U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos: 50-275/86-32 and 50-323/86-30

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: November 9, 1986 through December 27, 1986

Inspectors: L. Mark Padovan 1/30/87
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Summary:

Inspection from November 9, 1986 through December 27, 1986 and January 16, 1987 (Report Nos. 50-275/86-32 and 50-323/86-30)

Areas Inspected: The inspection included routine inspections of plant operations, maintenance and surveillance activities, follow-up of onsite events, allegations, open items, and LERs, as well as selected independent inspection activities. Unit 1 restart following a refueling outage was also examined. Inspection Procedures 30703, 61706, 61710, 61726, 62703, 61708, 71707, 71710, 71711, 90712, 92700, 92702, 93702, and 94703 during this inspection.

Results of Inspection: No violations or deviations were identified.

DETAILS

1. Persons Contacted

J. D. Shiffer, Vice President Nuclear Power Generation
*R. C. Thornberry, Plant Manager
*J. A. Sexton, Assistant Plant Manager, Plant Superintendent
*J. M. Gisclon, Assistant Plant Manager for Technical Services
*J. D. Townsend, Assistant Plant Manager for Support Services
D. B. Miklush, Maintenance Manager
W. G. Crockett, Instrumentation and Control Maintenance Manager
L. F. Womack, Operations Manager
*T. L. Grebel, Regulatory Compliance Supervisor
S. R. Fridley, Senior Operations Supervisor
R. S. Weinberg, News Service Representative
D. A. Malone, Senior I&C Supervisor
R. M. Nanninga, Senior Maintenance Engineering Supervisor
M. R. Tresler, Project Engineering

The inspectors interviewed several other licensee employees including 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 January 16, 1987.

Note: Acronyms are used throughout this report; refer to the Index of Acronyms at the back of the report.

2. Operational Safety Verification

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 LCOs as prescribed in the facility 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) Essential safety feature equipment alignment and conditions.

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

b. Unit 1 Post-Reload Containment Walkdown (Engineered Safety Features System Walkdowns)

Prior to startup from the refueling outage, the inspectors performed a walkdown of physically accessible portions of the safety injection, residual heat removal, accumulator and containment spray systems inside containment. Further discussion of this item is provided in the Unit 1 post-reload startup section of this report (Section 11).

c. Improper Storage of Portable Gas Cylinders

During a pre-startup walkdown of the Unit 1 Auxiliary Building, the inspector observed three gas cylinders roped off to containment penetration piping. The cylinders were located in the penetration area near one of the containment hydrogen monitors and were probably staged for use as test gas for calibration. If toppled, portable gas cylinders could fail and become missiles, potentially damaging safety related equipment. Additionally, if a bottle remains secured to safety related piping during an earthquake, the bottle could cause unreveiwed loading to the piping. This condition was previously identified in NRC Inspection Report 50-275/86-09 (Section 2.b), and was again discussed with plant management. Licensee management committed to ensure existing plant procedures for removal of temporary bottles were followed.

No violations or deviations were identified.

3. Chronology of Significant Items

a. On November 10, 1986 a surveillance was missed in Unit 2. With the rod position deviation monitor inoperable, the DRPI and the Rod Demand Position indication are to be checked and verified to be in agreement every four hours. This was successfully done at 2200 on November 9, missed at 0200 on November 10, and done at 0545 November

10. The licensee states the problem occurred because the oncoming operator (graveyard) became sick and went home after a temporary relief was found. The sick operator missed the logging of the check in the control operators log which is the official record of the check. Operations supervision stated the agreement (between rod position indications) was in fact checked more periodically than every four hours but the log entry was not made.

The licensee wrote an AR and NCR to effect permanent corrective action and indicated it would consider methods to strengthen the administrative controls and checks on logging technical specification log entries.

The activities discussed in this section involved apparent or potential violation of NRC requirements identified by the licensee for which appropriate licensee actions were taken or initiated. Consistent with Section IV.A of the NRC Enforcement Policy, enforcement action was not initiated by Region V.

b. On November 22, 1986 in Unit 2 an inoperable auxiliary feedwater flow indicator was declared inoperable but was not recognized as a technical specification action item. The flow indicator acted erratically. The shift foreman declared it inoperable, but did not recognize that the indicator was part of the Post Accident Monitoring TS requirements (3.3.3.6).

The TS require a shutdown within 48 hours if the indicator is inoperable. The licensee discovered the failure to follow the TS action statement and notified the senior resident at 0205 on November 28, 1986. The licensee proposed, and the resident concurred, that the TS action statement should start at the time of discovery i.e. the morning of November 28. To shut the reactor down would have required the use of the AFW system and accordingly the use of its inoperable flow indicator. The licensee considered the problem was attributable to air in the vent lines which could be vented. Subsequently, later in the morning of November 28, the indicator was successfully vented, returned to service and declared operable.

The licensee prepared LER 86-026 which describes the event and corrective action. The activities discussed in this section involved apparent or potential violation of NRC requirements identified by the licensee for which appropriate licensee actions were taken or initiated. Consistent with Section IV.A of the NRC Enforcement Policy, enforcement action was not initiated by Region V.

c. On November 24, 1986 a management meeting was held in the Region V office in Walnut Creek to discuss technical issues involving the containment door violation, clearance control on snubber work, and the SG snubber with a missing pin. Management subjects discussed were:

- o Root cause analysis - Getting to the bottom of problems, not accepting a mystery.

- o Ensuring problems are looked at broadly as well as focusing on the hardware aspect.

d. On December 7, 1986 an earthquake occurred approximately 18 miles NW of San Luis Obispo, about 7 miles west of Morro Bay and was reported to be 2.9 on the Richter scale. The earthquake was not felt at the site but did activate the most sensitive recording instrument (Terra-Tech) and alarm.

e. On December 9, 1986 Unit 1 entered Mode 4 on its return to service from the refueling outage. The inspectors perform a containment inspection. Minor items needing correction were identified. The inspectors noted that the licensee's practice does not require senior management examination of the containment prior to final closure. This was discussed with management who then conducted an examination. Management also stated they would consider such examination for future final containment closures.

f. On December 11 Unit 1 entered Mode 3 in its return to service.

g. On December 12, 1986 the containment ventilation isolation valves were opened by operations personnel even though one of the noble gas stack monitors was declared inoperable about 45 minutes earlier. The licensee issued LER 86-19, and took appropriate corrective action. The activities discussed in this section involved an apparent or potential violation of NRC requirements identified by the licensee for which appropriate licensee actions were taken or initiated. Consistent with Section IV.A of the NRC Enforcement Policy, enforcement action was not initiated by Region V.

h. During the week of December 15, 1986 an environmental qualification of equipment inspection was performed by NRC and contractor personnel. This report will be issued separately, however the basis for component operability of certain equipment with record deficiencies was reviewed by the residents at the end of the inspection on December 19, 1986. The licensee provided sufficient rationale to justify of continued operation of Units 1 and 2.

i. On December 15 the residents examined Unit 1 auxiliary building spaces for readiness for return to service. Several relatively minor items were identified and subsequently corrected. The inspectors noted that the licensee does not have an established practice for management to examine the auxiliary building prior to returning the unit to service. Licensee management then conducted an examination of Unit 1 and Unit 2 auxiliary building spaces and committed to consider performing such examinations in the future after extensive outages.

j. On December 19, 1986 there was a water hammer incident on the Unit 1 condensate system which resulted in a broken butterfly valve (isolation valve to the hydrogen coolers - FCV 420) and some leaking flanges.

The incident was initiated by a flow control valve (FCV 230) drifting shut (cause unknown) which created a low apparent condensate system pressure leading the operator to consider the possibility of a line break in the system (there was no break, however). The operator stopped the condensate and booster pumps in response. As soon as it was determined there was no line break, the pumps were restarted. However, at this time since the condensate system was in recirculation to the condenser (a normal startup condition), and portions of the condensate system in high locations (e.g. by the hydrogen coolers) were in a vacuum condition and the lines voided. On restart of the pumps the water hammer occurred.

The residents examined the licensees corrective actions and found them satisfactory in terms of hardware inspection and correction. The reason for FCV-230 drifting shut was not determined absolutely. Hardware checks showed nothing wrong. The licensee theorized that the operator at the control switch position when preparing to "open" the valve a little further (the intended action) actually moved the switch to the closed position (with the seal in feature) when he turned away from the control board to answer a question.

The licensee is pursuing procedure changes to clarify the proper action to take following pump shut off in abnormal situations like long recirculation during startup.

The changes to FCV-230 switch operation (from outage modifications) were discussed in training but the sufficiency of detail is being questioned by the licensee.

The licensee stated that as a peripheral action, they will include a review of switch standardization in their ongoing human factors study.

The licensee had not provided a courtesy notification to the resident inspectors for this water hammer event. The licensee agreed to notify the residents of such events.

k. On December 21, 1986 at 0303 the Unit 1 reactor was taken critical for the first time since its refueling. The inspectors observed the approach to criticality and the criticality operations. Engineering personnel performed the operation in an organized and controlled fashion. All conditions at criticality were well within predicted values. The inspectors also observed the subsequent zero power physics testing as detailed later in this report.

l. On December 28, 1986 the reactor tripped from about 7% power. Prior to the trip, the licensee had commenced ramping the turbine speed down, using the turbine speed control mode, to take the turbine off line. This, as expected, caused the 10% atmospheric steam dump valves to open as the turbine governor valves shut. However, the overall effect of shutting the turbine governor valves caused steam generator level to shrink to the low level setpoint and steam flow perturbations caused the steam flow/feed flow mismatch bistables to flicker resulting in the trip.

Additionally, there at first appeared to be an anomaly in the post trip review in that on the first steam flow/feed flow mismatch signal (flickering bistable) the trip did not occur. Subsequent analysis showed that signal to be so brief that the reactor trip breakers did not and would not be expected to open.

The licensee is pursuing corrective actions involving possible long term design changes to eliminate inadvertent reactor trips and safety injections due to flickering steam flow bistables.

No violations or deviations were identified by the NRC.

4. Maintenance

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

a. Accumulator Safety Valves

The inspector observed portions of MP M-51.5, "Setpoint Calibration for Safety and Relief Valves," performed on the Unit 1 accumulator safety valves. The procedure provides the steps by which safety valves are removed, tested, and reinstalled. The inspector observed the reinstallation of the safety valve for accumulator 1-4. The replacement was performed by qualified technicians. Proper clearances were obtained and QC hold points were followed.

No violations or deviations were identified.

5. Surveillance

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

a. Incore Instrumentation Input to OT delta T Comparater Channel Calibration

The inspector observed portions of the subject STP I-5B4. TS 4.3.1.1 and Table 4.3-1 require that the excore instrumentation be compared to and recalibrated to match incore instrumentation flux data every 92 effective full power days (EFPD). This is accomplished through STP R-13, the data collection procedure, and STP I-2D, the recalibration procedure. STP I-2D calls out STP I-5B4 which provides the procedure for the recalibration of the gains on the four channels of upper to lower power range delta flux inputs to the OT delta T comparater. The inspector found that the proper SSPS channel had been activated and control channel has been defeated. All required information and out-of-service tags were properly hung, and testing was accomplished by qualified personnel.

b. Pressurizer Safety Valves

As a onsite follow-up to the safety valve problems noted in IE Notice 86-92, the inspector examined licensee surveillance activities on the pressurizer code safety valve testing. On August 30, 1986, while in Mode 3, following commencement of the Unit 1 refueling outage, the pressurizer safety valves were pressure tested per STP M-77 to find their lift setpoint. According to TS 3.4.2.2, the design lift setpoint for the pressurizer safety valves is 2485 psig ± 1% (2460.15 to 2509.85 psig). The testing was performed for PG&E by Fermanite using the Trevitest method. The test requires that RCS pressure be maintained at approximately 2100 psig while an air assist is applied to simulate the added pressure needed to open the valve. The first lift test of all three valves was exceptionally high, 2747.8 psig (+10.6%), 3028 psig (+21.9%), and 2661 psig (+7.1%) for valves 8010A, 8010B, and 8010C respectively.

The second tests were 2555 psig (+2.8%), 2494 psig (+0.4%), and 2437.6 psig (-1.9%) respectively. Valves 8010A and 8010C were adjusted and left at 2464 psig and 2503.7 psig respectively.

The licensee's investigation into the exceptionally high first test readings on the valves revealed that the test had been performed without draining the upstream loop seal. The pressurizer safety valves are designed to "pop" open when the design gas pressure is reached. However, these valves will only lift a fraction of their travel and not "pop" open under water pressure. Therefore, it is postulated that when design pressure was reached the valve lifted enough to allow the loop seal water to pass. In the time it took for the loop seal to completely blowout and the valve to "pop" open, the force supplied by the air assist had significantly increased and high test values were recorded. Both Westinghouse and Crosby, the manufacturer of the valves, confirmed for PG&E the results of performing a test with the loop seal present. In addition, Westinghouse indicated that the presence of a loop seal, which is used to protect a valve from direct impingement of pressurizer steam, does not affect the ability of the valve to perform its overpressure protection function during a plant transient. PG&E is revising the pressurizer safety valve test procedure to require that the loop seal be drained prior to the test.

After the testing had been performed, PG&E questioned the effective valve seat area used by Fermanite in the calculation of equivalent pressure supplied by the valve air assist. PG&E subsequently sent a spare valve of the same design as the pressure safety valves to Wyle Laboratories for empirical testing to find the actual effective valve seat area. Wyle Laboratories discovered the effective valve seat area to be slightly larger than that used by Fermanite. The use of the higher effective seat area in the calculation of valve lift pressure results in higher lift valves. On valve 8010C, the recalculated "as left" lift pressure was 2515 psig or +1.2%. As a result, PG&E reset lift pressure on the one valve.

PG&E determined that, because the pressurizer safety valves were returned to $\pm 1\%$ of the design setpoint within the action time specified in the TS LCO, the high as found lift pressures were not reportable per 10 CFR 50.73. However, PG&E has committed to submitting a voluntary LER.

c. <u>Unit 1 Main Steam Line Hydraulic Snubber Reservoir</u>

On a routine plant walk through, the inspectors discovered a hydraulic snubber reservoir on the Unit 1 main steam line from steam generator 1-4 in a degraded condition. This portion of the main steam line is located in the pipe rack penetration area outside containment which is exposed to the elements. The hydraulic fluid reservoir lid was found partially opened. With a flashlight, the inspectors observed contaminants on the surface of the hydraulic fluid. The lid itself appeared to have a rusted seat. This item was brought to the attention of plant mechanical maintenance management.

As immediate corrective action, the licensee replaced the lid, cleaned the hydraulic fluid, and functionally tested the subject snubber. The snubber was found to be operable. In addition, the licensee inspected all other snubbers with the same hydraulic reservoir design. Currently, the licensee has a program to redesign and install a replacement lid for reservoirs of this design.

All Unit 1 snubbers, including the snubber in question, were visually inspected according to STP M-78A at the beginning of the Unit 1 refueling outage (September 1986). STP M-78A "Inspection Acceptance Criteria" states "Remote reservoirs shall be leak tight...." The fact that the maintenance inspectors overlooked the condition of the snubber reservoir in question may be indicative of a lack of formal pre-inspection training. A formal training program is currently being developed by the training department together with maintenance engineering and will be implemented prior to the Unit 2 refueling outage. The program will include lessons learned from the Unit 1 refueling outage and will cover snubber inspection, removal, and reinstallation. The inspector will review the snubber training program during the course of routine inspection.

d. <u>Snubber Washers</u>

During the refueling outage,the licensee identified a wide spread problem with missing washers on piping snubbers. A nonconformance report was written which described the problem and the background associated with the situation specifically. On February 3, 1986 a QC inspector, on a routine walkdown of Unit 2, discovered a snubber missing a washer on its rear bracket. Design drawings show two washers are required on the rear bracket. The purpose of the washers is to position the paddle to allow $\pm$ 5 degrees of misalignment. The QC inspector initiated an AR which went to the onsite Maintenance Department for corrective action and also requested an engineering evaluation. Maintenance initially determined the immediate corrective action to be to replace the missing washer. However, a subsequent evaluation by onsite mechanical maintenance engineering stated that two washers were unnecessary for the snubber in question and that no further action was required. Although the QC inspector questioned the design authority of maintenance engineering and documented his disagreement in the AR, no further action was taken, i.e. the washer was not replaced.

On November 1, 1986 while Unit 1 was in refueling, on a routine inspection, a QC inspector found two snubbers missing washers. Both snubbers had been removed and functionally tested during the outage. Craft personnel assigned the task of reinstalling the snubbers indicated that they had discussed the requirements for washer installation with their foreman and were informed that the installation of only one washer was acceptable.

Immediate Corrective Actions Taken

The licensee's immediate corrective action was to institute a program to inspect all 758 Unit 1 snubbers that had been functionally tested during the outage and 10% of all other Unit 1 snubbers. For each snubber found without a washer in the 10% sample, an additional 10% inspection would be completed. In addition to washer number requirements, the inspection criteria included verifying the proper washers (i.e. Anchor-Darling washers are not installed on PSA snubbers) and verifying proper gaps. Based on the results of this inspection, criteria was to be developed to inspect Unit 2.

Of the 758 Unit 1 snubbers which had been functionally tested, the snubber washer inspection resulted in 268 snubber repairs. A large portion of the repairs consisted of inserting a second washer. The results of the 10% inspection sample resulted in increased sampling such that all snubbers not functionally tested were inspected (698 snubbers). The inspection found 110 snubbers were deficient including 30 snubbers that were missing washers. All deficiencies found were corrected.

Unit 2 Snubber Operability

The licensee investigated consequences of additional possible missing washers in Unit 2. A missing washer could cause a side loading to be applied to the snubber. The washers provide assurance that a $\pm$ 5 degrees of axial motion exists to allow for the movement of piping. If axial movement is not allowed, the forces on the paddles can cause side loading. The licensee contacted snubber manufacturers to determine the amount of permissible side loading. The manufacturers had test data for snubbers with side loading which demonstrated the snubbers remained functional. In conjunction, the licensee calculated the maximum side loading that a snubber with a missing washer might see during a seismic event and concluded that there would be insufficient loading to cause a snubber failure.

Finally, the licensee has committed to the visual inspection and repairs of all Unit 2 snubbers missing washers during their next refueling outage. It appears that the licensee has performed a through analysis. There is no immediate concern with Unit 2 snubber operability due to missing washers.

The Unit 2 snubber found with a missing washer in February was repaired December 19, 1986 and an operability analysis was performed. The snubber was found to be operable (under all design conditions) with one washer missing.

Corrective Action to Prevent Recurrence

The licensee has initiated action to revise two sets of procedures. The first, MP M-55.1, .3, and .4 are the procedures which describe the reinstallation of Grinnell, Pacific Scientific, and Anchor Darling hydraulic snubbers. The procedures will be revised to include specific requirements for the installation of snubbers. The second procedure, STP M-78A, is the snubber visual inspection procedure. It will be revised to include specific criteria for spacer washer inspection.

The licensee has also committed to take action to reiterate to its staff what constitutes a design change and what specific organizations have design change authority.

The completion of adequate corrective action to prevent recurrence will be the subject of a follow-up inspection (Open Item 50-323/86-30-1).

No violations or deviations were identified.

6. Event Follow-up

a. Inadvertent Addition of Water to the Reactor Vessel

As briefly discussed in Section 3.k of NRC Inspection Report No. 50-275/86-29, three feet of water was inadvertently added to the Unit 1 reactor vessel on October 31, 1986. With Unit 1 in the refueling mode, power production engineers performed leak rate testing of containment penetration 51B and its associated isolation valves in accordance with STP V-651B "Penetration 51B Containment Isolation Valve Leak Testing." Clearance Request Number 2724 had been obtained to close boundary valves and isolate the piping to be tested. During the removal from service process, the normally sealed open discharge valve (SI-8921A) from safety injection pump 1-1 was closed, as required by STP V651B. Valve SI-8802A, the safety injection system hot leg isolation valve located downstream from SI-8921A, had been previously closed and its motor operator control switch in the control room was caution tagged in accordance with operating procedure OP L-5 "Plant Cooldown From Minimum Load to Cold Shutdown" to prevent gravity feeding the RWST to the RCS. While testing penetration 51B, valve SI-8802A was opened in accordance with STP V-651B. After completing leak rate testing, the power production engineers reported off the clearance, and operators then began repositioning only the previously cleared boundary isolation valves. The "return to service" portion of STP V-651B was not performed by operations personnel, and only the boundary valves specified on the clearance were repositioned. Accordingly, valve SI-8802A was not closed, and water from the RWST drained to the reactor vessel when boundary valve SI-8921A was returned to the open position at 9:18 p.m. on October 31, 1986. At 10:33 p.m., control room operators recognized a downward trend in RHR temperature. Further investigation revealed the water level in the reactor vessel had risen about 3 feet, and valve SI-8802A was then closed at 10:35 p.m.

Failure to accomplish the required "return to service" portion of STP V-651B was attributed to poor communications between the power production engineers and operators, and shortcomings in the existing clearance control system when it was applied during refueling outage conditions. During outage conditions, clearances need to be better controlled and use of existing procedures for removal and return to service should be enhanced. In this particular instance, reference to the return to service section of STP V-651B should have been specified on the clearance.

This issue is further complicated by inadequacies in the return to service section of STP V-651B. The return to service instruction specified valve SI-8921A be opened, nine valves be manipulated and valve SI-8802A then be closed. During the estimated 15 to 20 minutes required to manipulate the valves, the RWST would have drained to the reactor coolant system. The licensee indicated STP V-651B would be revised to correct the sequence of valve manipulations during return to service of the system.

Corrective actions to enhance system configuration control during refueling outage conditions were described in Section 3K of the previously mentioned Inspection Report.

No violations or deviations were identified.

7. Allegation Follow-up

ATS No.: RV-86-A-096

a. Characterization

The concerns center on the validity of Technical Review Group (TRG) decisions on reactor protection system (RPS) response time problems and the associated reportability. Portions of STP I-33A and I-33B were not performed in accordance with TS 4.3.1.2 and 4.3.2.2 for RPS response time. In response to this problem, the TRG assumed "conservative" times for the portions of the STPs that were not performed. The TRG also decided this problem was not reportable. The concerns are that the assumption for response times and decision on reportability should be examined to determine if they are in compliance with NRC requirements or licensee commitments to the NRC.

b. Implied Significance to Plant Design, Construction or Operation

Without acceptable response time testing for RPS functions, the safety functions that were assumed in reactor safety analyses would not be operational.

c. Assessment of Safety Significance

The inspector reviewed STPs I-33A and I-33B. STP I-33A basically combines all the response times measured from other STPs, including STP I-33B, and verifies that the total time is within acceptable limits in accordance with TS. STP I-33B measures RPS response times from initiation of a simulated instrument trip signal through activation of a reactor trip breaker or essential safety features master relay. These STPs implement, in part, TS Requirements 4.3.1.2 and 4.3.2.2 which require that RPS response times "be demonstrated within its limit".

The inspector then examined the TRG's actions as documented in the NCR DC1-86-TN-N129 associated with this allegation. The description of this nonconformance is that "Surveillance tests I-33A (RX Trip & ESF Response Time) & I-33B (RX Trip & ESF Logic Response Time) sequences 3 & 4 were not performed when Unit 1 made initial entry to Mode 4 on February 20, 1984." The licensee could not find the STP I-33A and I-33B data sheets for two out the four protection set channels. The licensee's NCR documented corrective actions included improved tracking of STP I-33A, and review by the quality support organization of similar tests that assured completion.

The licensee's corrective action included an improved tracking system for STP I-33A tests, i.e., each sequence would be given a distinct identity in the licensee surveillance tracking system. The inspector questioned the need for improvements to assure that STP I-33B would be performed. The licensee pointed out their tracking program had been enhanced through the Surveillance Test Improvement Action Program, which had been initiated partially in response to the NRC issued violation (50-275/86-21-01 and 50-323/86-13-01) for missed surveillances as reported in multiple LERs. This improvement program has been the subject of a inspection report (50-275/86-21 and 50-323/86-21) in which it was determined to be acceptable corrective action for the violation. The licensee noted that there has been no LERs issued for missed surveillance since about March 1986 when the improvement program became effective; and that the improvement program provides additional assurance that no STP I-33B would be missed (or have no documented evidence of it's conduct) in the future.

In the evaluation of the TRG's NCR, licensee management made a technical evaluation as to the operability of the RPS functions for which there was no data sheets. For the STP I-33B response time testing, the licensee determined that a functional test, STP I-16A2 (for modes 1-4) and STP I-16D2 (for modes 5 and 6), verifies the RPS function. This test verifies the RPS logic from bistable actuation through actuation signal for the RPS function (reactor trip breaker or Solid State Protection System master slave relay). This logic verification is performed with a built-in semi-automatic test device that is itself tested and that assures that the each RPS logic responds correctly in 0.2 seconds or less. The inspector reviewed the STPs I-16A2 and I-16D2, as well as the test equipment logic for this functional test. This test is performed on a staggered 62 day frequency for each Solid State Protection System train. The inspector determined that STPs verify that the RPS logic responds correctly in less than or equal to 0.2 seconds. Further the inspector verified that these STP I-16s do test the same portion of the RPS logic that is tested by STP I-33B. Finally, the inspector reviewed the data sheets for the STP I-16D2 around the time frame of the missing STP I-33B data sheets and verified documented evidence of the test conduct.

The licensee in their NCR resolution stated that IEEE 338 does not require the measurement of the I-33B data for which there was no documentation. The inspector's review of IEEE 338 found that the 1975 and 1977 versions of this standard provide that measurement of response times need not be taken for specific conditions. However, since the licensee provided objective evidence, STP I-16D2, that the response times in question were less than or equal to 0.2 seconds, the inspector did not consider this rationale in this assessment.

For STP I-33A, the licensee recreated the data sheets using the assumed "conservative" 0.2 second response time for the missing I-33B data sheets. The inspector examined these recreated data sheets and also verified selected portions of the "other data" that was used in the I-33A recreation ("other data" refers to that data for which there was documented evidence). The inspector's review of the recreated data sheets found that all response times were within TS limits for the initial heatup. The licensee also pointed cut that although the recreation was an after-the-fact verification, there was evidence at the time of initial heatup that demonstrated that the response times were within TS limits. Specifically, the acceptance criteria for the measurements of the "other data" assures response times that are consistent and will assure compliance with TS response times. Therefore, the licensee with the I-16 tests and the "other data" feels that response time tests had been verified, although no formal, documented compilation (STP I-33A) could be found.

In regards to the reportability issue, the licensee's NCR evaluation found that: 1) Sufficient documentation verified that response time limits were met prior to entry into the TS required mode; 2) Sufficient documentation existed to conclude no surveillance was missed; and 3) Sufficient evidence existed to conclude that the plant was not in an unanalyzed condition. The inspector concurs in these findings, since STP I-16 provided an upper limit response time for the STP I-33B missing data sheets, and the manner in which the licensee verified the "other data" to be within acceptance criteria assured that the response time for RPS functions were within TS limits.

d. Staff Position

The inspector concluded that there was acceptable evidence that response time measurements had been taken and assurance that the response times met TS surveillance requirements. Based on this conclusion the inspector also found that the decision to not report was consistent with regulatory requirements. This allegation is unsubstantiated.

e. Action Required

No further action is required.

8. Follow-up of Regional Requests

a. Valves Identification for Radiation Monitors

A LER at another Region V facility identified a potential problem where manipulation of an incorrect valve disabled a radiation monitor for a period greater than that allowed by TS. The inspectors examined the licensee's procedures (STP I-101B1 and STP I-101B4) for removal from and return to service of radiation monitors (RM) 14A and 14B. This procedure had a drawing that showed valve designations and specified valve positions steps for various operational configurations. The procedure was straight forward and easily followed. The inspector then observed actual valve configuration and tagging at RM 14A and B. The only anomalies observed were that three of the twelve valves did not have tags. The inspector concluded that because of the clear procedure and associated drawing the lack of tags designation on the three valves was not an immediate concern. However, the licensee has committed to an investigation to assure that all valves on radiation monitors are tagged.

No violations or deviations were identified.

9. Licensee Event Report Follow-up

Based on an in-office review, the following LERs were closed out by the resident inspector:

Unit 1: 86-10, 86-19
Unit 2: 86-24, 86-26

The LERs were reviewed for event description, root cause, corrective actions taken, generic applicability and timeliness of reporting.

No violations or deviations were identified.

10. Open Item Follow-up

a. Steam Generator (S/G) 1-3 Overfill (Unresolved Item 50-275/86-29-01, Closed)

This unresolved item was principally associated with valve position control during the refueling outage. The inspector reviewed the licensee's proposed corrective actions (described in IR 50-275/86-29), and verified an "Operational Controlled Systems List" was implemented during the remainder of the refueling outage. Longer term corrective actions to revise administrative controls prior to the Unit 2 refueling outage will be followed by the inspectors under the normal inspection program.

No violations or deviations were identified.

11. Unit 1 Post-reload Startup

Prior to plant startup from the Unit 1 refueling outage, the inspector performed a walkthrough of physically accessible portions of the safety injection, residual heat removal and containment spray systems inside containment. The safety injection (SI) system flow adjusting (runout) valve (SI-1-8822D) to the RCS loop 4 cold leg, when viewed from the normal access area below the valve, appeared to be missing the administrative seal required by Operating Procedure (OP) K-10G1. This seal assures the valve remains in the required position for proper SI system flow distribution to the cold legs. The licensee viewed the valve from an overhead position and determined the valve was sealed.

Containment walkthroughs were also made by the inspectors to determine housekeeping status and the general condition of components, systems and supports. Minor housekeeping deficiencies were identified and corrected, but no material capable of plugging the RHR sump during accident conditions was noted. However, the inspector identified a load pin on snubber #11-145L (on the pressurizer spray line) was locked into position with a cotter pin which did not have its ends spread. A housing on pressurizer thermocouple TC 454 was also found to not be securely tightened down on its threads. The cap could be rotated five or six turns. As a result of discussions with the inspector, licensee personnel located a second thermocouple on the pressurizer with a loose housing. The licensee stated the cap was essentially a cleanliness cover and that its presence or absence did not affect operability or environmental qualification. Other items discovered inside containment include apparently missing "u" bolts on reactor coolant tank drain piping, and a crane operating instruction manual remaining on the operator's console of the containment polar crane. The U bolt condition was determined to be in accordance with as-built drawings.

No violations or deviations were identified.

12. Unit 1 Restart Following First Refueling Outage

a. Initial Criticality - The approach to initial criticality was conducted in accordance with STP R-30 "Reload Cycle Initial Criticality." The procedure required that after the prerequisites were met, RCCA banks were withdrawn maintaining sequence and overlap, until Bank D was at 190 steps. This is proceeded by dilution using the "alternate dilute" mode until the inverse count rate ratio (ICRR) reached .30. At this point, Bank D rods were withdrawn until criticality was achieved on withdrawal of Bank D to 208 steps. The approach to criticality was made in a slow and controlled manner.

b. Zero Power Physics Tests - The inspector observed all or selected portions of the following tests:

- o All-rods-out Critical Boron Concentration (all)
- o ITC/MTC Determination (all)
- o Rod and Boron Worth Measurements

All tests, with one exception, were conducted in accordance with requirements of the procedure or acceptable revisions to the procedure by qualified personnel. The exception noted above occurred during the performance of STP 7A, ITC/MTC Determination. Since the secondary plant was unavailable due to recovery from a water hammer event, Unit 1 initial criticality was performed with the MSIVs closed using the 10% atmospheric steam dump valves to regulate T(ave) instead of the normally available steam dump to condenser valves. The atmospheric dump valves do not control as smoothly as the condenser dumps. Additionally, the procedure for determining MTC requires a cooldown temperature ramp approaching Lo-Lo Tave.

The shift foreman on duty was astute and recognized the possibility of an inadvertent safety injection due to Lo-Lo Tave in conjunction with high steam flow. The high steam flow signal sometimes comes in, in the form of flickering bistables, when using the 10% atmospheric dumps. He therefore conceived the idea of using the steam generator bottom blow to induce the desired cooldown ramp.

The inspector inquired as to whether operations management concurred with the change in plan and whether a procedure change was deemed necessary. The foreman checked with management, who concurred, and initiated a procedure change (for which he has the approval authority).

The inspector subsequently discussed this occurrence with licensee management. Licensee management agreed that such changes should be discussed with management and that a procedure change was required. The licensee agreed to reemphasize this point with personnel. For the tests observed, review and acceptance criteria were met prior to authorization for power ascension. Compliance to selected TS requirements was observed.

The data collected during the tests listed and the results will be reviewed in further detail by the inspectors.

No violations or deviations were identified.

13. Exit

On January 16, 1987 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.

INDEX OF ACRONYMS

AR	Action Request
AFW	Auxiliary Feedwater
DRPI	Digital Rod Position Indication
EFPD	Effective Full Power Days
IE	Inspection and Enforcement (NRC)
ITC	Isothermal Temperature Coefficient
LER	Licensee Event Report
LCO	Limiting Conditions for Operation
MP	Maintenance Procedure
MTC	Moderator Temperature Coefficient
MSIV	Main Steam Isolation Valve
NCR	Non-Conformance Report
NW	Nowthwest
OT	Overtemperature
PG&E	Pacific Gas and Electric
QC	Quality Control
RCCA	Reactor Control Cluster Assembly
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RM	Radiation Monitor
RPS	Reactor Protection System
SFM	Shift Foreman
SG	Steam Generator
SI	Safety Injection
SSPS	Solid State Protection System
STP	Surveillance Test Procedure
T	Temperature
TRG	Technical Review Group
TS	Technical Specification