U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos: 50-275/87-26 and 50-323/87-26

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: June 28 through August 15, 1987

Inspectors: ---------- 9/1/87
L. M. Padovan, Resident Inspector — Date Signed

---------- 9/2/87
K. E. Johnston, Resident Inspector — Date Signed

---------- 8/31/87
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Approved by: ---------- 8/28/87
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Summary:

Inspection from June 28 through August 15, 1987 (Report Nos. 50-275/87-26 and 50-323/87-26)

Areas Inspected: The inspection included routine inspections of plant operations, maintenance and surveillance activities, follow-up of on-site events, open items, and licensee event reports (LERs), as well as selected independent inspection activities. Inspection Procedures 30703, 61708, 61710, 61720, 62703, 71707, 71710, 71711, 92700, 92701, 92703, 93702, and 94703 were applied during this inspection.

Results of Inspection: One violation was identified in the area of late event notification to the NRC.

DETAILS

1. Persons Contacted

*J. D. Shiffer, Vice President, Nuclear Power Generation
*J. D. Townsend, Acting Plant Manager
*J. A. Sexton, Assistant Plant Manager, Plant Superintendent
*J. M. Gisclon, Acting Assistant Plant Manager for Support Services
*C. L. Eldridge, Quality Control Manager
K. C. Doss, On-site Safety Review Group
R. G. Todaro, Security Supervisor
*D. B. Miklush, Maintenance Manager
*D. A. Taggert, Director Quality Support
T. J. Martin, Training Manager
*W. G. Crockett, Instrumentation and Control Maintenance Manager
J. V. Boots, Chemistry and Radiation Protection Manager
*S. G. Banton, Engineering Manager
*L. F. Womack, Operations Manager
*T. L. Grebel, Regulatory Compliance Supervisor
S. R. Fridley, Senior Operations Supervisor
M. W. Stephens, I&C General Maintenance Foreman
*R. S. Weinberg, News Service Representative
D. A. Malone, Senior I&C Supervisor
*M. J. Angus, Work Planning Manager
M. L. Smith, Maintenance Engineer
M. Tressler, Project Engineer, NECS

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 on August 21, 1987.

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 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. Unit 2 Pre-Restart Containment Walkdown

The inspectors walked down portions of the safety injection system inside containment including the accumulators. No discrepancies were found.

Prior to Unit 2 startup, and after the completion of management walkdowns, the inspectors performed a walkdown of Unit 2 containment areas. The walkdown was extensive and included relatively inaccessible areas such as the pressurizer enclosure area, the top and bottom areas of the steam generators, and tops of pipe racks outside the biological shied. The examination was a general area examination for cleanliness, unauthorized material, work completion, and general hardware conditions. The inspectors noted several apparent discrepancies which were brought to plant management's attention for resolution. These included loose insulation, head area electrical cables not properly "tucked" in cable trays, and an oil leak on a hydraulic steam generator snubber. These matters were resolved. In the case of the snubber oil leak, the licensee had previously identified the leak, had hydrostatically tested the leaking seal, provided a rationale for operability, and had instituted a periodic inspection for leakage and oil reservoir level. The overall conditions inside containment was satisfactory. A lessor number of minor items were noted in the Unit 2 walkdown than had been noted in Unit 1 prior to restart, presumably due in part to the management walkdowns.

One problem area not fully resolved was the routing of cables in the cable tray on the reactor vessel head. As observed, the cables were not tied down in the cable trays and were not continuously located in the bottom of the cable tray. Specifically, the cable trays periodically have rods across the top of the cable tray and the cables as a group were placed on top of the rods, effectively coming up and out of the tray at these locations. The inspector questioned this condition. Two actions occurred. First, maintenance personnel placed the cables under the rods. The maintenance manager stated this was done as a housekeeping action after checking appropriate drawings which did not show the rods. Second, engineering personnel determined that the cables should pass over the rods but could not arrive as to why that was required. Licensee engineering stated that the condition had been analyzed and that the head area cabling situation was satisfactory as installed (under the rods) and was satisfactory as designed (over the rods).

Subsequent follow-up by the inspector after startup identified further problems. Specifically, engineering personnel stated that the rods were not shown on a drawing.

The inspector has several outstanding questions; specifically:

- Why were the rods installed and when?
- How long were the cables run over the rods?
- Was that condition acceptable?
- How was apparent misinformation passed on prior to startup?
- Why did the maintenance personnel of placeing the cables under the rods without a work authorization?

The questions regarding the Unit 2 head area cables are considered an unresolved item (50-323/87-26-01).

c. <u>Unit 2 Safety Injection System Walkdown (Engineered Safety Features System Walkdown)</u>

The inspector performed a walkdown of physically accessible portions of the Unit 2 safety injection system including electrical breakers and control room indication. The system was found to be appropriately lined up for its operational mode. The inspector reviewed outstanding action requests (ARs) on the system. No ARs affected the operability of the system and the ARs were addressed in a timely manner. The inspector did observe some housekeeping items in the walkdown most notably, new and discarded plastic ties used to secure "sealed valve" positions were found on the floor and on cabinets in the 100 foot penetration area. This was pointed out to the operations supervisor who committed to address it with the operations crews who were responsible for sealing valves. Failure to control these sealed valve ties had been brought to the licensee's attention previously.

d. Seismic Hazard Sensitivity

The inspector also examined general areas of the Auxiliary Building including the cable spreading room.

Once again large I&C test carts were observed in the area of safety panels. The carts were not in use, not secured, and are mounted on wheels. They thus represent a seismic hazard to the equipment in the area.

Likewise, on the Unit 1 side of the cable spreading room, the overhead fluorescent lights were noted to be installed by having been hung from safety related conduit by temporary chains. Although the lights do not represent a heavy weight, the licensee was asked to determine if the lights and the I&C carts represented an unanalyzed condition. The licensee committed to evaluate significance of the lights and carts from a technical standpoint.

Additionally, at the exit interview, the inspectors noted that the subject of seismic hazards and the licensee programs to identify and remove such hazards had been discussed on a number of previous occasion but that the inspectors have not noted a significant change in the licensee staff's awareness of such hazards.

The licensee management stated the programs in place would be reemphasized.

During a routine plant walk through, the inspector identified an improperly supported argon gas pressurized bottle located immediately west of demineralizer regenerative receiver tank 0-2. The pressurized bottle was tied off loosely with a small diameter rope, and could be easily tilted and swung in several directions. This bottle was also located near the equipment drain receiver tank 0-1, which normally contains high activity levels. Accordingly, during an NRC exit meeting on July 31, 1987, the inspector discussed this situation with plant management, and received acknowledgement and assurances that the situation would be corrected.

On August 20, 1987, the inspector again toured the receiver tanks area and observed that the argon gas bottle was still inadequately supported. Apparently, appropriate management corrective actions were not implemented to rectify this situation. Additionally, in NRC Inspection Report 50-323/87-12 (and earlier inspection reports), examples of unsatisfactory pressurized gas bottle support have been brought to the attention of plant management for resolution. As discussed in the exit meeting on August 21, 1987, aggressive plant management attention to self-identify and provide timely, effective corrective action from problems of this nature is imperative. Licensee management stated the bottle in question would be resolved and that the attentiveness to gas bottle storage would be reemphasized.

The licensee's actions regarding the cable spreading room lights, the I&C test cart, and actions to increase licensee identification and correction of such items is a follow-up item 50-275/87-26-02.

No violations or deviations were identified.

3. Onsite Event Follow-up

a. Unit 2 Auxiliary Feedwater (AFW) Pumps Start on Low-Low Steam Generator Level

On July 1, 1987, at 0052 hours, while in mode 5, the Unit 2 motor driven AFW pumps automatically started as a result of low-low steam generator level (15% narrow range). The operators restored the steam generator levels and declared a significant event under 10 CFR 50.72 due to the initiation of ESF equipment (the AFW pumps).

On June 30, 1986, prior to the event, the unit was in mode 4 with the reactor coolant system (RCS) at 330 degrees F and 360 psig. The residual heat removal (RHR) was in service with RHR pump 2-1 running. Preparations were underway for a special evolution to shutdown and clear all four reactor coolant pumps (RCPs) to resolve seal injection orifices problems (discussed separately in section 3. b.). The licensee's plan was to attempt to maintain plant heat and mode 4 operation with the RCPs off by isolating the steam generators and running both RHR pumps to provide heat.

By 1930 hours all steam generator levels had been raised above 45% to preclude having to add cold AFW which would increase cooldown. At 1944 hours the turbine and reactor trip breakers were manually tripped (although initially the turbine was on the turning gear and all rods were at the bottom of the core) in preparation for removing the RCPs from service. At 2033 hours the final RCP had been secured and both RHR pumps were started. It became evident at 2114 hours that without the RCPs in operation there was not enough heat to hold the plant in mode 4 and RHR pump 2-2 was secured. The unit entered mode 5 at 0052 hours indicating that the RCS temperature dropped from about 330 degrees F to 200 degrees F in about 2.5 hours. Levels in all four steam generators had been steadily dropping due to some steam generator blowdown and RCS cooldown effects. At 0052 hours the AFW pumps started on steam generator 2-2 low-low level.

During the entire scenario, the control room operators were concerned about steam generator level loss. Since the reactor trip breakers were opened, they were not concerned about the levels in two of the steam generators decreasing, since the other two generators were maintaining relatively stable levels. They were intent on maintaining two of the levels 15% to satisfy the technical specifications on operable reactor coolant loops. The operators were hesitant to add water to the steam generators since this would have aggravated the cooldown. Also, the shift foreman wanted to minimize the amount of water added to the steam generators, he had been informed that the chemistry department had requested the steam generators be drained. Since the reactor trip breakers were opened

prior to shutting down the RCPs, dropping to less than 15% in any one steam generator was not considered a problem. The SFM and operators did not consider that this would result in an AFW initiation.

As described in LER 50-323/87-13 corrective action taken by the licensee to prevent recurrence is an operations incident report was written describing the event. These reports are reviewed by all operations personnel on a formal basis. In addition, the licensee also inspected all steam and feedwater piping for steam generators 2 and 3. A review of LER 50-323/87-13 is included in section 8. b. of this report.

b. Unit 2, Flow Orifices Installed Backwards

On June 29, 1987, I&C technicians discovered a Unit 2 flow orifice installed backwards. The orifice is in FE 144 and is used to determine the Reactor Coolant Pump seal water flow.

This error could be significant because a reversed orifice could lead to establishing a different actual flow than indicated. The reactor coolant pump seal flows are limited to 40 gpm by technical specifications because this number was used in safety analysis as a maximum allowable bypass flow around (past) the Boron Injection Tank (BIT) during a safety injection.

The inspector attended the licensee's action plan meeting on the following day. The action plan included a physical inspection of all important flow orifices in Units 1 and 2, an examination of when and why the orifices were installed backwards, an attempted determination of the quantitative effect of a reversed orifice, a determination of the effect of any reversed orifices on system operability, a revision to library work orders for orifice installation to require QC verification.

As reported in LER 50-323/85-029, issued July 28, 1987, subsequent to the event, all flow measurement orifices that provide data for technical specification tests were reinspected for orientation. Four additional orifices were found installed backwards but were of a nature which did not adversely affect test results or performance. Likewise Unit 1 was inspected and one orifice found backwards. This orifice did not require correction however.

The cause of the event was lack of sufficient detail in written instructions for orifice installation. The inspector reviewed some of these cases and found varying degrees of detail and differing degrees of independent verification. The licensee correction to this problem includes a detailed installation instruction specifically for orifices. Most of the orifice installation errors were in the June to July 1985 time frame. The instructions utilized since that time were likewise not very detailed but did not result in additional examples of reversed orifices.

As a result of the event, the licensee has determined that it was in violation of technical specification requirements since startup of Unit 2 on August 27, 1985, (Mode 2) since the backwards seal injection orifices resulted in higher than allowable flow.

The licensee performed engineering analysis to show that although seal injection flow was higher than allowed, the excess flow did not reduce the remaining flow available through the boron injection tank below the minimum assured in safety analysis and no safety consequences resulted.

Licensee corrective actions are described in LER 85-29 and appear adequate.

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.

c. Unit 2 Turbine/Reactor Trip on Steam Generator High Level

On July 14, 1987, at approximately 0800 hours a Unit 2 turbine/reactor trip occurred on high steam generator level with power greater than 10% (P-10). A subsequent safety injection occurred on high steam flow coincident with low steam header pressure. The reactor trip had been preceded by a high steam generator level (P-14) turbine trip below 10% power (P-7) at 0441 hours and a manual turbine trip in anticipation of an automatic trip on P-14 at 0551 hours. These events resulted from a number of contributory causes including the licensed operators lack of experience of operations with a positive moderator temperature coefficient, lack of a smoothly operating steam dump system, and a miswired control room megawatt meter. Following these events, the licensee initiated a comprehensive action plan of items which was addressed prior to plant restart.

Prior to these events, the plant was in mode 2, less than 5% power, following completion of the startup physics testing program. Reactor coolant system boron concentration was greater than 1800 ppm resulting in both a positive moderator temperature coefficient (MTC) and a positive isothermal temperature coefficient. The licensee's plan was to start the turbine, parallel it to the grid, and proceed to 30% power.

The following is a sequence of events:

Time	Event
0429	Entered mode 1
0441	The main turbine and feedwater pump 2-2 tripped on P-14. The automatic turbine trip resulted in a feedwater isolation and auxiliary feedwater system actuation. This

automatic engineered safety feature actuation was reported under 10 CFR 50.72 as a 4 hours non-emergency event.

0448 The reactor was stabilized at approximately 2% in mode 2.

0520 - 0545 Reactor power was raised to approximately 8% in preparation to roll the main turbine.

0551 The main turbine was manually tripped due to unstable steam generator water level control. The licensee determined that the subsequent manual feedwater isolation and auxiliary feedwater start were not reportable.

0645 A third steam dump valve (PCV-1) was made available although it was leaking by. Shortly after PCV-1 was valved in its packing blew out creating a large steam leak at the valve. To compensate power was raised to 8.5%.

0715 - 0758 The reactor was at 9 - 10%. Feedwater regulating valves were in manual. The operators were experiencing wide variations in steam generator water level.

0759 An operator synchronized the main generator to the grid. He noted the reference reading on the turbine digital electro-hydrolic control (DEHC) system switched to 66 MW as it should. The senior control operator (SCO) noted that there was not a characteristic drop in Tave and noted that the megawatt meter on the DEHC console read zero. Assuming that the turbine was not picking up load, the SCO took manual control of the turbine governor valves to open them in fast action mode. This resulted in a marked increase in steam flow, approximately 37% of total flow. All steam generators swelled with S/G 2-4 reaching high level, resulting in the turbine/reactor trip.

The high steam flow coincident with the decrease in steam line pressure as a result of the governor valves in fast action caused a safety injection.

0800 - 0900 The operating personnel responded to the reactor trip and safety injection in accordance with emergency operating procedure E-0. The plant was stabilized in mode 3.

0930 A post trip review of the incident was conducted by the operations supervisor. Attendees included the control room operating personnel, plant management, and resident inspectors. The actions taken by operating personnel, control system response, and plant problems were discussed.

Following the events, after discussions with the NRC resident inspectors, the licensee drafted an action plan of items that needed to be addressed prior to an attempt to restart. The action plan was

based on the discussion with the operators following the event. In general, the action plan covered the following areas:

- An investigation of the cause of the reactor trip and safety injection.
- Training of all operators with regards to operations with a positive MTC, incorporating lessons learned from the events and lessons learned from other operating reactors.
- An investigation into the turbine DEHC system.
- The verification of the proper set-up and operation of the condenser steam dump valves.
- The enhancement of instrumentation available to the operators.

Event Review and Investigation

In reviewing the events it was determined that the first two instances of high steam generator level resulted from the contributing factors of slow response of the condenser steam dump system to changes in RCS Tavg and a positive MTC. Simplistically, as Tavg increased, reactivity and steam generator level both increased. The increase in reactivity resulted in a corresponding increase in Tavg. Another destabilizing effect is with an increase in Tavg and a subsequent increase in steam header pressure, the demand for condenser steam dumps increases. This results in a swell of steam generator level. Combined, these effects resulted in two high steam generator level turbine trips.

Prior to attempting a third startup, a third steam dump valve (PCV-1) was made available. However, it blew its packing and established a constant steam flow. This lowered Tavg requiring the operators to withdraw control rods to increase reactor power. Although it had been the control room staff's intent to spend more time analyzing their condition, leakage past PCV-1 forced the operators to increase power to maintain Tavg. The operators did not immediately isolate the dump since they felt that the ensuing steam generator shrink would be sufficient to trip the reactor on steam generator low-low level, but did subsequently manually isolate PCV-1. The reactor stabilized at 9 to 10 percent power. The shift foreman (SFM) and on-shift senior management decided to attempt to parallel to the grid.

Within ten seconds of paralleling to the grid, the SFM and SCO noticed that the megawatt meter on the DEHC console read zero and that Tavg was not responding. Assuming the turbine was not loading properly, the SCO took the governor valves to "fast action" open. Shortly thereafter, the reactor tripped. It was subsequently discovered that the megawatt meter had been miswired (as described later) and that the turbine was in fact picking up load as designed. When the governor valves were taken to "fast action" open, steam flow increased and steam generator levels swelled. Steam generator

level reached the 67% narrow range high level set point, tripping the turbine. Since the reactor was greater than 10% power (the P-7 setpoint), a reactor trip occurred. Steam flow reached approximately 37% of full power flow and was high enough to activate the high steam flow bistable. The fast action opening of the governor valves lowered steam header pressure at a great enough rate to activate the low steam header pressure bistable. These combined to provide the safety injection signal.

The initial review of the event was conducted in accordance with Administrative Procedure (AP) A-100 S1 "Return to Power After a Reactor Trip." The inspector reviewed the licensee's report and found that while its contents were accurate, the event description and operation statements did not contain much detail. As follow-up to this finding the inspector pursued two concerns, specifically compliance with AP A-100 S1 and the potential loss of information.

AP A-100 S1 step A.8. states, "As a minimum, statements should be made by the Control Operator, Senior Control Operator, and Shift Foreman." Only one individual statement was taken. The four other members of the operations staff signed a joint statement prepared by the operations supervisor based on the post trip briefing. The statement did not discuss the effects of a positive MTC, the problems experienced with steam dump control, and other items of detail that may have been noted had individual statements been required. The inspector discussed this with the operations manager. The licensee's policy states that a procedural requirement is expressed by "shall," and "should" represents good practice, but not a requirement. In this case, the crew had finished a midnight to 0800 shift and had been asked to participate in a 0930 briefing. The operations supervisor waived the requirements of individual statements so that the crew could go home. The inspector concluded that while this may be an adequate reason to waive the requirements for individual statements, to do so, should require preparation of of a more complete joint statement. As a follow-up, the inspector reviewed nine past AP A-100 S1 reports for adequacy of operator statements and found the statements were quite detailed. In some cases in addition to a detailed description of the sequence of events, the licensee operators used the statement as a forum to describe possible corrective actions. Finally, the SCO and control operator did write up their experiences to be included in the positive MTC startup training lesson plan. Based on this, the inspector concludes that while the AP A-100-S1 report does not contain all the information generated from the trip, the information was not lost and is addressed in some manner in the restart action plan.

In reviewing operator actions taken during these event, two weaknesses were noted. First, the operators took the turbine governor valves to manual without adequately surveying the response of other instrumentation. Second, the operators were not adequately prepared for a positive MTC startup.

As noted above, as it became apparent later, the DEHC megawatt meter was wired incorrectly and read zero megawatts during the event. It should be noted that this is not the only indication of megawatts generated and that a second megawatt meter existed approximately two feet to the left of it. The second meter was not checked by the operators. Other indications of megawatts are included in the P-250 computer display. A check of other plant parameters would have also indicated that the turbine was loading. The operators were concerned that the turbine was not loading and the 30 second generator anti-motoring relay had been activated. The operators took manual control of the governor valves within ten seconds. However, 30 seconds should have been enough time to have made a confirmation through an independent instrumentation reading that either the turbine was or was not loaded.

Training

In the operator debriefing on the morning of the events, the operators expressed surprise at the severity of the effects of a positive MTC. Prior to attempting the startup, the operators had been given classroom training in this area and had performed a startup on the plant simulator. However, the simulator did not accurately model the effects of the Unit 2 since the overall isothermal temperature coefficient (ITC) was negative whereas the actual Unit 2 ITC was positive. Three action plan items specifically addressed corrective actions regarding the operators experiences during startup. The first action was to provide all Unit 2 operators with a description of the observed response of the unit during the startup attempt. This description was based on operator logs, annunciator and instrumentation recordings, and operator statements. In addition, the event description discussed operator response following the attempt to parallel to the grid. It pointed out that the best action to take would have been to separate the generator from the grid instead of trying to pick up load. This action has been added to the paralleling procedure. The description also stressed that operators should not take drastic action based on the response of a single instrument when redundant instruments exist.

The second action item was to provide the operators with additional training in the area of positive MTC startup. The lesson plan included lessons learned at other plants including successful operating strategies. The lesson plan also stressed patience and finesse.

The third action plan item in the area of training is a commitment by the licensee to ensure the simulator will be modeled with the expected ITC for the Unit 1 next core in sufficient time to allow training of operators. This action item will take a number of months to complete after the core design is finalized.

Digital Electro-Hydrolic Control System

The action plan also included an investigation into the response of the DEHC. Shortly after the reactor trip, it was determined that leads from a generator megawatt transducer in the plant P-2000 EHC computer had been miswired on initial installation. During outage maintenance, a technician lifted one end of the leads for testing. The technician was not required to log the leads as he lifted them. After testing, the technician questioned how to return the leads. To resolve his concern, he returned them to the convention used in the P 2000 in Unit 1. While this was the designed position, since the Unit 2 wires had been reversed at both wire ends originally, the megawatt meter was returned to service wired backwards. The technician performed a return to service with the assistance of electrical maintenance, however the voltage and amperage applied by the electrician was not applied properly due to miscommunication with the I&C technician and resulted in a positive reading at the meter indicating wrongly that the instrument was wired correctly. The corrective action by the licensee was to return the wires to their designed configuration and institute a jumper log that tracks lifted leads when a system is out of service. Although a jumper log exists for equipment, the licensee has not maintained jumper logs for systems taken out of service. However, due to recent events the licensee had initiated an effort to design a wire log for all work. This log had been scheduled to be in place a month after the event, however due to the event, the licensee began to included the log in work packages issued in the following days.

Steam Dump Control System

Prior to restart, the licensee committed to inspect the packings on all condenser steam dump valves, to disassemble and inspect PCV-1, and to do a full functional test on the control system. When mechanical maintenance attempted to reinstall PCV-1 it was discovered that structural bracing for a walkway partially obstructed the insertion of the valve internals. Although this valve did not have a history of leak problems, it is possible that due to the partial obstruction, the valve internals were not inserted properly during the outage. A design change was issued to have the bracing modified so as not to obstruct work, and the valve internals were subsequently inserted.

Following the inspection and selected maintenance of steam dump valve packings and maintenance performed on PCV-1, the licensee performed a full functional test on the condenser steam dump system. The functional test was performed in accordance with a temporary procedure written by the licensee to ensure a smooth and accurate response of the steam dump valves to a given steam header pressure signal. A review of the procedure and observation of its performance was conducted by the inspector. The inspector noted good communications between the I&C technicians in the control room the I&C technicians at the steam dump control module and I&C technicians and maintenance mechanics at the valves.

The test established that the valves were functioning properly with one exception. The current to pneumatic (I/P) signal converter for group 2 valves PCV 4 and 7 was wired incorrectly and would not open on demand. The signal from the control module had been installed incorrectly upon original construction. It is speculated that during pre-operation startup functional testing, this wiring fault had been corrected by rolling the leads from the I/P converter. This correction was not documented on the system drawing. The I/P assembly was replaced prior to startup when water in the air system fouled the assembly. After the installation, the leads were set in accordance with the drawing, resulting in a reversal of polarity from the control module to the valves.

This reversal would have been prevented had the technician installing the transmitter been required to log each lifted lead. This was the second example of plant wiring, originally installed incorrectly, being reversed to its design position at one set of leads. The inspectors discussed with the licensee reviewing all plant systems important to the reliable operation of Unit 2 to assure themselves that no more such wiring problems existed. In response to the concern, the licensee performed a review of 28 systems. For systems that were either not functionally tested during the outage, or already proven to be operating satisfactorily, a review was made of past work packages for maintenance involving wiring. A total of 393 packages in 3 systems were reviewed. Of the 393 packages, 5 items were determined to require further review after plant startup. The inspectors determined that the licensee's evaluation was accurate and complete.

The licensee experienced steam dump problems on the restart of Unit 1. The licensee is considering the completion of a steam dump mechanical and control system functional test as a procedural requirement for all future startups.

Restart

The inspector observed the restart of Unit 2 on July 17 from criticality to paralleling to the grid. In the area of training, the inspector noted that those involved had attended the sessions on positive MTC startup. Two members of the crew involved in the previous startup attempt were available in the control room for consultation. In addition, a senior licensee manager was on shift. The startup proceeded in a slow, controlled manner taking six hours from criticality to paralleling to the grid. The inspector did note that the crew went through a learning curve with respect to positive MTC startup operation. This seems to emphasize the need for an accurate simulator model.

The inspector noted that plant equipment responded as designed. No problems were experienced with the condenser steam dumps or the DEHC. The smooth restart of Unit 2 is due, in large part, to the comprehensive action plan implemented by the licensee.

d. Automatic Diversion of Radioactive Liquid Discharge

On July 23, 1987, an Unusual Event was declared and immediately terminated when liquid radwaste discharge line effluent monitor RE-18 alarmed during a discharge from chemical drain tank (CDT) 0-1. The RE-18 alarm also caused the discharge to be automatically diverted to an equipment drain receiver. Count rates observed from RE-18 at the time of the alarm indicated the activity of the liquid passing through RE-18 was about 18.5% of the maximum permissible concentration. When discharge pipe length, flow rate, and divert valve response time was evaluated, the licensee concluded that no radioactive discharge occurred to the ocean.

High activity in the discharge water was attributed to residual water that was trapped in piping "dead legs" during a previous resin transfer from the spent resin storage tank to a solidification liner. Since this portion of the liquid radioactive waste discharge piping is common to the spent resin transfer piping, the discharge from the CDT picked up some of the residual high activity resin water and transferred this residual water past RE-18.

The licensee indicated the emergency procedure would be revised so that in the future, this type of occurrence will not be categorized as an unusual event. Also, the licensee committed to evaluate possible changes to the piping configuration to separate the liquid radioactive waste system from the spent resin transfer system.

A more detail evaluation of this occurrence and subsequent corrective actions are provided in NRC Inspection Report 50-275/87-30.

e. Unit 2 Residual Heat Removal (RHR) Suction Valve 8701 Inadvertent Closure

On June 29, 1987, with Unit 2 in Mode 4, a faulted relay coil initiated a voltage transient on instrument power panel PY-24, which resulted in closure of RHR valve 8701 for a period of approximately five minutes. The momentary voltage transient resulted in an actuation of the RHR autoclosure interlock (ACI) function since the ACI and the faulted relay share a common instrument power supply. The ACI actuation caused RHR valve 8701, one of two common series suction valves from loop 4 for trains A and B of the RHR system, to close.

Operator response to this event was considered to be good. The valve takes two minutes to close and its closure is not immediately apparent in the control room other than by a small indicating light to the valve control switch. The operator did notice RHR heat exchanger 2-1 discharge temperature dropping on a trend recorder and quickly deduced the problem. The control operator properly shutdown RHR pump 2-1 and reopened valve 8701. Two minutes later, with valve 8701 fully open, the operator restarted the RHR pump, terminating the event.

Since no operations were in progress that involved a reduction in reactor coolant system boron concentration, the requirements of the technical specifications were met. The four hour non-emergency report required by 10 CFR 50.72 was made at 1945 PDT.

Following the event, there was a question as to why an alarm for low flow on the RHR system did not actuate during the event. The alarm was subsequently determined to have behaved as designed, since the alarm conditions that required RHR flow must decrease to less than 500 gpm for greater than 30 seconds were not satisfied. When flow fell below 500 gpm, the RHR pump recirculation valve automatically opened as designed. With the recirculation valve open, flow increased to greater than 500 gpm before the 30 second clock had expired. The alarm logic is proper because the low RHR flow alarm in intended to protect against pump damage due to no flow with a running pump.

The licensee examined the failed relay, TC 441 Hx (an auxiliary relay off the overpower delta temperature channel 4), to determine the cause of its failure. The relay is closed during normal operation. The inspection of the relay showed slight corrosion at the iron core surfaces and melted nylon around the iron core interface surfaces. It is postulated that the slight corrosion separated the iron cores by some amount. This increased the current draw through the coil. As it heated up, the nylon structure heated and began to melt. The melting nylon increased the separation of the coils, increasing the current draw, increasing the heat, ultimately resulting in the shorting of the coil. Since the contacts are made up for approximately 40% of the coil travel, as the coils separated the contacts did not open prior to the relay failure.

The licensee performed an experiment with a good relay to demonstrate the hypothesis. By holding the relay full open a current draw of .5 amps was established, too small to blow any fuses in the circuit. The nylon began to melt after 2 hours and the coil failed after 3 1/2 hours. This rapid rate of failure would not be duplicated in the field since the contacts would open at 40% of full travel.

As corrective action, the licensee used an infrared device to determine if any other similar relays were showing signs of increased heating. In addition, the licensee is planning a long term program of surveillance using the infrared imaging radiometer to find unusually hot electrical components.

As the RHR ACI function has been a contributor to other temporary losses of RHR capability on several occasions, the licensee submitted letter number DCL-87-187, dated August 4, 1987, to the NRC providing a Westinghouse evaluation in support of removal of the ACI function. However, the licensee has committed to retain the ACI function until approval of the proposed changes in received from the NRC.

f. Inadvertent Actuation of the Fuel Handling Building (FHB) Ventilation System

On July 7, 1987, at 1140 PDT, the Unit 2 FHB ventilation system transferred to the iodine removal mode. This mode transfer constituted an actuation of an engineered safety feature (ESF). The area around the FHB exhaust fans, the ventilation logic cabinets, and the FHB were surveyed. There were no indications of unusual conditions or work in progress, and operators checked radiation monitors RE-58 and RE-59. Because the radiation monitors indicated normal background, operators reset the FHB ventilation system to normal. The required 4-hour non-emergency report to the NRC was made at 1658 PDT, July 7, 1987, 1 hour and 18 minutes later than the time allowed by 10 CFR 50.72. Accordingly, late reporting of the ESF actuation is an apparent violation (Open Item 50-323/87-26-03).

An investigation of this event was conducted by the licensee, but no specific cause of the FHB ventilation mode change was identified. The investigation included the following:

- The annunciator printout was examined for actual or spurious radiation monitor alarms. No alarms were observed.

- Clearances were checked to determine if any electrical or electronic work was in progress that could have initiated this event. No indication was found of any work in progress that could have caused this event.

- The normal supply fan (E-4) and its associated damper was visually inspected and then returned to service with no indication of any mechanical problem that could have caused or contributed to the event. The lack of any indication of a mechanical or electrical problem, the lack of a history of a similar event, and the failure of the event to repeat led the licensee to conclude that although a momentary fan or damper failure was possible, it was highly improbable.

- Personnel with potential knowledge of the event and/or equipment involved were interviewed by the licensee to determine if there were other potential causes of the event. One possibility, a very short duration spurious signal or electromagnetic noise, was eliminated by the fact that any signal or noise strong enough to cause actuation of the mode change would have produced an indication on the annunciator printout.

The licensee's evaluations of the three sources of signals that cause the FHB ventilation system to switch to iodine removal are as follows:

- Radiation alarm from RE58 or 59

  This alarm locks in and prints out on the alarm typewriter. Since there was no indication of the alarm on the alarm

typewriter, the cause was determined to not be an actual or spurious radiation monitor alarm.

- Manual initiation from the FHB

  Security access records were reviewed at the inspector's request and confirmed the auxiliary operator's observation that no one was in the FHB at the time of the event. Therefore, local manual initiation was not probable.

- Failure of normal supply fan

  Failure of the normal supply fan would have produced an indication on the alarm typewriter. In addition, in its start and operation after the event, the fan (E-4) and its associated damper (M-29) functioned properly and gave no indication of a problem.

The licensee concluded these investigations of the three sources that can provide an actuation signal for this mode change showed all three to be improbable. Since the cause of this event was not determined, no corrective actions were identified that would preclude recurrence.

This spurious FHB ventilation system mode change from normal to iodine removal mode, represents a conservative equipment response. Thus, there were no adverse safety consequences or implications resulting from this event. However, the inspector emphasized to plant management that definitive, plausible mechanisms for occurrences such as this must be identified. Rather than proceeding in the face of uncertainty, thorough, rational explanations should be provided.

Corrective actions associated with the late reporting include:

- The personnel responsible for the event were counseled.

- A shift foreman's memorandum was issued to further stress the necessity of making 10 CFR 50.72 reports within required time limitations and stressed that making these reports has a higher priority than normal plant activities.

- Administrative Procedure C-11S2, "Supplement 2 to Non-Routine Notification and Reporting to the NRC and Other Governmental Agencies - Significant Event Reports," was revised to provide additional examples of event reporting.

- An operator training session, focusing on selected events and proper reportability, is to be conducted during the regular training week for each shift beginning July 27, 1987.

- During each operator training session thereafter, reportability training is to be discussed, using specific examples of industry events.

- o During at least one of the simulator training sessions for each week, excluding examination sessions, reportability of at least one event is to be included in a scenario.

- o When a test is administered for a week of training, at least one reportability test question is to be asked.

- o The emphasis discussed in items 5, 6, and 7 is to continue until PG&E management determined the emphasis should be either reduced or increased.

g. Loss of Unit 1 Containment Isolation Capability

Nuclear steam supply sampling valves 9355B and 9357B were removed from service for maintenance on July 23, 1987. On July 24, with Unit 1 in mode 1 operation, the licensee identified these containment isolation valves were not in compliance with the action statement of Technical Specification 3.6.3. The action statement required that when a containment isolation valve was inoperable, each affected penetration must be isolated by at least one deactivated automatic valve secured in the isolated position.

Contrary to this requirement, plant personnel restored power to the solenoids that control air to these air-operated containment isolation valves, to allow post-maintenance testing. The testing was postponed and the valves remained in service for a period of 28 hours and 20 minutes until the misalignment was discovered by operations personnel, who isolated the penetration in accordance with technical specification requirements. Subsequent testing verified that the valves were operable during the event and capable of performing their intended function in providing containment isolation.

Restoration of power to the solenoid valves resulted in the requirements of the technical specification action statement not being met. During the period of time the valves were returned to service and not yet verified operable, a control room operator opened the valves to allow chemistry personnel to take a sample. To perform this evolution, the operator had to operate through control board caution tags on the hand switches for the inside containment isolation valves (nuclear steam supply sampling valves 9355A and 9357A). These upstream valves on the sample lines were tagged out as part of the post-maintenance test procedure and did not reference the technical specification action statement requirement. Accordingly, the operator did not relate the evolution back to the technical specification action statement requirements.

As part of the resolution of this event, the licensee indicated Administrative Procedure (AP) C-7S1, "Plant Tagging Requirements" will be reviewed and revised as necessary to strengthen requirements associated with caution tags. Additionally, AP C-6S1 "Clearance Request/Job Assignment" will be revised to provide additional instructions for use of the report off for test function, including time requirements and responsibilities. Further guidance will also

be provided to operating crews reinforcing the importance of fully investigating caution tags prior to operating equipment.

During the period of time outside containment isolation valves 9355B and 9357B were inoperable and returned to service, the inside containment isolation valves 9355A and 9357A were still operable and capable of performing their intended function in providing containment isolation of the penetrations. Subsequent testing of valves 9355B and 9357B verified that these valves were operable and capable of closing as required during the time period of the event. These containment isolation valves are required to close on a phase A isolation signal and ensure that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment.

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. Events

On August 6, 1987, the licensee made a 4 hour 10 CFR 50.72 report regarding an automatic ESF actuation. The actuation reported was the automatic isolation of steam generator blowdown in Unit 2 due to a high radiation signal. No blowdown was in progress at the time.

Subsequent investigation determined that a health physics technician was doing other work in the area of the radiation monitor panels and inadvertently pushed the power pushbutton for the monitor causing it to alarm. The licensee is taking appropriate follow-up action in accordance with their administrative procedures.

On August 14, 1987, an automatic ESF actuation occurred at 9:27 p.m. (PDT). The actuation was the automatic start of an emergency diesel generator due to apparent degraded voltage on a vital 4160 volt electrical bus.

The cause of the event was that when the 4160 volt circuit breaker (which had been removed for reasons not related to the event) was rolled into its cubicle, the breaker physically caught a wire in the breaker cubicle and broke and shorted it. The shorting of the wire in turn caused a fuse in the power circuit to it to blow.

The affected wire and fuse were 120 volt components in the second level undervoltage protection circuits for the 4160 volt vital bus.

The effect of the situation was that the circuit sensed an undervoltage condition on vital bus H and stripped the bus from the normal source (auxiliary power), attempted to close on startup power but did not because the same undervoltage was perceived and properly signalled the start of the diesel generator. The diesel generator

properly closed on the bus (its protective circuits are separate and would have protected the diesel had there been a true bus fault). A portion of the vital loads on the bus did not actuate, since their protective circuits were affected by the blown fuse and wire short. This failure to actuate was consistent with design.

Initially, the blown fuse was discovered and replaced. Indicated bus voltage returned to normal (but at this time broken wire was not discovered and only a portion of the damaged control circuit was restored by the fuse replacement). At 11:13 p.m. the operator attempted to parallel the bus to normal auxiliary power. After a few seconds the auxiliary power breaker opened again and power for the bus was maintained by the diesel generator. This led operators to suspect the second level undervoltage protection which is a delayed protection system.

Subsequent investigation discovered and corrected the broken wire. Subsequent to tests on the affected circuit, the normal auxiliary power was restored and the diesel generator secured at 7:32 a.m. on August 15, 1987.

Licensee follow-up actions included an engineering verification that all affected components operated (or did not operate) as expected, a review to ascertain whether circuit improvements are indicated, and instructions to maintenance/operators regarding care in rolling in circuit breakers. These actions will be followed-up in the normal course of future inspections.

One violation was identified in paragraph 3. b. above..

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. Unit 2 Valve Repacking

The inspector observed mechanical maintenance personnel perform valve repacking on main steam supply to auxiliary feedwater Terry turbine valve MS-2-948. Work requested by action request A79986 was performed in accordance with work order C17386 and mechanical maintenance procedure MP M-51.22 "Implementation of the Valve Packing Improvement Program." The inspector verified use of a calibrated torque wrench, and through discussions with the involved maintenance personnel, ascertained the individuals were qualified to perform the task. No discrepancies in the use of clearance request 7751 were observed.

b. Unit 1 Component Cooling Water Valve

The inspector examined investigative repair work on Unit 1 component cooling water valve CCW-1-459. The valve is a handwheel operated butterfly valve using a mechanical gear box arrangement. The valve had been noted as failing to fully open and was discovered by the low CCW flow to the RHR heat exchangers during a test.

The inspector observed the clearance tagging for the jobs and discussed the jobs with the mechanic investigating the manual operator and ascertained that he was knowledgeable of it. The problem was determined to be a sheared pin in the manual operator. The pin was half missing and the remaining half was broken in three pieces. The break areas were old (as evidence by grime) and appeared brittle. The acting maintenance manager stated a full examination of maintenance history and root cause would be performed in a TRG on the subject.

The inspector examined other similar operators in the area and noted no other pins that had outwardly apparent indications of failure such as a missing piece or excessive apparent length.

c. Unit 2 Condenser Steam Dump Valve Maintenance

During the course of follow-up of the July 14 reactor/turbine trip (see section 3. c.) the inspector observed maintenance performed on condenser steam dump valves. Details of the maintenance performed are contained in section 3. c..

d. Component Cooling Water (CCW) Valve Manual Operator

The inspector observed portions of repair assessment activities on the manual operator of CCW valve 2-353. Work was performed in accordance with AR A67754 and work order C20125 to determine the cause of freewheeling of the handwheel. Maintenance personnel determined the operator worm gear shaft valve stem was bent, and was missing a steel collar and alloy steel grooved bushing retaining pin, which permitted the handwheel to freely spin after the valve had been fully closed. Apparently, the collar and its retaining pin were not installed correctly during initial fabrication, since no previous maintenance had been performed on the valve operator by the licensee. At the inspector's request, the licensee indicated a missing part assessment of other identical manual operators would be performed.

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.

Testing observed by the inspectors was performed in accordance with the following surveillance test procedures (STPs):

STP R-6 "Low Power Reload Physics Tests"
STP R-30 "Reload Cycle Initial Criticality"
STP R-7A "Determination of (MTC) at (BOL)"
STP R-31 "Rod Worth Measurements..."
STP R-32 "Rod Worth Measurements..."
STP R-13 "Nuclear Power Range Incore/Excore Calibration"

A more detailed explanation of these surveillances is provided in section 7 of this report.

No violations or deviations were identified.

6. Follow-up of NRC Information Notice (IN) No. 87-34

IN No. 87-34 "Single Failures in Auxiliary Feedwater Systems" dated July 24, 1987, identified potential single failures of auxiliary feedwater (AFW) pump start and protective pump trip circuitry that could cause partial or complete loss of capability to supply AFW to the steam generators. Circumstances described in the IN occurred at two Westinghouse supplied nuclear plants. As Diablo Canyon also uses a reactor coolant system supplied by Westinghouse, the inspector requested the licensee to provide an onsite evaluation of the applicability of IN No. 87-34 to Diablo Canyon on a priority basis.

The licensee's onsite evaluation of the AFW pumps start and trip circuits determined there were no single failures which would prevent automatic safety related start or trip of both motor-driven AFW pumps. The licensee did indicate a single relay does start both motor-driven AFW pumps on loss of both main feedwater pumps, which does represent a potential single failure. However, according to the licensee, this automatic AFW pump start is non-safety related, not referenced in technical specifications, not assumed in accident analysis, and accordingly not in conflict with the AFW system design basis.

A routine formal evaluation of this IN will also be conducted by the licensee's offsite engineering office.

No violations or deviations were identified.

7. Startup Testing

On July 11, 1987, at 2028 hours, Unit 2 achieved criticality following its first refueling outage. The inspectors observed initial criticality and portions of the subsequent physics testing, including the following surveillance test procedures (STPs).

STP R-6 "Low Power Reload Physics Tests"
STP R-30 "Reload Cycle Initial Criticallity"
STP R-7A "Determination of Moderator Temperature Coefficient at Beginning of LIfe"

STP R-31 "Rod Worth Measurements Using Rod Swap Method"
STP R-32 "Rod Worth Measurements Using Boration or Dilution"
STP R-13 "Nuclear Power Range Incore/Excore Calibration"

The inspectors observed that prerequisites and initial conditions were met and that precautions and limitations were observed. It was also noted that plant conditions were maintained as specified in the procedure. In general, the inspectors noted that startup and physics tests were performed with caution, applying lessons learned from previous startups. Specific details of Unit 1 and Unit 2 startup testing follows.

a. Determination of Isothermal and Moderator Temperature Coefficients

While Unit 2 was at beginning of cycle and hot zero power, the inspector observed the licensee's determination of the isothermal temperature coefficient (ITC) and moderator temperature coefficient of reactivity (MTC). From an average moderator temperature (Tavg) initial condition near its no load value of 547 degrees F, the RCS was cooled down about five degrees utilizing steam generator blowdown, and reactivity changes were plotted in response to the Tavg change. By isolating blowdown, RCS temperature was then permitted to return to its initial condition, providing another reactivity change measurement. The ITC was then determined from the slopes of the reactivity / Tavg traces from an X-Y recorder connected to the reactivity computer. The MTC was then calculated by subtracting the Doppler temperature coefficient (obtained from design calculations) from the ITC.

Testing was conducted in accordance with STP R-7A. RCS cooldown and heatup rates were established and maintained within specified criteria. The inspector also verified boron concentration values were obtained at required intervals, and pertinent plant parameters were maintained within allowable bands.

Measured average ITC, derived from the slope of reactivity/ temperature recorder traces, was determined to be +1.7 PCM/DEGF. This value was within the acceptance criteria defined for the test. MTC was calculated to be +3.36 PCM/DEGF, which was less positive than the technical specification upper limit of +5 PCM/DEGF.

A review of the Unit 1, cycle 2 STP R-7A final data was also performed by the inspector. All test results were within acceptance criteria. The measured average ITC was -1.58 PCM/DEGF and the MTC was calculated to be +.17 PCM/DEGF.

b. Rod Worth Measurements Using the Rod Swap Method

The inspector observed portions of the licensee's measurement of Unit 2 integral rod bank worths by swapping banks with a reference bank in accordance with STP R-31. Starting from zero power, in an all-rods-out condition, reference bank D was inserted into the core by performing an RCS dilution. The measured integral worth of the reference bank, calculated from data taken by the reactivity computer during bank insertion, was 1216.5 PCM. With bank D fully

inserted and essential plant parameters stabilized, a test bank was inserted several steps and reactivity and flux were balanced by subsequent withdrawal of the reference bank. Rod swapping continued until the test bank was fully inserted into the core. The worth of the test bank was then inferred from the new position of the reference banks. This process was then repeated for the remainder of the shutdown and control banks.

The inspector observed plant conditions were maintained as specified in STP R-31, and required boron concentration samples were taken and analyzed. Values obtained for control rod bank worths were found to be within acceptance criteria.

Regarding test results from the Unit 1, cycle 2 STP R-31, all values obtained from control rod bank worths were also found to be within acceptance criteria.

c. Rod Worth Measurement Using Boration

Test data obtained from the Unit 1, cycle 2 Startup Test Program in accordance with STP R-32 "Rod Worth Measurement Using Boration or Dilution" was reviewed by the inspector. Bank D rod worth and overlap integral reactivity worth of the control banks (with rods having been borated outward from the rod insertion limit position) were determined to be within the acceptance criteria. Changes made in boron concentration as a consequence of the shutdown margin calculation were verified by chemical analysis.

No violations or deviations were identified.

8. Licensee Event Report Follow-up

a. Status of LERs

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

Unit 1: 87-09

Unit 2: 87-13, 85-29

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

b. Autostart of AFW Pumps in Mode 4 on Low-Low Steam Generator Level Due to Personnel Error LER 50-275/87-13

The inspector noted that the Description of Events section of the LER stated that the unit was in Mode 4 (Hot Shutdown) at 330 degrees F at 0052 PDT, July 1, 1987, the time of the AFW pump start. In fact the unit was in Mode 5 with RCS temperature less than 200 degrees F. The conditions listed in the LER describe the unit at 1930 PDT June 30, prior to securing the RCPs. This discrepancy was

pointed out to licensee management, who took appropriate corrective actions to address verification of LER technical content.

c. Red Telephone vs LER Tracking

The licensee has evaluated the following 10 CFR 50.72 events for reportability under 50.73 and has determined that 50.73 report is not required. The resident inspectors have examined the licensee's rationale and determined that regulatory requirements have been met.

50.72 Report Date/Unit	Event Reference (NCR, etc.)
7/23/87 Unit 1 Liquid Radwaste Discharge Radiation Monitor Alarm	NCR DC1-87-OP-N088 Licensee's reporting criteria was too restrictive. No radiation release occurred. No discharge technical specification limits were exceeded.

No violations or deviations were identified.

9. Open Item Follow-up

a. Notice of Violation on Pumpdown of Unit 2 Refueling Cavity (Open Item 50-323/87-20-04, closed)

In Inspection Report (IR) 50-323/87-20, the NRC issued a Severity Level IV violation as a result of operators failing to stop residual heat removal pump 2-2 when reactor vessel water level reached 113'. PG&E letter number DCL-87-176 contained a response to the violation. The inspector has reviewed the licensee's response and has verified the identified corrective actions have been implemented at the facility. Accordingly, this item is closed.

b. Notice of Violation on I&C Technician Failure to Follow Procedures (Open Item 50-275/87-23-01, closed)

IR 50-275/87-23 contained a severity level IV violation pertaining to the failure of an I&C technician to follow STP I-9A. In response to this Notice of Violation, PG&E issued letter DCL-87-198 on August 10, 1987, describing corrective steps taken. The inspector reviewed the licensee's letter and observed implementation of selected corrective actions. Accordingly, this item is closed.

No violations or deviations were identified.

10. 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.

11. 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 inspection.

No violations or deviations were identified.

12. Exit

On August 21, 1986, 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.