG2. Therefore, when the 4 KV startup feeder breaker was opened, an undervoltage condition existed on 4 KV bus F, and diesel generator 1-3 started as intended by design but not intended during this evolution. The diesel generator was manually shutdown and the electrical lineup error was corrected. The licensee's initial review indicated that the operators had questioned whether they were working on the right relay and while they noted discrepancies in relay numbering in the clearance documentation, they failed to resolve the discrepancies prior to taking actions to deactivate the relay. The licensee's review and corrective actions (AR A0244519 and QE) had not been completed at the end of the inspection period and will be reviewed in a future inspection.

d. Missed Surveillance Tests on Containment Air Lock Door Seals - Unit 1

On September 27, 1991, the licensee identified that the Unit 1 containment air lock door seal tester had been isolated for the last eight days. During this time period the air lock doors had been opened three times. The design of the air lock door seal tester is to automatically perform a pressure test on the door seals after each opening to meet Technical Specification surveillance requirements. The licensee's preliminary review (NCR DC1-91-OP-N082) indicated that a shift foreman did not recognize that the door seal tester was made inoperable when I&C technicians made preparations for performing a routine calibration of the tester. Problems with the tester's power supply delayed completion of the calibration. The licensee's review indicated that additional problems exist with regard to the air lock tester, including; previous indications of tester problems dating back to 1986, daily auxiliary operator rounds failing to identify the out-of-service tester, and operator response to tester alarms in the control room failing to identify the tester problems.

The licensee performed a manual leak test of the air lock door seals after identification of the missed surveillance tests. The door seals were found to be acceptable. A conditional surveillance sheet was initiated to track the inoperable leak tester and provide for manual testing should the air lock doors be opened. The failure to perform surveillance testing required by Technical Specifications and the licensee's corrective actions will be reviewed in a future inspection (Unresolved Item 50-275/91-27-01).

e. Inadvertent Actuation of Control Room Ventilation System - Unit 2

On October 3, 1991, in Unit 2, when operators were preparing to perform maintenance on an instrument inverter, they mistakenly went to the wrong inverter panel and removed power from a panel which caused the control room ventilation system to switch to the safety mode (ESF actuation). The licensee's preliminary review indicated that the operators were following the general procedure steps in the body of the procedure rather than confirming the specific breaker identification numbers listed in an attachment to the procedure. It appears that while concurrent verification was being used in this instance, sufficient care was not taken to fully understand the procedure and follow its instructions. The licensee restored the intended system lineups. The licensee's evaluation of the event and corrective actions (NCR DC2-91-OP-N089) had not been completed at the end of the inspection period. An LER will be submitted which will be reviewed in a future inspection.

f. Inadvertent Safety Injection Signal While Shutdown - Unit 2

On October 6, 1991, in Unit 2, while I&C technicians were performing work on the Solid State Protection System, an inadvertent Safety Injection signal was initiated. Preliminary information indicated that the technicians did not follow procedure STP I-16D4 and performed steps out of order. Concurrent verification should have been performed, but was not in this instance. The licensee confirmed that systems which were in service responded as expected and equipment which had actuated were restored to their original lineups. There was no actual injection of water into the reactor vessel. The licensee's review of the event and corrective actions (NCR DC2-91-TI-N088) had not been determined at the end of the inspection period. An LER will be submitted which will be reviewed in a future inspection.

The inspector noted that the number of noteworthy personnel errors which had occurred in the past two months appeared to be high even when considering the ongoing refueling outage in Unit 2. While individually each event was not considered of high safety significance, the occurrence of so many in a relatively short period of time is of concern. In discussions with QA personnel who are responsible for trending and a review of the most recent trend report, the inspector noted that the normal trending mechanism, a semiannual trend report, would not be timely enough to be of real-time value to management. The inspector discussed the issue with the Human Performance Evaluation System coordinator and determined that this issue had been discussed in a recent General

Office Nuclear Plant Review and Audit Committee (GONPRAC) meeting held on September 25, 1991. In addition, the issue was previously raised in a July 1991 GONPRAC meeting by members of the Onsite Safety Review Committee. At the end of this inspection period, licensee management had not yet developed an overall strategy to address the matter. The inspector noted that some managers had initiated individual actions in response to the events, but an overall site strategy had not been established to address this issue (Followup Item 50-275/91-27-02).

6. Operational Safety Verification (71707)

a. General

During the inspection period, the inspectors observed and examined activities to verify the operational safety of the licensee's facility. The observations and examinations of those activities were conducted on a daily, weekly or monthly basis.

On a daily basis, the inspectors observed control room activities to verify compliance with selected Limiting Conditions for Operation (LCOs) as prescribed in the facility Technical Specifications (TS). Logs, instrumentation, recorder traces, and other operational records were examined to obtain information on plant conditions and to evaluate trends. This operational information was then evaluated to determine if regulatory requirements were satisfied. Shift turnovers were observed on a sampling basis to verify that all pertinent information on plant status was relayed to the oncoming crew. During each week, the inspectors toured the accessible areas of the facility to observe the following:

(a) General plant and equipment conditions

(b) Fire hazards and fire fighting equipment

(c) Conduct of selected activities for compliance with the licensee's administrative controls and approved procedures

(d) Interiors of electrical and control panels

(e) Plant housekeeping and cleanliness

(f) Engineered safety feature equipment alignment and conditions

(g) Storage of pressurized gas bottles

The inspectors talked with operators in the control room and other plant personnel. The discussions centered on pertinent topics of general plant conditions, procedures, security, training, and other aspects of the work activities.

b. Radiological Protection

The inspectors periodically observed radiological protection practices to determine whether the licensee's program was being

implemented in conformance with facility policies and procedures and in compliance with regulatory requirements. The inspectors verified that health physics supervisors and technicians conducted frequent plant tours to observe activities in progress and were aware of significant plant activities, particularly those related to radiological conditions and/or challenges. ALARA considerations were found to be an integral part of each Radiation Work Permit (RWP).

c. Physical Security

Security activities were observed for conformance with regulatory requirements, the site security plan, and administrative procedures, including vehicle and personnel access screening, personnel badging, site security force manning, compensatory measures, and protected and vital area integrity. Exterior lighting was checked during backshift inspections.

No violations or deviations were identified.

7. Onsite Event Follow-up (93702)

a. Check Valve Problems - Unit 2

In August 1991, Unit 2 showed an increasing reactor coolant system (RCS) leak rate which eventually led to an earlier than expected shutdown to commence a refueling outage. Two problems were identified during the investigation of the RCS leakage issue. The first involved two check valves which exhibited body to bonnet gasket leaks with several eroded/corroded bonnet bolts (2 of 12 bolts broken on the normal charging line - valve 8378B; 1 of 12 bolts broken on the alternate charging line - valve 8378A). The second problem was identified on September 13, 1991, when check valve 8378A bonnet was opened and the valve disk was found to be stuck in the open position. Its normal operating position is closed against RCS pressure.

The licensee is continuing to evaluate the root cause of check valve body to bonnet leakage and failure of the bonnet bolts. Part of this evaluation involves assessment of an increase in bonnet bolt torque, which has been recommended by the vendor (170 ft-lbs recommended versus 83 ft-lbs actual). Preliminary indications are that bolt preload did not have any impact on joint leakage, since the licensee had determined that bolt failure was not the result of preload. The licensee had completed an engineering evaluation of the as found condition of the damaged check valves and prepared a justification for continued operation for Unit 1. The licensee concluded that continued operation of Unit 1 with a check valve configuration similar to Unit 2 was safe in that: (1) an inspection of Unit 1 check valves did not indicate similar leakage; (2) a review of industry experience with bolted joint leakage indicates a leak before break mechanism which would be detectable and allow appropriate corrective actions were it to occur on Unit 1; and (3) an engineering evaluation of the worst case bonnet bolt

deterioration observed on Unit 2 confirmed substantial margin to joint failure.

The licensee performed a detailed root cause investigation of the stuck open check valve; however, a failure mechanism was not determined. Initial investigations centered around the possibility of excessive clearances creating the potential for the bushings on the check valve hanger pin to rotate and bind. This problem had been previously identified in a Part 21 report submitted by Velan Valve Corporation on January 18, 1991. However, a review of the clearances which existed in check valve 8378A revealed that excessive clearances did not exist and that it was not considered possible for the bushings to bind. Another consideration was a coating of oxidation that was observed on the hinge pin and bushings, but this oxidation was not considered to have sufficient binding potential to bind the check valve as firmly as described by the engineer who initially inspected the valve and found the stuck open condition.

Making the investigation more difficult was the fact that between September 13 and 18, 1991, when radiation protection shielding was being installed around check valve 8378A, somehow the valve went closed. On September 18, the valve was found in the closed position. Reinstallation of the valve internals and additional testing by the licensee did not reveal a mechanism for the valve to have been stuck open. Other failure mechanisms were investigated such as a loose foreign object blocking the valve, valve hanger block misalignment, valve body internal projections, and valve disc size. Sufficient evidence was not found to support any of these failure mechanisms.

Other similar check valves in Unit 2 were inspected by the licensee and none were found to be in the open position. In addition, the licensee reinstalled the valve internals of valve 8378A, verified flow through the line, pressurized the downstream side of the valve, and then radiographed the valve. The radiograph revealed that the check valve was fully seated in the closed position.

The licensee documented their evaluation of the potential impact on Unit 1 of a stuck open check valve due to bushing binding in Operability Evaluation 91-08R0, dated October 1, 1991. The evaluation took credit for inspections performed in the last Unit 1 refueling outage and surveillance tests which showed proper check valve operation. For the check valves not covered by the inspections or surveillance testing (14 valves), individual evaluations were performed to determine the impact of a check valve not closing. In all cases, the impact was found not to affect safe operation (alternative means were available to perform the safety function, failure consequences were bounded by previous safety analyses, or there would be no impact). The inspector reviewed this evaluation and considered the licensee's determinations to be acceptable. The licensee will inspect those Unit 1 check valve not covered in the last refueling outage in outage 1R5.

At the request of NRC Region V, the licensee presented a discussion of these findings in a meeting in the Region V Office on October 11, 1991. This meeting is described in NRC Inspection Report 50-275/91-38.

b. <u>Failure of Steam Admission Valve to Auxiliary Feedwater Pump to Open - Unit 1</u>

On September 26, 1991, the steam admission valve (FCV-95) to the auxiliary feedwater pump in Unit 1 failed to open during a surveillance test (STP M-16N). This surveillance test was intended to test the operation of slave relays and included monitoring the opening of FCV-95. The upstream steam line isolation valves (FCV 37 and 38) were closed to prevent an actual start of the turbine-driven auxiliary feedwater pump. During the surveillance test the motor operator for valve FCV-95 tripped on thermal overload. Subsequently, the motor operator was again actuated and the motor again tripped on thermal overload. Licensee personnel then manually opened the valve. The licensee documented the investigation of this event in NCR DC1-91-MM-N011.

The licensee conducted a series of tests in an attempt to duplicate the failure of valve FCV-95 to open. The failure was not repeated in any of these attempts. The testing included a cold start of the turbine-driven auxiliary feedwater pump. Based on the series of tests and successful re-performance of the surveillance test, the licensee declared valve FCV-95 and the turbine-driven auxiliary feedwater pump operable. The licensee's evaluation is documented in Operability Evaluation 91-07R0, dated September 29, 1991.

Engineering personnel worked with site personnel to develop theories on the failure mechanism for valve FCV-95. In this instance the failure of FCV-95 to open is significant in that FCV-95 has failed several times in the past to open and the problem was thought to have been resolved. In the past, thermal binding of the valve discs (flexible wedge gate valve) due to different material used for the discs and valve body was believed to be the cause of the valve binding. However, after the last previous failure in May 1990, the valve discs had been changed out to be the same material as the valve body (carbon steel). Licensee personnel were not able to determine the root cause(s) of the valve binding. It was noted that of the 6 cases in which FCV-95 failed to open, 4 were during surveillance tests in which the upstream steam isolation valves (FCV-37 and 38) are closed. This does not represent the actual plant lineup when the auxiliary feedwater pump would be called upon to operate (FCV-37 and 38 would be open). In the 2 other cases, thermal binding may have occured when FCV-95 was closed in the cold condition and the system was heated up.

The licensee has instituted increased frequency testing of FCV-95 and is currently testing the valve weekly. The licensee is reviewing whether weekly testing should be continued and, if not, what the appropriate testing frequency should be.

At the request of NRC Region V, the licensee discussed this issue at a meeting held on October 11, 1991. The discussions are summarized in Inspection Report 50-275/91-38.

c. Failure of Rotork Actuator - Unit 1

On September 22, 1991, the component cooling water (CCW) outlet valve (FCV-430) from the 1-1 (Unit 1) CCW heat exchanger was found by the licensee to be separated from the Rotork motor operator. The motor operator was found to be completely sheared from the valve/operator mounting flange. The valve was found to be approximately 85% open. The licensee estimated that the valve was inoperable for only one day since the last time the CCW heat exchanger was placed in service. The safety function of the valve is to open to provide CCW heat removal and, if necessary, CCW loop isolation can be accomplished using other valves. FCV-430 receives no automatic control signals. The licensee replaced the Rotork operator with a replacement within the 72 hours allowed by Technical Specifications 3.7.3.1.

The licensee's preliminary root cause investigation found that the mounting flange was cast iron and that sufficient force could be developed by the operator to completely separate the operator from the valve. The licensee investigated several possible causes for the failure including limit switch failure, mechanical stops not properly set, and torque switch not properly set or functional. It appears that there was a drift or shift in the limit switch setting due to either improper setup or manual operation of the valve past the electrical limit setpoints. Manual operation past the electrical limits was shown to change the electrical limit setpoint. The last time the valve setpoints were adjusted was in June 1986. In March 1987 the setpoint procedure was changed to account for the possible limit switch setpoint change during manual operation of the valve.

The licensee has inspected the setpoints of all Unit 2 Rotork operators and confirmed that they were set properly. In addition, the licensee will inspect the Unit 1 Rotork operators on a prioritized basis. The licensee has documented this issue in AR A0244019 and NCR DC2-91-EM-N086.

d. 480 V Bus 2G Fault While Shutdown - Unit 2

On October 2, 1991, while Unit 2 was conducting surveillance testing (STP M-13G), a major bus fault occured in a 480 V breaker cubicle. A minor fire and smoke resulted from the fault which was terminated when power to the 480 V bus (2G) was removed by a control room operator. This occured approximately two minutes after a fire alarm was received.

The surveillance test involved functionally testing the ability of the diesel generators to energize the vital emergency buses and for the timers to properly sequence loads back onto the buses. At the time of the fault, diesel generator 2-1 had loaded onto 4KV bus G

and loads were being sequenced onto the 4 KV and 480 V buses. At the time that containment fan cooler 2-3 was loaded onto the 480 V bus, the control room operator noted that the 4 KV bus amps had increased and the speed of diesel generator 2-1 had dropped 200-300 rpm. Approximately 10 seconds later a fire alarm was received. The operator then opened the feeder breaker from the 4 KV bus to 480 V bus 2G. Normal power sources were re-established, and diesel generator 2-1 was manually cooled down and secured.

The licensee performed a detailed review of the fault and an evaluation of the equipment potentially affected by the fault, including diesel generator 2-1, the 4 KV to 480 V transformer, the 4 KV and 480 V loads on the buses, and associated breakers. The licensee's evaluation determined that the fault occured just upstream of the breaker for containment fan cooler 2-3 in a section directly connected to bus 2G. No components were significantly affected by the fault. Except for repairs to the breakers and breaker cubicle involved with the fault and cleanup of minor oil leakage from two valve covers on diesel generator 2-1, no further actions were needed. The licensee's review of this issue is documented in AR A02452791 and NCR DC2-91-EM-N084.

The NRC's review of the licensee's evaluation and corrective actions will be addressed in Inspection Report 50-275/91-31.

e. Diesel Generator 2-2 Loose Camshaft Dampener Fastener

On September 13, 1991, the licensee's inspection of diesel generator 2-2 identified that one of four nuts on the left vibration dampener flywheel was only hand tight, although still restrained by a lockwire. Further investigation revealed that there was some wear and slight fretting of the end of the camshaft. The licensee's evaluation of this condition is documented in NCR DC0-91-MM-N079 and AR A0242726. The licensee determined that this condition could not render the diesel generator inoperable.

The licensee replaced the affected left camshaft section and performed inspections of the right side vibration dampener and found the nuts to be tight, as were the nuts on diesel generator 2-1. Only one abnormality was identified which involved a surface indication on one bolt perpendicular to the threads. This was metallurgically examined and determined to be caused by the manufacturing process and did not affect the strength of the bolt.

The licensee stated that the inspection of the camshaft vibration dampener will be added to the diesel generator inspection procedures and that inspections of the Unit 1 diesel generators will occur in December 1991 for diesel generators 1-1 and 1-2 and while a definite schedule has not yet been determined for diesel generator 1-3, inspections should occur by the end of 1991. The inspector considered the licensee's actions appropriate and had no further questions.

No violations or deviations were identified.

8. Maintenance (62703)

The inspectors observed portions of, and reviewed records on, selected maintenance activities to assure compliance with approved procedures, technical specifications, and appropriate industry codes and standards. Furthermore, the inspectors verified maintenance activities were performed by qualified personnel, in accordance with fire protection and housekeeping controls, and replacement parts were appropriately certified. The observations included:

- o MP I-3-LIII for steam generator AFW supply level control calibration
- o Work Order C0092171 for termination of FCV-430
- o Work Order R0087074 for breaker overhaul
- o Work Order C0091790 for check valve retorque
- o Work Order C0097225 for checking and adjusting piping gaps

The inspector observed eight untaped leads and an unattached connector under the Unit 2 control board next to the ERFDS circuit boards. The licensee stated the leads were part of vibration monitoring gear which was no longer used and other leads were associated with ongoing installation of a new diesel generator. The licensee issued an action request to properly tape and tag the leads.

No violations or deviations were identified.

9. Surveillance (61726)

By direct observation and record review of selected surveillance testing, the inspectors assured compliance with Technical Specification requirements and plant procedures. The inspectors verified that test equipment was calibrated, and acceptance criteria were met or appropriately dispositioned. These included:

- o STP M-81A and E - Diesel Generator Cylinder Inspection
- o STP M-12A - Battery Performance Test

No violations or deviations were identified.

10. Unit 2 Refueling Activities - Unit 2 (60710)

The inspector observed Unit 2 refueling activities which included verification that plant conditions and equipment were as specified in Technical Specifications, procedural checklists were signed, staffing was in accordance with Technical Specifications, fuel movement was coordinated, and communications were maintained between the control room, fuel handling building, and containment. The refueling was accomplished in approximately 50 hours and with minimal deviations in the preplanned fuel movement procedure. The short length of time to reload the core

appears to be due to the preplanning done in preparation of the reload and a minimal number of fuel elements which could not go into their preassigned core positions. The fuel movements appeared to be well coordinated.

No violations or deviations were identified.

11. Startup Bus Outage - Unit 2 (71707)

The inspector observed the licensee's preparations and implementation of an outage on the Unit 2 startup buses. This outage resulted in the backfeeding of the main transformers to the auxiliary transformers to provide power to the vital and non-vital 4 KV buses. This lineup was the same as the lineup used during the Unit 1 refueling outage in March 1991, during which a crane came too close to the main transformer lines and caused a loss of offsite power. The inspector observed that the licensee's work planning did consider the potential risks while having only one source of offsite power and that certain corrective actions such as barriers around the main transformers were effective in preventing a reoccurrence of the Unit 1 event. Licensee personnel were sensitive to the Unit 1 event and were meeting the guidance contained in Operations Department Policy B-26 in taking additional precautions to ensure the reliability of the one source of offsite power.

No violations or deviations were identified.

12. Engineered Safety Feature Verification (71710)

During this inspection period selected portions of the main steam and component cooling water systems were inspected to verify system configuration, equipment condition, valve and electrical lineups, and that local breaker positions were proper.

No violations or deviations were identified.

13. Licensee Event Report (LER) Follow-up (92700)

The LERs identified below were also closed out after review and follow-up inspections were performed by the inspectors to verify licensee corrective actions.

a. Licensee Event Report (LER) 50-275/91-13-00 and 50-323/91-01-00 (Closed)

On August 10, 1991, a spurious containment ventilation isolation (CVI) occured. An I&C technician installed a jumper without complete knowledge of the results of his actions. This particular jumper caused a voltage transient which actuated output relays of radiation monitors RM-14A and RM-28A, causing the CVI.

The licensee documented in NCR DCI-91-TI-N068 that the root cause of the CVI was failure by the technician to follow Procedure AP C-154, Control of Main Annunciator System Problems, in that the specific actions required were not identified prior to beginning the work, although general steps had been considered.

Corrective actions included disciplinary action against the technician, issuance of a maintenance bulletin and an operations incident summary emphasizing the importance of stopping work when unsure of results, and inclusion of procedure AP C-154 requirements in recurring procedure training.

On July 15, 1991, a spurious CVI occured as a result of a technician inadvertently dropping a screw on a power switch while performing maintenance. This action cause a voltage transient on the output relay of radiation monitors RM-11 and RM-12, resulting in a CVI.

Corrective actions included counseling the technicians on establishing temporary electrical barriers when practical, issuing a maintenance bulletin discussing hazards of working in panels, and emphasizing precautions such as barriers, tape, or mats.

Based on review of the bulletins, formal licensee commitments, and interviews with I&C technicians who appeared to have been informed of these specific risks and requirements associated with work in panels, these LERs are closed.

b. <u>Licensee Event Report (LER) 50-323/90-01-00 (Closed)</u>

This LER addressed the shift of the fuel handling building ventilation system from the normal mode to the iodine removal mode as a result of an inadequate procedure used to implement a design change. This event was also documented in NRC Inspection Report 50-323/90-05.

As a result of this event, Nonconformance Report DC2-90-TI-N010 was initiated. The inspector reviewed the nonconformance report and the licensee event report. The licensee's corrective action was to issue a maintenance bulletin which addressed the event and the wiring configuration which led to the inadequate procedure. The maintenance bulletin was to be reviewed with I&C supervisors, engineers, technicians, and work planners. This item is closed based on the licensee's corrective actions.

c. <u>Licensee Event Report (LER) 50-275/90-15-01 (Closed)</u>

This LER addressed an automatic feedwater isolation and feedwater pump trip which occured on December 8, 1990, during startup operations. A description of this event is also documented in NRC Inspection Report 50-275/90-27. This event was caused by leakage through feedwater regulating valve FCV-530 and feedwater regulating bypass valve FCV-1530. Contributing to this event was backleakage

through feedwater check valve FW-531 and leakage through feedwater recirculation control valve FCV-420.

This event was originally addressed in LER 50-275/90-15-00. The licensee was requested to reconsider the report as the root cause did not appear to be insightful and the report did not appear to address all of the management issues pertaining to the event. LER 50-275/90-15-01 was submitted after the licensee reconsidered the event and the initial event report.

The inspector reviewed the licensee's revised event report. The report provided a more detailed history of feedwater valve leakage and a more detailed description of the event. Additionally, the licensee reassessed the safety significance of the leaking feedwater valves and documented their reassessment. The licensee concluded that there were no adverse safety consequences resulting from the event or from the leaking valves. Additional corrective actions, added to the revised event report, included transmitting a memorandum from the plant manager to emphasize that equipment problems should be evaluated in a timely manner, and a management review with operations supervisors of the importance of obtaining plant management concurrence for recovery plans following safety system actuations and other significant plant transients. The inspector also reviewed changes made to Operating Procedure OP L-3, Secondary Plant Startup, to check for feedwater regulating and bypass valve leakage prior to placing main feedwater in service. Finally, the inspector reviewed Nonconformance Report DC1-90-OP-N083 which addressed this event. The feedwater valves that leaked and caused this event were repaired during a forced outage in December 1990 and during Unit 1's fourth refueling outage in February and March 1991. This item is closed based on the licensee's corrective actions.

d. Licensee Event Reports (LER) 50-275/90-17-00 and 50-275/90-17-01 (Closed)

These LERs addressed a Unit 1 reactor trip that occured on December 24, 1990, as a result of a pressurizer spray valve that failed open due to the valve's feedback linkage becoming disconnected. The feedback linkage became disconnected because a locking device was not installed on the screw holding the linkage to the valve stem. During this event a condenser steam dump valve failed to close which contributed to overcooling of the reactor coolant system. This event is also described in NRC Inspection Report 50-275/90-30.

The licensee initiated two nonconformance reports for this event. DC-1-90-TI-N090 was initiated as a result of the failed pressurizer spray valve and DC0-90-TI-N091 was initiated as a result of the failed condenser steam dump valve. NRC Open Item 50-275/91-10-02 was used to follow the licensee's actions regarding the steam dump failure and is presented in paragraph 14.d of this report.

The inspector reviewed the licensee's corrective actions as a result of the failed pressurizer spray valve. Corrective actions included:

issuing a maintenance bulletin discussing the event and the lack of adequate locking devices on feedback linkages, changing the design drawing to clarify the installation of the feedback linkages, sending a letter to the vendor describing the problem, and changing maintenance procedures to address use of appropriate locking devices. Additionally, the inspector contacted maintenance department personnel and found the personnel aware of the need for locking devices on valve components. These items are closed based on the licensee's corrective actions.

e. Licensee Event Report (LER) 50-275/91-07-00 (Closed)

This LER addressed a Unit 1 reactor trip that occured on April 23, 1991, as a result of a turbine trip caused by a high steam generator level. The high steam generator level resulted from feedwater transients that occured after a main feedwater pump speed controller failed. Feedwater regulating valve FCV-530 was in manual rather than automatic control during this event and therefore did not respond to the feedwater transients. After the reactor trip, a condenser steam dump failed. This event is also described in NRC Inspection Report 50-275/91-10.

The licensee concluded that the initiating cause was an isolated failure of an operational amplifier on a circuit board for the main feedwater pump speed control system. The licensee repaired the circuit board. Corrective actions from this event also included repairing the failed condenser steam dump valve, repairing the positioner for feedwater regulating valve FCV-530, and issuing an operations incident summary to aid operators in identifying and responding to abnormal feedwater occurrences. This item is closed based on the licensee's corrective actions.

f. Licensee Event Report (LER) 50-275/91-08-00 (Closed)

On April 24, 1991, plant operators initiated a manual reactor trip to terminate an increase in reactor power due to failure of a fuse in the bus duct disconnect panels of the rod control system. The fuse that failed was an older model which had been prone to failure during routine operation due to manufacturing problems. Although a work order and materials request indicated that improved fuses had been procured and installed, old style fuses were still installed in the movable coil fused disconnect panels. It is believed that a contract electrician replaced the fuses in the wrong place (i.e., the rod control cabinet rather than the requested bus duct disconnect panel).

The licensee replaced all moving coil bus duct disconnect box fuses with new style fuses. Also, the licensee is in the process of establishing unique panel identification for each panel located in the rod control system. The inspector reviewed the licensee's corrective actions and concluded that they were acceptable. This LER is closed.

g. Licensee Event Report (LER) 50-275/90-13-00 (Closed)

On November 3, 1990, Unit 1 made three power changes, each greater than 15% rated thermal power (RPT), to reduce load. According to TS 4.4.8 a reactor coolant system grab sample is required to be taken between two and six hours following a power change greater than 15% RPT. However, only one grab sample was made due to poor shift turnover.

As a corrective action, the licensee revised the procedure to account for multiple power level changes. The inspector reviewed the revised procedure and found it to be acceptable. This LER is closed.

h. License Event Report (LER) 50-275/91-11-00 (Closed)

On July 15, 1991, while performing surveillance testing of the Solid State Protection System (SSPS), an operator mistakenly actuated the wrong train's relay which started engineered safety feature equipment. The operator performing the test had the test procedure in hand but failed to pay adequate attention to the test content. Also, the concurrent verification process was improperly performed because operators involved were not clear as to the specific verification requirements for this type of testing.

The licensee's corrective actions included adding control of the SSPS access keys and specifying in detail which type of verification is to be utilized for various operations activities. The inspector concluded that the corrective actions were acceptable. This item is closed.

No violations or deviations were identified.

14. Open Item Follow-up (92701 and 92702)

a. Vibration and Loose Parts Monitoring System Out-of-Service, Enforcement Item 50-275/90-30-01 (Closed)

This item was related to magnetic tape and strip chart recorders for the vibration and loose parts monitoring (V&LPM) system which had been out-of-service for an extended period of time. The equipment recorded the output of V&LPM system channels when a channel setpoint was reached so that plant staff could perform analysis for excessive vibration or loose parts in the reactor coolant system. The V&LPM system is not safety-related.

The licensee's response to the Notice of Deviation indicated that the magnetic tape and strip chart recorders would not be returned to service because the vendor no longer manufactured component parts and the devices were not readily repairable. The licensee's corrective actions to avoid further deviations included implementation of an interim, computer based V&LPM system for assessment of core barrel vibrations, purchase of new V&LPM equipment to record and analyze core barrel vibrations and loose

parts, issuing a new procedure regarding the V&LPM system, and adding the V&LPM system to an administrative procedure for the control of equipment not covered by Technical Specifications.

The inspector reviewed the licensee's closure documentation for this open item and Nonconformance Report DC1-91-TN-N016 which addressed generic V&LPM system problems. The inspector also reviewed surveillance test procedure STP-R-21, Reactor Internals Vibration Monitoring. The system engineer was contacted regarding the status of the new V&LPM equipment. The equipment had been purchased and installation of the new equipment was scheduled to be complete by December 31, 1991. Finally, the inspector observed that the status of inoperable V&LPM system channels was being tracked in the control room, and the system had been added to Administrative Procedure AP-A-58, Control of Plant Equipment Not Required by the Technical Specifications. This item is closed based on the licensee's corrective actions.

b. Corrective Actions for Fuel Handling Building Enforcement Item Not Fully Implemented, Enforcement Item 50-323/90-30-01 (Closed)

This item was related to warning signs that were not reinstalled on two personnel doors in the Unit 2 Fuel Handling Building (FHB) and one personnel door in the Unit 1 FHB. The licensee committed to installing the signs on certain FHB doors to warn personnel that the doors needed to be closed to ensure FHB ventilation system operability.

The licensee's response to the Notice of Deviation indicated that the three missing signs were reinstalled, that a new administrative procedure for door control would be issued, and that doors would be added to the Plant Information Management System (PIMS) database.

The inspector entered the FHB for Unit 1 and Unit 2 and observed that the three warning signs were installed; the inspector did not observe any missing warning signs. The inspector reviewed portions of Administrative Procedure AP C-66, Control of Doors Important to Safety, and the inspector reviewed Action Request A0215640 which indicated that information regarding door signs was added to the PIMS database in mid-June 1991. This item is closed based on the licensee's corrective actions.

c. Operability of the Motor-Driven Auxiliary Feedwater Pumps with Inoperable Fuel Handling Building Ventilation Supply Fans, Unresolved Item 50-275/91-10-01 (Closed)

This item was related to a licensee determination which concluded that the Unit 1 auxiliary feedwater system (AFW) was operable even though the fuel handling building (FHB) ventilation supply fans were inoperable. The FHB ventilation supply fans provide room cooling necessary for operation of the two motor-driven AFW pumps.

The resident inspector addressed questions to design engineering after a documented operability evaluation on this matter was completed on April 18, 1991. The questions pertained to the environmental qualification (EQ) of the motor-driven AFW pumps. The licensee answered the resident inspector's questions in a conference call. Specifically, the licensee indicated that the EQ analysis of the pump motors did not assume the FHB ventilation supply fans would operate for the first hour after a crack occured in the auxiliary steam header located in the FHB. After one hour, the analysis assumed that the leak would be secured and the doors could be opened to cool the AFW pump rooms. Finally, the licensee indicated that the AFW system was not needed for recovery from an auxiliary steam header crack. The resident inspector had no further questions regarding the operability determination. In a question pertaining to the formal documentation of operability issues, the licensee indicated that a procedure for performing operability determinations would be reviewed by the Plant Staff Review Committee in October 1991. This item is closed based on licensee's answers to the resident inspector's questions.

d. Main Condenser Steam Dump Failures 50-275/91-10-02 (Closed)

This item pertained to failures of six Unit 1 main condenser steam dump valves which occured after December 1990. On two occasions, failure of the valves after reactor trips resulted in overcooling of the reactor coolant system. The steam dump failures were discussed in NRC inspection reports 50-275/90-30, 50-275/91-10, and 50-275/91-13, as well as LERs 50-275/90-17, 50-275/91-07, and 50-275/91-09.

On May 28, 1991, a management meeting was held with the licensee in the Region V office. The management meeting focused on the licensee's investigation of the valve failures, the root cause of the failures, and the corrective actions. The details of the management meeting are documented in NRC inspection report 50-275/91-17.

Subsequent to the management meeting, the licensee completed replacement of the internals of all Unit 1 and Unit 2 main condenser steam dump valves. The replaced internals incorporated design changes to strengthen the individual parts that had previously failed. The licensee also conducted testing of the new internals, and no additional problems were observed. This item is closed.

e. Fire Brigade Manning 50-275/91-20-01 (Closed)

This item pertained to the initial assignment of a non-licensed auxiliary operator to the position of fire brigade leader, which occured on July 5, 1991. While the position of fire brigade leader was normally filled by a licensed operator, the non-licensed auxiliary operator was on the roster of qualified fire brigade leaders and the roster was used to assign fire brigade members. After the non-licensed operator explained that he was uncomfortable with the assignment, action was taken to assign a licensed operator to the position of fire brigade leader.

The regulatory requirements of 10 CFR Part 50, Appendix R, indicate that the fire brigade leader shall be competent to assess the potential safety consequences of a fire and advise control room personnel. Competency may be evidenced by possession of an operator's license or equivalent knowledge of plant safety-related systems. Chapter 9.5 of Diablo Canyon's Final Safety Analysis Report (FSAR) indicates that the fire brigade leader is typically a senior control operator but may be any licensed operator trained as a fire brigade leader. Likewise, plant emergency fire procedures indicate that the position of fire brigade leader would be filled by a senior control operator or a licensed operator.

The inspector reviewed Action Request A0235728 and Quality Evaluation Q0008977 that were initiated because of this occurrence. As previously stated, the licensee took action to assign a licensed operator to the position of fire brigade leader. Prior to making the assignment, the training records of the licensed operator were reviewed and updated to insure the individual's qualification as fire brigade leader. Additionally, the licensee took action to revise the roster of fire brigade members. The revised roster clearly depicted the qualifications or limitations of all fire brigade members. The inspector verified that all individuals listed as potential fire brigade leaders were licensed operators. The revised roster of fire brigade members was completed by July 10, 1991, and the inspector verified that the roster was located in the control room. The inspector also contacted the Fire Marshall and was told that the fire brigade roster will be revised when the qualifications of individuals change. The Fire Marshall also indicated that Diablo Canyon is considering submitting a FSAR change which would state that non-licensed operators could be assigned as fire brigade leaders, provided the individual had fire brigade leader training.

While the initial assignment of a non-licensed operator to the position of fire brigade leader was not in accordance with the FSAR or plant emergency procedures, the inspector concluded that the licensee took prompt action to resolve this matter. Therefore, this item is closed.

No violations or deviations were identified.

15. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations, or deviations. An unresolved item disclosed during this inspection is discussed in paragraph 5.d of this report.

16. Exit Meeting

On October 9, 1991, an exit meeting was conducted with the licensee's representatives identified in paragraph 1. The inspectors summarized the scope and findings of the inspection as described in this report.

bcc w/enclosure:
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Resident Inspector
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G. Cook
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Region V/dkm

BOlson	MMiller	WAng	HWong
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[YES NO]	[YES NO]	[YES NO]	[YES NO]

PMorrill	SRichards	RZimmerman
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[YES NO]	[YES NO]	YES NO
		(Para. 14.e only)

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