U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos: 50-275/88-17 and 50-323/88-16

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: May 29 through July 16, 1988

K. E. Johnston, Resident Inspector — Date Signed 8/3/88

P. P. Narbut, Senior Resident Inspector — Date Signed 8/3/88

Approved by: M. M. Mendonca, Chief, Reactor Projects Section 1 — Date Signed 8/3/88

Summary:

Inspection from May 29,1988 through July 16,1988 (Report Nos. 50-275/88-17 and 50-323/88-16)

Areas Inspected: The inspection included routine inspections of plant operations, maintenance and surveillance activities, follow-up of onsite events, open items, and licensee event reports (LERs), as well as selected independent inspection activities. Inspection Procedures 25026, 30703, 37700, 61726, 62703, 71707, 72700, 92700, 92701, 92703, and 93702 were applied during this inspection.

Results of Inspection: No violations or deviations were identified.

Indications of weaknesses are indicated in the enclosed report in the following areas:

- Paragraph 4.a. describes an AFW spill. The licensee did not pursue a root cause analysis (by issuing a Quality Evaluation) until prompted to do so by the NRC inspector.

- Paragraph 4.b. refers to a missing surveillance test for venting ECCS piping due to an administrative error by plant engineering. Paragraph 4.f. refers a missing functional test on the Low Temperature Over Pressure protection system because of a lack of an administrative system for surveillance tests not related to a specific mode.

- Paragraph 4.h. deals with leaking six inch Velan Check Valves which had been the subject of generic correspondence as early as 1983. The licensee's root cause analysis appeared to require NRC prodding in order to assure an acceptable resolution.

- Paragraph 4.i. deals with inadvertent MSIV closure due to a verbal miscommunication between I&C and operations personnel. Although these miscommunications have decreased in frequency, this is a repeat of the informal communications issue raised in 1987.

- Paragraph 4.j. deals with an inadvertent diesel generator start caused by pulling the wrong fuses during preventative maintenance activities. This was a similar occurrence to that which previously occurred on August 15, 1987.

Indications of strengths are indicated in the enclosed report in the following areas:

- The licensee demonstrated timely investigation and action in the area of pressurizer surge line movement which had been discovered at another site as described in paragraph 11.b..

- The licensee initiated design based QA audits (paralleling NRC SSFI inspections) as indicated in 11.c..

- The licensee is providing timely investigation and action regarding potentially falsified piping fittings as described in paragraph 10.b..

DETAILS

1. Persons Contacted

*J. D. Townsend, Plant Manager
D. B. Miklush, Assistant Plant Manager, Maintenance Services
*L. F. Womack, Assistant Plant Manager, Operations Services
*J. M. Gisclon, Acting Assistant Plant Manager for Support Services
*B. W. Giffin, Assistant Plant Manager, Technical Services
*C. L. Eldridge, Quality Control Manager
*K. C. Doss, Onsite Safety Review Group
T. A. Bennett, Assistant Maintenance Manager
D. A. Taggert, Director Quality Support
*W. G. Crockett, Instrumentation and Control Maintenance Manager
J. V. Boots, Chemistry and Radiation Protection Manager
T. L. Grebel, Regulatory Compliance Supervisor
S. R. Fridley, Operations Manager
R. S. Weinberg, News Service Representative
#M. R. Tresler, Project Engineer
#M. J. Jacobson, Project Quality Engineer
#S. M. Skidmore, Quality Assurance Manager
#M. C. Freund, QA Supervisor
#S. C. Auer, Electrical Engineering Group Supervisor

The inspectors interviewed several other licensee employees including shift foreman (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 onsite on July 20, 1988.
\# Denotes those attending inspection at PG&E General Office.

2. Operational Status of Diablo Canyon Units 1 and 2

During the report period, Unit 1 ended its second refueling outage on July 13, 1988. At the end of the period the Unit was at 30% power performing testing. Notable occurrences included: (1) the discovery of a loose steam generator manway bolt due to the absence of verification measurements, (2) entry into Technical Specification 3.0.3 due to a missed surveillance on ECCS venting, (3) the completion of work on the containment purge valves, (4) the actuation of pressurizer low temperature over pressure protection system due to a pressure transient, (5) a residual heat removal water hammer event due to a leaking Velan check valve, (6) and two reactor trips during startup; the first due to an apparent failure to follow procedure; the second due to unexpected divergent steam generator level oscillations while paralleling to the grid at 20% power.

Unit 2 remained at power for the reporting period.

3. Operational Safety Verification (71707)

a. General

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

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

(a) General plant and equipment conditions.

(b) Fire hazards and fire fighting equipment.

(c) Radiation protection controls.

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

(e) Interiors of electrical and control panels.

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

(g) Plant housekeeping and cleanliness.

(h) Essential safety feature equipment alignment and conditions.

(i) Storage of pressurized gas bottles.

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

b. Containment Walkdown

The inspector performed a walkdown of the Unit 1 containment shortly following entry into Mode 4. The inspector verified material condition of the Unit and implementation of the licensee's pre-service cleanliness program in accordance with TS 4.5.2. The inspector observed that material condition and cleanliness were acceptable. The inspector did discover an unsecured nitrogen bottle in the seal table room in addition to the bottle normally used to

support the incore flux instrumentation. The extra bottle was tied to its cart, however the cart was unsecured and lacked stability. This was brought to the attention of the Outage Manager who had the bottle removed. The Outage Manager noted that on an earlier walkdown no bottles had been in place. He had requested two organizations (work planning and maintenance) to assure that a bottle was installed. This extra bottle would probably have been identified by the licensee during seal table leakage inspections conducted prior to startup. However, this is an example of the reappearance of a previous problems which received considerable focus.

No violations or deviations were identified.

4. Onsite Event Follow-up (93702)

a. Auxiliary Feedwater System Spill

One June 1, 1988 a spill of several hundred gallons of uncontaminated Condensate Storage Tank (CST) water occurred through the Auxiliary Feedwater (AFW) system. AFW pump 1-3, which takes suction from the CST, was started to perform STP P-23 (Acceleration Timing of Safety-Related Pumps). The pump, rated at 1456 psi, ruptured a temporary hose connected to a vent line on the motor driven AFW pump cross connect piping. The hose was part of a temporary system for the rapid recirculation of steam generator 1-1. The boundary valve for the temporary system on the AFW cross connect piping had been left open.

In review of the incident, two apparent weaknesses were identified. First, the operators did not comply with their procedure. STP P-23 Step B.1 refers to operation procedure OP D-1:I to make the pump available for operation. OP D-1.I assumes that OP D-1.II, the system lineup checklist, is complete as a prerequisite. OP D-1.II had not been completed due to the temporary lineup for the SG rapid recirculation. A review of OP D-1.II would have told the operators that there was a direct path from the AFW pump discharge to the low pressure SG rapid recirculation system.

The second weakness identified was that the SG rapid recirculation temporary lineup did not have the pump discharge valve controlled with an administrative tag. A tag would have prevented the operators from opening the pump discharge valve and connecting the high pressure AFW system to the low pressure SG rapid recirculation system.

In review of this event a month following its occurrence the inspector found that the Operations Department had not established a Quality Evaluation of this event. The Operations Manager concurred that in order to track corrective actions to quality related systems and procedures that a QE should have been established. Corrective actions to be identified in the QE include a revision to the SG rapid recirculation procedure to establish administrative tagouts on is boundary valves.

In response to this event and previous outage spill events the licensee is establishing procedures to formalize its system control philosophy. One procedure will establish who is allowed to operate what equipment in a given condition. The other procedure establishes a Controlled Systems list. A system not on the Controlled Systems list, such as a system cleared for maintenance during an outage, will be assumed to have uncertain status and can not be operated until it is returned to the list. To return to controlled status a system must have a completed system walkdown (such as OP D-1.II for the AFW system). A system on the Controlled Systems list which is not configured in accordance with procedures or the plant drawings shall have these exceptions documented. The licensee has committed to have these procedures in place for the Unit 2 second refueling outage. These procedures and the corrective actions committed to in the Human Performance Evaluation System (HPES) related to a spill on May 8, 1987 address the inspectors concerns with control of system during an outage. The inspector has determined that, based on the safety significance of the spills on May 5, 1987 and June 1, 1988 and the corrective actions committed to by the licensee in response to these events, no enforcement action is warranted. This closes Unresolved Item 50-323/87-20-05. The inspector will follow the implementation and effectiveness of these planned corrective actions during routine inspection. (Open Item 50-323/87-20-05 closed)

b. Missed Unit 2 ECCS Venting Surveillance

On June 6, 1988 at 2230 hrs, the licensee discovered that the monthly surveillance test for Emergency Core Cooling System (ECCS) venting had not been performed as required by TS 4.5.2.b.1).. The surveillance should have been performed by June 2, 1988 (31 days plus 25% past the last performance on April 26). As a result, the shift foreman entered TS 3.0.3 until the surveillance, STP M-89, was completed at 11:42 p.m..

It was determined that the surveillance had been missed due to an administrative error by the plant Engineering department test coordinator during the review of the April 26 surveillance. The licensee determined that the missed test was of no safety significance since (1) no substantial gases were vented from the ECCS during the performance of the test, (2) there is no history of substantial gas venting, and (3) the amount of gas that could form in the four days the surveillance was passed due would not likely be enough to damage an ECCS pump.

Review of the licensee's corrective actions will be completed with the review of the LER to be submitted for this event.

c. Unit 1 Loose Steam Generator Cold Leg Manway Nut

On June 8, 1988 an inservice inspection inspector discovered a loose steam generator cold leg manway bolt during a pre-service inspection of the bolts. The Unit was in cold shutdown, vented at the

pressurizer, and the static head at the manway was less than 60 feet of water.

During the refueling outage, all Steam Generator (SG) manways were removed to support refueling activities. Upon their replacement, Westinghouse used a new method to tension the fasteners. The method was in accordance with a Westinghouse procedure, endorsed by the PSRC, and supported by Westinghouse QA. Due to confidence in the method of tensioning the fasteners, a method of fastener elongation was not used. Westinghouse QA only used a final visual inspection and was not present during stud tensioning. Previously, the licensee has measured fastener elongation following manway installation, eliminating concerns for the possibility of loose fasteners on Unit 2.

The licensee could not identify the specific problem which resulted in the loose stud. As a result, the licensee has had inspection data sheets included into the manway installation procedure. The data sheets include tension and elongation measurements.

The licensee measured elongation on all eight manways and found an additional 16 studs marginally under tensioned and one over tensioned. These problems were corrected.

The licensee determined that had the loose stud not been found prior to startup testing then it possibly would have resulted in a leak which would likely have been found during a leak check inspection of the gasket as a part of STP R-8A, "Reactor Coolant system Operational Pressure Leak Test." If a leak had developed during power operation, it could have been identified by the RCS leakage detection system (containment radiation monitors, containment sump level, RCS inventory balance).

The inspector reviewed the licensee's Non Conformance report and found the corrective actions to be acceptable.

d. <u>Three Unit 2 Component Cooling Water System Valves Fail Inservice Testing</u>

On June 10, 1988, Component Cooling Water (CCW) valves RCV-16, LCV-69, and LCV-70 failed inservice testing (IST) stroke time requirements. The criteria for these valves is to stroke in 10 seconds and they stroked in 13, 11 and 11 seconds, respectively.

RCV-16 is the surge tank atmospheric vent high radiation isolation valve. Inspection Report 50-323/88-03 contained a Notice of Violation concerning the return to normal test frequency of RCV-16 after its stroke time had increased by 141% without corrective maintenance. The licensee had committed to perform the corrective maintenance during the next Unit 2 outage of sufficient duration. The next refueling outage is scheduled in October 1988. As a result of the increased stroke time, RCV-16 was isolated and declared inoperable. The engineering department considered the possibility of over pressurization (the tank has a relief valve) and drawing a

vacuum on a CCW leak below the tank (the tank is designed for -15 psid) prior to isolating the valve.

The LCVs supply makeup water to control level in the surge tank. They were not declared inoperable, since there is no time requirement for their actuation. The inspector discussed it with the cognizant engineer who stated that loss of make up (i.e., the LCVs failure to open) was bounded by the analysis of the failure of a CCW header. Both the valves will be worked during the next refueling outage.

e. Diesel Generator Declared Inoperable Due to Slow Start

On June 9, 1988, Diesel Generator (D/G) 1-1 was declared inoperable following an engineering review of STP M-9A (D/G Routine Surveillance Test) which had been performed on May 23, 1988. The D/G had failed to attain rated speed in 12 seconds on two air start motor as stated in the FSAR.

The STP requires the test to be run with both two and all four air start motors. If it failed to come to rated speed in 10 seconds on two air start motors the STP requires an Action Request to be written, which was done. If the D/G had failed to come to speed in 10 seconds on four air start motors the STP requires it to be declared inoperable. The STP did not reflect the FSAR assumption that the D/G came to speed in 12 seconds on two air start motors.

It was discovered on June 9 that the turbo air assist solenoid had come loose from its associated valve and was not operating the valve. The turbo air assists D/G starts and load increases and is safety related. The licensee subsequently inspected all other D/G turbo air assists solenoid valves to ensure that the valves were properly secured.

The licensee determined that the root cause of the turbo air assist valve failure was a "random" failure. It was also determined that this failure and the failure of the D/G to come to rated speed in 12 seconds was not a non-conformance. Since time did not permit full examination of this item it will be followed up as an Open Item (50-275/88-17-01).

f. Unit 1 Missed Low Temperature Over-Pressure Protection (LTOP) Functional Test

On June 18, 1988, the licensee discovered that a channel functional check had not been performed on the LTOP within 31 days prior to closing all RCS vent paths as required by TS 3.4.9.3. All Unit 1 pressurizer relief and safety valves were closed on June 16 at 0750 in preparations for Mode 4. The test was subsequently performed by 0200 hrs on June 19, 1988.

The test was missed because it did not fall into the categories of either a test required to be performed periodically or prior to entry into an established mode. These situations are controlled in

procedure and by the recurring task scheduling program. This particular maintenance is required to be performed prior to closing all RCS vent paths which occurs sometime in Mode 5 but prior to Mode 4. Previously this surveillance had not been missed because an I&C planner had informally kept track plant status and had scheduled the functional test to be performed just prior to the closing of the RCS vent.

The inspector and the region discussed with the licensee that this missed surveillance was not missed due to a problem previously identified. Further follow-up and review of corrective actions will be conducted with a review of the licensee's LER.

g. Unit 1 LTOP System Actuation

On June 21, 1988, Unit 1 experienced a pressure transient in Mode 5 which resulted in the actuation of LTOP and the lift of a pressurizer PORV. The PORV lifted at 425 psig and the normal operating pressure when controlled for use of the RHR system was 375 psig. The lift was for approximately three seconds. The licensee determined that the transient was initiated when letdown pressure control valve PCV-135 overcompensated for a pressure change caused when the letdown divert valve LCV-112A was switching to divert. The normal letdown path (the Volume Control Tank or VCT) was at 18 psig while the divert path (the Liquid Holdup Tanks or LHUTs) was at atmospheric pressure.

The licensee determined that PCV-135 overcompensated due to sluggish and jerky response to the pressure signal. The valves behavior had not been noticed previously since it had not been called upon to react quickly as in this case.

A contributing factor was that the RCS was in a solid condition. Following the PORV lift, in the course of routine startup procedures, a bubble was established in the pressurizer reducing the risk of further pressure transients.

The licensee is required by TS to report this actuation in 30 days by TS 3.4.9.3.c. In addition, the licensee initiated a Non Conformance report. The inspector will review the licensee's actions in review of this report.

h. Unit 1 RHR Water Hammer in Mode 4 and Check Valve Leak

On June 25, 1988, Unit 1 was in Mode 4 operation using reactor coolant pump heat for a heatup to return to service following a refueling outage. As part of the return to service, surveillance tests for leakage were being performed on various check valves in the Emergency Core Cooling System (ECCS) including the Residual Heat Removal System (RHR). The RHR system was not in operation, core heat removal, if desired, was available through steam generator steaming.

At 5:10 p.m. PDT, RHR pump 1-2 was started primarily to test the check valve on pump 1-1 and to "flush" some other check valves that were suspected of leakage. A water hammer was reported by auxiliary operators and an investigation was commenced.

Initial walkdowns by engineering personnel likewise did not identify damage or distress. Snubber removal and operational testing was performed and no damaged snubbers were identified.

Subsequent check valve testing identified that valve 8818C, a Safety Injection check valve to loop 3 (downstream of RHR pump 1-2 and the RHR heat exchanger) was leaking about 8 gpm, in excess of technical specification 3.4.6.2 limits for identified leakage of 1 gpm. Consequently the licensee proceeded from Mode 4 to Mode 5 (cold shutdown) in compliance with technical specifications.

A notification of an unusual event per 10 CFR 50.72 (b)(1)(i)(a) (shutdown in accordance with technical specification) was declared at 1:45 p.m. PDT on June 26, 1988, and terminated at 5:52 p.m. PDT after reaching cold shutdown.

The licensee entered Mode 5 at 5:52 p.m. PDT and commenced disassembly of valve 8818C.

Water Hammer

Subsequent analysis determined that the water hammer occurred because the water remaining in the RHR piping was relatively hot (approximately 270 degrees F) and the water was subsequently depressurized (to perform valve testing) which caused the formation of water saturated steam voids. The voids were collapsed and the water hammer occurred when the pump was turned on to exercise other valves being tested.

The licensee walked down all affected piping and tested affected snubbers and found no evidence of damage, distortion or inoperable components including snubbers.

The licensee revised their valve test procedures to recognize the possibility of void formation and to eliminate the voids subsequent to testing and prior to pump operation.

The licensee's actions are described in Nonconformance Report DC1-88-TN-N072 and will be followed up in the normal course on nonconformance review.

Check Valve Leakage

Independent of the water hammer event the licensee determined that check valve 8818C was leaking by its seat.

Subsequent disassembly and inspection showed that the valve disk anti-rotation pins could rotate under the disk swing arm and cause

the valve to be slightly unseated. The valve is a 6 inch Velan swing check valve, Velan drawing No. 78704.

This situation was considered possibly generic and was closely examined by the licensee and the NRC and discussions were held with licensee management and NRC management in Region V and headquarters.

The licensee had examined one other such check valve during the refueling outage as part of the routine check valve sampling program initiated subsequent to generic check valve problems in industry and had not found any problems with that valve.

The licensee decided that further check valve disassembly and inspection was not required for Unit 1 prior to restart from refueling based on safety analysis of the 6 inch check valves and other sized Velan check valve which might be suspect.

The licensee recorded their rationale for this discussion in a PSRC meeting held on July 5, 1988. That rationale will be documented in Nonconformance Report NCR DC1-88-MM-N073 and an LER to be submitted. Therefore, the rationale will not be repeated here.

It was further determined that NRC Information Notice 88-06 and INPO SER 20-83 and its supplement dealt with similar problems with Velan check valve anti-rotation pins, that the manufacturer offers two alternate physical corrections to the problem but doesn't consider the problem generic or reportable, and that PG&E had evaluated this information in 1986 but had not successfully maintained this information available for plant staff.

The NRC expressed some concerns with PG&E's actions in regards to the check valve investigation:

- Although the final analysis for restart was satisfactory, it appeared that NRC "prodding" was necessary to achieve the final root cause and safety analysis.

- The licensee moved slowly to formalize their action plan. An action plan was not formed until June 29.

- Plant management determined readiness for restart verbally and did not record their integrated rationale in a PSRC reviewed and approved position until requested to do so.

- Subsequent to a formal decision to restart additional generic information was uncovered (SER 20-83) which, although it did not negate the rationale for restart, it did demonstrate a weakness in PG&E methodology for researching and uncovering generic information.

The licensee committed to address these weaknesses in the nonconformance report actions in a meeting between the senior resident and the assistant plant manager for support services held on July 8, 1988. At this meeting the APM also committed to inspect

at least 4 Velan check valves in the upcoming Unit 2 refueling outage and to schedule inspection of all other safety related Velan check valves in future sampling plan.

This item will be followed up through the LER to be submitted on the event.

i. Unit 1 Main Steam Isolation Valve (MSIV) Closure in Mode 4

On June 25, 1988, at 2101 hrs while Unit 1 was in Mode 4 preparing for restart, Instrumentation and Controls (I&C) technicians troubleshooting main steamline differential pressure safety injection (SI) bistables tripped the high steam flow SI bistables for protection set II. This, coincident with both low-low Tavg (RCS temperature less than 543 degrees) and low steam line pressure, resulted in a main steam isolation signal. The high steam flow SI was blocked as is normal for this mode.

Earlier on June 25, steamline d/p bistables comparing loops 1 and 3 had spuriously actuated. The I&C technicians had tailboarded with the Shift Foreman (SFM) and Control Operator (CO) prior to troubleshooting the circuit. At that time it was recognized that at some point the I&C technicians might have to trip other bistables to inject dummy signals for testing. Operations recognized that although the high steam flow SI was blocked, and actuation of that logic would cause a main steam isolation. They requested I&C to notify them if they came to this point.

When the technicians came to a point where they needed to trip the high steam flow bistables they contacted the control room by phone and got the Senior Control Operator (SCO) who had not participated in the tailboard. Following a miscommunication between the SCO and the CO and an independent status check by the SCO where he failed to recognize that the MSIV close signal was not blocked, permission was given to trip the high steam flow bistables. This resulted in an MSIV closure and at 2107 hrs the valves were reopened.

This event was the subject of an NCR and an LER and review of the licensee's corrective actions will be reviewed with the LER.

j. Diesel Generator 2-1 Start

On June 30, 1988, at 8:52 a.m. the Unit 2 Diesel Generator 2-1 auto started. The auto start of an emergency diesel is an ESF actuation and a 4 hour non emergency report was made by the licensee at 1201 p.m. PDT.

The cause of the diesel start was the inadvertent pulling of a fuse by an electrician performing preventative maintenance in the cubicle for Component Cooling Water Pump 2-2 4kv breaker. The cubicle (52-HG-12) contains an additional fuse, not found in adjacent cubicles for 4kv breakers. The fuse is for the second level undervoltage protection circuit whose logic senses degraded bus voltage. Although the bus voltage was not degraded, pulling the

fuse caused the logic circuit to sense an undervoltage condition and therefore automatic action to strip the bus (bus G) of its loads and start the diesel generator ensued.

The electrician realized what had been done and contacted the control room. The fuses were replaced at 0847.

One anomaly occurred and that was that ASW pump 2-1 should have automatically started and did not. The pump should have sensed low pressure when ASW pump 2-2 was stripped off the bus and also should have sensed the undervoltage signal from Bus G logic.

Subsequent investigation and corrective action showed that ASW 2-1 didn't auto start because of two independent problems. The low ASW pressure start was blocked by corroded connections at the pressure switch. The undervoltage signal from Bus G was not reviewed because of a bent contact on its logic relay.

Both of the above signals are not safety related actuations. ASW is actuated by separate ESF logic in the event of SI signals or other ESF actuations.

Operators responded to the event properly restoring charging, letdown, and manually starting ASW pump 2-1 in a matter of minutes.

The licensee will submit an LER on this event defining corrective actions.

It is noted however that this is a repeat occurrence exactly similar to the August 15, 1987, occurrence reported on Unit 1 in LER 87-14, except that an operator vice electrician had pulled the same fuse.

Follow-up of this event will be performed in conjunction with follow-up of the LER.

k. Unit 1 Over Temperature Delta Temperatures Trip (OT delta T)

On July 10, 1988, the unit experienced a reactor trip on OT delta T. The trip appeared related to I&C testing activities and will be followed by an ongoing team inspection and the LER to be submitted on the reactor trip.

l. Unit 1 Reactor Trip

Unit 1 experienced a turbine trip/reactor trip on July 13, 1988, at about 5:30 p.m.. The licensee's post trip review and analysis were acceptably completed in accordance with Nuclear Plant Administrative Procedure A-100. The licensee concluded that the cause of the trip was a dynamic interactions between the Main Feedwater Control and Steam Dump Systems, which resulted in divergent oscillations of steam generator level. The turbine trip on high-high steam generator level resulted in an associated reactor trip. The inspector reviewed the post trip review data package to assure the data appeared consistent with the licensee's identified cause.

The startup procedure had been changed to parallel the unit at 20% power rather than 8% power in order to reduce the potential for reactor trips. It is apparent upon review of the June 12 trip that the dynamic interaction between the feedwater control and steam dump systems were exaggerated at 20% power resulting in the divergent oscillations of steam generator level.

The inspector discussed the review process of the procedure change with the licensee, specifically the involvement of engineering. The plant manager indicated that :

(1) Engineering did not perform a detailed review of the procedure. However, they were involved in a trip reduction task force, coordinated through the Westinghouse owners group, which established a subgroup to revise the power ascension procedure. In summary, they were cognizant of the changes but not involved in the details.

(2) This subgroup was headed by senior operations supervisor and had an SRO and a senior training involved. The SRO discussed power ascension procedures with every Westinghouse PWR. The discussion found that most utilities were doing what Diablo had historically done, i.e., parallel at about 8%. However, some had experienced problems similar to Diablo's previous problems, but were content to live with them. Others had gone to paralleling at higher power levels, e.g., Farley 15% and Sequoyah 20%. The subgroup developed a procedure.

(3) The Instrumentation and Control department checked the Steam Dump Control System capacity to take the increased power change.

(4) The procedure was used in simulator training for all licensed individuals and their comments resulted in Revision 1.

The problem resolution effort on this included investigating the benefit of having engineering do an analysis of the procedure change. Preliminarily, the licensee feels that available engineering analytical tools would not have identified this problem. The inspector will review further corrective actions as follow-up of the LER to be submitted for this event.

The licensee modified their power ascension procedure to provide a more stable steam demand by paralleling the turbine at a lower power level. The inspector observed the PSRC deliberations on this procedure change and concluded that the PSRC evaluation was acceptable. The inspector observed selected portions of the subsequent plant startup on July 13, 1988.

No violations or deviations were identified.

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

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

a. Containment Purge Valves

As described briefly in inspection report 50-275/88-11, during the Unit 1 containment integrated leakage rate test (ILRT) it was noted that the inside containment purge supply and exhaust valves (RCV 11 and FCV 660) did not hold pressure. It was subsequently determined that the valves had a preferential seating characteristic and that the local leak rate test (LLRT), which pressurizes the volume between the inside and outside valves, did not conservatively test the valves leak rate. The valves had been designed with a tapered seat.

The licensee submitted LER 1-87-25-00 on June 21, 1988 describing the above in detail. The LER was submitted due to the potential loss of Containment integrity when on December 9, 1987 FCV-661 on Unit 2 failed an LLRT assuming FCV-660 was inoperable. FCV-661 was declared inoperable for approximately 3 hours. While the situation technically warranted the description of a loss of containment integrity there were mitigating circumstances. First, the licensee was unaware that FCV-660 was inoperable. Second, FCV-661 seated itself when a pressure of approximately 1.5 psig was supplied by the test pump. Therefore FCV-661 would have performed its intended function following an accident.

The above is the only instance the licensee identified an outside containment purge or exhaust valve to be inoperable in a mode where it was required for service.

The licensee did not recognize until the Unit 1 ILRT that these valves, Fisher Model 9200 butterfly valves, had a preferential seating characteristic. They stated that this was a failure of the manufacturer to supply sufficient information to engineering to recognize this fact. The inspector reviewed the purchase order, vendor manual, and records of previous ILRTs and concurred with the licensee's conclusion. The licensee ordered valves which held pressure in either direction. The vendor supplied valves that were tested from both directions. However, with its tapered seat, the Fisher Model 9200 valves, when set up and tested in the preferential direction, does not necessarily hold pressure when used in the opposite direction. Therefore, when past ILRT results showed that the inside valves were not holding pressure, the licensee, assuming the valve was fully equivalent in both directions, would adjust the valve and retest from the opposite (LLRT) direction.

The inside valves were declared inoperable on Unit 2 and sealed closed. The outside valves have been tested in the same direction

as they would be required to operate during an accident. Therefore, they have remained operable.

As a result of their investigation, for Unit 1, the licensee reversed FCV-660 and RCV-11 such that an increase in containment pressure would tend to press the rubber t-ring gasket on the valve disc into the taper of the valve seat. These modifications are planned on Unit 2 for its second refueling outage. Until then, the licensee will be purging Unit 2, using 10 inch purge and will maintain the 48 inch valves closed and deactivated when in Modes requiring containment integrity.

The generic implications of the preferential leakage characteristics of Fischer Series 9200 valves are being addressed by NRR. The LER 87-25 is considered closed.

b. Unit 2 Turbine Driven Auxiliary Feedwater (AFW) Pump

On June 1, 1988, Unit 2 turbine driven AFW pump 2-1 failed its ASME inservice testing surveillance test due to high outboard bearing vibration. The pump was disassembled and the rotating element from AFW pump 1-1, which was not required to be in service, was installed to exit the TS action statement.

The mechanics disassembling the pump identified that there was evidence of heat at the matched set bearings. The inspector observed that the removed bearings were discolored and chrome was flaking supporting the mechanics observations. The maintenance general foreman also pointed out to the inspector where the shaft had been worn approximately .006 inches under the inside of the bearing pair.

Maintenance investigation of the problem determined that the wrong bearings had been used in replacement. The bill of materials for the pump lists SKF 7311 Beagy or equivalent bearings. The mechanical engineer found that two separate bearing manuals list, as replacement bearings, New Departure 30311DT and 30311DB. The bearing used was a 30311DT. Upon investigation, the maintenance engineer determined that the DT and DB signify thrust direction.

The inspector reviewed the licensee's Quality Evaluation for corrective actions. The QE stated that as corrective action only the SKF bearings could be stored with the stock code and not the New Departure or other equivalent bearings. While this solves the problem, it does not address the root cause which is that the wrong parts were ordered. No evaluation was performed to determine why a wrong bearing was ordered. The inspector discussed this with the Quality Control Manager who committed to assure that the procurement aspects of the problem are analyzed. This problem will be followed up by normal inspection activity.

c. Other Maintenance Activities Observed

Selective portions of preventive maintenance activities on Diesel Generator 2-2 were observed to be in accordance with work instructions.

The inspector also followed up maintenance activities associated with the Unit 1 loose SG manway stud, the RHR water hammer investigation, preventative maintenance of CCW pump 2-2 4kv breaker, modification activities for reversing FCV 660 and RCV-11, bearing replacement for AFW pp 2-1, material sampling activities for falsified material including fittings and bolting, and check valve 8818C disassembly, inspection, and internals replacement. These areas are discussed in the body of this report.

No violations or deviations were identified.

6. Surveillance (61726)

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

a. Main Steam and Pressurizer Safety Valves

The inspector followed up the actions taken by the licensee with regard to surveillance testing of both the Main Steam (MS) and Pressurizer (Pzr) Safety Valves (SVs). Prior to the refueling outage, in Mode 3, the licensee tested all three Prz SVs and all three did not meet the lift setting criteria of +/-1% of 2485 psig. One lifted high by 1.6%, and two lifted low by 1.1% and 5.1%. The licensee also tested all 40 MS SVs and found 10 outside the acceptance criteria with four recorded as "no lifts" prior to adjustment.

During the lift testing the test director determined that for four valves the lift setpoints were clearly above the acceptance criteria, terminated the tests, and declared "no lifts". The licensee determined using conservative assumptions for the affect of the adjustment on the lift point that the four "no lift" could have lifted between six and nine percent. Of the other six MS SVs, one lifted 1.3% high and 5 lifted between 1.4 and 4.1% high.

The licensee had an analysis performed by Westinghouse that determined that operation with setpoints in these ranges was not outside the plant design basis.

The licensee could not determine a root cause of the out of calibration lift points although they inspected four MS SVs and all three Prz SVs during the outage. As a result the licensee could not identify any corrective actions to prevent recurrence of SVs lifting outside their acceptance criteria. The licensee identified this as an industry wide problem. The Region discussed this with both NRR and AEOD which concurred with the licensee that the results were within those expected for SV performance.

The licensee was studying what criteria to establish such that fewer "no lifts" are recorded. Specifically, they were studying how much force to allow the hydraulic assist to supply to the valve stem.

The inspector will continue to evaluate the licensee's SV testing program as necessary. This item will be followed up in the normal course of future inspections.

b. Unit 1 Physics Testing for Restart from Second Refueling

The inspector observed Unit 1 startup testing subsequent to the Unit 1 refueling outage.

Specifically the inspector observed portions of:

o STR R 1C Digital Rod Position Indicator Functional Test

In this test, which exercises the rods 24 steps and ensures digital rod position indication and the demand step counter agree, Shutdown Bank A, rod J-11 gave indications of being dropped. The operations personnel responded by performing their alarm response procedure properly.

They subsequently determined that the dropped rod indication only came in at 27 1/2 steps and went out at 34 1/2 step. When using DRPI in A train only, the rod indicated as expected. Further test showed another location on J-11 indicated improperly on Train B. The licensee concluded that the problem was probably in the rod position junction box in the refueling cavity wall which was inaccessible with the missile shield in place. The licensee's PSRC further determined that the situation was acceptable for continued operation in that the shutdown banks are kept fully withdrawn during operation (228 steps) and the erroneous indication on rod J-11 occur only at less than 100 steps and only on one train on DRPI. Therefore, the indication requirements of the technical specification are met (+ or - 12 steps is available on Train A of DRPI).

o STP R-30 Reload Cycle Initial Criticality

The inspector observed the licensee's approach to criticality which occurred at 1:16 p.m. PDT July 7, 1988, by dilution. The licensee's estimate of criticality was required by their procedure to be within 50 ppm. The licensee was well within their limits which were more conservative than technical specification. Criticality was achieved at 186 1/2 steps on Control Bank D with a boron concentration of 1827 ppm boron versus predicted values of 170 steps and 1836 ppm. The net effect equalled approximately 15 ppm boron reactivity worth.

o STP R-31 Rod Worth Measurement Using the Rod Swap Method

The inspector observed portions of this test on July 8 and July 9. The test had to be reperformed due to unfavorable results

initially. The unfavorable results occurred because the test results were unrealistically conservative if the neutron flux levels are too high or low. Specifically, if flux levels are near the point of adding heat flux increases are flattened by Doppler effects. Therefore, the licensee required flux levels to be at the low end of the zero power test range. This however caused the uncompensated gamma input to be a significant factor causing the apparent flux rise to be flattened giving erroneously low rod worth reading.

Consequently the licensee had to reperform portions of the rod worth testing. The results of this reperformed portions and associated physics calculations were reviewed and appeared acceptable to the inspector.

No violations or deviations were identified.

8. Radiological Protection

The inspectors periodically observed radiological protection practices to determine whether the licensee's program was being implemented in conformance with facility policies and procedures and in compliance with regulatory requirements. The inspectors verified that health physics supervisors and professionals conducted frequent plant tours to observe activities in progress and were generally aware of significant plant activities, particularly those related to radiological conditions and/or challenges. ALARA consideration was found to be an integral part of each RWP (Radiation Work Permit).

No violations or deviations were identified.

9. Physical Security

Security activities were observed for conformance with regulatory requirements, implementation of the site security plan, and administrative procedures including vehicle and personnel access screening, personnel badging, site security force manning, compensatory measures, and protected and vital area integrity. Exterior lighting was checked during backshift inspections.

No violations or deviations were identified.

10. Licensee Event Report Follow-up

a. Status of LERs

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

Unit 1: 83-23, 87-09 Revision 1, 86-23, 88-09, 88-15

Unit 2: 87-05 Revision 2, 87-22, 87-06, 88-03

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

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

b. Reportable Occurrence on Suspect Material in Response to NRC Bulletin 88-05

On July 8, 1988, at 4:00 p.m. PDT, the licensee made a 48 hour report to HQ duty officer pursuant to NRC Bulletin 88-05 Supplement 1 reporting requirements.

The licensee reported that four safety related 4 inch 160 lb, flat faced, slip on, carbon steel ASTM A105 flanges on vacuum relief lines to the Auxiliary Salt Water System (the Diablo Canyon ultimate heat sink) for both Unit 1 and Unit 2 had been determined not to have valid material certifications. The licensee further reported that the flanges were of heat number x 45786 and were purchased from Columbia Specialty Company of Paramount, California. The inspector reviewed the licensee's safety evaluation of the consequences of continued operation and found its conclusion acceptable. Supplemental investigation by the inspector determined that the flanges in question were manufactured by West Jersey Manufacturing.

The licensee based continued operation on:

(1) Calculations were performed demonstrating piping adequacy. The calculations used an ultimate tensile strength equal to the minimum reported by other utilities which had received falsified materials.

(2) Previously successful hydrostatic testing.

(3) Operation for two fuel cycles without failure or leakage.

(4) No noted abnormal deformations in service or in a special walkdown conducted.

Additionally, the licensee's search of all records had identified 25 items from the suspect manufacturers. To date the licensee had located 13 locations of the items and has performed sampling on 12 items (one item will not be sampled as it is in abandoned fire water piping). The located items were in air supply piping to the external hydrogen recombiners, the ASW vacuum relief lines and blind flanges on the residual heat removal system.

The licensee sampling included samples from each located item for chemical and physical analysis and hardness testing. The hardness testing was used to make approximate correlations to material strength.

All stainless steel specimens passed (RHR). The four carbon steel flanges, which did not meet material specification requirements, all had low manganese. This was not considered a serious deficiency. Two of these four carbon steel flanges had low hardness values (HRB 68 and 67 versus 75) which correlate to strengths of 59 and 58 ksi.

The licensee had performed an analysis on July 1, 1988, (prior to the receipt of these results) to justify the approach to criticality for Unit 1 (subsequent to its refueling outage). That analysis utilized the lowest known strengths of material known to have been discovered by other utilities (e.g. 43 ksi). Using those lower values, the licensee determined that the flanges were acceptable for intended service.

This item will closed and subsequent followup to the licensee's response will be performed at the directions of Headquarters.

No violations or deviations were identified.

11. Independent Inspection

a. Fastener Testing (NRC Compliance Bulletin 87-02)

On November 6, 1987, the NRC issued NRC Compliance Bulletin 87-02, "Fastener Testing to Determine Conformance with Applicable Material Specifications." The inspector reviewed the licensee's program for sampling bolts for testing in inspection report 50-275/87-42. This report documents the completion of the inspection requirements contained in Temporary Instruction 2500-26.

The licensee submitted their response to Bulletin 87-02 on March 25, 1987. The inspector reviewed the licensee's receipt inspection program for safety-related and non-safety-related fasteners to determined that it was accurately reflected in the licensee's response to Bulletin 87-02. The inspector reviewed applicable procedures for the reason for the most current revision and found that generally revisions had been made to accommodate the computerized tracking system.

It should be noted that while the licensee's bulletin response stated that sampling practices were used on fasteners, as a result of the inspector's discovery of SA 194 Grade 4 bolts in a SA 194 Grade 7 bin, sampling has been suspended pending licensee review.

The inspector reviewed the licensee's maintenance and warehouse procedures for issue and control of safety related and non-safety related fasteners and found that they accurately reflected the licensee's description provided in the bulletin response.

Finally, the inspector reviewed the follow-up actions to be taken by the licensee and finds them to be acceptable. Therefore this Bulletin is closed.

b. Pressurizer Surge Line Movement

The phenomenon of the pressurizer surge line movement was discussed in report 50-275/88-11.

During this reporting period the licensee had decided to and did install monitoring instrumentation to measure the pressurizer surge line movement and temperature profile during heatup and during operation.

In addition, the licensee had performed non-destructive examination of the surge line to verify that no pipe cracking was present.

Prior to criticality, the licensee presented a Westinghouse preliminary analysis which determined that based on conservative calculations the fatigue cycles induced by heatup and cooldown were satisfactory for a least 10 more cycles. They also considered that actual data taken during heatup would allow a more refined calculation which would a greater number of allowed fatigue cycles.

PG&E engineering personnel involved in the surge line movement measurements during heatup, stated that the movement experienced was less than that assumed in the calculation and was in accordance with predictions for the temperature profile achieved.

c. Quality Assurance

Quality Support

The inspector reviewed the licensee's Quality Support onsite activities. The activities were generally pre-planned and acceptably completed. The Quality Support organization was also involved in various problems, e.g., plant housekeeping requirements. The inspector reviewed selected Quality Support surveillance reports. Additionally, the inspector determined the extent of the Quality Support surveillance activity on a modification to the isolation signal to RHR valve 8701. From discussions with the involved quality support individual and supervisor, the inspector determined that the extent of the review was to assure that the modification was conducted in accordance with the design change and that the requisite analyses were complete. A more detailed review of the modification is planned in conjunction with the closeout of the associated NCR, consistent with licensee procedures.

The inspector also discussed the in-progress efforts on Safety System Outage Modification Inspection Surveillances by Quality Support. The first such effort had just been completed. The effort consisted of a "vertical slice" of technical issues to assure acceptable design operation, maintenance, testing, and modifications for selected systems. Preliminary, the effort indicated some improvements were needed in the engineering area. The licensee's efforts in this area were encouraging and routine inspection will continue to follow licensee developments. Additionally, the inspectors review of Quality Support's Monthly reports showed that performance and conditions are tracked, and follow-up of problems was acceptable.

Quality Assurance

The inspector reviewed several system audit reports performed by the Quality Assurance Department:

1. System Audit of Auxiliary Saltwater System Audit 86259T.

2. Control Room Ventilation System Audit 87153T.

3. Diesel Generator (DG) System Audit 87247T.

4. 4160 Volt System Audit 88803T.

These audits were similar to Safety System Functional Inspections (SSFIs). The initial audit on the Auxiliary Saltwater System was programatic and did not identify the problems discussed in Inspection Report 50-275/88-11. However, the inspectors review determined that there seemed to be an improving trend in the audit reports, i.e., the later reports were more technically detailed. The inspector was informed that the latest report was performed by an onsite auditor which may have contributed to the improved technical detail. This was discussed with the QA manager.

The resolution of the audit report findings was discussed with various individuals. QA auditors, maintenance, and operations personnel indicate that follow-up and resolution of audit findings was appropriate. The inspector verified through review of the NCR on the 4160 Volt System Ventilation problem that the licensee's follow-up was acceptable.

The inspector reviewed a PG&E "White Paper" on SSFIs. This paper established PG&E's plans to continue performing and developing their own SSFI effort.

The inspector also reviewed a QA audit of QC functions (Audit 88817T). The audit appeared to be an extensive and indepth evaluation of QC functions related to Diablo Canyon. Audit findings and there significance or resolution were documented. The audit report was acceptably prepared and issued in accordance with the appropriate portions of Quality Assurance Department Procedure 18.2, Revision 11.

d. Configuration Management

The licensee's activities to establish a configuration management system were inspected at the General Office.

The licensee has approached this activity by: (1) conducting system audits on safety related systems, and (2) establishing a configuration management task force to evaluate Diablo Canyon Power Plant configuration management practices and procedures.

Of the four systems audited (Auxiliary Saltwater system, 4160 Volt System, Diesel Generator System, and Control Room Ventilation

System), the audits were found to be of equivalent scope and depth to the NRC Safety System Functional Inspections utilizing a pre-approved audit plan directed toward evaluating system operation, maintenance, and surveillance activities for implementation of design and licensing bases. Audit findings were well documented and tracked through resolution. The findings appeared to be of a substantial technical nature and not of programatic nature.

The licensee is in the formative phase of establishing a configuration control and management system. A configuration management task force has been established to evaluate the current practices employed to maintain configuration control and evaluate their consistency with a written set of industry acceptance standards. The task force had recently completed their evaluations and issued a draft report, for management review, containing recommendations formulated as a result of the evaluations.

The recommendations encompassed the spectrum of configuration management activities: including organizational interface, design control, configuration management modifications, release to operation of modifications, plant operations, maintenance, training, control of vendor information, record control, setpoint control, and control of design bases. Licensee representatives indicated that using these recommendations, they intend to establish a corporate policy and program to effect a comprehensive configuration management system addressing the above areas and activities. The licensee then intends to establish an implementation schedule. In the interim, the licensee will continue processing design changes and material replacement in accordance with previously approved procedures, which appear adequate.

The area of configuration management will be evaluated during future inspections.

12. Open Items

a. Quality Hotline (Open Item 50-275/87-20-02, Closed)

The inspectors reviewed the resolution of a quality hotline concern identified in a previous inspection. The Quality Hotline Concern No. 87-006, related to overtorquing valves during testing. The licensee had assured that the valves were acceptable for current operations and had requested verification of long-term acceptability from the venders. All venders have replied and determined that the testing methods used were acceptable for the long-term, except one valve had a marginal valve that is continuing to be evaluated by the licensee. The time frame for response for one valve venders seemed excessive, in that, this was only recently completed, whereas, other venders had completed their evaluations around December 1987. The licensee's records showed that the concerned individual had been kept appraised of the development of the issue. Based on this review, Open Item 50-275/87-20-02 is closed.

b. Other Open Items

The inspector reviewed the following open items which had been carried as open for a considerable period. These items are considered closed based on the general actions known to have been taken by the licensee. Detailed verification of licensee committments was not considered warrented in these items:

- o Violation 50-323/87-39-02, RHR Pipe Heating
- o Follow-up 50-323/86-23-01, 52 HF14 Actuation
- o Follow-up 50-323/86-27-01, Accumulator Leaks
- o Follow-up 50-323/87-12-01, EQ Gaskets
- o Unresolved 50-323/87-20-02, Loop Tests
- o Follow-up 50-275/87-08/01, Procurement Dedication
- o Follow-up 50-275/87-38-01, Wrong Unit/Wrong Train
- o Follow-up 50-275/87-42-01, Steam Dump Grooming
- o Follow-up 50-275/88-03-01, Manual Valves/Casualty Procedure
- o Follow-up 50-275/88-11-04, Pzr Surgeline
- o Information Notice 50-275 & 50-323/87-59, RHR Deadhead (Superceded by NRC Bulletin)
- o Unresolved 50-275/86-23-03, Hydraulic Snubber
- o Unresolved 50-275/87-20-03, Hydraulic Snubber Leak

c. <u>(Closed) Temporary Instruction (TI-15-73), IEB 85-03 on MOV's</u>

This item was open pending NRR review. NRR review was completed and documented in a memorandum dated June 24, 1988, Berlinger to Kirsch, which stated:

"As requested by action item e. of Bulletin 85-03, "Motor-Operated Valve Common Mode Failures During Plant Transients Due to Improper Switch Setting," the licensee identified the selected safety-related valves, the valves' maximum differential pressures and the licensee's program to assure valve operability in their letters dated May 13, Stptember 2, and November 26, 1986, and March 9, July 2, and September 14, 1987. Review of these responses indicated the need for additional information which was contained in Region V letter dated March 15, 1988.

Review of the licensee's April 14, 1988, response to this request for additional information indicated that the licensee's selection of the applicable safety-related valves to be addressed and the valves' maximum differential pressures meets the requirements of the bulletin and that the program to assure valve operability requested by action item e. of the bulletin is now acceptable."

Therefore, this item is closed for Units 1 and 2.

13. <u>Exit</u>

On July 22, 1988 an exit meeting was conducted with the licensee's representatives identified in paragraph 1. The inspectors summarized the scope and findings of the inspection as described in this report.