U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos: 50-275/88-31 and 50-323/88-29

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: October 23 through December 3, 1988

Inspected by: M. M. Mendonca for 12/20/88
K. E. Johnston, Resident Inspector Date Signed

M. M. Mendonca for 12/20/88
P. P. Narbut, Senior Resident Inspector Date Signed

Approved by: M. M. Mendonca 12/20/88
M. M. Mendonca, Chief, Reactor Projects Section 1 Date Signed

Summary:

Inspection from October 23 through December 3, 1988 (Report Nos. 50-275/88-31 and 50-323/88-29)

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 30703, 36700, 61726, 62700, 62703, 71707, 92700, 92701, 92720, 93702, and 94703 were used as guidance during this inspection.

Results of Inspection: One violation was identified regarding the failure of a test engineer to follow a procedure as described in paragraph 6.a.. No deviations were identified.

Areas of Strengths

o Although it occurred immediately after the reporting period (on December 5, 1988) the licensee notably achieved a "black board" on Unit 1. This effort reduced the number of lit annunciators during normal operation from approximately 40 (two years ago) to zero.

- The licensee's management response to the damage and loss of a Unit 2 residual heat removal pump while in a midloop condition was considered to be timely, thorough, and commendably conservative. The action plan generated and executed was detailed and actions specified were carried out in formal ways such as the issuance of a temporary operating procedure.

Areas of Weakness

- Instances of valve lineup problems were emphasized in the last resident inspector report (50-275/88-26). Additional examples of valve lineup problems occurred during this reporting period which reemphasize the need for licensee action. Specifically, this report discusses the discovery of missing position seals on an auxiliary feedwater pump recirculation valve (paragraph 3.b.), the discovery of a mispositioned valve providing sample air to the containment vent noble gas radiation monitor (paragraph 4.q.) and the unplanned closure of the suction valve to a running safety injection pump (paragraph 4.i.). Associated with the valve lineup problems, paragraph 11.b. discusses several instances of ineffective action on the part of quality surveillance personnel conducting valve lineup surveillances.

- This report contains several examples of operator error and/or lack of operator attention, which, coupled with the inattentive overfilling of a steam generator discussed in the last resident inspector report (50-275/88-26) indicates the need for management attention. This report discusses a lack of operator attention in removing a clearance which led to the damage of running safety injection pump (paragraph 4.i.), a lack of operator attention resulting in four actuations of the low temperature overpressure protection devices (paragraph 4.o.), and operator error in failing to recognize a need to perform compensatory action when a quadrant power tilt ratio alarm was generated during nuclear instrument calibrations (paragraph 4.h.).

- The violation, identified in this report regarding a test engineer not following procedure for reading an erratic gauge during a surveillance test, is a particularly noteworthy since the licensee has been ineffective in resolving the previously identified problem of adequately reading test instrumentation. A similar violation was identified earlier in February 1988. Subsequently, in September 1988, a notice of deviation was issued because the licensee had not issued a procedure as committed in the violation response. The procedure was subsequently issued but personnel were apparently not informed or trained in its use. The issue of ineffective communication of expectations was also a concern of the most recent SALP report and this violation reenforces the need for continued management action.

DETAILS

1. Persons Contacted

*J. D. Townsend, Plant Manager
*D. B. Miklush, Assistant Plant Manager, Maintenance Services
*L. F. Womack, Assistant Plant Manager, Operations Services
*B. W. Giffin, Assistant Plant Manager, Technical Services
J. M. Gisclon, Assistant Plant Manager for Support Services
C. L. Eldridge, Quality Control Manager
K. C. Doss, Onsite Safety Review Group
T. A. Bennett, Maintenance Manager
W. G. Crockett, Instrumentation and Control Maintenance Manager
J. V. Boots, Chemistry and Radiation Protection Manager
T. L. Grebel, Regulatory Compliance Supervisor
S. R. Fridley, Operations Manager
R. P. Powers, Radiation Protection Manager
*W. J. Kelly, Compliance Engineer
*S. M. Skidmore, Quality Assurance Manager
*D. A. Taggert, Quality Surveillance Supervisor
*W. T. Rapp, Onsite Review Group Chairman
*W. D. Barkhuff, Senior Quality Control Engineer
*T. J. Martin, Training Manager

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

*Denotes those attending the exit interview on December 12, 1988.

2. Operational Status of Diablo Canyon Units 1 and 2

Unit 1 was in power operations at the beginning of the reporting period and remained so during the reporting period. No reactor trips or significant events occurred. Reportable events such as containment ventilation isolation occurred as detailed in Section 4 of this report.

Unit 2 remained in its second refueling outage for the reporting period. The period began with fuel load just completed and ended with the unit in Mode 3 in preparation for return to service. During the period numerous events occurred as detailed in Section 4 of this report. The most notable of these events included severe damage to two safety related pumps; specifically, a residual heat removal pump was damaged due to an reassembly error and a safety injection pump was damaged due to operator error in processing a clearance.

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 Operations (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 trends were reviewed for compliance with regulatory requirements. Shift turnovers were observed on a sample basis to verify that all pertinent information of plant status was relayed. 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) Radiation protection controls.

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

(e) Interiors of electrical and control panels.

(f) Implementation of selected portions of the licensee's physical security plan.

(g) Plant housekeeping and cleanliness.

(h) Engineered safety feature equipment alignment and conditions.

(i) 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 involved work activities.

b. Auxiliary Feedwater Pump Recirculation Stop Valve Missing Seal

On November 9, 1988, during a routine walkdown of the Unit 1 auxiliary building, the inspector discovered valve FW-1-189, the auxiliary feedwater (AFW) motor driven pump 1-3 recirculation stop valve, was not sealed. The inspector brought this to the attention of the Shift Foreman.

A subsequent review by the inspector of the applicable sealed valve check list for the AFW system revealed that the valve was required to be sealed in the throttled position. The monthly pump test requires that the valve be throttled to allow between 49 and 51 gpm recirculation flow with discharge to the steam generator isolated.

The inspector discussed these findings with the shift supervisor who concluded that to determine if the valve was in the appropriate position an "as found" position was to be determined (one quarter turn open), and a partial pump test to be performed. Initially, during the pump test, the recirculation flow gage read between 40 and 140 inches of water, well outside the acceptance criteria of 96 to 104 inches of water which corresponds to between 49 and 51 gpm. However, due to erratic readings, the gauge was suspected of being inaccurate. The gage was removed and a new gauge was installed. The second reading determined that recirculation flow was 50 gpm and that the valve's as found position was appropriate.

The inspector discussed this repeat occurrence of a valve missing its seal (see inspection report 50-275/88-26) with the Operations Manager. In the last inspection report, the Operations Manager described a new procedure for sealed valves. As a result of this finding and others by operations, the licensee is continuing to review the sealed valve program for adequacy and has initiated a Quality Evaluation. In addition, an Action Request was initiated to evaluate the bad gauge. The inspectors will continue to follow-up the licensee's corrective actions with regards to the sealed valve program.

No violations or deviations were identified.

4. Onsite Event Follow-up (93702)

a. Unit 1 Inadvertent Containment Ventilation Isolation

On November 2, 1988, an auxiliary operator erroneously source check tested the wrong monitor in the process of source check testing the liquid radwaste radiation monitor RM-18, a prerequisite for a liquid radwaste discharge. The operator tested the plant vent gas radiation monitor (RM-14B), causing a containment ventilation isolation (CVI). The event was reported as a four hour non-emergency event and was also the subject of LER 1-88-23. The erroneous source check of RM-14B and consequent CVI happened twice in 1987. Corrective actions taken in 1987 included implementation of a source check procedure and improved labelling (red labels on all radiation monitors whose actuation results in a CVI). Corrective action for this most recent events includes the installation of plexiglass covers on radiation monitors which can cause a CVI. The licensee considers that the installation of covers will inhibit operators from source checking the wrong radiation monitor.

b. Unit 2 Residual Heat Removal Pump 2-2 Failure

On November 3, 1988, the lower motor bearing for Residual Heat Removal (RHR) pump 2-2 failed shortly following its start. It was discovered by an auxiliary operator who smelled and subsequently saw smoke coming from the pump. The pump was immediately shut down from the control room.

The unit was in Mode 5 with the reactor coolant loops partially filled. This condition required both RHR pumps to be operable since the RHR pumps were the only normal and available way to remove core decay heat. With the reactor coolant loops not filled, the steam generators were not available as a heat removal mechanism.

Other plant conditions germane to the event were that the containment equipment hatch was open (containment integrity is not required in Mode 5) and the reactor coolant pumps were uncoupled and on their backseat (which provides possible leak path if the Reactor Coolant System pressurized as it would have if all RHR cooling were lost for several hours).

Plant management and the operating staff responded to the event in a timely, systematic and thorough manner.

The resident inspector interviewed operations supervision and noted that their initial actions included elimination or stopping all work on control and power supplies that might effect the remaining RHR pump and, further, ordering the accelerated hookup of at least two core exit thermocouples (so that core conditions could be monitored if RHR was lost).

The resident inspector attended plant management's deliberations and action plan formulation meeting and noted that the situation, possible scenarios, and commensurate actions were thoroughly discussed, evaluated and proper actions formulated and listed for accomplishment. The actions included:

- Establishing containment closure capability within 1 hour of loss of RHR. This action included staging of tools personnel and coordination with radiological personnel. Later, in the evening of November 3, 1988, this action was changed to straight away containment closure by direction of corporate management.

- Providing an adequate Reactor Coolant System (RCS) vent path. The licensee blocked open a Pressure Operated Relief Valve (PORV) and had the Primary Relief Tank (PRT) rupture disk physically removed to provide a large vent path and preclude RCS pressurization.

- Establishing a contingency plan for operations. The licensee prepared and issued a temporary procedure for operations on actions to be taken if RHR were lost. The plan included methods of feed and bleed cooling and plant condition

prerequisites including the blocked open PORV, the removed PRT rupture disk, maintaining steam generators full (for reflux cooling), maintaining two reactor thermocouples, maintaining a charging pump operable, maintaining a safety injection pump operable, maintaining wide range and narrow range temporary reactor vessel level indication, and maintaining containment closure. The procedure also included requirements for increased monitoring of the operating RHR pump including trending of selected parameters.

Licensee management also addressed the paths to recovery from the loss of the RHR pump specifically, to repair the damaged pump or alternately to fill and vent the RCS thus providing steam generator availability. Both paths were accelerated but were predicted to require about 3 days.

The licensee exited the event on November 8, after the reactor coolant pumps were coupled and the RCS was filled and vented. The repair of the RHR pump was delayed due to unpredicted problems such as replacement shaft runout problems (lack of being straight) and assembly with improper lubricant. On November 11, 1988, the RHR pump was successfully tested and declared operable.

The cause of the RHR pump failure was the loosening of a nut on the pump/motor shaft. The nut was designed with a lock tab washer which should have prevented the loosening of the nut. One tab of the lock tab washer is turned up against a nut flat and one tab is turned down against a flat (or keyway) on the pump shaft thus preventing relative rotation of the nut and shaft. On the shaft of the failed pump the flat spot had been hand ground approximately flat as opposed to more current replacement shafts which have a keyway machined in the shaft. The approximate flat spot on the shaft coupled with the fact that the lock tab washer was reused after pump overhaul (the mechanic did not obtain a new lock tab washer) resulted in a lock tab washer that did not perform its function and allowed the nut to loosen. Since the pump is a vertical shaft assembly, the loosening of this nut allowed the entire assembly to move vertically downward with time. The pump had been successfully tested after overhaul during the refueling outage and had successfully run for about 350 pump hours. The first item to be damaged as the pump moved vertically downward was the lower motor bearing lube oil sump which cracked allowing oil to spill and smoke due to contact with hot rubbing surfaces.

At the close of the reporting period the licensee was preparing but had not issued a nonconformance report on the event, NCR DC2-88-EM-N127. The licensee had determined that the event was not reportable under 10 CFR 50.73 but was preparing to issue a voluntary LER.

The licensee had not completed root cause analysis at the end of the reporting period but initial indications expressed by the maintenance manager are that the maintenance instructions were not adequate.

The licensee had not defined all actions required to prevent recurrence (in the absence of a completed root cause analysis) but had defined certain prudent actions; specifically:

- The other Unit 2 RHR pump was partially disassembled and the lock tab washer installation was confirmed to be satisfactory;
- The licensee has prepared a contingent design change to stake the nuts in place if required, and
- The licensee is preparing to examine the Unit 1 RHR pumps and the Unit 1 and Unit 2 Auxiliary Saltwater (ASW) pumps which are also vertical pumps and have a similar nut locking device.

The inspectors will follow-up this item through the licensee's LER (2-88-15).

c. Component Cooling Water Isolated to RCP Thermal Barrier Cooler Of Wrong Unit

On November 4, 1988, an I&C technician isolated component cooling water to a Reactor Coolant Pump (RCP) thermal barrier cooler for the wrong unit.

The I&C technician was to have worked on Unit 2 to fill and vent a flow indicator (2FI-90), the reactor coolant pump thermal barrier return flow indicator. This work was performed on Unit 1 instead, which caused an alarm in the control room and an automatic isolation of component cooling water (CCW) flow to the thermal barrier.

The technician realized and reported his error to the control room. Operators restored cooling to the thermal barrier in accordance with their procedure AP-11 which requires slow restoration to minimize thermal shock.

During the event normal reactor coolant pump seal injection was in service, therefore the thermal barrier cooler function was not required and nothing detrimental occurred to the reactor coolant pump seals.

The I&C manager initiated a nonconformance report (NCR DC1-88-TI-N216). The underlying cause of the event was determined to be that the I&C technician was dispatched by his supervisor to perform two jobs in sequence (both requested by operations). The first job was to check an indicator locally at the waste gas compressor in Unit 1 and then to perform an assist step in a surveillance test (STP-V-619, Containment Isolation Leak Valve Testing) Step 8.4.8 to cut in, fill, and vent FI-90 in Unit 2. The I&C technician was verbally instructed by the supervisor and picked

a copy of the surveillance test procedure page from the operations shift foreman. For most jobs, I&C technicians are issued color coded work packages, the color accentuating the unit to be worked.

As an aftermath of the event, it has become clear that many "assist jobs" (where I&C action is invoked by an engineering or operations procedure) do not result in a work package being given to the technician. The licensee's actions defined in the nonconformance report were reviewed by the inspector. The planned actions included counseling of the I&C technician and his supervisor and establishing policy that "assist jobs" will be performed with work packages.

The licensee determined that the event was not reportable under 10 CFR 50.73. The inspectors determined that the licensee's actions appeared to be acceptable. The effectiveness of the licensee's actions will be judged in the course of future inspection.

d. Diesel Generator Technical Specification Interpretation - 24 Hour Load Test

On November 4, 1988, the licensee's Assistant Plant Manager for Operations and the Engineering Manager discussed with the Senior Resident Inspector a technical specification interpretation which had been made by the licensee.

Technical Specification 4.8.1.1.2.b.8 requires a 24 hour load test of diesel generators to be performed every 18 months. The technical specification test requirement as specifically written also requires that the generator achieve a required voltage and frequency within 13 seconds after the start signal. This 13 second requirement had not been accomplished for one of the diesel generator units during the 24 hour lead test. However, the same parameter is specifically measured monthly during a start and 1 hour run. Therefore, the licensee concluded that there was no technical question regarding diesel generator operability. The licensee also concluded that the technical specification requirements were met in that all specified test functions had been accomplished in a relatively short time period.

The resident inspector discussed the licensee's technical specification interpretation with regional management and the NRR project manager. The conclusion drawn was that the licensee's interpretation was acceptable based on the fact that the verification of voltage and frequency within 13 seconds had been added to the 18 month surveillance test and continued use of the interpretation would not be required.

e. Contaminants in Air & Nitrogen Systems

On November 4, 1988, the licensee issued a nonconformance report, NCR DCO 88-TI-N125 on contaminants found in the Nitrogen system. The contaminants consisted of rust and scale particles. The nonconformance was generated as a result of a maintenance review of maintenance events. Reviewed events included (1) an August 1, 1985,

Boric Acid Evaporator overpressurization (and rupture disk blowout) caused by contamination on nitrogen supply valve seats which in turn caused in-leakage and (2) an August 1988 nitrogen pressure control valve acting erratically in supplying nitrogen to the ECCS accumulators.

The licensee determined the root causes to be oxidation during construction and a design deficiency in that critical components should contain filters.

The licensee actions defined in the NCR were to issue design changes for the installation of filters in the boric acid evaporator nitrogen supply, to develop and perform a system blowdown, to inspect and clean nitrogen system components, and to define and initiate design action for the installation of additional filters. The licensee actions are primarily in the planning stage.

A similar nonconformance (NCR) DCO-88-OP N116 was written on October 17, 1988, on grit, rust, and scale in the Instrument Air system. The NCR was written as a result of finding contamination in instrument air piping on October 12, 1988, during modification of the main steam isolation valve air system. The licensee defined actions to prepare a procedure to clean the system by air blow, inspect a sample of air instruments, and to analyze the contaminants found. At the end of the report period, the licensee had not yet determined long term corrective action.

The licensee I&C manager stated that immediate operability concerns were allayed by the operating experience to date which has successfully identified failing components through inservice checks. The I&C manager stated that the identification of the problem and the orderly performance of corrective actions were appropriate to the circumstances.

The inspector will follow-up the licensee's actions through the nonconformance review process.

f. Lubricating Oil Spill

On November 6, 1988, during the Unit 2 main turbine bearing oil flush after turbine disassembly and maintenance, approximately 300 gallons of lubricating oil was spilled in the turbine building. The area affected by the oil included the 140 foot deck with spillage down to the 85 foot level.

The spill was caused when a oil return hose loosened and sprayed oil. The condition was immediately noted and engineers stopped the flush. The licensee conducted a cleanup under the direction of an engineer. In addition QA personnel performed an audit of the adequacy of the clean up effort.

The licensee defined the cause of the spill to be not having the return hose properly tied off and a procedural failure to limit the operating pressure of the flush system. The licensee maintenance

manager stated that an Action Request (AR) and Quality Evaluation (QE) were prepared to document and track corrective actions specifically to more securely fasten the oil hose and to limit system pressure.

The licensee's recovery from this event appeared to be largely verbally directed except for some specific tasks such as exciter cleaning. The inspectors did not devote additional time to this item since the areas affected were not safety related.

g. Improper Wire Lugs on Battery Chargers

On November 7, 1988, the licensee discovered improperly sized lugs crimped to various wires on a safety related Unit 2 battery charger 232. Subsequent examinations identified the same conditions on battery chargers 231, 221, and 222.

The licensee prepared a nonconformance report (DC2-88-EM-N130) on November 15, 1988.

Discussions with the assistant plant manager for maintenance indicated the following:

- The improperly sized lugs were not obvious because the involved wire has a thick insulation.
- Some wires could physically be pulled out of their crimped lugs, putting their seismic qualification in question.
- The condition was caused during manufacture by the vendor.
- Unit 1 was checked and found to be satisfactory.
- Unit 2 battery chargers have been corrected.
- The Unit 2 battery chargers had functioned successfully since startup.
- The licensee had not yet determined reportability under 10 CFR 50.73 or Part 21 but would do so as part of the nonconformance process.

The inspectors will follow-up this item through the nonconformance process and through the licensee report if determined to be reportable.

h. Missed Quadrant Power Tilt Ratio Surveillance

Following a periodic incore/excore nuclear instrumentation (NI) cross calibration, the power range channels were, one at a time, removed from service for adjustment. From the time the first power range channel was adjusted on November 8, 1988, until the last channel was completed on November 10, 1988, the QPTR alarm was lit. The shift foreman had originally determined that the QPTR alarm

annunciated because the adjustment made to N-41 gave a false indication of quadrant power tilt and that the alarm would clear when all four channels were adjusted. Although his assumption was correct, the SFM did not make the determination that the QPTR alarm was inoperable until the alarm was discussed with the operations manager and operations supervisor on November 10. It was then determined that once the individual adjustment of the NI's began, the QPTR alarm was inoperable since it could not perform its intended function had an actual quadrant power tilt occurred.

The license initiated a nonconformance report and will issue a Licensee Event Report (LER 1-88-27). The licensee determined the root cause to be personnel error in that the annunciator response manual was not used when the QPTR alarm annunciated (it requires a quadrant power tilt calculation or a flux map) and that the appropriate determination of inoperability was not made. The licensee considers that contributory causes included inadequate training on the QPTR alarm and less than adequate procedures; specifically that the excore recalibration procedure should specify that its performance renders the QPTR alarm inoperable.

The inspector will review the licensee's corrective actions in conjunction with the review of the LER to be submitted.

i. Unit 2 Safety Injection Pump Failure

On November 11, 1988, at 12:50 a.m., operations discovered that the suction valve for Safety Injection (SI) Pump 2-2 had been isolated since 10:30 p.m. that night. This resulted in the failure of the pump due to a sheared pump shaft. The Unit was in Mode 5 and operability of the safety injection pumps was not required.

SI pump 2-2 had been placed inservice at 9:09 p.m. to fill three accumulators in accordance with Operating Procedure OP B-3B:I. At that time, pump suction valve 8923B was open with power removed and on a clearance. At 10:30 p.m., the clearance was reported off for test (ROFTed). Since the control room pump position switch was in the closed position, when power was returned to the valve it closed. This eliminated suction to the running SI pump. The subsequent heating caused the impeller to expand in its housing, deform, and finally shear its shaft at the third element from the inboard seal. The motor continued to turn this portion of the shaft until the pump was stopped at 12:50 a.m..

The licensee initiated an Event Response Plan which evaluated the cause, reviewed the damage, and initiated repair efforts. It was determined that although the pump casing was reusable, it required machining at the inboard seal prior to use. As a result, a new pump was procured from another plant and installed. It was determined that the motor did not experience excessive wear or heat and could be reused. Testing confirmed that the overcurrent trip relays were functioning properly, indicating that the motor did not experience an overcurrent condition.

The licensee also reviewed control room annunciation indications and found that no annunciators "came in", and on further review of annunciator location and design that none were expected. Calibration checks indicated that all inputs (motor bearing temperatures, stator temperature, and seal water temperature) were functioning as designed. At the close of the inspection period, the licensee was reviewing the adequacy of annunciation for the pump. One proposed solution was the use of a low current alarm, which would serve the purpose of a low suction pressure alarm and be relatively simple to install given existing wiring.

The Technical Review Group (TRG) reviewing the nonconformance report determined the following root causes to the event:

- The clearance procedure did not require adequate review of the return to service of a clearance point with its affected system in operation.
- The senior control operator failed to recognize that the control board valve positioner was in the closed position and what impact it would have on system operation when he removed the clearance tag from the valve positioner.
- Operations personnel failed to adequately monitor the accumulator fill evolution in that it took over 2 hours to recognize the status of the system.

The TRG identified the following corrective actions:

- Revisions to the clearance procedure.
- Addition of a low SI pump motor current alarm.
- Counseling of the operators.
- Generic instructions on filling tanks.

The inspectors will follow-up licensee actions through the nonconformance report and the voluntary LER (2-88-16).

j. <u>Diesel Generator 1-3 Failed to Start</u>

On November 12, 1988, Diesel Generator 1-3 failed to start during testing. The test was a specific test of the second level undervoltage relays, the first level undervoltage relays were jumpered out for the test.

A licensee electrician determined the cause to be dirty contacts on second level undervoltage relay 27 HG B4. The contacts were cleaned and the test was reperformed satisfactorily. Licensee records show that the relay had been removed on September 21, 1988, for periodic calibration. The procedure used required contact cleaning and an continuity check at that time.

The licensee's Nonconformance Report NCR DC2-88-TN-N132 was in draft at the close of the inspection report. The licensee had not resolved the reason for dirty contacts occurring on November 12, 1988.

Further, the licensee is preparing a special report required by technical specifications to report all valid and non-valid failures to start. The residents will follow-up the licensee's action through review of the nonconformance and special report process.

k. Boron Injection Tank Relief Valve Heat Tracing

On November 18, 1988, during a routine walkdown, the system engineer for the chemical and volume control system observed that thermal insulation over heat tracing on the Unit 1 Boron Injection Tank (BIT) relief valve (RV) was not properly restored following maintenance. Additionally, the heat tracing had been lifted away from the valve approximately 4" to 6" to facilitate RV maintenance performed during the Unit 1 refueling outage earlier this year. Temperature measurements of the relief valve subsequent to the discovery found the temperature to be 130 degrees F, 15 degrees F less than the Technical Specification (TS) 5.4.2 required 145 degrees F (which maintains boron in solution).

It was determined by the Onsite Project Engineering Group (OPEG) that 130 degrees would not have precipitated enough boron to have prevented the relief valve from lifting at its designed pressure. The licensee also determined that the heat tracing TS 3.5.4.2 did not apply to the RV since it is not a part of the BIT flow path piping.

The root cause was determined to be a failure to provide separate instructions for the removal and reinstallation of heat tracing and insulation during the Unit 1 outage in conjunction with other work. The licensee revised its practices prior to the Unit 2 outage and supplied separate work orders for the installation and removal of heat tracing and insulation and for the work performed on components.

l. Inadvertent Start of Auxiliary Feedwater Pumps

On November 21, 1988, the licensee made a 4-hour non-emergency report due to the inadvertent start of Unit 2 auxiliary feedwater system pumps.

The pumps started due to a start signal from the newly installed AMSAC system (Accident Mitigation System Actuation Circuitry) during testing of the newly installed system. Testing of the system had been ongoing since October 30, 1988, but had not caused actuation since the auxiliary feedwater (AFW) had been de-energized for other refueling outage reasons. When operations personnel made the AFW system available on November 21, testing then induced a start of the now energized equipment. The plant computer (P-250) had been taken out of service for modifications about one-half hour prior to the

pump start. The AFW was made available and started but was not noted by operators for about another one-half hour until the P-250 was restored and the alarm typewriter started printing an alarm.

In discussion with the I&C manager and the plant operations manager, the following was established:

- The AFW pumps were lined up on recirculation to the condensate storage tank, therefore no damage was incurred.

- The motor driven pumps started. The steam driven pump had its steam admission valve open it did not start due to the absence of steam in Mode 5.

- The steam generator blowdown did not isolate. This feature was part of the intended design. Subsequent examination showed the wiring design to be in error. Although this was subsequently corrected, it pointed out a separate problem according to the I&C manager. Specifically the problem was that test requirements were not specified by PG&E design engineers. The test requirements are deduced by test engineers at the site based on the modification drawing logic. The I&C manager further stated that in this case the drawing circuitry as described in modification drawings did not describe a logic where steam generator blowdown would be isolated. Therefore, test engineers did not specify it as a feature to be tested.

  The licensee's response to the maintenance team inspection indicated that, in the future, test requirements would be specified by design engineers and that details of the test methods would be invoked by plant staff personnel.

The inspectors will follow-up licensee actions through the nonconformance and event report process.

m. Residual Heat Removal Water Hammer

On November 23, 1988, a water hammer was noted in the control room concurrent with the start of an Residual Heat Removal Pump in Unit 1 during a routine surveillance test. Operators performed a walkdown and noted no damage. Subsequently, walkdowns were performed by engineering and again no damage was noted.

Engineering personnel conducted a series of pump starts with several personnel stationed at various points along the RHR system. The engineers noted decreasing energy in the water hammer effect with subsequent pump starts and noted the location of the loudest noise to be near the suction check valve to the Refueling Water Storage Tank (RWST).

The licensee engineers developed two theories regarding the cause of the water hammer, one involving entrapped air in long horizontal runs and one involving temporary opening of the RWST check valve on starts due to suction dynamic action. The licensee engineers have

referred the matter for further study by a general office group referred to as the water hammer task force.

The licensee engineers do not consider the energy demonstrated to be an operational concern based on engineering judgement. A second similar water hammer event occurred on December 1, 1988, as noted in paragraph 4.s..

The inspectors will follow-up this as an open item, since the licensee does not consider the item to be a nonconformance (Follow-up Item 50-275/88-31-01).

n. Containment Ventilation Isolation (CVI) Event in Unit 2

On November 12, 1988, the licensee made a 4 hour non-emergency report to the NRC due to a containment ventilation isolation (CVI) event in Unit 2.

The event occurred during planned calibration of plant ventilation radiation monitor 2 RM-14B. The procedure calls for lifting leads to prevent a CVI. The cause of the event was determined to be that the lifted leads were lifted and taped away in a manner which allowed the lead terminal lugs to come into contact and complete a CVI signal when, later in the procedure, fuses were pulled.

The inspectors will follow-up the licensee's corrective action through the event report to be issued.

o. Unit 2 Low Temperature Overpressure Protection System Actuation

On November 25, 1988, while in Mode 5, Unit 2 experienced four low temperature overpressure protection (LTOP) system actuations. The first actuation occurred at 6:20 a.m. following filling and venting the RCS while operators were attempting to pressurize to 390 psig to run the reactor coolant pumps. The lift involved pressurizer power operated relief valve PCV-456, which at low temperatures is set to lift at 435 psig hot leg pressure. The other three lifts occurred within the span of four minutes while operations brought the RCS to 400 psig to perform RCS leakage inspections. As a result of these actuations, the licensee is required by technical specifications to submit a special report.

The hot leg pressure transmitters are 0-3000 psig instruments accurate to 1% or 30 psig; and although the controls for PCV-456 and the control room instruments are fed from one transmitter, PT 403, the process loops are separate. In this case, the instrumentation in the control room read approximately 25 psig lower than the controls for PCV-456 were sensing. As a result, operators were operating much closer to the lift point than perceived. In addition, a contributing cause to the first lift, as determined by the operations manager, was operator inattention. A contributing cause in the second set of lifts, as determined by the operations manager, was lack of procedural guidance on the use of the seven means of control room indication supplied by two pressure

transmitters. The inspector will follow the determination of corrective action in follow-up of the special report to be submitted.

p. Unit 2 Containment Ventilation Isolations

On November 26, 1988, Unit 2 experienced two containment ventilation isolations (CVIs). The first CVI occurred when radiation monitor 2-RM-14B spiked high. The cause was determined to be a detector tube failure. The second CVI occurred during removal of the failed detector from service for repair. Since the original CVI signal had been reset and ventilation was in normal mode the act of lifting leads to remove the failed high radiation monitor caused the electrical contact to be broken and then made up again (during the physical act of lifting a round termination lug off the termination post). The recontact provided a second "spike" to the logic circuit causing the CVI actuation.

The inspectors will follow-up licensee actions through the LER process.

q. Unit 1 Containment Air Particulate Monitor (RM-12) Inoperable

On November 26, 1988, instrumentation and controls (I&C) technicians discovered the sample supply isolation valve for RM-12 closed. It was determined by the licensee that it had been closed on or sometime since October 11, 1988, when I&C had last performed routine testing. Either RM-12 or the containment fan cooler condensate monitoring system are required to be operable as part of the reactor coolant system (RCS) leakage detection system (Technical Specification 3.4.6.1). The condensate monitoring system was not put in service during this time frame and was therefore not used to detect RCS leakage.

The licensee's determination of root cause and corrective action will be followed up by the inspector in response to the LER to be issued on this subject.

r. Electrical Transient Resulting in Engineering Safety Features Actuations

On November 28, 1988, at 8:08 p.m., when Unit 2 was in Mode 4 (Hot Shutdown) a temporary loss of power to vital instrument AC distribution panel PY-22 resulted in the actuation of several Engineered Safety Features (ESF) as well as several other actuations. Actuations included CVI, fuel handling building ventilation mode shift, pressurizer heater trip, steam dump closure, and letdown isolation.

At the end of the report period, the cause of the electrical transient was still under investigation. The inspector will follow-up the event through review of the LER to be submitted on the event.

s. Second RHR Water Hammer

On December 1, 1988, Unit 1 experienced a second RHR water hammer when the RHR pump was started for surveillance testing. Paragraph 4.m. regarding the RHR water hammer event of November 23, 1988, provides further discussion.

5. 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.

a. Residual Heat Removal Pump 2-2

As described in the previous section, on November 3, 1988, the lower bearing on RHR pump 2-2 failed shortly after an attempt was made to start the pump. Details of the initial failure and subsequent problems are contained in section 4. The inspector observed the following maintenance activities on the pump; portions of the as-found inspection, as-left shaft runout measurements, and portions of the motor reassembly. The activities observed were found to be performed in accordance with appropriate procedures. It was noted that the activity was observed by quality control inspectors and the maintenance department manager.

b. Unit 1 Centrifugal Charging Pump 1-2 Lube Oil Leak

On November 17, 1988, during a routine walkdown, the inspector noted that centrifugal charging pump 1-2 (CCpp 1-2), which was in operation, had a significant amount of lube oil under and around the pump. No specific leak point was apparent, although it appeared to come from the area of the pump outboard bearing. The condition was noted to the Unit 1 shift foreman and the maintenance manager.

Lube Oil System - A Brief Description of Operation

In order to understand the issues in this section of the report a brief description of the operation of the charging pump bearings lubrication oil system is necessary. Specifically, two pumps take suction from the lube oil (LO) reservoir; the CCpp shaft driven "main" LO pump and a motor driven "Auxiliary" LO pump. The two pumps supply a header which supplies system flow and bypass flow. Bypass flow is controlled by a relief valve which is designed to maintain system pressure between 10 and 12 psi. Main flow goes through the lube oil cooler (cooled by component cooling water), through a filter and to a header. The header supplies the inboard and outboard pump bearings, pressure instrumentation and controls. The pressure instrumentation and controls include a local indicator, a low lube oil pressure annunciator, a lube oil pressure CCpp start

permissive, and start and stop pressures for the Auxiliary LO pump. The system is designed such that on a control room start, the Auxiliary LO pump starts and raises lube oil pressure from essentially zero psig. The lube oil pressure permissive (PS 295/296) allows the CCpp to start when pressure reaches the setpoint of about 9 psig. The Auxiliary LO pump and the Main LO pump build up system pressure to a setpoint which turns off the Auxiliary pump (PS 293/294). System pressure should then reach an equilibrium based on the setting of the relief valve which acts as a pressure regulating device.

Inspection:

The inspectors investigation of the leak revealed a number of concerns described below:

- The inspector reviewed action requests and determined that there is long history of charging pump lube oil system problems with a number of unresolved issues. Starting in March 1983 problem reports chronicle pressure switch setpoint problems, oil pressure outside manufacture recommendations, excessive auxiliary LO pump cycling and lube oil leaks. One quality evaluation was open at the time of inspection. It was opened on November 16, 1986, and identifies problems on CCpp 1-2 and CCpp 2-2 such as excessive clearances, leaking valves, lube oil quality and instrument setpoints. Responsibility and due dates on the QE had changed and when reviewed by the inspector the target date was September 1989. This appeared to be an example of a lack of timely corrective action and a lack of clear problem ownership which was identified to the licensee at the management SALP meeting held in Walnut Creek, California, on October 26, 1988.

- Instrumentation and Relief Valve setpoints were inadequately controlled. The pump manual requires that pressure to the pump bearings be maintained between 10 and 12 psig. The system engineer, following questions from the inspector, found that the relief valve, which acts as a lube oil system pressure regulator was set to 19 and 20 psig, respectively for the two charging pumps, by the periodic maintenance procedure. As a result, system pressure has not been controlled by the relief valve since with the valve fully closed main LO pump discharge pressure is between 12 and 17 psig. In addition, the Unit 1 and 2 CCpp start permissive setpoints were different and documentation did not definitely established what the appropriate settings for the permissive were. As a result, the LO system has operated consistently outside the recommended 10 to 12 psig band.

- The leak on CCpp 1-2 had received little attention since the leak was identified by the licensee. The leak was identified on August 23, 1988, on an Action Request. The inspector brought the matter to the maintenance managers attention on

November 18, 1988. At that time, no actions to analyze or correct the situation had been performed.

- The amount of oil added to pumps and motors is not trended. An informal log at the auxiliary building auxiliary operator panel was used to track how much total oil was put into various pumps. However, the log did not specify exactly where the oil went (e.g. the log indicated that 3 gallons of oil had been added to the CCpp on October 25, 1988, did not specify where it was added; the pump, the speed increaser, or the motor). In addition, through interviews with the auxiliary operators (AOs) it was determined that not all AOs were aware of the log.

These concerns were discussed with the assistant plant manager for maintenance on November 29, 1988. As a result of these discussions a system engineer was given the task of establishing what problems existed and what corrective actions were necessary. In addition, the work planning manager stated that a procedure in draft would be revised to include actions to be taken following the discovery of an oil leak similar to the actions being specified in the draft for a boron leak. These actions include a timely engineering walkdown and evaluation. Finally, the plant manager committed in the exit meeting to consider implementing pump and motor oil consumption trending. The inspectors will follow-up the licensee's actions in the course of future inspections.

No violations or deviations were identified.

6. Surveillance (61726)

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

a. Auxiliary Saltwater Pump 2-2 Baseline Performance Test

On October 28, 1988, the inspector observed portions of the performance of the Auxiliary Saltwater Pump 2-2 baseline performance test (STP P-7A). The test was performed to determine a new pump curve for the ASW pump following impeller replacement. Except for the one discrepancy discussed below, the test was performed in accordance with the procedure.

The procedure requires the reading of an annubar flow gauge to determine flow with varied heat exchanger outlet valve position (steps 8.11 to 8.15). The inspector observed that the annubar was fluctuating erratically ± 5% of full scale. The test engineer, after attempting to throttle the gauge isolation valves to minimize the oscillation, observed the gauge for between 30 and 60 seconds to visually determine a mean flow value. This reading was not obtained in accordance with procedure AP C-3S3, "Administrative Procedure Dealing With Gauge Oscillations During the Performance of ASME Section XI Required Tests", issued September 23, 1988. The

procedure requires that if a gauge is oscillating irregularly greater than 2% of the midpoint reading but not exceeding 10% of gauge range, to "..take 5 spot readings at 10 second intervals, sum the 5 readings and divide the sum by 5 to obtain an average reading." In addition, the procedure also requires that an action request should be written which was not done. The failure of the test engineer to follow procedure is an apparent violation (Item 50-323/88-29-01).

The above incident was preceded by a history of enforcement actions dealing with improper test instrument reading. A similar instance was observed by an inspector on February 10, 1988 when fluctuations of flow of greater than that allowed in the procedure were observed when testing a Containment Spray pump 1-1. This resulted in a notice of violation (Inspection Report 50-275/88-04) for failure to obtain test reference values within tolerances specified in ASME XI. In response to the notice of violation, the licensee committed to write an an administrative procedure for reading and interpreting test instruments by July 1, 1988. An inspection in September found that the licensee had not implemented this commitment. This resulted in a notice of deviation (Inspection Report 50-275/88-25). Procedure AP C-3S3, which implemented the licensee's original commitment was issued shortly after the inspection (Open Item 50-275/88-25-01, closed).

The inspector discussed the system engineer's failure to follow the procedure with the assistant plant manager for technical services. Three issues were discussed. First, from interviewing the system engineer, the inspector determined that he had been unaware of the issuance of procedure AP C-3S3 and that a determination of why he had been unaware and corrective actions to prevent recurrence was needed. Second, the inspector requested the licensee provide the technical basis for the sampling method used in procedure AP C-3S3. Finally, the inspector expressed concern that the issue of gauge reading had been handled slowly and was another example of untimely resolution of identified problems discussed in the SALP report. Following the discussion a nonconformance report was initiated.

The technical review group (TRG), which convened to review the nonconformance report determined that the engineer had not been informed nor trained on AP C-3S3, although it was his own supervisor who had written the procedure. Further, the TRG determined that no formal mechanism existed to notify and train plant engineering personnel of new and revised administrative procedures. Corrective actions identified by the TRG included establishing a formal program to accomplish training in new and revised procedures for plant engineering and to assess the need for such a program in other departments. The inspector will review these corrective actions in follow-up of the notice of violation enclosed in this report.

At the end of the report period, the licensee had not provided the inspector with a basis for the averaging technique described in AP C3S3. This was discussed in the exit meeting and the plant manager

committed to include the basis in their response to the notice of violation enclosed in this report.

b. Continuity Testing of Feedwater Isolation Slave Relay

On December 2, 1988, the inspector observed the testing of the train "A" solid state protection system (SSPS) feedwater isolation slave relay (K601A) for Unit 1. Three attempts were required to actuate K601A (which is normally closed and opens on an actuation signal). During the first two attempts, the relay failed to open. These first two attempts were performed by the senior control operator and an auxiliary control operator. The third attempt was witnessed by the shift foreman and supervising instrumentation and controls (I&C) technician.

To test slave relay K601A, test switch S801A is taken from "normal" to "push-to-test." This actuates test relay K801A which provides a bypass circuit which ensures that the feedwater isolation valves remain open when K601A is tested. In addition, K801A provides a permissive which allows S801A, when depressed, to actuate K601A. It was determined by the I&C technician that the set of contacts which provide this permissive did not make up. The determination was based on indirect evidence as opposed to direct observation of the contacts or evidence which ruled out failure of the slave relay. The evidence included:

- K801A made a buzzing all three times which, per the I&C technician, indicates that the relay had not rotated completely when it actuated.

- Visual observation by the I&C technician on the third attempt that K801A had not rotated completely.

- The slave relay K601A did not actuate at all the first two tries and rotated fully the third try indicating it had not received any power on the first two attempts.

- A history of test relay problems and no history of slave relay problems.

The inspector discussed the test with the I&C manager and concurred that the licensee determinations appeared to be appropriate.

One violation was identified as noted above in paragraph 6. a..

8. Radiological Protection (71707)

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 professionals conducted frequent plant tours to observe activities in progress and were generally aware of significant plant activities, particularly those related to radiological conditions and/or

challenges. ALARA consideration was found to be an integral part of each RWP (Radiation Work Permit).

Removal of Scaffolding From Unit 2 Containment

The inspector observed health physics (HP) practices in the removal of scaffolding from the Unit 2 containment while the Unit was in Mode 5 on November 6, 1988, between approximately 9:30 p.m. and midnight. Scaffolding was delivered to the containment equipment hatch at the 140' level from the 115' level by PG&E General Construction (GC) personnel. The scaffolding and clamps were then wiped down by the GC personnel. The wipes were then frisked by HP personnel monitoring the evolution. The scaffolding and clamps were then passed out the containment equipment hatch, over a walkway of herculite, which had been laid down prior to opening the hatch, to a holding area. The equipment remained controlled inside a surface contamination area and did not pass from one level of contamination control to another.

The inspector interviewed one of two HP technicians monitoring the work. The HP technician stated that all wipes were being frisked to determine the relative contamination of the scaffolding. The technicians acceptance criteria was 10,000 dpm. The technician stated that no contamination greater than the acceptance criteria. The technician also indicated that the intent was not to decontaminate scaffolding but to identify scaffolding with relatively high contamination. The inspector discussed the work with the radiation protection foreman for containment. His understanding of the process concurred with that of the technician. In addition, he stated that the scaffolding would be bagged and frisked before being taken outside the Radiological Controls Area for storage as radioactive material. He noted that this was the practice used in three previous outages. The RP foreman stated that scaffolding taken from a hot particle zone (HPZ) received inspection and either decontamination or bagging prior to removal from the HPZ. He noted that to his knowledge no scaffolding was at that time being removed from an HPZ.

The inspector also interviewed the security guard who was present when the equipment hatch was opened. He stated that the laydown area and path to containment had been established prior to opening the hatch.

The inspector discussed with and observed GC personnel transfer scaffolding from the 115' level to the 140' level. At the time of the inspection it was observed that no scaffolding was being disassembled and that scaffolding being transferred were parts staged for removal outside the bioshield on the 115' level.

The inspector found practices of HP and GC to be acceptable. Additionally, the following morning, the radiological protection manager was requested to independently assess whether radiological practices in the movement of the scaffolding were proper. His subsequent response after a survey of radiological personnel involved in the job was that radiological practices were proper. The request to the radiological protection manager was made in response to the fact that some workers involved in the job had expressed concerns regarding the adequacy of controls exercised.

No violations or deviations were identified.

9. Physical Security (71707)

Security activities were observed for conformance with regulatory requirements, implementation of 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.

10. Licensee Event Report Follow-up (92700)

a. Status of LERs

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

Unit 1: 88-14, 88-20

Unit 2: 87-26, 88-04, 88-08, 88-11, 88-12

b. (Open) Unit 2 Inoperable Reactor Cavity Sump Level Indicator (LER 2-88-13-00)

On November 14, 1988, the licensee issued LER 2-88-13-00 which discussed the Unit 2 inoperable reactor cavity sump level (RCSL) indicator. The level indicator was found to be inoperable during the recent refueling outage due to the isolation of it's instrument air supply. The RCSL indicator is part of the technical specification 3.4.6.1 reactor coolant leakage detection system which includes the containment structure sump, the containment particulate and gaseous radiation monitors RM-11 and RM-12, and the Containment Fan Cooler Collection Monitoring System (CFCCMS).

The inspector reviewed the "Analysis of Event" portion of the LER. In a review of the operability status of the CFCCMS and RM-11 and RM-12, the submittal stated that "Except during routine testing of the radiation monitors, all channels were available to perform their intended function. The above two monitoring systems remained operable and would have indicated increased signs of RCS leakage, had there been any." The inspector found approximately five corrective maintenance work orders on RM-11 and RM-12, indicating that the radiation monitors had been out of service for other than "routine testing." In addition, a review of the inspectors notes showed that the radiation monitors had been inoperable from September 28 to October 1, 1987. The licensee was requested at the exit meeting to provide the out of service times for RM-11 and RM-12.

In addition, the LER is misleading in that the CFCCMS was made operable as a compensatory action only when RM-12 was taken out of service. The analysis submitted did not fully discuss the adequacy of the remaining leakage detection systems.

These questions were discussed with the Regulatory Compliance Supervisor who committed to submit a revised analysis. This item is considered an unresolved item (Item 50-323/88-29-02) pending resolution of the inspectors questions.

c. (Open) Emergency Core Cooling System (ECCS) Not Vented Within Technical Specification Required Limit (LER 2-88-06)

The LER issued July 5, 1988, specified, as corrective actions, revision of Administrative Procedure AP C-3S1 " Surveillance Testing and Inspection." The revision was to emphasize the timely closure of completed recurring surveillances so that a new test can be scheduled. At the end of the report period, this revision had not been completed (a period of five months). At the exit meeting, the inspectors discussed the ongoing concern with lack of timely corrective action. This item will remain open.

d. (Closed) Inadvertent Autostart of Diesel Generator 1-3 Due to Personnel Error (LER 2-88-12-00)

The licensee submitted LER 2-88-12-00 on November 8, 1988. The LER discussed the inadvertent start of a diesel generator when a maintenance contractor for the Unit 2 outage tried to obtain power to test an auxiliary transformer relay from the startup transformer and energized its differential relay.

The inspectors found the root cause determination corrective actions to be acceptable. This was an example where personnel did not recognize that instructions were not adequate and did not stop their activity. This issue was the subject of discussion in the SALP meeting (Inspection Report 50-275/88-30). The inspectors will continue to monitor the licensee's progress in this area (LER 50-275/88-12-LO, Closed).

No violations or deviations were identified.

11. Reactive Inspection

a. Containment Temperature (Temporary Instruction 2515/98, CLOSED)

In response to high containment temperatures affecting safety related components at a number of plants, a Temporary Instruction (TI 2515/98, issued June 20, 1988) was issued requiring an inspection of containment temperatures and monitoring systems. The TI included an attachment that listed eight questions. The inspectors findings for the questions are included as an attachment to this report.

In summary, the inspector found that the licensee's temperature monitoring was acceptable to meet design basis accident assumptions. The licensee's efforts to formalize its procedures for monitoring and evaluating peak temperature experienced during a fuel cycle were found to be prudent and will be followed through routine inspection.

b. Effectiveness of Quality Assurance Inspections (36700)

A review was performed of a limited sample of Quality Support surveillance inspection. Quality Support (QS), the onsite division of Quality Assurance, performs periodic surveillances on all aspects of plant activities in accordance with QS procedure QS-4. The inspector reviewed surveillances QS 88-0562, 0715, and 0746. All three were walkdowns of containment penetration manual isolation sealed valve checklists.

Although a number of discrepancies between the checklist and as-found condition were noted in the three surveillances, none of the surveillances adequately discussed the cause of the discrepancies or invoked adequate tracking of corrective actions.

QS 88-0562

The QS inspector identified five discrepancies with the inside containment isolation valve sealed valve checklist OP K-10B1, including valves in the positions other than specified in the checklist and missing seals. The "Disposition/Conclusion" section of the surveillance stated:

> "These valve positions are satisfactory for the mode we are currently in, but must be corrected before entry to Mode 4."

An independent verification by the inspector determined that the plant was in Mode 6 "Core Alterations" at the time of the QS inspection. In this mode TS require a level of containment isolation, although not as stringent as the Modes 1 to 4 alignment. The operations department was controlling the Mode 6 containment isolation with a clearance and OP K-10B1 was "inactive" (essentially not controlled). The inspector determined that QS had not verified that the discrepancies identified agreed with the containment clearance although the resident inspector independently made this verification. The QS effort identified seal valve "discrepancies" from a list that was not applicable.

QS 88-0715

This surveillance documented five discrepancies of outside containment isolation valve checklist OP K-10B2. The disposition stated "The above must be corrected before entry to Mode 4." In an interview with the QS inspector, the inspector learned that QS had handed the list of discrepancies to the Unit 2 shift foremen (SFM) for action. In addition, no action was taken to formally follow-up the correction of the discrepancies and to determine the cause. The inspector independently discussed the QS list with the SFM and

discovered that the OP K-10B2 valve alignment was in process. Four of the points had yet to be signed off. The other two points involved end caps and plugs not installed. On follow-up, after discussions with the resident inspector, QS determined that the appropriate end caps were installed and the original QS finding had been erroneous. This is another example where QS did not perform a verification that the applicable controls were, in fact, functioning.

QS 88-0716

This QS inspection resulted from discussions the resident inspector had with the QS supervisor as an effort to formally resolve discrepancies identified in the previously discussed surveillance QS-88-0715. The new report (QS-88-0716) stated "Deviations listed previously have been corrected with the exception of valve AIR-S-2-200." Again, the deviation was not tracked nor did QS indicate in the surveillance report that the valve had not been closed by operations or that Op K-10B2 had not been completed by operations.

As a result of the findings discussed above, the resident inspector discussed weaknesses identified in the conduct of QS surveillances with the QS supervisor. Specifically, the inspector considers that if a "deviation" is found by QS, its validity should be verified, the cause of the deviation should be identified, and formal corrective action should be taken. If these final steps are not taken, then the effectiveness of the QS surveillance program of identifying quality problems and initiating lasting corrective actions is limited. While it was noted that QS has accomplished the above in some of their recent inspections (such as the Penetration 63 issue during the Unit 1 second refueling outage and the Auxiliary Saltwater impeller issue), the concept that inspections should be conducted to a meaningful conclusion appears to need additional attention.

As a result of the discussion, the QS supervisor initiated a Quality Evaluation on the issue of QS surveillance follow-up. The inspector will evaluate the adequacy of the corrective actions in a future inspection.

12. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, items of noncompliance, or deviations. An unresolved item disclosed during this inspection is discussed in Paragraph 10.b. of this report.

13. Exit (30703)

On December 12, 1988, 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.

ATTACHMENT TO INSPECTION REPORTS 50-275/88-31 and 50-323/88-29
INFORMATION FOR TI 2515/98 CONTAINMENT TEMPERATURE SURVEY

1. Plant Name: Diablo Canyon Units 1 & 2
2. Unit 1 Docket Number: 50-275 Unit 2 Docket Number: 50-323
3. What are the average containment temperatures during operations as recorded by the licensee? Note: We are interested in the peak operating temperatures during the hottest summer months.

   Discussions with the Operations Department indicated that Diablo Canyon normally operates with containment temperatures below 110 degrees. The inspector reviewed containment temperature history data provided by plant engineering which confirms this for the months of April to October 1987 and April to September 1988. The temperatures provided were the technical specification required daily recorded average of four containment temperature monitors. The average containment temperatures varied for these summer months from between 94 and 103.3 degrees F. The hottest temperature recorded was 108.4 degrees in October 1987 for Unit 1.

   Diablo Canyon rarely experiences high ambient temperature conditions due to the coastal climate. During the summer months, coastal fog covers the site for most of the day, keeping temperatures in the 60's and 70's. Infrequently, inland winds will warm the coast as in October 1987. The containment is cooled by five containment fan cooler units (CFCUs), which are cooled by the component cooling water system which is cooled by the auxiliary salt water system (ASWS), the ultimate heat sink, which take suction from the Pacific Ocean. The ocean temperature normally remains below 64 degrees F. The ASWS and CFCUs are sized for accident conditions and at normal temperatures can easily handle containment ambient conditions.

4. Containment temperature at which the plant is licensed to operate (i.e., operating temperature specified in the FSAR).

   Plant Technical Specification 3.6.1.5 requires that average containment temperature shall not exceed 120 degrees F in modes 1 through 4. If 120 degrees F is exceeded for over eight hours the licensee is required to be in hot standby in the following six hours and cold shutdown in the following 30 hours. To verify containment average temperature the licensee is required to take an average of four monitors. The monitors are located inside the bioshield between the steam generators, outside the bioshield on the same level, on the refueling deck level, and on top of the steam generator missile barriers away from the steam generators.

   The basis for Technical Specification 3.6.1.5 is to ensure that the overall containment average air temperature does not exceed the initial temperature condition assumed in the safety analysis for a loss of coolant accident. These initial conditions for the LOCA analysis are described in FSAR Table 6.2-4.

5. Review the temperature readings and provide your assessment as to whether or not you believe the average temperature readings accurately reflect containment conditions, or if there is a significant difference, due to

temperature sensor location or stratification of containment atmosphere which could produce hot spots.

The average temperature readings appear to provide an accurate containment average temperature in that it is a simple assessment of what is the average temperature of the containment air volume, providing an energy input for the LOCA calculation. The containment does have "hot spots" which are not accounted for by the average temperature.

6. What temperatures are used by the licensee in its equipment environmental qualification program when calculating the remaining qualified lifetime for all equipment inside containment, and are these temperatures consistent with temperatures experienced?

   Post-LOCA environment temperatures are based on the initial ambient average temperatures of 120 degrees. In addition, the equipment life calculations are based on 120 degrees at the component. Currently, the licensee is establishing a program of monitoring the peak temperature experienced at all environmentally qualified equipment locations inside containment. This involves attaching temperature recording stickers (which record the highest temperature to which they are exposed) at the beginning of a fuel cycle and removing them during the next refueling outage. The results are then forwarded to Engineering for analysis. At the time of this report a final analysis had not been performed for either Units 1 of 2. Preliminary data indicates that some equipment is exposed to greater that 120 degrees, such as equipment on top of the pressurizer. The solenoid valves, which operate the pressurizer power operated relief valves, have been replaced and will be examined by Engineering.

   The inspector will follow-up the results of Engineering's evaluation of operational temperature data during routine inspection.

7. Administrative temperature limit for the containment, if no technical specification limit exists.

   Not Applicable, see item 4.

8. Recent history of temperatures inside containment. Provide containment average air temperature in addition to the containment air temperatures to compute the average containment temperatures for the months of April, May, June, July, August, and September 1987, if the plant has not operated during those months use an operating period close to these months.

   A table was forwarded to NRR separately showing the daily containment average temperatures, recorded in accordance with TS surveillance requirement 4.6.1.5, for the months of April to October 1987 for Units 1&2 and April to October 1988 for Unit 2. Days where data was not recorded the unit was not in Mode 1 to 4.