U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos: 50-275/89-21 and 50-323/89-21

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: July 30 through September 9, 1989

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Summary:

Inspection from July 30 through September 9, 1989 (Report Nos. 50-275/89-21 and 50-323/89-21)

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, 37702, 40500, 61726, 72703, 71707, 71710, 92701, 92702, 92720, and 93702 were used as guidance during this inspection.

Additionally, an examination of the licensee's programs for system engineering and root cause analysis was conducted by the NRC Region V Reactor Safety Branch Chief and the Senior Reactor Engineer. Also an examination of radiological practices and operator medical qualification records was conducted by the Chief of the Emergency Preparedness and Radiological Protection Branch and the Chief of the Facilities Radiological Protection Section, NRC Region V.

Results of Inspection: One violation was identified regarding a fire door made inoperable by maintenance personnel (paragraph 5.a.). One noncited violation (NCV) is identified in paragraph 11.a. dealing with the traceability of control valve air regulators.

Strengths and Weaknesses

The licensee strength noted during this reporting period included progress in the conduct of the system engineering program (paragraph 13.) and a well considered and executed event analysis and response on the August 28, 1989, Unit 2 manual reactor trip (paragraph 4.c.).

Additionally, the depth of and plant staff response to the licensee's safety system functional audit and review (SSFAR) was noted to be a serious effort to identify and resolve design basis problem areas (paragraph 4.a.). Also, the licensee's well considered and well executed replacement of a containment control rod drive ventilation fan motor while at power was noted (paragraph 4.b.).

The licensee also demonstrated some weaknesses which were discussed with plant management at periodic meetings with the NRC residents. These included:

- A lack of timely and comprehensive engineering action when changing the designated quality class of heat tracing in the licensee's Q list. Follow through was lacking (paragraph 7).

- Since there were three examples of fire barriers having been defeated by maintenance personnel without the performance of necessary compensatory measures (one of which was acceptably identified and resolved by the licensee); the inspectors concluded that additional plant attention was warranted in light of the upcoming refueling outages (paragraph 5.1.).

- The formality of engineering troubleshooting plans and engineering formality in interfacing with operations was noted as an area requiring attention. This was exemplified by the plant engineering's informal approach and misunderstanding with operations in dealing with positive displacement pump vibration problems (paragraph 14.).

- The licensee experienced a spill of reactor coolant water which resulted in a personnel contamination. The cause of this spill was an improper valve lineup which was caused by an incomplete clearance and a lack of knowledge of system status which as been the subject of previous management discussions (paragraph 4.e.).

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
*M. J. Angus, Assistant Plant Manager, Support Services
*C. L. Eldridge, Quality Control Manager
*K. C. Doss, Onsite Safety Review Group
T. A. Bennett, Maintenance Manager
D. A. Taggert, Director Quality Support
W. G. Crockett, Instrumentation and Control Maintenance Manager
J. V. Boots, Chemistry and Radiation Protection Manager
T. L. Grebel, Regulatory Compliance Supervisor
*J. A. Shoulders, Onsite Project Engineering Group Manager
M. E. Leppke, Engineering Manager
*M. G. Burgess, Senior Power Production Engineer
S. R. Fridley, Operations Manager
R. P. Powers, Radiation Protection Manager

The inspectors had discussions with 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 September 22, 1989.

2. Operational Status of Diablo Canyon Units 1 and 2

Unit 1 operated at power for the reporting period. Power was temporarily reduced to 92% on August 3, 1989, due to high generator vibrations. Vibration levels were controlled, after discussions with Westinghouse, by combined variances in the generator hydrogen gas temperature, impedance and voltage changes. The unit returned to 100% power by August 9, 1989. The licensee plans to perform major generator and exciter work during the upcoming October refueling outage which should correct the vibration problem.

Unit 2 operated at power during the reporting period except for a manual reactor trip on August 28, 1989, due to an electrical fault in 12kv motor lead to reactor coolant pump 2-1. The unit returned to power operations on August 31, 1989.

During the reporting period senior NRC Region V personnel, the Reactor Safety Branch Chief and the Senior Reactor Engineer, visited the site and evaluated the licensee's programs for root cause analysis and system engineering. Also an examination of radiological practices and operator medical qualification records was conducted by the Chief of the Emergency Preparedness and Radiological Protection Branch and the Chief of the Facilities Radiological Protection Section, NRC Region V.

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.

Medical Examinations

At the request of Region V, compliance with the frequency of medical examinations provided for licensed reactor operators, pursuant to the provisions of 10 CFR 55.21, was examined on August 24, 1989. Review of forms NRC-396 maintained for 18 of 48 senior licensed operators and 15 of 33 licensed operators indicated that all 18 senior licensed operators and all 15 licensed operators have

received a medical examination and certification within the last two years. Based on discussion with representatives of the training department, it appeared that they were aware of the regulatory requirements in this area and carefully tracked the schedule and completion of the required physical examinations.

No violations or deviations were identified.

4. Onsite Event Follow-up (93702)

a. Quality Assurance Safety System Functional Audit Review

Between July 10 and August 4, 1989, the licensee's Quality Assurance organization conducted a "Safety System Functional Audit Review" of the Auxiliary Feedwater System (AFW). The inspector attended the exit interview held on August 4. While the audit determined that there were no immediate operability concerns, they identified a number of significant findings, such as;

- The minimum Condensate Storage Tank (CST) level specified in the Technical Specifications (TS 3.7.1.3) does not provide sufficient water to meet the TS basis. The licensee's JCO was reviewed and appeared to be acceptable.

- The steam supply valves to the AFW turbines may not be designed to operate against maximum design pressure (1085 psid vs 950 psid vendor specified maximum).

- A blind flange with a hose bib was found attached to the CST overflow connection and could have restricted overflow possibly causing an overpressurization in the event of high rejection rate from the main condenser hotwell.

- A potentially non-conservative inservice testing criteria for the turbine driven AFW pumps.

Many of the findings resulted in the initiation of NCRs and some resulted in justification for continued operations. Noted improvements in this effort as compared to previous QA SSFARs was the quality and size of the team, the plant and engineering support, and the responsiveness of the licensee to the QA findings.

At the end of the inspection period, QA's final report had not been issued. The inspectors will continue to evaluate the licensee's follow-up of the SSFAR finding during routine inspection.

b. Control Rod Drive Mechanism (CRDM) Fan Replacement

On August 10, 1989, the licensee replaced a failed CRDM fan motor inside containment. At the time, approximately 60 days prior to the Unit 1 third refueling outage, two of four CRDM fan motors had failed. Given past experience of the motor service life, the licensee made the decision to replace one of the motors while at 100% power. The job, which involved the lifting of a complete CRDM

fan including its discharge damper from its installed position to an adjacent work area, was completed inside containment in an area which is ordinarily restricted for heavy load handling.

The licensee performed a number of safety evaluations, included in a Design Change Package, for the job. The safety evaluation topics included the use of a temporary cover over the ducting following the removal of the fan, the additional aluminum brought into containment while at power, the lift path of the motor to its work area, and the travel path and use of the polar crane while at power. A temporary procedure, which included a safety evaluation, was also issued to perform the work. The inspector found the planned work activities to be well documented.

The inspector observed portions of the work from the reassembly of the motor to the reinstallation of the motor. Except for minor items (i.e. a wrong size set screw was issued to the job due to lack of specificity resulting in a delay while the proper size was obtained) the job was well planned and executed and containment stay time was minimized.

c. <u>Unit 2 Manual Reactor Trip Following Reactor Coolant Pump 2-1 Motor Lead Failure</u>

At 8:57 p.m. (PDT) on August 28, 1989, the Unit 2 reactor was manually tripped from 100%. Two minutes earlier, operators had noted ground alarms on the reactor coolant pump (RCP) 2-1, the circulating water pumps, and the 12kv startup transformer. Subsequently, the RCP 2-1 smoke detector alarmed and amperage swings were noted on RCP 2-1.

Operators performed a manual trip in accordance with procedures, entered their emergency procedure for reactor trip, and made a 4 hour non-emergency report to the NRC in accordance with 10 CFR 50.72.

All safety systems functioned normally but some plant equipment had anomalies which the plant staff later analyzed and corrected (e.g. a lo lo level lockout alarm was received on the Electrohydraulic fluid level). Additionally, diesel generator 2-2 started but did not load. The diesel was not expected to start on fast transfer to startup power, but did and has on occasion in the past. The licensee has plans to reset actuation relay setpoints to minimize these starts due to voltage transients.

The licensee made initial containment entry at about 2:00 a.m. on August 29 and determined that the phase A 12kv motor lead to RCP 2-1 had shorted and "vaporized". Initial electrician assessments were that repair was possible if the motor successfully passed high potential testing (hi-pot) which it did. The licensee had a spare RCP motor available if repairs were not possible to the existing motor.

The reactor coolant pump 2-1 damaged motor lead was successfully repaired by use of a crimped-on butt sleeve splice and the installation of Raychem splice insulation.

The other two phase leads (B and C) on RCP 2-1 were determinated and examined to establish a probable root cause. One lead was found to have a loose lug connection apparently caused by the failure to note and remove a spot of solder on the lug seating face. These internal motor lug connections were made at the time of motor manufacture.

The licensee has previously reworked the connections on pumps RCS 2-3 and 2-4. RCP 2-2 had two leads remaining which had not been previously worked. These were examined on August 30 by thermographic means with the pump operating. No hot spots were noted. The licensee intends to physically check these terminations in their upcoming February 1990 refueling outage.

On August 31, 1989, at 2:55 a.m. PDT Unit 2 achieved criticality in its startup subsequent to the August 28 manual reactor trip.

In review of the licensee actions, the inspectors noted that operators responded quickly and acceptably to the event and that management was rigorous in instituting action plans for repair and recovery.

The inspectors were involved in review of the sequence of events and noted with licensee management that the annunciator typewriter had failed to record alarms for a critical period of about 40 seconds following the trip. Licensee troubleshooting identified a failed electronic card in the annunciator typewriter memory which limited the amount which could be electronically retained while the manual typewriter "caught up". The licensee committed to implement an on-line check of the typewriter electronic buffer as a periodic test to identify such faults prior to an event (Follow-up Item 50-323/89-29-01).

The licensee noted that the annunciator typewriter and its memory buffer are old and scheduled to be entirely replaced with modern equipment in the upcoming Unit 1 and 2 refueling outages.

The licensee plans to issue an event report (10 CFR 50.73) on the reactor trip.

The licensee prepared a justification for continued operation (JCO) for reactor coolant pump 2-2 which was the only other RCP in Units 1 or 2 which was in a state of original manufacture at the failed connection. This JCO was reviewed and acceptable.

The resident inspectors held a telephone conference with licensee engineering personnel and NRR on August 31, 1989, reviewing the event and its similarities to the July 17, 1988, event involving the same reactor coolant pump motor lead failure (but not the same connection point). The licensee indicated that the grounding detection system was to be improved by a design change. The

licensee also stated that a study of the circuit breaker by an outside consultant pursuant to the July 17, 1988, event indicated a second startup feeder breaker to the startup transformers was required to prevent a loss of both units startup power for a single fault at a startup transformer. This issue, raised in July 1988, has been confirmed by a consultant. The licensee indicated the appropriate design change would be implemented but has not been fully authorized. The inspectors will continue to follow licensee progress on this matter.

d. Inservice Inspection Waivers

On September 1, 1989, the resident attended a plant safety review committee (PSRC) meeting on the subject of special tests to be performed at power to fulfill inservice inspection (ISI) program requirements.

The required tests represented a few remaining ISI required hydrostatic tests and checks for leakage which had been deferred from the previous refueling outage. The licensee had deferred the tests on the premise that most could (and were) performed at power and secondly, the original schedule for the upcoming refueling outage (previously September but now October 1989) was within the required time frame for performance of the tests.

The licensee submitted two letters requesting one time schedular reliefs to extend the test periods for 60 days to allow the test to be done in the October 1989 refueling outage. NRR approved the requests in two letters dated September 7, 1989.

The licensee prepared a nonconformance report on the subject, NCR DCI-89-TN-N087, in order to identify root cause and corrective action. The inspectors will follow-up licensee corrective action in the normal course of future inspection.

e. Unit 1 Auxiliary Building Spill

On September 6, 1989, a spill of letdown reactor coolant water to the Unit 1 Auxiliary building occurred. During the event, which resulted from an inadequately prepared clearance and operators unaware of a system lineup, two operators were sprayed with water resulting in some contamination.

An equipment clearance had been written to allow maintenance on a discharge valve of the 1-2 gas stripper feed pump. The gas stripper feed pump takes suction from the letdown liquid holdup tanks and feeds the boric acid evaporator ion exchangers.

Prior to the hanging of the clearance, the 1-1 gas stripper feed pump was in an alternate lineup feeding the evaporator ion exchangers normally associated with the 1-2 pump and was feeding through what would be the clearance boundary. When auxiliary operators (AOs) began performing the clearance valve lineup, unaware of the system alignment, one of the first clearance points realigned

was a valve which isolated the 1-1 pumps flow path. Shortly following, the 1-1 pump tripped on thermal overload. The AOs did not make a connection between the trip on thermal overload and their actions.

Subsequently, a drain and a vent valve were opened and the pump header crosstie valve, which should have been on the clearance and was not, was left open. When the 1-1 pump was restarted, it pumped water out the open vent and drain. One operator was caught under the vent and was thoroughly sprayed. A second operator nearby called the auxiliary operator (AO) station to shut off the pump.

Both operators were decontaminated and given whole body counts. The operator who had been drenched showed a count of nine nanocuries. Although it could not be determined whether it was internal or external contamination, even as an internal dose it represents only a small fraction of allowable dose.

The event was discussed with operations management who concurred that this was an example of the valve misalignment similar to those discussed in depth at the beginning of the year. The operations manager stated that the underlying responsibility for ensuring that an off normal alignment does not affect a clearance belongs to those hanging the clearance and in this case the auxiliary operators should have been aware of the system alignment and the effects of the clearance. It was determined that while the status of the gas stripper feedpump alignment was generally described on the AO station system on a status board, the board was not an effective means of communicating the precise system alignment. Additionally, since the clearance was not adequate (it was missing two essential clearance points), the operations manager stated that actions needed to be taken in the area of clearance development and review. In the clearance process, reviews are performed by the clearance writer, the operations clearance coordinator, the shift foreman, and the operators hanging the clearance.

A non-conformance report was initiated following the event. Proposed corrective actions include the issuance of a policy document defining responsibilities of all involved in the clearance process and the use of schematic status boards to track systems which often have optional alignments. Such systems include liquid radwaste, condensate polishing, and boric acid evaporators. The inspectors will follow-up the effectiveness of licensee action through the non-conformance report.

5. <u>Maintenance (62703)</u>

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. Maintenance activities examined were discussed in section 4

of this report including reactor coolant pump motor lead recovery actions and control rod drive fan replacement. In addition the following was examined:

a. Emergency Borate Heat Tracing Corrective Maintenance

On August 2, 1989, the inspector observed portions of corrective maintenance being performed on Unit 2 Emergency Boration flowpath heat tracing. The work was required following the documentation on Action Request (AR) A0148513 of a low temperature reading on the emergency borate line.

The inspector observed electricians removing heat tracing from the line. The electricians stated that they were removing heat tracing that they had previously installed on the same job. Following the initial installation of heat tracing and prior to the installation of insulation, as required by the insulation procedures, chemistry sampled the pipe exterior for Chlorides and Fluorides. The line failed the test. The chemistry general foreman stated that the piping probably failed the test due to the chlorides depositing from the electricians hand to the piping during the installation of the heat trace. As a result, the heat tracing was removed, the line was cleaned and new heat tracing was required to be installed.

b. Fire Door Latch Taped Open

On the August 2 inspection, the inspector noted that the door to the 2-2 RHR heat exchanger room, where the heat trace work was being performed, had its latch taped so that it would not engage when shut. On subsequent review, the inspector determined that the door was a Technical Specification fire door. On the evening of August 7 the inspector observed that the door was closed and the latch was engaged. On August 8, the inspector brought this to the attention to the Safety and Emergency Services Supervisor who committed to follow-up.

It was noted in the above discussion the limiting condition for operation for Technical Specification 3.7.10, which applies to fire barrier penetrations (including fire doors), requires that fire doors be maintained operable. The action statement allows a fire barrier to be inoperable if within one hour a continuous fire watch is posted or an hourly watch patrol is established and a detector on at least one side of the barrier is operable. The licensee maintains an hourly patrol regardless of the status of fire barriers and there were operable detectors both inside and outside of the room.

On August 15, on a follow-up inspection, the inspector noted that the same door was propped open with a set of pliers and on further inspection nobody was in the room. After removing the pliers and assuring the door was closed, the inspector notified the Shift Foreman and Shift Supervisor. They were not aware of the condition of the door and had not issued a Technical Specification Operability Status Sheet to implement the requirements of TS action statement

for TS 3.7.10. This is an apparent violation (Item 50-323/89-21-02).

An emergency boration line fire penetration through the same room was defeated on July 17, 1989, resulting in the issuance of a Non-Conformance report. Therefore, the incident with the pliers was the third example on one job where fire barrier penetrations were made inoperable. Additionally, different people were involved in each event. The apparent lack of plant sensitivity to fire protection issues was discussed with plant management and subsequently, a Non-Conformance report was issued. Plant management committed to increase plant user awareness of fire protection issues and procedures and to investigate the ease of use of procedures.

Ambiguity of the Quality Classification of Heat Tracing

The inspector found that there were ambiguities related to the quality classifications of heat tracing. A detailed discussion of this issue is contained in Section 7, ESF Walkdown.

One violation was 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. Specific surveillance tests examined are discussed in Section 4 of this report regarding ISI testing.

No violations or deviations were identified.

7. Engineering Safety Feature Verification (71707)

Safety Injection System Heat Tracing

As discussed in Section 5.a. the inspector found that there were ambiguities related to the quality classifications of heat tracing. As a result, the inspector performed a more detailed review of the Safety Injection System heat tracing including a system walkdown.

The Quality Assurance Auditing group in April 1988 during the 4KV SSFAR audit identified that the Q list description of quality heat tracing did not include all quality related heat tracing (Audit Finding Report AFR 88-843). The Q list only specified heat trace on boric acid lines between the Boron Injection Tank (BIT) and the Reactor Coolant System (RCS). The audit finding cited a 1982 design criteria memorandum as the basis for the finding and interpreted it as requiring all heat trace of design class 1 piping requires design class 1 heat trace. As corrective action, the Q list was revised on November 14, 1988 to include heat tracing on "Boric Acid between Boric Acid Tanks, BIT, and RCS."

The inspector found the following weakness with the implementation if the new design class 1 boundaries of the Q list:

1) No Dedication Activities Performed

   When the licensee engineering group expanded the boundaries of design class 1 heat tracing, they did not perform any dedication activities of heat tracing previously treated as Class II, that is they did not evaluate whether the Class II heat trace equipment was suitable for Class I service.

2) Design Documents Ambiguous and Contradictory

   The Design Criteria Memorandum (DCM E-20, dated January 1982) describes the requirements for design class 1 heat tracing states that the "...criteria is applicable only for boric acid piping and equipment that are Design Classification 1." The "Q" list which describes the classifications of plant systems, and is general in nature, did not list any heat trace as design class 1 until 1987 and has since extended its boundary of design class 1 to include "Boric Acid between Boric Acid Tanks, BIT, and RCS." The Component Database (CBD), a computer database which reflects component data including design classifications, was not revised until May 1989, to reflect these changes.

3) Some Work Performed Subsequent to Q List Revision Was Performed to Wrong Classification

   The inspector did a limited review of work performed subsequent to the Q list revision and found two examples where work on heat trace lines described as design class 1 (i.e. between the boric acid tanks, BIT, and RCS) was not performed in accordance with applicable design class 1 quality assurance procedures.

4) QA Follow-up of Audit Finding Inadequate

   The audit finding was closed out based on the revision to the Q lists. QA did not address the implications of the finding on installed equipment. Additionally, it was apparent that Engineering knew of some of these weaknesses and were involved in informal action to address them. However, the actions were neither comprehensive nor timely.

These issues were discussed with engineering management and on September 19, 1989, were the subject of an NCR technical review group meeting.

There is little safety significance to the design classification of heat tracing. Heat trace is purchased commercial grade and dedicated to class 1 by functional testing. Verification of heat tracing operation is accomplished every 12 hours when line temperatures are recorded. Failed heat trace is investigated expeditiously whether or not the line is safety related due to the

consequences of a "rocked up" line. However, these problems are indicative of a breakdown in the control of quality related equipment with missed opportunities by engineering and quality assurance for their identification. This item is unresolved pending the licensee's response to the inspector's concerns (Unresolved Item 50-323/89-21-03).

No violations or deviations were identified.

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).

On August 23 and 24, 1989, the Region V Emergency Preparedness and Radiological Protection Branch Chief and Facilities Radiological Protection Section Chief toured the facility and met with licensee and NRC resident inspection staff to discuss the licensee's performance in the radiological controls area. Based on these discussions, it appears that the licensee is dedicating adequate resources and management attention to maintaining a high level of performance in this functional area. The licensee has performed self critical reviews and is striving to improve performance in reducing occupational radiation exposure and the number of personnel contamination incidents. Tours of the radiation controlled areas indicated the licensee is implementing good radiological controls. Some minor examples which might be characterized as a lack of attention to detail were brought to the licensee's attention. These involved matters like faded radioactive material labels on the Unit 2 high range stack monitor, out of date calibration stickers on the Unit 2 Fuel Handling Building PING, air samples being taken near the floor and corrosion on a shipping container. In one case, a health physics technician was observed performing surveys of a mock fuel assembly being removed from the Unit 2 spent fuel pool. The technician was also directing the crane operator and hosing off the mock assembly as it was being withdrawn. This observation was discussed with the Plant Manager in context of previous industry experience involving radiation technicians that allowed themselves to engage in performing work activities at the expense of providing radiation protection coverage. The Plant Manager exhibited sensitivity to the observation.

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 follow-up inspections were performed by the inspectors to verify licensee corrective actions:

Unit 1: 88-29

Unit 2: 89-07

No violations or deviations were identified.

11. Open Item Follow-up (92703, 92702)

a. Traceability of Auxiliary Saltwater Control Valve Air Regulators (Unresolved Item 50-275/89-14-02, CLOSED)

In inspection report 50-275/89-14, the issue of whether the air regulators installed in the backup air supply to the air operated component cooling water (CCW) heat exchanger (hx) inlet isolation valves (FCV-602 and FCV-603) were installed as design class 1 as required by the licensee's drawings, was left unresolved.

Subsequently, the licensee has found that the Unit 2 regulators clearly were not installed in accordance with the design change requirements. DC2-EJ-14042, dated February 1984, specified the installation of Fisher model 67AF design class 1 air regulators without internal reliefs. Both Unit 2 regulators had internal reliefs and were in all probability class 2 regulators that were part of the original design and incorporated into the later design change.

Additionally, while it appeared that the Unit 1 valves regulators were installed as design class 1, there was no documentation that showed this conclusively.

This individual instance was of minor safety significance. The licensee performed an engineering analysis of the use of air regulators with and without internal relief capability. The function of an internal relief is to prevent the downstream leg of tubing to pressurize above the relief setpoint. Engineering reviewed the failure modes of the two types of regulators and found that the internal relieving did not create a new system failure mode or create the potential for a common mode failure. Additionally, there was minor safety significance due to regulators being design class 2 and not design class 1. The licensee has in the past

evaluated the same model for use in class 1 applications and found it acceptable given dedication activities confirming size and function of the regulators. The regulators were pre-service tested and have subsequently operated successfully.

The licensee has taken appropriate corrective action. A non-conformance report (NCR) was initiated following the identification of the issue by the inspector. All air regulators on the same design change (a total of eight) were scheduled for removal, inspection, and replacement. Included in the NCR was a review of current procurement programs compared to those which were in effect when the subject design change was implemented. The licensee found that the programs had been substantiated and recent experience has not shown similar problems. The NCR found no generic implications of this finding based 1) this was the only safety application of this model air regulators and 2) extensive system testing.

The issue discussed above is an apparent violation, the violation is not being cited because the criteria specified in Section V.A. of the Enforcement Policy were satisfied.

b. Reading of Oscillating Gages (Enforcement Item 50-323/88-29-01, CLOSED)

The inspector reviewed the licensee's March 20, 1989, response to a February 17, 1989, letter questioning the basis of the "average of five readings" approach to the reading of oscillating gages.

The response committed to revise the gage reading procedure (AP C-3S3) to require that when a gage has irregular oscillations between 2% of the gage reading and 10% of the full gage range, a plant engineering evaluation to determine the cause of the oscillation and its effects on acceptability of the data will be required prior to test completion. A review of AP C-3S3 shows that for irregular oscillations, management approval is required for the use of an averaging technique and the procedure no longer specifies an average of 5 readings for these cases.

Based on the above, this item is closed.

c. Adequacy of Analysis Contained in LER 50-323/88-13 Revision 1 (Unresolved Item 50-323/88-29-02, CLOSED)

Licensee Event Report 50-323/88-13 was issued on November 14, 1988, addressing an inoperable reactor cavity sump level indicator. The "analysis of event" portion of the LER was found by the inspector to be misleading as to what instrumentation was available in lieu of the reactor cavity sump level indicator.

On March 3, 1989, the licensee submitted a revised LER and clarified its analysis. In addition, the licensee has taken action to improve its review of LER including move involvement of plant engineering in the review and an independent review performed by the Onsite Safety Review Group (OSRG). Based on the above, this item is closed.

12. Events Evaluation/Root Cause Programs

During the period August 1-3, 1989, these areas of the licensee's programs were examined by regional-based inspectors. The purpose of this effort was to review changes the licensee has made during the past year to expand the population of events requiring formal root cause determination, and to assess the effectiveness of the licensee's implementation of programs for event evaluation and root cause determination.

a. Background

The status of the licensee's programs for events evaluation and root cause determination were examined by a regional-based inspector during the period April 20-22, 1988, and reported upon in Inspection Report Nos. 30-275/88-11 and 50-323/88-10. At that time the licensee's programs required formal root cause determination for all Nonconformance Reports (NCRs), and for Human Performance Evaluation System (HPES) reports as determined appropriate by the HPES coordinator. Approximately 150 events per year were subjected to formal root cause determination.

In discussions with the NRC inspector, the Plant Manager expressed his view that the threshold for formal root cause determination should be lowered to include a larger population of events. During a meeting with NRC inspectors on April 22, 1988, the Plant Manager committed to the development of an action plan which would address criteria to be incorporated in revised or new administrative procedures to lower the threshold for events to be subjected to formal root cause determination. Specific consideration was to be given to revising applicable procedures to require formal root cause determination in the dispositioning of Quality Evaluation (QE) reports, of which there were approximately 660 per year at that time.

b. Actions Taken by Licensee to Improve Programs for Events Evaluation/Root Cause Determination

Administrative Procedure NPAP C-12/NPG-7.1, Identification and Resolution of Problems and Nonconformances, Revision 14, was distributed for implementation on July 12, 1988. This revision added the requirement to perform root cause analysis on QE reports (except for minor, non-repetitive problems which do not have generic implications). The procedure also requires that personnel assigned responsibility for performing root cause analysis and QC personnel assigned responsibility for concurring with these analysis complete specified training in root cause analysis.

To date, more than 125 personnel have attended a course entitled "Root Cause Analysis for Power Plants". This three day course is presented by a contractor with substantial experience in root cause analysis relating to nuclear power plants. Facility records also showed that since January 1989 approximately 200 individuals had

attended QE Root Cause Analysis training presented by the Diablo Canyon Quality Control Department.

A new Administrative Procedure, NPAP C-26, Root Cause Analysis, describing commonly used methods for root cause analysis was approved on July 10, 1989.

The onsite focal point for root cause analysis of QE is the Quality Control (QC) Department. AP C-12/NPG-7.1 specified that a QC Department Reviewer will concur in the appropriateness of root cause analysis and corrective actions on all QEs initiated by plant personnel.

c. Implementation and Effectiveness of Events Evaluation-Root Cause Analysis

Facility records included an Evaluation of Quality Evaluation Root Cause Determinations by the On Site Review Group (OSRG) dated January 4, 1989. The evaluation included a review of 50 QEs which had been dispositioned following the completion of initial training of the plant staff in root cause analysis and for which the QEs were in a completed status as of October 24, 1988. Of the 50 QEs examined by the OSRG, 12 were determined not to require root cause analysis consistent with the requirements of AP C-12/NPG-7.1. Of the remaining 38 QEs the OSRG evaluation found the root cause analysis to be inadequate or incorrect for 31. In most instances the OSRG evaluation found the statement of root cause to be a statement of the problem. An independent review of selected QEs previously evaluated by the OSRG was conducted by the inspector, and the conclusions reached by the OSRG were confirmed.

Discussions with QC management representatives revealed that they did not disagree with the results of the evaluation by the OSRG, although it was determined that many of the QEs evaluated by the OSRG were in fact initiated and had undergone partial dispositioning prior to the effective date for implementation, July 12, 1988, of Revision 14 to AP C-12/NPG-7.1. They also stated that a substantial amount of training in root cause analysis had been conducted subsequent to the OSRG evaluation, including retraining of QC review personnel. All QEs initiated after the effective date of AP C-12/NPG-7.1 and found to be deficient by the OSRG were re-evaluated by the QC department. Those determined to be of importance on a case-by-case basis were reopened by initiation of either a new QE or Action Request. This re-evaluation also, according to QC management, led to a practice of assigning QEs to a lesser number of individuals within the QC department for review and concurrence of root cause analysis.

Based on experience for the year 1988, licensee representatives have estimated that more than 1000 QEs per year will be subjected to root cause analysis in accordance with current program requirements. Licensee representatives did state, however, that they are considering changes to the criteria for events requiring root cause analysis, based upon the current INPO screening guide. This

consideration was prompted, in part, by a desire by licensee management to increase the number of balance-of-plant (e.g., non-safety related) events which will be subjected to root cause analysis while at the same time keeping the total number of events subject to root cause analysis to that number for which effective analysis can reasonably be conducted. In a meeting with plant management on August 3, 1989, the NRC inspectors expressed the view that to maintain a reasonably effective events evaluation/root cause program they would expect several hundred events per year to be subjected to root cause analysis.

In an effort to determine the quality of root cause analysis of QEs dispositioned subsequent to the OSRG evaluation, the NRC inspectors examined several QEs initiated during the period March 16-31, 1989, and processed to the point of QC concurrence. A total of 15 QEs were examined, of which only 1 was determined to have an incomplete or unclear root cause analysis documented. This QE (No. Q0006203) had been initiated and closed (placed in "History" status) on March 22, 1989. The QE related to the discovery of a power failure to an air sampler at the main site meteorological tower. The root cause analysis section contained two entries; the first being "The cause is under investigation", and the second being, "Cause determined to be circuit breaker failure". The record was unclear as to whether the cause of the circuit breaker failure had been pursued in an effort to determine the cause of failure, or providing justification for not doing so. This QE had been initiated and dispositioned by the company's Department of Technical and Ecological Services (TES), an offsite services organization. The QC manager stated that this QE would be returned to TES for further evaluation or clarification of root cause analysis.

In reviewing QEs initiated during the period March 16-31, 1989, the inspector observed two which were still an open ("assigned") status, and for which root cause analysis had not yet been documented. Each, however, had initials of a QC reviewer in the "concurrence" section. In a subsequent interview with the inspector, the QC reviewer stated that he had mistakenly placed his initials in the concurrence section of both QEs. He further stated that his initials were intended to indicate concurrence with the "Immediate Planned Corrective Actions" documented on the QEs, and not the "Root Cause Analysis" which was indicated as yet to be determined on both QEs. He also explained that each QE must be returned to him for final verification of the completion of corrective action to prevent repetition.

The inspector's observation in this instance was discussed with licensee management in the context of a lack of attention to detail on the part of the QC reviewer. It was stressed that the QC review of root cause analysis was a vital step in assuring that such analysis are of high quality. Licensee indicated agreement with the inspector's observations, and stated that an Action Request had been initiated to evaluate the circumstances of the errors and necessary corrective actions.

Overall, the NRC inspectors concluded that the licensee's efforts over the past year had resulted in substantial improvements in the events evaluation and root cause analysis program. The need for increased attention to detail on the part of individuals performing root cause analysis and those individuals charged with the review and concurrence of the adequacy of root cause analysis was observed.

13. System Engineering Program Review

The inspector examined procedure number AP A-350 (System Engineering Program) and concluded that this procedure contains the necessary provisions to effect an effective system engineering function.

The procedure sets out an acceptable set of system engineer responsibilities stressing: "ownership" of the system, close attention to maintenance, operations, and testing activities, and providing for a focal point of plant system knowledge concerning all aspects including design bases, system operation, maintenance and testing. The licensee has defined 10 different areas of responsibility; these are: routine (monthly) system walkdowns, evaluation of system problems, system performance trending, technical reviews of procedures and safety evaluations of surveillance test results, design change coordination, system operating experience assessment, review of system training material, multi-discipline task coordination, review of regulatory submittals, and evaluation of restart readiness.

The procedure defines appropriate system engineer interface relationships with the nuclear engineering and construction services design system engineer, the maintenance department, and the operations department engineers. The procedure further provides for the training and qualification of system engineers by specifying a set of minimum requirements to be met prior to system assignment and completion of the technical staff training program specified by procedure AP B-350, within two years of initial assignment as a system engineer.

Program Implementation

The inspector reviewed selected aspects of system engineer responsibility implementation.

a. Monthly and Quarterly Walkdown

The inspector reviewed the results and checklists used for the monthly walkdown of the emergency diesel generator, ventilation system and auxiliary saltwater system walkdowns. The checklists were prepared and used in the walkdowns; however, the checklists had not been reviewed by the design engineers to assure that there was a consensus agreement on the depth and scope of periodic system walkdowns.

The inspector obtained and reviewed the checklists used for other safety related system and observed an inconsistent level of quality and depth between the checklists. Licensee management had

recognized this situation and has instituted action to achieve a more uniform level of quality and depth.

The licensee reported that they had not completed all their checklists, e.g. auxiliary feedwater system walkdown checklists did not exist and will be developed within the month.

The inspector reviewed the results of the quarterly system walkdowns conducted by the system engineer and system design engineer for the auxiliary feedwater, component cooling water, compressed air, plant ventilation, 120 volt instrument AC, and 125/250 volt DC systems. These walkdowns were detailed and in-depth assessments of system status, problems and trends. The problems identified in the reports were, however, presented without addressing a solution; a fact which was also noted by licensee management. The licensee indicated that future walkdowns will address potential solutions.

Management conducts periodic system walkdowns with system engineers on a periodic basis. These management walkdowns consist of both site and general office management.

Training Qualification

The licensee has 27 system engineers; all degreed engineers. The majority have completed the Technical Staff Training Program, Root Cause Training, and Design Basis training. Others are in the Technical Staff Training class currently in progress, or will attend the next Root Cause training class. The inspector found that the licensee is progressing in the implementation of specified training and qualification programs for system engineers.

Trending

The inspector examined the performance of system trending. Generally, system surveillance data is trended by the system engineer; however, the system design engineer has not reviewed the information to be trended to arrive at a consensus of what is important and should be trended, and what the alert and limit criteria should be. The licensee indicated that the counsel of the design engineers would be sought to improve the usefulness of information trending.

50.59 Review

The licensee has recognized a need to improve the depth and quality of their 50.59 review processes. The first step has been to contract with an organization to develop a 50.59 training program based upon current industry and NRC guidance. Following this, the licensee intends to train managers and engineers in the details of 50.59 assessments to assure a uniform level of knowledge. Conjunctively, the licensee intends to establish a basic core of engineers who will perform 50.59 analysis and expand this core as familiarity with the program requirements and quality of 50.59 reviews improves.

14. Formality of Plant Engineering Troubleshooting

The inspectors noted an apparent weakness in the Plant Engineering troubleshooting/problem solving efforts. It was found that some recent problem solving efforts have lacked substantial forethought or planning and tend to be trial and error. The following are examples of this perceived weakness:

- In the past year, Plant Engineering has made an effort to repair long-standing problems with the charging system positive displacement pumps (PDPs) and return them to service as the normal charging supply. Early in this effort, it was found that with the PDP running, the RHR to charging isolation valve on Unit 2, Valve CVCS-2-8804A, would vibrate with up to 1/4" displacement at the actuator. The system engineer had thought that a modification to the PDP valves would eliminate the problem. On July 31, 1989, it was discovered that the modification had not eliminated the vibration problem. The inspector noted that the PDP was returned to service that morning following discussions between the system engineer and the shift supervisor which concluded that an informal troubleshooting plan would be written by the system engineers. Issues which had not been formally addressed included an evaluation of what is too much vibration and the use of vibration instrumentation in the troubleshooting effort. Additionally, there was miscommunication between management and the system engineer and shift supervisor as to the need for a formalized procedure. As a result, when the valve began to vibrate in the early afternoon, engineering was not prepared to evaluate or troubleshoot the problem. Two weeks following the above, the system engineer concluded that the suction stabilizer was not maintaining its hydrogen bubble due to the differential head between it and the volume control tank.

- The Unit 2 PDP discharge relief valve 8116 weld leak was attributed to the lifting of relief valve. The licensee postulated that an increased discharge header and the pulsation of the PDP contributed to achieve the lift point. The follow-up did not address what lessons could be learned from an operations standpoint.

- Although Engineering was aware of heat trace qualification problems (discussed in section 7) only informal review was being conducted.

- The review of diesel generator shroud cracking for safety significance was poorly documented.

- The review of discrepancies between moderator temperature coefficient measurements (discussed in more detail in Inspection Report 50-275/89-19) lacked formality.

These observations were discussed with plant management at the exit interview. Licensee management committed to examine the area of engineering formality of troubleshooting and action planning. The inspectors will follow-up licensee actions in the normal course of future inspections.

15. Walkdown Problem Areas

During a walkdown of plant areas on August 2, 1989, the NRC Region V, Reactor Safety Branch Chief identified several apparent problem areas for licensee evaluation and action as appropriate. A discussion of these areas follows:

a. Wiring Separation

During maintenance on diesel generator DG 1-3, the inspector noted that separation criteria for normal and backup 125VDC control power was not maintained, that is, minimum separation criteria of 3 inches was not maintained and the two trains of control power were in fact bundled together.

The separation criteria was committed to in the FSAR section 8.3.1.4.1.

The licensee management took certain prompt actions such as prohibiting work on DG 1-3, inspecting other diesel generators and posting a fire watch at DG 1-3.

On August 4, 1989, the licensee issued a justification for continued operation (JCO). Operability was based on the restriction of activities and the posting of a fire watch.

DG 1-3 was subsequently taken out of service and the wiring separation corrected. All other DGs were likewise taken out of service and examined. No other unacceptable wiring separations were found.

Previous to the NRC discovery on DG-13 on August 2, 1989, the licensee was performing an in depth audit, a safety system functional audit and review (SSFAR), of the auxiliary saltwater system and on July 27, 1989 discovered a missing separation barrier in the Unit 1 Hot Shutdown panel. Licensee management suggested that the audit finding response would have instigated further investigative action in the wiring separation area.

The licensee prepared a non-conformance report, NCR DCO-89-TN-N077, on both the QA and NRC findings. At the end of the inspection period the technical review group (TRG) had not yet finalized their root cause analysis nor corrective actions. Preliminary information still under review by the TRG indicated that the DG 1-3 condition was caused by a change order performed by general construction in August 1983, and that sampling or full reinspection of control cabinet wiring separation is being considered.

The lack of control wire separation in DG 1-3 is considered an unresolved item pending licensee identification of root cause and corrective action (Unresolved Item 50-275/89-21-04).

b. Plant Conditions

The inspector also noted that conditions in the area of the 140 foot elevation of the auxiliary building root, which is an outdoor area, were questionable. Specifically, near the Unit 1 main steam relief valves certain rusted components needed evaluation. Pipe snubbers on the relief header had visible rust on their spherical bearings and the snubbers could not be rotated by hand. Additionally, some fastening devices in the area such as conduit clamps had visibly corroded fasteners. The licensee was asked to evaluate these conditions and determine if a program was required to periodically assess the effects of the coastal atmosphere on outdoor safety equipment. The licensee responded with an engineering assessment of the large snubbers which could be rotated by use of a small pry bar. Their assessment was that the minor restriction in movement would not affect operability of the large snubbers. In regards to general corrosion of outdoor safety components, the licensee committed to initiate a survey and determine if an enhanced program was required.

Licensee action on this matter is a follow-up item (Follow-up Item 50-323/89-21-05).

c. Blocked Floor Drains

During an inspection of DG rooms the inspector noted what appeared to be blocked floor drains with some debris blocking flow holes in an inner basket under the floor grating. Subsequent discussion with the system engineer revealed that the drain was not blocked in that the inner basket had a large peripheral flow area available.

Further discussion indicated that the licensee did not have a formalized periodic inspection for blockage or a periodic test for these important drains which are required to remove the majority of diesel fuel oil should a significant fuel line failure occur.

The licensee had not completed their evaluation of the need for improved programs in this area at the end of the inspection period. licensee action on this matter will be followed up (Follow-up Item 50-275/89-21-06).

16. Unresolved Item

Unresolved items are matters about which more information if required to determine whether they are acceptable items, violations or deviations. Unresolved items addressed during this inspection are discussed in paragraphs 7 and 15 of this report.

17. Exit (30703)

On September 22, 1989, 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.