U.S. NUCLEAR REGULATORY COMMISSION
REGION V

Report Nos:	50-275/93-22 and 50-323/93-22
Docket Nos:	50-275 and 50-323
License Nos:	DPR-80 and DPR-82
Licensee:	Pacific Gas and Electric Company Nuclear Power Generation, B14A 77 Beale Street, Room 1451 P. O. Box 770000 San Francisco, California 94177
Facility Name:	Diablo Canyon Units 1 and 2
Inspection at:	Diablo Canyon Site San Luis Obispo County, California
Inspection Conducted:	July 7 through August 17, 1993
Inspectors:	M. Miller, Senior Resident Inspector F. Gee, Resident Inspector M. Tschiltz, Resident Inspector D. Corporandy, Project Inspector

Approved by: P H Johnson 9/28/93

P. Johnson, Chief
Reactor Projects Section 1
Date Signed

Summary:

Inspection from July 7 Through August 17, 1993 (Report Nos. 50-275/93-22 and 50-323/92-22)

Areas Inspected: Routine, announced, inspection of plant operations; maintenance and surveillance activities; followup of onsite events, open items, and licensee event reports (LERs); and selected independent inspection activities. Inspection Procedures 37700, 41701, 61726, 62703, 71500, 71707, 71710, 90712, 92700, 92701, 93702 and Temporary Instruction (TI) 2515/028 were used as guidance during this inspection.

Safety Issues Management System (SIMS) Items: None

Results:

General Conclusions on Strengths and Weaknesses:

Strengths: No significant strengths were noted during this report period.

<u>Weaknesses:</u> Long-standing failure to correct inadequate control of lubricants (Paragraph 5).

<u>Significant Safety Matters:</u> None

<u>Summary of Violations:</u> One violation was cited for inadequate corrective actions to control lubricants (Paragraph 5).

DETAILS

1. Persons Contacted

Pacific Gas and Electric Company

*J. Townsend, Vice President and Plant Manager, Diablo Canyon Operations
W. Fujimoto, Vice President, Nuclear Technical Services
D. Miklush, Manager, Operations Services
B. Giffin, Manager, Maintenance Services
W. Crockett, Manager, Technical Services
*R. Powers, Manager, Nuclear Quality Services
*T. Grebel, Supervisor, Regulatory Compliance
*J. Bard, Director, Mechanical Maintenance
*D. Taggart, Director, Site Quality Assurance
S. Fridley, Director, Operations
*D. Oatley, Director, Materials
R. Washington, Acting Director, Instrumentation & Controls
*T. Bennett, Director, Outage Management
*J. Skaggs, Senior Engineer, Operations
*J. Becker, Acting Director, Operations
*J. Rappa, General Foreman, Electrical Maintenance
*K. Hubbard, Engineer, Regulatory Compliance
*R. Gray, Director, Radiation Protection
*R. Glynn, Senior Quality Assurance Supervisor
*R. Hess, Assistant Director, Onsite Nuclear Engineering Support
*D. Stetson, Engineer, Quality Control
*P. Dahan, Engineer, Regulatory Compliance

*Denotes those attending the exit interview.

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

2. Operational Status of Diablo Canyon Units 1 and 2

During this inspection period, both Units 1 and 2 operated at 100% power for the entire report period, with the exception of a Unit 2 reduction to about 95% power on August 7, 1993, for routine turbine steam admission valve testing.

3. 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 whether 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 accessible areas of the facility to observe the following:

(1) General plant and equipment conditions

(2) Fire hazards and fire fighting equipment

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

(4) Interiors of electrical and control panels

(5) Plant housekeeping and cleanliness

(6) Engineered safety features equipment alignment and conditions

(7) Storage of pressurized gas bottles

The inspectors talked with control room operators 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. <u>Radiological Protection</u>

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 RWP (Radiation Work Permit).

c. <u>Physical Security</u>

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.

4. Followup of Onsite Plant Events (93702)

Charging Regulating Valve (FCV-128) Packing Leakage (Unit 2)

On July 16, 1993, the Unit 2 control room operators observed volume control tank level steadily decreasing. Level decrease is an indication of reactor coolant system (RCS) leakage. The operators entered the appropriate TS action statements for RCS leakage, estimated to be about 18 gallons per minute, and in 2 hours identified that the packing for charging pumps discharge flow control valve FCV-128 had failed. The valve was isolated and repaired. Since the valve could be isolated from the RCS without degradation of any safety function, the leakage was not considered RCS leakage once it had been identified.

On August 6, 1993, similar indications of a Unit 2 RCS leak of about 9 gallons per minute occurred, and operators quickly identified that FCV-128 packing had again failed. After discussions with the vendor, the licensee concluded that the earlier repair procedures had not identified valve-specific repair techniques. The license added valve-specific information to the repair procedure, concerning the unexpected tapered configuration of the stuffing box interior, and repacked the valve. No additional failures have occurred to date.

The licensee issued a Quality Evaluation to determine the root cause of the packing leaks, as well as to examine the adequacy of past maintenance. The licensee's actions appeared appropriate.

No violations or deviations were identified.

5. Inadequate Corrective Actions to Control the Use of Lubricants

Licensee Requirements for Control of Lubricants

Quality-related administrative procedure AP D-753, "Control of Lubricants," Revision 20, dated February 2, 1993, documents the requirements for the storage and use of lubricants for plant equipment. The procedure requires that a log book be available at the bulk storage areas to keep a record of all lubricants disbursed. The log documents the lubricant used, quantity taken, quantity used, equipment to receive the lubricant, date taken, product quality verification, and person and department identifications. Appendices 7.1 and 7.2 of the procedure list the recommended and alternate lubricant for each piece of mechanical and electrical equipment, respectively.

Previous Conditions Adverse to Quality

On March 26, 1987, NRC Inspection Report No. 50-275(323)/87-01 identified a violation involving the failure to properly label lubricant containers and to maintain the required log book at lubricant storage areas. The licensee's corrective actions included reemphasizing to the plant staff the expectations of management regarding the use and control of lubricants, including maintenance of the log book.

Between March 18, 1989, and January, 1992, the licensee identified eight instances of incorrect oil or lubricant usage or improper labeling of lubricants. Four of these instances (March 18 and December 6, 1989; November 3, 1991; and January 8, 1992) involved the actual addition of improper oil to safety-related components.

The licensee has also issued two nonconformance reports (NCRs) involving the control of lubricants. NCR DCO-89-WP-N029, issued on March 21, 1989, documented the evaluation and corrective actions for instances when auxiliary feedwater pumps (AFPs) 1-1 and 2-1 were declared inoperable due to incorrect oil in the turbine and pump. NCR DCO-91-NM-N-061, issued on July 12, 1991, documented discrepancies in lubrication storage and handling practices. The discrepancies included unlabelled and mislabelled grease guns, potential cross-contamination of greases through the use of a single pump, and potential cross-contamination of oils through the use of a single pump. In each instance, the licensee initiated corrective actions to prevent recurrence of the problem.

Recent Improper Mixing of Lubricants

On June 22, 1993, the licensee found a one-gallon bottle of oil which was labelled "Auxiliary Saltwater (ASW) Pump" filled with a half-gallon of oil and labelled with an incorrect type of oil, "GST-32." The correct oil as specified in Administrative Procedure AP D-753, Appendix 7.2, is AW Machine Oil-100. The licensee sampled ASW pump 1-2 bearing oils during scheduled maintenance on the same day, but the laboratory did not find any contamination in the sampled oils. On June 29, 1993, the licensee sampled the bearing oils from ASW pump 1-1 during scheduled maintenance and found that the bearing oils were contaminated with less than 10% of the same type of oil found in the one-gallon bottle.

On July 15, 1993, the inspectors questioned the licensee concerning the operability assessment of the Unit 2 ASW pumps. The inspectors noted that (1) the licensee's assessment was based on the conclusion of the lubricant vendor without contacting the pump vendor, (2) the lubricant log book did not contain an entry to show the type of oil used in the ASW pump, and (3) technical concerns remained regarding the bearing geometry and clearances, the viscosity of the mixed oils, precipitates which might result from mixing of the oils, and the existence of suspended particles in the sampled oils which could indicate bearing deterioration.

On July 16, 1993, the licensee advanced the scheduled preventive maintenance and sampled the oil in the motor bearings of the two ASW pumps in Unit 2. The result of the samples showed that the oil in the upper and lower bearing reservoirs of both motors was contaminated with less than 10% of GST 32 oil, similar to that found in ASW pump 1-1. On July 22 and 23, 1993, the licensee changed the oil in ASW pumps 2-1 and 2-2, respectively.

The licensee contacted the bearing manufacturer and discussed with the oil manufacturer concerns regarding the viscosity, bearing geometry and clearances, hardness of the precipitate particles resulting from the mixing of the two oils, and the loss of rust inhibitor additives in the oil. Test results satisfied the viscosity concern of the bearing

manufacturer. The oil manufacturer reconfirmed that the precipitates in the mixed oils were soft. The laboratory did not specifically look for suspended particles in the oil samples. The discussion with the bearing and oil manufacturers confirmed the licensee's previous conclusion that no apparent degradation in the bearings had occurred.

The licensee initiated nonconformance report NCR DCO-93-MF-N039 to investigate and correct the lack of compliance with the procedure in June and July 1993.

Inadequate Corrective Actions

The inspectors noted that the corrective actions taken in response to the violation cited in 1987 by the NRC and the two nonconformance reports issued by the licensee in 1989 and in 1991, including reemphasizing the control and use of lubricants to the plant staff, had not been adequate to properly control the use of lubricants. Violations of the requirements of Administrative Procedure AP D-753, involving the addition of incorrect lubricants to several safety-related components, had occurred on four previous occasions (March 18, 1989; December 6, 1989; November 3, 1991; and January 8, 1992). Mixed oil was subsequently found in three ASW pumps in June and July 1993, as discussed above. Although no equipment has failed due to the inadequate control of lubricants, there have been several instances when safety-related equipment has been declared inoperable due to their improper use. The inadequate corrective actions by the licensee to properly control the use of lubricants is a violation of NRC requirements (Violation 50-275/93-22-01).

6. Incorrect Torque for Pneumatic Operator Diaphragm Bolts

In response to industry information concerning the failure of power-operated relief valves (PORVs) due to improper actuator installation, the licensee obtained information from the vendor, including actuator bolt torque. The licensee included this new information in the work procedures which were used during the most recent Unit 2 refueling outage. These torque values were included in an attachment to the procedure. However, these values were contradicted by more prominent instructions in the procedure which had always been used on these valves.

The licensee later determined, as documented in Action Report (AR) A0310798, that the torque values actually used on the actuator bolts were incorrect, in that the values were too high for the bolt material used at Diablo Canyon. The vendor, Masoneilan/Dresser, now supplies actuators with bolts of a different, harder material than that supplied in the 1970's, and the higher torque values were intended for these newer bolts. Licensee analysis using the most conservative potential bolt strength values concluded that the higher torque value may result in exceeding the yield strength of 36 KSI for the installed (older design) bolting material. The actual torques applied to the installed bolts were unknown at the time of the calculation. Actual tensile strength values measured at a later date appeared to be about 87 KSI.

The power operated relief valves (PORVs) and several other air-operated valves were potentially affected by the improper torque values. The

inspector questioned the licensee's prompt operability analysis for the PORVs, which concluded that no safety concern existed, because seismic and operating loads were not included in the evaluation. A later licensee evaluation included these concerns, and also included evaluation of the effects of the post-maintenance test which applied 55 pounds of air pressure to the actuator. The later analysis concluded that the valves would remain operable, with minimal if any elongation of the bolts. In addition, the analysis concluded that no operating or seismic load would be higher than that already applied during the torquing and subsequent air test. Therefore, if the bolts had not failed during that process, they would perform their design basis function.

The licensee reviewed work packages and interviewed personnel involved in actuator work during the outage. Based on records of torque wrench check-out, the licensee determined that the bolts on four valves had been overtorqued, and that the remaining valves had been torqued to lower, appropriate levels as instructed in mechanic training and specified in the procedure.

One of the valves with the higher torque, a containment isolation valve on a Unit 2 sample line (NSS-2-9356B), had its bolts replaced on August 11, 1993. The bolts were inspected for indications of failure, and the material properties were measured. Hardness measurements and the corresponding strength values were equal to or greater than 87 KSI. This appeared to substantiate the availability of margin in bolt strength.

The licensee initiated a QE (Q0010795) to document the root cause and corrective actions for the overtorqued bolts. The QE identified that a communication deficiency between the plant and the vendor had caused the incorrect torque values to be prescribed. The inspector was concerned that the scope of the QE did not appear adequate. Although the initial analysis by maintenance engineering of the adequacy of the vendor-supplied torque values did not identify the potential for an overtorque condition, a later analysis by design engineering raised the overtorque concern. By the time the concern had been raised, the torque values had already been included in work packages and implemented in the field during the outage. The lack of a detailed engineering evaluation prior to inclusion of improper torque values in work packages was not addressed in the QE. Quality control personnel agreed to address the inspector's concern in further root cause evaluation of issue. This concern will be followed as Followup Item 50-323/93-22-02.

No violations or deviations were identified.

7. Maintenance (62703)

During the inspection period, 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 that maintenance activities were performed by qualified personnel, in accordance with fire protection and housekeeping controls, and that replacement parts were appropriately certified.

The inspectors observed portions of the following maintenance activities:

Description	Dates Performed
Work Order C0115962, Troubleshoot Power Range Channel N-42, Unit 2	July 9, 1993
Work Order C0116096, Investigate Valve LCV-109, Failure to Open, Unit 2	July 15, 1993
Work Order C0115599, Replace Bearing Oil, ASW Pump 2-2	July 23, 1993
Work Order R0120300, Power Range Incore-Excore Calibration, Units 1 and 2	August 3-4, 1993
Work Order C0113953, Block Wall Modifications, Elevation 119', Unit 1	August 4, 1993
Rod Position Indication Trouble-shooting by I&C, Unit 1 (non-intrusive, no work order)	August 12, 1993

No violations or deviations were identified.

8. Surveillance (61726)

The inspectors reviewed a sampling of Technical Specifications (TS) surveillance tests and verified that: (1) a technically adequate procedure existed for performance of the surveillance tests; (2) the surveillance tests had been performed at the frequency specified in the TS and in accordance with the TS surveillance requirements; and (3) test results satisfied acceptance criteria or were properly dispositioned.

The inspectors observed portions of the following surveillance activities on the dates shown:

Procedure	Description	Date Performed
STP M-9A	Diesel Engine Generator 1-1 Routine Surveillance Test	July 13-14, 1993
STP M-26	Auxiliary Salt Water System Flow Monitoring, Units 1 and 2	July 27, 1993
STP M-89	Emergency Core Cooling System Venting, Unit 1	July 27, 1993
STP I-1A	Shift Checklist, Units 1 and 2	August 1, 1993

STP I-2C1	Removal of Power Range Channel from Service, Units 1 and 2	August 3-4, 1993
STP I-2C2	Calibration of Power Range Channel, Units 1 and 2	August 3-4, 1993
STP I-2C3	Return Power Range Channel to Service, Units 1 and 2	August 3-4, 1993
STP I-2D	Power Range Incore/Excore Calibration, Units 1 and 2	August 3-4, 1993
STP R-25	Calculation of Quadrant Power Tilt Ratio	August 5, 1993

No violations or deviations were identified.

9. Observation of Licensed Operator Training (41701)

On July 29, 1993, the inspectors observed licensed operator training in the simulator (Lesson ECA00-B). The training involved a loss of all AC power. Skills exercised and discussed included understanding of plant equipment configurations, individual and team diagnostic abilities, and team communications proficiency. The purpose of the simulator exercise was to assess a newly developed lesson guide; therefore, the operators were not evaluated. Several problems were noted by the instructors during the simulator training which were investigated and determined to be caused by a lesson guide error in a console entry parameter, which added an unexpected component failure; and a simulator hardware problem, which caused an additional unexpected instrument failure.

The inspector observed the licensee's critique of the simulator training, and found it to be appropriate to the simulator training scenario.

On August 11, the inspectors observed simulator training on Abnormal Procedure AP-8, "Control Room Evacuation." The operators used the simulator hot shutdown panels, and were trained on use of the remote panels and required remote operations. Since this also was a training scenario, the instructors were available to discuss the need for the various activities as they were performed by operators.

Adequacy of Shift Crew Staffing

The licensee recently reduced the minimum shift crew staffing required by Operations policy. During Modes 1 through 4, the Technical Specifications require a shift crew of 9 operators including:

1 Shift Foreman with a Senior Reactor Operator (SRO) License
1 other individual with an SRO License
3 individuals with reactor operator (RO) licenses
3 unlicensed auxiliary operators (AOs)
1 Shift Technical Advisor (STA)

The licensee's revised Operations policy assigns at least 18 individuals to each shift crew, including at least 3 SROs and 4 ROs. In the event of illness or other unexpected absence, however, the policy allows up to three of the non-licensed operator positions not to be replaced by call-out of other individuals, unless work conditions require. This could result in a shift crew of 15 individuals. The inspector therefore evaluated each of the scenarios assuming a shift crew of 15. This was done to assess licensee assumptions regarding the number of operators available to perform the two procedures observed in the simulator, which appeared to be the procedures most challenging for the defined shift crew manning level. Each procedure is discussed separately below:

Loss of All AC Power (ECA 0.0) The licensee procedure for recovery from a loss of all AC power, ECA 0.0, "Loss of All AC," directs operators in the recovery from the loss of offsite as well as onsite emergency power. This procedure directs operators to strip electrical loads off vital busses, and to perform other local actions. Design basis assumptions for loss of all AC include the availability and successful operation of one of the three emergency diesel generators (EDGs). Two EDGs are required for design basis response to a loss of coolant accident. Subsequent procedure steps in ECA 0.0 and ECA 0.3 allow cross-tie of vital busses in the affected unit to provide RCP seal cooling during controlled plant depressurization or, if vital bus cross-tie is not used, depressurization at a rate consistent with the vital equipment which is available. The recovery of vital AC power by cross-tie of vital busses, prescribed by Appendix X of ECA 0.3, "Restore 4KV Busses," provides better control of plant conditions. This is a simple and flexible procedure for operators in the control room, but is a complex operation at the three vital busses, requiring numerous local breaker manipulations.

Loss of All AC Without Cross-tie of Vital Busses The inspector reviewed the NRC Supplemental Safety Evaluation Report (SSER) dated May 29, 1992, and concluded that the NRC staff did not allow credit for use of the Appendix X vital bus cross-tie during a loss of all AC power. Therefore, the availability of shift crew personnel to perform recovery actions was examined for the scenario of a loss of all AC (ECA 0.0). Operator actions in the plant were focused on removal and restoration of electrical loads. Since only one vital bus is assumed to be energized if the vital bus cross-tie procedure (ECA 0.3, Appendix X) is not credited, operator actions are limited to the available vital bus at various voltages. Removal and restoration of vital bus loads appeared to be within the capability of the operators within the four-hour time period allotted by design basis assumptions of the SSER. It appeared that operators had time within design basis assumptions to perform some additional actions to cope with additional equipment failures, such as those listed in the "Response Not Obtained" column of ECA 0.0. These additional failures would be considered beyond the engineering design basis.

Recovery from Loss of All AC Using Vital Bus Cross-tie The licensee's preferred method to recover from a loss of all AC power is use of a vital bus cross-tie as described in ECA 0.3, Appendix X, which requires removal and restoration of loads on some or all vital busses at all voltages. This would allow cooldown at the normal cooldown rate. The load removal process is challenging to the operators. However, it appeared to be

performable within design time constraints, and the plant conditions associated with Appendix X appeared to be bounded by the single bus recovery process described above.

Training Consistent With Design Basis The inspector verified that operators were trained on each of the loss of all AC recovery procedures discussed above.

Control Room Evacuation (OP AP-8A) Procedure OP AP-8A, "Control Room Inaccessibility - Establishing Hot Standby," Revision 5, identifies assigned stations for the five-member fire brigade, (one SRO and four unlicensed nuclear operators, all with fire brigade training), as well as specific duties assigned to nine remote shutdown operators. In accordance with OP AP-8A, the nine remote shutdown operators fill the same positions as described in Technical Specifications. Each unit shutdown is supervised by a SFM or SRO. Each unit's hot shutdown panel is operated by an RO. Watch positions in the turbine building and auxiliary building are filled by nuclear operators (AOs) or ROs. To accomplish safe plant shutdown with the control room inaccessible, the procedure directs activation of control stations at local plant areas such as the dedicated shutdown panel, 480V switchgear, and the 4KV switchgear.

The licensee's safe shutdown time-line associated with these activities showed by analysis that these activities can be accomplished by the staff available. The design basis analysis for a fire allows the assumption that all safe shutdown equipment works as designed. This would result in all equipment actions being performed successfully, with no instances of "Response Not Obtained" occurring; with the exception of unprotected indications discussed in Appendix E of OP AP-8A, which is accounted for in the time-line. Therefore, the crew staffing levels meet NRC requirements, and appear to implement design basis assumptions.

The licensee is currently preparing a revision to OP AP-8A. The licensee plans to review the current control room staffing levels with respect to the procedure's assumptions of available crew staffing. This revision to the procedure is being done within the scope of the several issues discussed in NRC open item 50-275/91-01-01 (Open).

No violations or deviations were identified.

10. Evaluation of Instrumentation and Controls Maintenance (63704)

The inspectors observed several work activities performed by the Instrumentation and Controls staff, in an effort to observe detailed practices and activities. Work activities which the inspectors observed included calibrations and repairs of safety related equipment which have been documented in this and the past two NRC inspection reports.

For all observations, troubleshooting and maintenance activities were performed in accordance with approved procedures, and appeared appropriate to the circumstances. Technical staff personnel appeared trained and knowledgeable, and performed work activities with attention to appropriate concerns. Calibration equipment appeared to be in good

condition, and appropriate to the application. Documentation of activities appeared appropriate with the exception of the following observation.

Instrumentation and control (I&C) activities observed included the troubleshooting of a mismatch between the Unit 1 Control Bank D, rod B6 digital rod position indication (DRPI) and the group demand indication for Control Bank D. On August 9, an NRC inspector observed that DRPI indication for Control Bank D, rod B6 was six steps lower than the other rods in the bank, and six steps lower than the position indicated by the group demand indication. The DRPI B train sensor for Control Bank D, rod B6 indicated 216 steps, while both the DRPI A train sensor and group demand indicated 228 steps. Troubleshooting was performed, involving evaluation of the DRPI system response while exercising full-length control rods in accordance with a periodic surveillance.

Following the surveillance, I&C concluded that the group demand indication for control bank D had been incorrectly set two steps higher than actual bank demand during restoration following rod control system troubleshooting in February 1993. Other instrumentation and control equipment that had been incorrectly set at that time included the bank overlap unit, rod control P/A converter and the plant process computer. Subsequent review of plant response and component troubleshooting, performed in February 1993, revealed that there had not been a fault in the rod control system. However, the instrumentation and control equipment was not reset in February 1993 when the incorrect setting was identified. Following the most recent troubleshooting, involving the exercising of full length control rods, I&C reset the affected instrumentation and control equipment two steps lower. After resetting the affected instrumentation and control equipment, Control Bank D group demand position and DRPI indication for Control Bank D rods were within the normal accuracy of the DRPI system.

Review of the troubleshooting with both I&C and reactor engineering personnel revealed that the group demand indication had been reset to read the same value as the DRPI based on a flux map and DRPI indications. Discussions with the reactor engineering supervisor indicated that the flux map was of insufficient accuracy to use as the basis for resetting group demand indication to within two steps. The inspector also questioned the I&C supervisor as to why the group demand indication and other affected parameters were not promptly reset to the correct values after it was determined that the rod control system had not been faulted. Operations and I&C personnel are evaluating the inspector's concerns, and a quality evaluation is being performed.

After completion of the licensee's troubleshooting activities, Unit 1 group demand and DRPI indications were observed to be reading within the expected accuracy of the system (± 4 steps). The TS requires that they be within 12 steps. The safety significance of an additional two-step error which was introduced by the improper adjustment of affected instrumentation and control equipment was minimal.

No violations or deviations were identified.

11. Employee Concerns Program (2500/028)

The inspector observed the employee concerns program, and recorded details of the program in Appendix A to this inspection report, in accordance with NRC Temporary Instruction 2500/28.

The licensee's hotline is a program established to obtain and resolve employee and contractor concerns and allegations in an anonymous fashion. The program is implemented by plant procedure IDAP OM 3.ID3, "Quality Hotline," and uses the overall quality problem and resolution program, governed by plant procedure C-12, "Quality Problems and Resolution". This procedure is applicable to all plant quality problems, and is used to resolve these concerns. C-12 is the primary program implementing the requirements of 10 CFR 50, Appendix B, Criterion XVI.

Additional information related to review of the employee concerns program is provided in Appendix A to this report.

No violations or deviations were identified.

12. Followup of Open Items (92701)

a. Failure of Auxiliary Feedwater (AFW) Steam Supply Containment Isolation Valve FCV-37 to Close (Followup Item 323/93-07-07, Closed)

On March 12, 1993, during valve disassembly and inspection following an incomplete closure of the valve during a surveillance test, the licensee determined that the grease in the valve operator for AFW steam supply valve 2-FCV-37 contained water, particulate matter, and corrosion. This appeared to have been due to lack of quad rings which protect the valve operator from intrusion of rain, spray, and particulate matter. In January 1993, when the valve failed to close during its surveillance test, the licensee's limited inspection concluded that the valve stem had been sticking, since later lubrication of the valve stem allowed the valve to pass its surveillance test. After inspection of the valve in March 1993, during the Unit 2 outage, the licensee concluded that the valve may not have been able to function upon demand with full differential pressure across the disk, as required by NRC Generic Letter 89-10.

FCV-37, a remote manual containment isolation valve, is installed in the steam supply to the turbine driven AFW pump. FCV-37 had two safety functions: FCV-37 must be closed either manually or by remote actuation to isolate (1) the contaminated steam source from the turbine-driven AFW pump in the event of a steam generator tube rupture, or (2) in the event of a steam line break just upstream of FCV-95, and downstream of FCV-37 and FCV-38, to isolate the steam generator 2 and 3 leads to the steam driven AFW pump, (which, if not isolated, could allow simultaneous blowdown of two steam generators). A Westinghouse analysis concluded that this valve is not required to isolate a downstream steam line break, since this type of line break should not initiate a plant trip, and main feedwater can be used to support plant operation until the break is

isolated manually. Therefore, the licensee concluded that no adverse effect would have occurred in the event this valve failed to function during remote operation.

During inspector review of the failure, several issues were identified which required followup. These items and their resolution are as follows.

(1) <u>Validity of the licensee's assumptions regarding habitability in areas to be accessed for manual operation of FCV-37 following a postulated steam line break</u>

A memo to Electrical Maintenance from the Manager of Nuclear Engineering Services, dated May 7, 1993 (licensee's chronological File No. 207103), documents the licensee's conclusion that remote manual closure of FCV-37 was considered possible since appropriate protective gear for operators in a steam break environment in the pipe racks is available.

Action Request A0308937 documented that, in the event of a rupture of this steam line, no reactor trip would be expected, and as stated above, main feedwater would be expected to keep up with the break. The inspector questioned the assumption that a plant trip would not occur, specifically if operators took manual action to trip the plant.

The inspector reviewed the valve's safety function requirements. The Westinghouse analysis assumed that the main feedwater system would be available to keep up with the break to prevent emptying of the two associated steam generators. This analysis apparently assumed that operators would not take actions to trip the plant, since main feedwater is isolated upon a plant trip. Control room staff had been given no direction to avoid tripping the plant in this situation, and had been given guidance to trip the plant in situations in which steam line breaks occur. The implementation of the Westinghouse design assumptions to not trip the plant in the event of a steam line break was further discussed in a Westinghouse letter dated August 31, 1981 (attachment to licensee Chron No. 207103).

The licensee's analysis concluded that, if a single failure of a motor-driven AFW pump occurs following a manual reactor trip, the event would be properly mitigated by available plant systems and procedures. Specifically, operators would be required to isolate feedwater to faulted steam generators, and to open the two manually operated cross-tie valves between the discharge of the two motor driven pumps. Once this is accomplished, feedwater flow to the two non-faulted steam generators could be established from the remaining motor-driven pump.

(2) <u>Length of time assumed during station blackout for unavailability of steam to the turbine driven AFW pump; specifically, regarding assumed single failure of FCV-38 (the redundant isolation valve in the AFW pump steam supply line) concurrent with mispositioning of FCV-37</u>

The only credible failure for FCV-38 in this analysis is to fail in the open position. No passive failures are assumed during loss of all AC power.

(3) <u>Scope and depth of corrective actions to ensure that components are appropriately identified and protected from weather effects, specifically regarding installation of quad rings which would exclude water and particulate matter from valve internals</u>

The procedural deficiency of MP E-53.10J has been superseded by MP E-53.10M, which added illustrations for quad ring installation (the "quad ring" is a sealing ring fabricated in four sections to facilitate installation). Technician training and on-the-job training now include quad ring installation. A plexiglass stem protector has been installed to prevent water intrusion in the stem area. The periodic maintenance inspection of MOV grease has shown no moisture intrusion for outdoor MOVs which have had correctly installed quad rings.

(4) <u>Safety significance of and corrective actions for rust and moisture in FCV-439</u>

FCV-439 was inspected and found to have no degradation, moisture in, or separation of grease. The rust was considered superficial and not significant to the valve function.

(5) <u>Maintenance procedure steps which ensure appropriate protection of component internals from weather effects</u>

The actions of item (3) above addressed this issue.

(6) <u>More detailed examination of reportability of the inoperable valve as a result of the failed surveillance test in January 1993</u>

The licensee documented the conclusion and basis for considering FCV-37's failure to be not reportable in Chron No. 207103. This document was reviewed by the inspector and discussed in item (1) above.

Based on the above discussion, this open item is closed.

b. <u>Hydrogen Recombiner System Walkdown (Followup Item 275/92-12-02, Closed)</u>

During the engineered safety features verification, the inspectors performed a review and a walkdown of the internal hydrogen

recombiner system. In addition, the inspectors also walked down the backup hydrogen purge system, a nonsafety-related system, and connecting piping to the external hydrogen recombiners in Units 1 and 2. The inspectors identified the following discrepancies associated with the hydrogen purge system and with the piping connections to the external hydrogen recombiners:

- The design drawings did not reflect the as-built conditions, in that blind flange connections were missing, and piping connections were misrepresented.

- The inspectors also identified a mislabelled containment penetration number and a missing valve label.

- The dose exposure to personnel required to put the hydrogen purge system into operation was unknown. Manual pump and valve operations are necessary to put the purge system into operation.

The licensee issued Field Change Transmittals (FCTs) 015728 and 015752 to revise both Units 1 and 2 piping schematics to reflect the as-build conditions of the piping connections. The licensee also re-labelled the containment penetration and re-attached the valve label. The licensee also performed a calculation of the potential dose exposure to personnel required to put the hydrogen purge system into operation.

The inspector reviewed the field change transmittals, walked down the penetration and the valve for correct labels, and reviewed the result of the dose calculation for the operators in placing the purge system in service during accident conditions. The inspector concluded that the licensee had completed the corrective actions as listed in the followup item. This followup item is closed.

Dose Rates During Operation of the Hydrogen Purge System

During the walkdown of the hydrogen purge system on May 21, 1993, the inspector inquired about the dose exposure to personnel required to place the system in operation at the 100-foot elevation in the auxiliary building as required by Emergency Operating Procedure (EOP) E-1, "Loss of Reactor or Secondary Coolant," Revision 9. The EOP required the hydrogen purge system to be placed in operation if, more than 28 days after a loss of coolant accident (LOCA), the containment hydrogen concentration is between 0.5% and 3.5%. In response to the inspector's concern, on July 30, 1993, the licensee calculated that the area of the supply fans would be inaccessible under calculated design basis post-LOCA recirculation conditions due to highly radioactive water in the recirculation piping. The licensee indicated that the thirty-day dose in the vicinity of the supply fans would be approximately 70,000 rads. However, the inspector noted that the local action checklist, dated November 1, 1989, for Operations Procedure OP H-8:I, "Containment Hydrogen Purge System - Make Available and Place in Service," documented that the

worst case expected radiation level to be 71,700 rads integrated over thirty days.

The inspector had the following concerns:

- The numerical values for the dose from the calculation in July 1993 and from that in November 1989 indicated the average dose to be approximately 100 rads per hour. In either case, the area is inaccessible for operators to place the hydrogen system in service when the containment hydrogen reaches 3.5%.

- An inconsistency existed between the actions specified by Westinghouse letter PGE-6740, dated May 22, 1986, to operate the system on or before the seventeenth day of the accident, and the EOP requirement to operate the system on the twenty-eighth day. The licensee initiated corrective action on July 29, 1993, to update the Final Safety Analysis Report (FSAR) and both normal and emergency operation procedures to account for the time change.

The inspector also inquired about the potential generic implications for EOPs which direct operators to other locations which are not accessible.

Section 6.2.5.2.2 of the FSAR indicates that the containment hydrogen purge system is designed for either intermittent or continuous flow operation. When hydrogen concentration reaches the control limit of 3.5%, the hydrogen purge system is placed into operation. This involves manual operation of the supply stream isolation valves and blower. However, when the containment hydrogen concentration reaches 3.5%, the area where the supply fans are located may not be accessible to operators because of high radiation levels. The licensee's nuclear engineering staff in San Francisco committed to review the FSAR and Design Criteria Memorandum for any appropriate changes to clarify the use of hydrogen purge system. (Followup Item 50-275/93-22-03).

The licensee's Operations staff committed to evaluate whether any necessary local action might be impossible to perform. The licensee will then review Westinghouse guidelines and NRC licensing commitments to determine if an additional review is necessary for actions performed if response is not obtained, as well as for actions directed by emergency contingency action (ECA) and functional recovery procedures.

c. <u>Code Interpretation for Relief Valve Drain (A/R A0283981) (Followup Item 275/92-31-03, Open)</u>

An NRC inspector raised a concern about the installation of relief valves with vertical discharge piping lacking drain connections to prevent the buildup of liquid. Diablo Canyon FSAR Table 3.2-3, Sheet 28, identifies that the emergency diesel engine starting air receivers are designed, fabricated, erected and tested in accordance with the ASME Boiler and Pressure Code, Section VIII. ASME Section

VIII requires provision for draining relief valve discharge piping. The NRC questioned whether the existing configuration of the relief valve discharge piping met the requirements of ASME Section VIII. The NRC noted that the issue would be kept open until the licensee obtained a code interpretation for clarification.

This inspector observed that the licensee had requested a code interpretation. The cognizant ANSI B31.1 code committee met in May of 1993 and assigned a committee member to prepare a response for review by other committee members. The next committee meeting on September 27, 1993, may approve the inquiry response and issue the committee's position. Once the licensee receives the B31.1 committee inquiry response on relief valve drain requirements, the licensee intends to formalize their understanding with the ASME Section VIII representative as deemed necessary to address their original commitment.

This followup item will remain open pending inspector review of the inquiry response on relief valve requirements as they are demonstrated to apply to the licensee's ASME Section VIII commitments.

d. Resolution of Outstanding Emergency Core Cooling System Issue (Followup Item 275/92-16-04, Open)

The inspector reviewed an outstanding emergency core cooling system (ECCS) issue. This was initially identified as the second of five issues listed in Inspection Report 50-275/92-16, paragraph 9, and was addressed by the licensee's Nonconformance Report NCR-DCO-92-NS-N007. The issue concerned inadequate flow following a loss-of-coolant accident (LOCA) during the hot leg recirculation mode due to a postulated single failure of residual heat removal (RHR) system valve 8703, the motor-operated valve (MOV) in the hot leg injection path. Failure of valve 8703 to open would prevent the RHR system from providing flow to the hot leg of the reactor coolant system (RCS), thus allowing only the safety injection (SI) pumps to provide flow. Two issues of concern were identified for this scenario: (1) the potential for boron precipitation and inadequate core cooling if the SI pumps alone could not provide adequate flow, and (2) possible SI pump flow runout in this configuration. If the single failure of valve 8703 were caused by failure of the associated emergency diesel generator, then other components in the ECCS train served by the emergency diesel generator would also be unavailable. In other words, the condition could exist where flow through the hot leg would only be provided by one safety injection pump.

Concerning the issue of potential pump runout, the licensee estimated that maximum flow through a single SI pump would be very near the pump runout limits. The licensee presented a surveillance test procedure (STP) V-15 which showed that the SI hot leg throttle valves were set and locked to limit flow through the pumps to 670 gallons per minute (GPM), a value less than the pump manufacturer limits of 675 GPM. According to the licensee, the pump manufacturer

had also acknowledged that the maximum pump flow at runout could exceed 675 GPM with no immediate effect on the pump. According to the licensee, periodic testing of the SI pumps had confirmed that no unusual degradation had occurred in their SI pumps even though test records showed the 675 GPM limits to have been exceeded on occasion.

The licensee acknowledged that STP V-15 was conducted with the SI pumps taking suction from the refueling water storage tank (RWST) and, hence, did not account for the higher flow rates which could occur during the hot leg recirculation mode when the SI pump is aligned to receive suction from the higher pressure RHR pump discharge. Consequently, the licensee revised STP V-15 to include setting the SI pump throttle valves to consider the flow during the hot leg recirculation mode. Since STP V-15 is still performed with suction aligned to the RWST, the licensee determines the flow setpoint based on an extrapolation for higher suction pressure and an additional margin for calculational uncertainties. The setpoint is set so that maximum pump flow will not exceed the pump manufacturer's administrative limit of 675 GPM.

The inspector concluded that the licensee had established sufficient measures to assure that SI pump flow would not exceed runout conditions when in the hot leg recirculation mode with only one SI pump running.

Regarding the issue of boron precipitation and flow adequacy, the inspector was also concerned that if valve 8703 failed to open, the lack of a flow path for the RHR pumps would result in deadheading of the pumps and subsequent pump failure. The inspector found that the RHR control circuitry was interlocked to assure that the minimum flow valves would automatically open to prevent the RHR flow from dropping below 500 GPM and that the minimum flow valves would automatically close when RHR pump flows exceeded 1000 GPM. The inspector concluded that the issue of the RHR pump deadheading was no longer a concern.

According to the nuclear steam supply system (NSSS) vendor, Westinghouse, "ECCS to the RCS hot legs will prevent boron precipitation given that the high pressure ECCS exceeds decay heat boiloff at the prescribed switchover time by 30% (1.3 times decay heat boiloff.)" Licensee calculations showed that this corresponded to a flow rate of about 270 GPM at the prescribed switchover time for Diablo Canyon. Since the output of one SI pump exceeds these requirements by a factor of two, the licensee's conclusion that flow would be adequate, even if valve 8703 failed closed, appeared reasonable. The issue addressed by NCR-DCO-92-NS-N007 is therefore closed. This followup item remains open pending review of remaining issues.

According to the licensee, an emergency procedure change has been developed by PG&E, and concurred with by Westinghouse to further improve the degree of reverse flow. The emergency procedure change called for the RHR to be realigned to inject through the RCS cold legs in the event that valve 8703 fails to open. The inspector

questioned whether the licensee had considered the flow dynamics of the SI injecting through the hot leg, concurrent with the RHR injecting through the cold leg. The inspector was concerned that all regions of the reactor vessel might not receive adequate cooling with this flow injection alignment. Review of flow adequacy with the SI pumps injecting into the hot leg and the RHR pumps aligned to the cold leg is an inspector follow-up item. (Follow-up Item 50-275/93-22-04)

13. Exit Meeting

An exit meeting was conducted on August 11, 1993, with the licensee representatives identified in Paragraph 1. The inspectors summarized the scope and findings of the inspection as described in this report.

The licensee did not identify as proprietary any of the materials reviewed by or discussed with the inspectors during this inspection.

Appendix A: Summary of Inspector's Review of Employee Concerns Program

APPENDIX A

EMPLOYEE CONCERNS PROGRAMS

PLANT NAME: Diablo Canyon LICENSEE: Pacific Gas & Electric Company
DOCKET #: 50-275 & 50-323

A. PROGRAM:

1. Does the licensee have an employee concerns program?

   Yes The program was implemented by procedure IDAP OM 3.ID3, "Quality Hotline".

2. Has NRC inspected the program?

   Yes Several inspection reports from 1982 to 1985 addressed the program, due to the large number of allegations. NRC Region V Instruction No. 1303, for allegation resolution, was used as a guideline for the Diablo Canyon procedure. NRC SER 21 also addressed the allegation program at Diablo Canyon.

B. SCOPE:

1. Is it for:

   a. Technical? Yes

   b. Administrative? Yes

   c. Personnel issues? No

   The procedure refers personnel problems to the Human Resources Department.

2. Does it cover safety as well as non-safety issues?

   Yes The program covers all "problems" as defined by the Diablo Quality Related Procedure OM7.ID1, "Problem Identification and Resolution of Action Requests"

3. Is it designed for:

   a. Nuclear safety? Yes

   b. Personal safety? Yes

   c. Personnel issues - including union grievances?

   No The procedure refers personnel to Human Resources Department for these issues.

4. Does the program apply to all licensee employees? Yes

5. Contractors? Yes

6. Does the licensee require its contractors and their subs to have a similar program?

   Yes — The procedure applies to all.

7. Does the licensee conduct an exit interview upon terminating employees asking if they have any safety concerns?

   No — The exit interview process does not ask about safety concerns.

C. INDEPENDENCE:

1. What is the title of the person in charge?

   Before May 1993, the Site QC manager was in charge. After May 1993, the Site QA manager.

2. Who do they report to?

   Before May 1993, Site QC reported to the Plant Manager. Since May 1993, Site Quality Assurance reports to the Nuclear Power Generation Senior Vice President.

3. Are they independent of line management?

   Before May 1993, No. After May 1993, Yes.

4. Does the ECP use third party consultants? No

5. How is a concern about a manager or vice president followed up?

   Same as any other. No exceptions. (None so far).

D. RESOURCES:

1. What is the size of staff devoted to this program?

   Based on the current demand, it has been a collateral duty of two members of the QA staff. However, during the 1982-1985 construction phase, 30 people were dedicated to the program full time. The licensee is prepared to provide staff for the Quality Hot Line as required by demand.

2. What are ECP staff qualifications (technical training, interviewing training, investigator training, other)?

   Calls come in from any phone, both on and off site. The QA inspector steps through a checklist to interview the hotline caller. Since the problems are documented in the licensee's problem reporting system, current training of QA inspectors to review the

resolution of plant problem reports and quality problems is relevant.

E. REFERRALS:

1. Who has followup on concerns (ECP staff, line management, other)?

   QA staff and others, as assigned by QA.

F. CONFIDENTIALITY:

1. Are the reports confidential? Yes

2. Who is the identity of the alleger made known to?

   No one, unless the alleger makes himself/herself known during the telephone call.

3. Can employees be:

   a. Anonymous? Yes

   b. Report by phone? Yes

G. FEEDBACK:

1. Is feedback given to the alleger upon completion of the followup?

   Yes — The alleger must call back on the hotline and ask the status of the allegation by allegation number.

2. Does program reward good ideas?

   No — A different program, Ideas and Action, allocates money for identifying problems and cost savings. Licensee employees have been rewarded for identifying NRC violations, time savings and cost savings ($25,000 has been awarded in the past for some specific ideas).

3. Who, or at what level, makes the final decision of resolution?

   All allegations are entered (by concern number, in such a way that the alleger's identity is not divulged) in a computer-based Action Request system, which is used for reporting all types of plant problems. Depending on the significance, problems may become NCRs, which is also controlled by the Problem Identification and Resolution Procedure, the same as any other quality problem.

4. Are the resolutions of anonymous concerns disseminated?

   They are given to the individual alleger upon request. Resolutions are also disseminated for some specific problems, as required by

corrective actions and the Problem Identification and Resolution Procedure. However, the source of the concern is not divulged.

5. Are resolutions of valid concerns publicized (newsletter, bulletin board, all hands meeting, other)?

   Only if done as part of problem resolution, as discussed in 4. above. However, all problem reports, including hotline problems, are available to everyone on the plant computer system.

H. EFFECTIVENESS:

1. How does the licensee measure the effectiveness of the program? Quantitatively, since the Problem Identification and Resolution Procedure requires resolution of plant problems. QA audits of the overall quality problem resolution process also are performed. However, no specific audit of the Hotline process occurs.

   Also, the alleger's satisfaction is assured by the process, or the alleger can initiate another call or identify the problem via another channel. There are no known examples of this at this time.

2. Are concerns:

   a. Trended?

      No — Except in the sense that all quality problems are trended per the Problem Identification and Resolution Procedure.

   b. Used? No

3. In the last three years how many concerns were raised? 19 Closed? 13 What percentage were substantiated? 9

4. How are followup techniques used to measure effectiveness (random survey, interviews, other)?

   People are encouraged to call back to determine if the problem has been resolved to the alleger's satisfaction. Also, the Quality Problem Resolution program is audited by QA.

5. How frequently are internal audits of the ECP conducted and by whom?

   Again, only the Quality Problem Resolution program as a whole is audited, not the Hotline specifically.

I. ADMINISTRATION/TRAINING:

1. Is ECP prescribed by a procedure? Yes

PACIFIC GAS & ELECTRIC
EMPLOYEE CONCERNS PROGRAM

2. How are employees, as well as contractors, made aware of this program (training, newsletter, bulletin board, other)?

   General Employee Training discusses the availability and use of the Quality Hotline. Also, Hotline information stickers are posted on many bulletin board and other surfaces throughout the plant.

ADDITIONAL COMMENTS: (Including characteristics which make the program especially effective or ineffective.)

1. All Hotline allegations are entered into the quality problem resolution system, subject to same requirements and deadlines for resolution of other 10 CFR 50 Appendix B problems.

2. Anonymity is guaranteed, the alleger is told his/her allegation number, is not required to provide any identifying information, and is encouraged to call back.

The person completing this form please provide the following information to the Regional Office Allegations Coordinator and fax it to Richard Rosano at 301-504-3431.

NAME: TITLE: PHONE #:
Mary Miller /Senior Resident Inspector /805-595-2354 DATE COMPLETED: 8/20/93

File Location: G:\PS1\DC\ECP-TI.MHM