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UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION V
1450 MARIA LANE, SUITE 210
WALNUT CREEK, CALIFORNIA 94596

SEP 26 1984

Docket Nos. 50-275 and 50-323

Pacific Gas and Electric Company
77 Beale Street, Room 1435
San Francisco, California 94106

Attention: Mr. J. O. Schuyler, Vice President
Nuclear Power Generation

Gentlemen:

Subject: NRC Inspection of Diablo Canyon Units 1 and 2

This refers to a routine inspection, conducted by Messrs. M. M. Mendonca, M. L. Padovan, T. M. Ross, T. J. Polich, and J. L. Crews of this office during the period of July 1 through August 4, 1984. This inspection examined your activities as authorized by NRC License No. DPR-76, and Construction Permit No. CPPR-69. Discussions of our findings were held with Mr. R. C. Thornberry and other members of your staff at the conclusion of the inspection.

Areas examined during this inspection are described in the enclosed inspection report. Within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel, and observations by the inspectors.

No violations of NRC requirements were identified within the scope of this inspection.

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Should you have any questions concerning this inspection, we will be glad to discuss them with you.

Sincerely,

/S/

T. W. Bishop, Director
Division of Reactor Safety
and Projects

Enclosure:
Inspection Report
Nos. 50-275/84-22 and 50-323/84-12

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9/24/84	9/24/84	9/25/84		

U. S. NUCLEAR REGULATORY COMMISSION
REGION V

Report Nos: 50-275/84-22 and 50-323/84-12

Docket Nos: 50-275 and 50-323

License No: DPR-76

Construction Permit No: CPPR-69

Licensee: Pacific Gas and Electric Company
77 Beale Street, Room 1435
San Francisco, California 94106

Facility Name: Diablo Canyon Units 1 and 2

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

Inspectors: DJ Willett for 9-24-84
M. M. Mendonca, Sr. Resident Inspector — Date Signed

DJ Willett for 9-24-84
M. L. Padovan, Resident Inspector — Date Signed

for D.F. Kirsch 9/25/84
T. M. Ross, Resident Inspector — Date Signed

for D.F. Kirsch 9/25/84
T. J. Polich, Resident Inspector — Date Signed

J L Crews 9/24/84
J. L. Crews, Technical Assistant to the Regional Administrator — Date Signed

Approved by: Dennis J. Willett for 9-24-84
P. H. Johnson, Chief — Date Signed
Reactor Projects Section 3

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Summary:

Inspection from July 1 through August 4, 1984 (Report Nos. 50-275/84-22 and 50-323/84-12)

Areas Inspected: Routine inspection of plant operations, conditions and events; maintenance; surveillance; independent inspection; and follow-up of open items, LERs, and enforcement actions. This inspection effort involved 447 inspector-hours for Unit 1 and 57 inspector hours for Unit 2 by four resident inspectors and one region-based staff member.

Results: No violations or deviations were identified.

DETAILS

1. Persons Contacted

*R. C. Thornberry, Plant Manager
R. Patterson, Assistant Plant Manager/Superintendent
J. M. Gisclon, Assistant Plant Manager for Technical Services
*W. B. Kaefer, Assistant Plant Manager for Support Services
C. L. Eldridge, Quality Control Manager
*R. G. Todaro, Security Supervisor
*E. M. Conway, Personnel and General Services
D. B. Miklush, Supervisor of Maintenance
*J. A. Sexton, Supervisor of Operations
J. V. Boots, Supervisor of Chemistry and Radiation Protection
W. B. McLane, Material and Project Coordination Manager
L. F. Womack, Engineering Manager
*B. W. Giffin, Acting Instrumentation and Control Manager
E. T. Murphy, Regulatory Compliance Supervisor
C. M. Seward, Supervisor of Quality Assurance

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

*Denotes those attending the exit interview on August 3, 1984.

2. Operating Safety Verification

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

On a daily basis, the inspectors observed control room activities to verify compliance with selected limiting conditions for operation as prescribed in the facility Technical Specifications (TS). Logs, instrumentation, recorder traces, and other operational records were examined to obtain information on plant conditions, trends, and compliance with regulations. Shift turnovers were observed on a sample basis to verify that all pertinent information on plant status was relayed. During each week, the inspectors toured the accessible areas of the facility to observe the following:

(1) General plant and equipment conditions.

(2) Surveillance and maintenance activities.

(3) Fire hazards and fire fighting equipment.

(4) Ignition sources and flammable material control.

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

(6) Interiors of electrical and control panels.

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

(8) Plant housekeeping and cleanliness.

(9) Operability of selected Engineered Safety Features (ESF) systems by performing comprehensive walkdowns of the system's components.

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

No violations or deviations were identified.

b. Technical Review Group (TRG)

A TRG meeting is convened by appropriate plant personnel to review problems or incidents which occur onsite and appear to represent a potential nonconformance. Participating personnel are intended to be knowledgeable of and responsible for the subjects involved. The prime purpose of this meeting is to determine root causes, propose corrective actions to preclude recurrence, and to evaluate the event's reportability as a Nonconformance Report (NCR) and/or Licensee Event Report (LER). TRG proceedings are required and administered in accordance with Nuclear Plant Administrative Procedure (NPAP) C-12, "Identification and Resolution of Problems and Nonconformances."

The inspectors attended a number of TRG meetings. These meetings, in general, appeared to provide timely and accurate resolution of plant problems. However, in one instance, an independent examination by an inspector revealed that a TRG did not correctly establish the sequence of events for a particular potential nonconformance. As a result, some of the conclusions documented in NCR #DC1-84-TN-N096 were inappropriate. This NCR was subsequently evaluated and appropriate conclusions were drawn. It should be noted that the first conclusions were excessibly conservative in nature in that the licensee had determined the condition to be reportable when, in fact, it was not reportable.

Plant management was informed of the discrepancy, and then made aware of those primary contributing causes considered by the inspectors to have created this situation. These can be paraphrased as follows: (1) key involved personnel were not present at the TRG meeting nor were they required to be, (2) the TRG chairmen was not specifically trained on responsibilities as a chairman, and (3) TRG personnel did not come prepared to address the problem.

Plant management has instituted a training program to assure that these findings are resolved. The inspectors have reviewed this program and will continue to follow this under normal inspection activities.

No violations or deviations were identified.

c. Initiation of Control Room Ventilation Pressurization Mode

On July 15, 1984, in preparation for response time testing on the Unit 2 Solid State Protection System (SSPS), jumpers were being installed on selected SSPS contacts. These jumpers were being installed so that equipment common to both units would not actuate as a result of testing. To effect this deactivation, an SSPS contact drawing was consulted to determine whether jumpers were to be installed for normally closed contacts, or whether normally open contacts were to be lifted. This drawing incorrectly indicated that the contacts for initiation of the control room ventilation pressurization mode were normally closed. When a jumper was placed around these normally open contacts, a contact was subsequently closed causing control room ventilation pressurization to actuate. The licensee reported this ESF actuation to the NRC's headquarters duty officer. The inspector's followup corroborated the licensee's findings that the event was due to an incorrect designation of contact position on Westinghouse prepared electrical drawing No. 458828. A program to review related drawings and verify SSPS contact positions was conducted by the licensee. Except for one other incorrect contact designation on a plant electrical schematic, all SSPS contacts were verified to be correctly designated. Based on this review, the applicable drawings acceptably reflect SSPS contact position.

Additionally, the inspector has reviewed operator response to the event. The operators determined the cause of the event and terminated the control room pressurization mode in an acceptable manner.

No violations or deviations were identified.

d. Inadvertent Safety Injection (SI)

The July 28, 1984, SI was initiated by a high steam flow signal coincident with a low-low T_{ave} (setpoint is 543°F) in the reactor coolant system (RCS). The high steam flow signal resulted from surveillance testing in progress. Although RCS temperature was greater than 543°F when surveillance testing began, a temperature decrease of several degrees subsequently occurred when steam generator water levels were increased using the ausiliary feed system. This provided the coincident signals necessary for an SI initiation. The inspectors discussed the event with the individuals involved. From these discussions, several key points were raised.

The primary cause of the event can be attributed to operator inattentiveness. The operators did not recognize the potential for an inadvertent SI with the steam flow bistables tripped for instrumentation and control (I&C) work and the Reactor Coolant

System (RCS) temperature approaching the low low setpoint due to the addition of water to the steam generators. Based on hindsight, the operators recognize that this point should have been understood.

Several contributory causes have also been identified. First, work activities in the control room were heavy when the SI occurred. Second, on-shift management involvement was not effective in assuring that plant activities were conducted in a sufficiently controlled manner. Finally, surveillance activities are designed for stable plant conditions, rather than varying conditions (e.g., changing RCS temperature). In this case with the plant in a transient condition, communications and control of activities are very important.

Plant management reemphasized to operators the importance of proper communications and control of operating activities. These items have been identified as being particularly important when preparing for or conducting shift turnover. Additionally, plant management stressed the desirability of minimizing the number of plant evolutions being performed concurrently.

Additionally, plant management is reevaluating the scheduling of on-shift management coverage. Previously, the on-shift management was on shift for a number of consecutive days. The existing schedule rotated managers through the backshifts on a nightly basis, and the Senior Operations Supervisor acted as the on-shift manager during day shifts. This scheduling did not allow time for managers to get acclimated to the shift activity, and it resulted in the Senior Operations Supervisor performing his normal work activities in lieu of looking at operating activities from an independent overview. The resolution of this on-shift management concern will be followed during future inspection activities.

No violations or deviations were identified.

e. Sealed Valve Control Program

Seals are used to verify and control the position of manual valves in the flow paths of plant safety systems required by TS. NPAPs C-9 and C-9S1 prescribe methods used to control and document the sealed valve program.

An undocumented sealed valve was observed to be out of position and unsealed by the inspector during performance of an ESF system (containment spray) walkdown. This situation was brought to the Shift Foreman's (SFM's) attention to resolve. Subsequent action to restore the sealed valve's original condition prompted the inspector to perform a detailed review of the licensee's sealed valve control program and its implementation.

The following problem areas were identified by the inspector:

(1) Operator actions necessary to resolve sealed valves discovered to be unsealed and/or out of position were not prescribed.

(2) Operating Procedure (OP) K-10, "Systems Requiring Sealed Valve Checklist", does not list all sealed valves specified in Surveillance Test Procedures (STP's) or valve identification drawings.

(3) The appropriateness of using "valve seal change forms" in conjunction with an STP which specifically addresses the repositioning of sealed valves was not clearly prescribed.

(4) Appropriate implementation of sealed valve checklists and control of safety system lineups when not required for a particular mode was not addressed.

All of the above concerns were discussed in detail with the licensee's operations department. Subsequently, a SFM memo dated July 24, 1984, was issued by the Senior Operations Supervisor to re-emphasize the requirements of sealed valve checklist procedures and to clarify the Operations Department's policy. This policy statement included a directive to insure control of vital valves by maintaining the sealed valve checklists in all operational modes. This memo and proposed administrative procedure revisions are considered to acceptably resolve each concern. Implementation of procedure revisions will be followed up during normal inspection activities. The effective response of the operations department to address identified program deficiencies indicated active and concerned management participation.

No violations or deviations were identified.

f. "Thermal Non-Repeatability" of Barton Pressure Transmitters

This item was addressed in an earlier inspection reporting period. The subject Barton pressure transmitters, as outlined in a July 15, 1984 Westinghouse letter from E. P. Rahe to R. C. DeYoung of the NRC, may not have met accuracy requirements for above ambient temperatures. The inspector verified that the subject transmitters have been verified to be removed from service at Diablo Canyon. This acceptably addresses the accuracy questions related to the subject transmitters.

No violations or deviations were identified.

3. Maintenance

a. Diesel Generator Starting Air Compressor

Selected portions of the corrective maintenance activities on a starting air compressor for diesel generator 1-3 were observed by an inspector. Procurement documentation and adherence to administrative work controls were verified to be acceptable.

No violations or deviations were identified.

b. Air Compressor Maintenance Test

Selected portions of preventive maintenance test 1A1-46M, on diesel generator starting air compressor 1-2B, were observed. The initial post maintenance test run was observed by the inspector, during which the licensee identified four air leaks in an instrument line. Three of these leaks were repaired and subsequently tested satisfactorily. The remaining leak was documented on a Nuclear Plant Problem Report and later repaired and retested. The cardox system for diesel generator room 1-2 was disabled while personnel performed maintenance and testing on starting air compressor 1-2B.

No violations or deviations were identified.

c. Boric Acid Transfer Pump

The inspector observed the replacement of mechanical seals on boric acid transfer pump 1-1. Maintenance Procedure M-52.2 "Mechanical Seal Removal and Installation (Crane)," was used in conjunction with Shop Work Follower MM-1-84-450 to perform the work. The appropriate administrative approvals and clearances were obtained before the work was initiated, and the maintenance activities conformed to applicable technical specifications. Subsequent to completion of the work, the inspector independently verified that the equipment was properly returned to service.

No violations or deviations were identified.

4. Surveillance

a. An inspector observed the following STPs, which are used to assess operational performance of valves in the safety injection system:

(1) V-3L1, "Exercising valves 8802A and 8802B, Safety Injection Pump Discharge Isolation to RCS Hot Legs"

(2) V-3L6, "Exercising valve 8835, Safety Injection Cold Leg Isolation"

(3) V-3L13, "Exercising valve 8976, RWST to Safety Injection Pump"

The inspector observed that all precautions and limitations required by the STPs were followed, and that the electronic clock used to measure the valve stroke times was in calibration. Upon reviewing the observed valve stroke times, the inspector found that all valve stroke times met the acceptance criteria specified in the associated STPs.

No violations or deviations were identified.

b. STP I-1B, "Routine Daily Check Required by Licenses," is used to meet certain TS requirements. Normally performed once per 24 hour period, STP I-1B encompasses two basic types of examination by operations personnel, channel checks and verification of plant conditions. The licensee has chosen to conduct this STP twice a day, to ensure the daily checks are completed at least once within any 24 hour period and to more closely monitor essential parameters indicative of overall plant status. Reactor Shutdown Margin (SDM) is also required to be calculated in accordance with STP R-19, and the result is recorded as a step in the routine daily checklist of STP I-1B.

During mode 5 plant conditions, an inspector observed an assistant control operator (ACO) perform STP I-1B and STP R-19. Conduct of these STPs, and appropriate responses to inquiries by the inspector, demonstrated the ACO's in-depth knowledge and familiarity with plant equipment and system operations. Information recorded on the mode 5 daily checklist and the data sheet for SDM calculations was determined by the inspector to be accurate and complete.

No violations or deviations were identified.

c. An inspector observed calibration of the steam generator water level channel for transmitter LI-538. This protection and safeguards channel was acceptably removed from service by a valid in-plant clearance, and subsequently calibrated in accordance with STP I-11B2. The test used simulated level input signals in lieu of the normal transmitter output, to calibrate the channel over its required indication range. Personnel who performed the testing were qualified and understood the procedure. The instrument was acceptably returned to service.

No violations or deviations were identified.

d. As a prerequisite for Natural Circulation (NC) tests, low range overpower trip setpoints of the Nuclear Instrumentation System (NIS) Power Range (PR) channels were reduced from 25% to 6%. Upon completion of NC testing operations, all of the NIS PR channels were scheduled for reinstatement of normal low range trip setpoints. Implementation of STP I-2B, "Nuclear PR Channel Functional Test," was monitored by the inspector for NIS channel 42. STP I-2B provides the necessary detailed instructions to remove a PR channel from service, to readjust the overpower trip high and/or low range setpoints, and to verify proper PR channel operation with a functional test.

Readjustment of NIS PR 42 low range overpower trip setpoint to 25% and a subsequent channel functional test were performed by qualified Nuclear Plant Operations (NPO) I&C personnel in accordance with STP I-2B. The inspector observed that test procedure steps and associated clearance controls were correctly applied throughout the surveillance evolution, including NIS channel removal from service and restoration.

No violations or deviations were identified.

e. An inspector observed selected portions of the calibration of the steam generator blowdown sample liquid radiation monitor. This calibration was conducted in accordance with STP I-18 J2. The calibration used radioactive source standards and electronic input signals to develop characteristic curves for the monitor. The inspector observed that proper cleanliness and controls were observed by licensee I&C personnel, and calibration of the test equipment was current. I&C personnel understood the test procedure and performed the test acceptably.

No violations or deviations were identified.

5. Startup Test Procedure Review

a. Shutdown from Outside the Control Room Test

It is the regulatory position that licensees will develop and conduct a test program to demonstrate remote shutdown capability mandated by General Design Criterion (GDC) 19. The test program should be able to verify that the nuclear power plant, from outside the main control room (MCR), can be: 1) safely shutdown, 2) maintained in a hot standby condition, and 3) shown to have the potential for being safely cooled from hot standby to cold shutdown. Startup Test Procedure (S/U TP) No. 41.1, "Plant shutdown from Outside the Main Control Room," was issued to demonstrate that stable hot standby conditions can be established and maintained from outside the MCR following a reactor trip. Testing requirements for this evolution were compared by the inspector against applicable provisions of Regulatory Guides (RG) 1.68 and 1.68.2, and the test program prescribed by Chapter 14 of the licensee's Final Safety Analysis Report (FSAR).

During the Hot Functional Test (HFT) program, preoperational testing of plant instrumentation, controls, and systems used at the Hot Shutdown Panel (HSDP) was completed and documented in S/U TP 37.20, "Control Room Inaccessibility." Subsequently, the potential capability for cold shutdown, by partially cooling down the plant from hot standby, was demonstrated by S/U TP 37.28, "Plant Cooldown from Outside the MCR." RG 1.68.2 specifically allows the demonstration of cold shutdown capability at a time not immediately following the demonstration of achieving and maintaining a safe hot standby condition from a moderate reactor power level. The inspector considered the performance of S/U TP 37.28 during HFT to meet the test program objective 3) identified above.

Objectives 1) and 2) from above, should be met by an acceptable performance of S/U TP 41.1. The licensee's test program for verifying remote shutdown capability was determined by the inspector to be consistent with commitments in the FSAR, and with regulatory requirements and guidance, except for the following:

(1) RG 1.68.2 states that shutdown of the reactor plant should "be initiated from a location outside the control room...at a moderate power level." The S/U Program Master Document TP 40.0 has scheduled a rod group drop test, of the most difficult to detect rods, which will cause a negative rate signal input into the Reactor Protection System (RPS) to initiate the necessary reactor trip. Should the plant fail to trip from this test,

the procedure instructs control room operators to manually trip the reactor from inside the MCR. These specific instructions are not consistent with regulatory guidance.

(2) In the preoperational test program, RG 1.68.2 recommends that "verification should have been made that control of transferred components from the MCR is not possible after control of these components from the" HSDP "has been established." A prerequisite for S/U TP 41.1 was verification of HSDP operability by S/U TP 37.20, which did not address this important "transfer of control" criterion.

(3) S/U TP 41.1 does not require recording important primary and secondary system parameters while hot shutdown conditions are being established and maintained. These data are considered essential for evaluating plant performance to determine if the test objectives have been met.

(4) RCS temperature is identified in S/U TP 41.1 as an essential parameter to be controlled, and yet it is not required to be monitored, recorded, or evaluated during the test. The inspector stated that an acceptable demonstration of hot shutdown capability should establish RCS temperature as a part of the acceptance criteria and monitor it accordingly.

The above findings were discussed in detail with the licensee's S/U engineering staff. Each concern appears to have been acceptably addressed in the form of proposed procedure revisions. The inspector will follow-up licensee activities to ascertain satisfactory implementation of these proposed resolutions. (275/84-22-01)

No violations or deviations were identified.

b. Net Load Rejection Test

A demonstration of the reactor plant's dynamic response following a full load rejection is necessary to verify performance capabilities of systems important to safety delineated by Appendix A to 10 CFR 50. S/U TP 43.2 "Net Load Trip from 100% Power," intends "to demonstrate the ability of the primary plant, secondary plant and the automatic reactor control systems to sustain a net load loss from 100% load rejection capability." Testing requirements of this power ascension test procedure were compared by the inspector with applicable provisions of RG 1.68 and with the test program prescribed in Chapter 14 of the FSAR.

With the plant at 100% rated thermal power, a full load rejection is initiated by opening the main transformer high side breakers. It is an objective of S/U TP 43.2 to evaluate the performance of automatic control systems as evidenced by variations of plant parameters during the transient, with minimal operational intervention, until the plant is stabilized. The plant design and Emergency Operation Procedures (EOPs) are such that this transient should not cause a turbine or reactor trip, safety injection actuation, or lift any safety valves.

The inspector concluded that an acceptable performance of S/U TP 43.2 will address the criteria established in RG 1.68. In addition, this test of the plant's full load rejection capability is consistent with commitments made in the FSAR and objectives stated in S/U TP 43.2, except for the following:

(1) A test objective identified in S/U TP 43.2, states "verify plant EOP." But no evaluation of EOP-34, "Generator Trip - Full Load Rejection," is required by the procedure.

(2) The FSAR establishes two test objectives for the net load trip: (1) to verify plant response to generator trip, and (2) to verify control system performance by observed variation of plant parameters within acceptable limits. It is the intent of S/U TP 43.2 to initiate a transient that will not result in a trip of the main generator. Full load rejection is, in this case, a total loss of off-site demand; the main generator should remain on-line during the entire evolution and continue to supply on-site household loads. However, the effects of actual test procedure implementation are not consistent with the FSAR description. Furthermore, the procedure does not appear to adequately provide for detailed evaluation and review of the plant's control systems performance or interactions, during and subsequent to the transient.

These findings were discussed with the licensee's on-site S/U engineering staff. Follow-up of proposed procedure and FSAR revisions will be performed by the inspector. (275/84-22-02)

No violations or deviations were identified.

c. Startup Program Master Document

Startup TP No. 40.0 "Startup Program Master Document" is the overall startup master document which defines the startup test program from pre-core loading through 100% power operation. The inspector reviewed the power ascension program portion (initial entry into Mode 1 to 100% rated thermal power testing) of this document. TP 40.0 specifies that power ascension testing will be conducted at 15%, 30%, 50%, 75% and 100% rated thermal power (RTP) testing plateaus. During power ascension testing, TP 40.0 requires that the NIS power range high trip-point be reset to a value of the next higher plateau power level plus 20% rated thermal power, prior to ascending to that power plateau (e.g., for the 50% power plateau, the trip point would be set at 70% RTP). The inspector observed that regulatory guidance suggests more conservative power range high trip-point settings for each plateau. Accordingly, this observation was discussed with the licensee, and the licensee agreed to revise TP 40.0 to follow NRC guidance.

No violations or deviations were identified.

d. Static Rod Drop and Rod Control Cluster Assembly (RCCA) Below Bank Position Requirements Test

Startup TP No. 42.3, "Static Rod Drop and RCCA Below Bank Position Measurements," specifies that core thermocouple and flux maps are to be taken to determine the following:

(1) Excore detector response with an RCCA below bank position.

(2) Excore detector response for the dropped control rod configuration.

(3) Differential and integral worth of the most reactive below-bank RCCA.

(4) Hot channel factors for the dropped rod case.

The inspector reviewed this procedure, and determined that S/U TP 42.3 meets applicable NRC guidance regarding the preparation, review and content of startup TPs.

No violations or deviations were identified.

e. Thermal Power Measurement and Statepoint Data Collection

Startup TP No. 42.5, "Thermal Power Measurement and Statepoint Data Collection," specifies that during isothermal conditions at each of the previously mentioned power plateaus, high accuracy plant heat balance measurements and corresponding flux maps are to be taken. These data will be used for alignment of RCS temperature and nuclear instrumentation; calibration of steam and feedwater flow instrumentation; and adjustment of the reactor control system.

The inspector reviewed this procedure and determined that TP 42.5 meets applicable NRC guidance regarding the preparation, review and content of startup TPs. However, regulatory guidance suggests that preliminary evaluations be performed at each power plateau (such as extrapolating minimum DNBR and maximum linear heat rate values to the high flux trip setpoint for the next power level) before ascending to the next power level. Provisions to perform these preliminary evaluations were not contained within TP 42.5. The licensee stated that the need for the preliminary evaluations would be evaluated. (275/84-22-03)

No violations or deviations were identified.

6. QA Program Reviews - Unit 2

a. Test and Measurement Equipment Control

The licensee's Quality Assurance Manual (QAM) Procedure 8.1, "Control of Measuring and Test Equipment," establishes the programmatic requirements "to assure that tools, gauges, instruments, and other measuring and testing equipment used in activities affecting quality are properly controlled, calibrated, and adjusted to maintain precision and accuracy within specified limits." Each responsible department (i.e., NPO, General Construction (GC), and Engineering Research) is required to develop and maintain a specific program for control of measuring and test equipment which conforms to the provisions of Procedure 8.1.

The inspector reviewed QAM Procedure 8.1 for compliance with Criterion XII of Appendix B to 10 CFR 50, RG 1.33, Chapter 17 of the FSAR, and ANSI Standards N18.7 and N45.2 (including applicable daughter standards). With two exceptions, this program procedure was determined to acceptably prescribe all the requirements in the aforementioned documents. ANSI N18.7-1976, section 5.2.16, specifically addresses the need for prescribing selection of testing equipment and measuring devices "of the proper range and type" for use in "measurements, tests, and calibrating." Furthermore, section 5.2.16 calls out that "special calibration shall be performed when accuracy of...equipment is questionable." QAM Procedure 8.1 does not address either of these areas. The onsite QA supervisor was briefed on the program deficiencies, and responded by assuring the inspector that responsible corporate office personnel, involved with an imminent QAM revision, would be appropriately informed. It should be noted, however, that these issues had been incorporated into the NPO Department Procedures even without benefit of QAM compliance.

Subsequent review of test and measurement equipment control procedures and implementation was limited in scope to an inspection of the NPO Department's program. To effectively evaluate this program, the inspector examined applicable administrative procedures, interviewed responsible personnel involved directly in program implementation or use of equipment, reviewed documented calibration records and usage logs, observed check-out procedure implementation and test equipment storage locations, and verified calibration status of over sixty individually identified pieces of equipment. In the NPO Department, administration and implementation of test and measurement equipment control is primarily the responsibility of the I&C organization and the Electrical and Mechanical Maintenance groups. Secondary responsibilities are assigned to the Chemistry and Radiation Protection (C&RP) organization. All of these groups were examined for conformance with provisions of the QAM, regulatory requirements, and industry standards.

With a few exceptions, the inspector determined that control of test and measurement equipment was acceptably developed in written procedures and was being acceptably implemented. Each specific comment generated during the inspection process was discussed in detail with the appropriate organization supervisor. Concerns of significance were discussed wit. plant management, as follows:

(1) Althou alibrations were be ng performed as required, a need for improvement in master calibration schedules was a generic problem with all organizations.

(2) Calibrations were generally performed by qualified journeymen. A program for qualifying and identifying personnel performing calibrations was not clearly established.

(3) Administrative procedures did not clearly prescribe the I&C interface with C&RP department.

(4) Although calibrated equipment was available as needed for maintenance activities, Mechanical Maintenance appeared well behind in applying onsite resources to effectively control test and measurement equipment inventory, usage and recall. Present methodology is marginal. Calibration records for mechanical maintenance were also deficient in necessary data and identification of acceptable standards.

(5) Timely attention was not being given to QA/QC audit items describing areas of weakness.

Resolution of these concerns will be followed up as open item 323/84-12-01. Present senior supervisory and upper management involvement has been markedly improved in this QA program area, even prior to the inspection activity.

No violations or deviations were identified.

7. Independent Inspection

a. Non-licensed Operator Training

The inspector reviewed the licensee's program for non-licensed operator training which includes systems, theory and administrative control classes. Class content and objectives were examined. Additionally, the inspector observed several class sessions. From this review and observations, it was determined the program acceptably addressed training of non-licensed operators.

No violations or deviations were identified.

b. Pipe Gouges Identified by an Anonymous Source

The inspectors were informed by anonymous construction personnel of gouges in line #2-K-106-18 near hanger number 47-55A. This item was turned over to PG&E's Quality Hotline. The Quality Hotline assigned Quality Control Summary Report (QCSR) #70 to this concern. The Quality Hotline investigation found that these gouges were addressed in Pullman Power Products Discrepancy Report (DR) No. 87-10 dated July 14, 1984. The inspector verified selected portions of the DR.

No violations or deviations were identified.

8. Open Item Follow-up

a. Unit 1

(1) Rad Waste Minimization (Open Item 83-19-02, Closed)

The licensee's program for rad waste minimization was reviewed by the inspector. This program consists of general employee training, as well as specific training for Chem and Rad Protection (C&RP) personnel. In addition, a controlling administrative procedure (No. C-254) prescribes the objectives, responsibilities and authority necessary to implement an acceptable program of waste minimization. This open item is closed.

(2) Borg Warner Check Valve Repair (Open Item 83-22-01, Closed)

An inspector examined welding documentation concerning check valve weld repair. The disc and nut were welded to the stud in the subject valves. This was done to prevent disassembly of the valve during operation. Work was performed in accordance with manufacturer recommendations. This open item is closed.

(3) Fire Protection and Medical Section Staffing (Open Item 83-39-01, Closed)

An inspector reviewed the licensee's staffing level and program. The inspector concluded that it acceptably closes this open item.

(4) Fire Protection Exemption on Auxiliary Feedwater Room Ventilation Damper (Open Item 83-39-09, Closed)

NRR has accepted the specific subject exemption. This action in SSER No. 23, NUREG-0675, closes open item 83-39-09.

No violations or deviations were identified.

b. Unit 2

Containment Fan Cooler Unit (CFCU) Bearing Vibrations (Open Item 82-13-01, Closed)

The licensee's program to reduce CFCU bearing vibrations has been reviewed by the inspector. Associated testing and design evaluations were considered acceptable to address this problem. This open item is closed.

No violations or deviations were identified.

9. Follow-up of Previous Notices of Violation

Inoperable Emergency Core Cooling System (ECCS) Flowpath (Unit 1 Open Item 84-06-01, Closed)

Inspection Report 84-06 cited a violation concerning inoperability of the ECCS flowpath through the Boron Injection Tank (BIT), and identified several open items requiring follow-up inspection. The licensee's response to the notice of violation (letter dated June 15, 1984 from G. A. Maneatis, PG&E, to R. C. DeYoung, NRC), and the documentation and programs affected by corrective action, have been reviewed by the inspectors. The following open items associated with this violation have been closed:

Open item 84-06-02: Operating Procedure B-1C, "12 Percent Boric Acid System," was revised to emphasize that isolation of the BIT necessitates close evaluation of all applicable technical specifications.

Open item 84-06-03: The licensee completed a review of operating procedures to assure appropriate TS were referenced.

Open item 84-06-04: The licensee developed and issued Procedure TP TA 8401, "Cross Reference of Plant Equipment with Technical Specification Requirements," which is considered to acceptably address this item.

Open item 84-06-05: The licensee has revised the procedure review program to require an independent technical review for procedure changes which affect technical content. In addition, packages containing substantial procedure changes will be submitted to the Plant Staff Review Committee (PSRC) for detailed discussions.

Open item 84-06-06: The licensee's programs to (1) place management on-shift, (2) review other licensees' operational control methods, and (3) walkdown systems for added verification of correct alignment and technical specification compliance have been reviewed. Implementation of these programs was determined to meet the licensee's commitments.

No violations or deviations were identified.

10. LER Follow-up (Unit 1)

Circumstances and corrective actions described in LERs, as listed below, were examined by the inspectors. The inspectors found that these LERs had been reviewed by the licensee, and were reported to the NRC within acceptable reporting intervals. The inspectors also verified that appropriate corrective actions were taken. Accordingly, these LERs are considered closed.

LER No. 82-03: The plant vent radiation monitors were inadvertently deenergized without this condition being indicated in the control room.

An annunciator was installed to ensure that control room personnel are aware of any loss of power to the plant vent radiation monitors.

LER No. 83-01: The steam generator blowdown flow recorder head was repaired to complete action on this LER related to equipment failure.

LER No. 83-02: Maintenance on the liquid radwaste flow recorder repaired this equipment failure.

LER No. 83-05: Repair of the earthquake force monitor reset switch and local cabling resolved this LER related to equipment failure.

LER No. 83-08: Electrical maintenance personnel incorrectly terminated a wire connection which removed power to the radiation monitors. The importance of proper circuit identification was discussed with all workers involved in similar activities.

LER No. 83-09: The power switch to the plant vent iodine sampler was inadvertently opened during construction activities. Construction personnel were counseled on the need for caution in their work activities.

LER No. 83-10: A construction electrician inadvertently grounded the power to the main annunciator system (corrective action coincides with that on 83-09).

LER No. 83-13: Plant vent air sample pumps were deenergized without recognition by operators. An equipment power supply cross-reference list has been prepared.

LER No. 83-15: A design change, which affected the annunciator indication for the plant vent iodine sampler, was not identified in related surveillance test procedures. The impact of design changes on procedures was reemphasized with the licensee's operations and engineering personnel to address this event report.

LER No. 83-17: The failed power supply breaker to the oily water separator flow monitor was replaced.

LER No. 83-18: On return to service from clearance, a valve on the fire water system was mispositioned. This was caused by the use of an incorrect valve checklist. Discussions with personnel reinforced the need for the use of proper clearance forms and valve lineup sheets for return to service.

LER No. 83-20: A gaseous radwaste monitor tube failed due to end-of-life and was subsequently replaced.

LER No. 83-24: An inadvertent ground of electrical connections caused the loss of main control room annunciators. Training was conducted for the General Construction Electricians involved.

LER No. 83-27: The diesel generator starting air compressor relief valve was repaired and the definition of an operable diesel generator was clarified to resolve this LER related to equipment failure.

LER No. 83-30: Completion of surveillance on the seismic monitoring system resolved this LER which was apparently caused by NPO personnel error.

LER No. 83-31: Surveillance frequency requirements were clarified concerning auxiliary hoist load testing.

LER No. 83-34: RHR pump control circuit inconsistencies were discovered between approved schematics and the as-installed configuration. The licensee determined that modifications to the control circuitry were incorrectly implemented. To ensure that modification controls were acceptable, the licensee examined all modifications to similar control circuits. Additionally, administrative requirements were provided, requiring the design intent to be included within the appropriate test procedure.

LER No. 83-35: Firewater system re-alignment was not completed due to lack of procedure comprehension by personnel. Operations personnel were instructed to review procedures prior to use.

LER No. 83-36: The control room ventilation supply fan motor was repaired, subsequent to its reported failure.

LER No. 84-01: Fuse replacement in the SSPS corrected the cause of this inadvertent SI.

LER No. 84-03: The licensee has continued to monitor instrument AC power which caused an inadvertent SI reported in this LER.

LER No. 84-05: Operations personnel error caused a diesel generator to start. Involved personnel were briefed and a protective guard was installed over the incorrectly moved breaker.

LER No. 84-07: Operations personnel incorrectly tried to reset a 125 V AC instrument power supply breaker which caused a mode transfer of the control room ventilation system. The function of this breaker was clarified by adding a descriptive label.

LER No. 84-09: An inadvertent start of a diesel generator was caused by personnel error in the alignment of the auto/manual selection switch. Corrective action included personnel counseling.

LER No. 84-12: Personnel error resulted in an inadvertent loss of main control room annunciators. Operations personnel were counseled and retrained.

LER No. 84-13: Inoperable emergency core cooling system flow path. This issue was followed-up and closed as item 84-06-01.

LER No. 84-14: Temperature instrumentation was replaced in the over-temperature Delta-T protection circuity which caused a reactor trip.

LER No. 84-15: A failed control module in the steam dump system caused an SI actuation to occur. The defective module was replaced.

LER No. 84-16: Construction personnel inadvertently opened a power supply breaker to several plant radiation monitors. These work activities have been placed under tighter administrative controls.

No violations or deviations were identified.

11. Follow-up on Items Identified During Special Team Inspection

At the conclusion of the Region V Special Team Inspection, on June 12, 1984, licensee management provided information and/or made commitments regarding specific findings and concerns identified during the inspection. (See paragraph 8 of NRC Inspection Report No. 50-275/84-07).

Subsequent to the inspection, facility records and procedures were examined and discussions were held with licensee representatives regarding the status of the following items.

a. Independent Verification of Operational Activities

Review of plant procedures revealed that an on-the-spot procedure change was made to NPAP C-104, "Independent Verification of Operating Activities," on June 6, 1984. Revisions were also made to the Diablo Canyon Administrative Procedure, Supplement 1 to NPAP C-104. These changes clarify instructions for independent verification of operational activities to require that, except for unusual circumstances, the independent verifier will not accompany the person performing the activity to be verified. Exceptions to this requirement, which require supervisor approval, are those circumstances where a substantial reduction in personnel radiation exposure will result, or where the presence of the independent verifier is important to ensure against an inadvertent unit trip or engineered safety features actuation. An example of the latter is the conduct of surveillance testing of the solid state protection system. In such a case the independent verification would be conducted on a step-by-step basis as the testing proceeds. The procedure (NPAP C-104, Supplement 1) includes a special notation for such circumstances that the independent reviewer, "...shall make every effort to act in an independent manner during the performance of his duties."

No violations or deviations were identified.

b. Work Planning

As of July 9, 1984, two additional persons had been hired and were on board to fill vacant positions in the I&C Work Planning group. Six additional contract employees were on board - two in I&C Work

Planning, and four in Mechanical and Electrical Maintenance Work Planning.

No violations or deviations were identified.

c. Post-Trip Information System Reliability

A review of facility records revealed that extensive trouble-shooting had identified several defective components in the power supply (inverter and oscillator board) of the sequence-of-events (P-250) computer. Replacement of the defective components and subsequent testing demonstrated that previous problems with reliability have been successfully corrected. The records also indicate that an investigation revealed a loose wire on an output buffer driver of the main annunciator recorder (typewriter) unit. Previously reported malperformance of the recorder/typewriter appears to have been corrected by reconnection of this loose wire.

No violations or deviations were identified.

12. Exit Meeting

On August 3, 1984, an exit meeting was conducted with the licensee's representatives identified in paragraph 1. The inspectors summarized the inspection scope and findings, as described in this report.