U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos: 50-275/89-23 and 50-323/89-23

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: September 10 through October 28, 1989, and
November 20, 1989

Inspectors: K. E. Johnston, Resident Inspector
P. P. Narbut, Senior Resident Inspector

Approved by: M. M. Mendonca 12/1/89
M. M. Mendonca, Chief, Reactor Projects Section 1 Date Signed

Summary:

Inspection from September 10 through October 28, 1989, and November 20, 1989
(Report Nos. 50-275/89-23 and 50-323/89-23)

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, 37700, 37702, 40500, 61726, 62703, 71707, 71710, 90712, 92700, 92701, 92702, 92703, 92720, and 93702 were used as guidance during this inspection.

Results of Inspection:

Areas of Strength Observed During the Period

The licensee's response to the Unit 1 reactor trip on October 6, 1989, with its attendant complications was noteworthy. Operator response at the time of the event was good in regards to command, procedure adherence, and controlled but timely actions. Plant management response subsequent to the trip was noted to be thorough and comprehensive and utilized the licensee's event response plan methodology effectively. Certain lessons were learned such as a follow-up group debriefing of operators to better ascertain certain facts through operator interaction.

The plant response to the October 17, 1989, San Francisco bay area earthquake was thorough and conservative even though the earthquake effects at the plant were exceedingly minor.

Areas of Weakness Observed During the Period

Operations: Although licensee efforts to preclude valve lineup errors have been committed to and have generally reduced errors, this inspection report identifies two areas where valve lineup problems were not identified by the licensee and should have been. Remote operated containment isolation valves, although properly closed, have not been deactivated and sealed per technical specification requirements (violation). Additionally, previous licensee commitments to track and trend missing manual valve seals (for sealed closed valves) has not been effectively implemented. This was demonstrated by the resealing of two unsealed valves identified by the NRC without initiating the tracking document by operations personnel.

Engineering: Onsite engineering personnel exercised poor command in the fuel inspections conducted in the spent fuel pool. Although radiation evacuation alarms occurred at the rate of about 15 times an hour, work was continued under these unacceptable conditions.

Poor Management Oversight: An example of poor management oversight was evidenced by the erroneous information provided in writing to NRR regarding the availability of a procedure to electrically cross tie diesel generators between units. The error was eventually identified by an STA at the implementation level.

An additional example of weak management oversight was demonstrated by the resident finding that overtime limits were exceeded on a broad basis by maintenance personnel during the refueling outage (violation).

Another example of poor management oversight in the engineering area was that the inappropriate Quality Classification of heat tracing, although identified by QA personnel in July 1988, was not addressed as a site hardware implementation problem until raised by the resident in August 1989 (violation).

DETAILS

1. Persons Contacted

* J. D. Townsend, Plant Manager
* D. B. Miklush, Assistant Plant Manager, Operations Services
* M. J. Angus, Assistant Plant Manager, Technical Services
* B. W. Giffin, Assistant Plant Manager, Maintenance Services
* W. G. Crockett, Assistant Plant Manager, Support Services
* W. D. Barkhuff, Acting Quality Control Manager
T. A. Bennett, Maintenance Manager
* D. A. Taggert, Director Quality Support
* T. L. Grebel, Regulatory Compliance Supervisor
H. J. Phillips, Work Planning Manager
* R. C. Washington, Acting Instrumentation and Controls Manager
* J. A. Shoulders, Onsite Project Engineering Group Manager
M. E. Leppke, Engineering Manager
S. R. Fridley, Operations Manager
R. P. Powers, Radiation Protection Manager
E. C. Connell, Acting Project Engineer
R. C. Webb, Acting Assistant Project Engineer, Systems

The inspectors interviewed several other licensee employees including shift foremen (SFM), reactor and auxiliary operators, maintenance personnel, plant technicians and engineers, quality assurance personnel and general construction/startup personnel.

*Denotes those attending the exit interview on November 21, 1989.

2. Operational Status of Diablo Canyon Units 1 and 2

Unit 1 began the reporting period at 100% power. On October 4, 1989, the Unit began operating in a reduced temperature mode at 100% power due to the depletion of boron. On October 6, 1989, the Unit tripped and had a safety injection both caused by pre-outage work in progress. The Unit began its third refueling outage that day about one week earlier than originally planned. At the end of the reporting period the Unit was defueled and steam generator work was in progress.

Unit 2 began the reporting period at 100% power. On October 27, 1989, the Unit was manually tripped due to the main electrical generator exciter experiencing failure of the permanent magnet generator component with attendant smoke and sparking. Unit 2 remained shutdown until November 4, 1989.

Common items of interest included an emergency preparedness exercise conducted on September 13, 1989, and plant visits on various dates by NRC Region V management and technical personnel including the responsible Section Head Acting Branch Head. Additionally, on two occasions the emergency notification system (ENS - red telephones) became inoperable due to telephone company problems. On October 17, 1989, the bay area

earthquake occurred and was marginally felt at the site with 0.0044 g's of ground motion.

3. Operational Safety Verification (71707)

a. General

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

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

(a) General plant and equipment conditions.

(b) Fire hazards and fire fighting equipment.

(c) Radiation protection controls.

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

(e) Interiors of electrical and control panels.

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

(g) Plant housekeeping and cleanliness.

(h) Engineered safety feature equipment alignment and conditions.

(i) Storage of pressurized gas bottles.

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

No violations or deviations were identified.

4. Onsite Event Follow-up (93702)

a. Emergency Exercise

On September 13, 1989, Diablo Canyon held its annual emergency preparedness exercise with regional NRC participation and evaluation. The results of the NRC evaluation will be published in a separate NRC inspection report. During this exercise the NRC residents participated as "players", that is they dealt with the simulated event and performed their functions as they would in an actual event.

b. Unit 1 Reduced Temperature Operation

On September 19, 1989, the licensee discussed plans to reduce Unit 1 average temperature by 5 degrees F in order to extend 100% power operations past the point of zero boron in the reactor coolant system when a "coast down" would ordinarily occur. The licensee's plans were discussed with NRR and regional management prior to implementation which occurred on October 3, 1989. The licensee issued a special temporary procedure for the operation and appeared to have performed a thorough evaluation prior to implementation.

c. Loss of Telephone Communications

On September 21, 1989, the licensee made a 10 CFR 50.72 non-emergency report due to a significant loss of offsite communication systems including the ENS (NRC Emergency Notification System). The problem was due to an offsite fire. Telephones were restored in about 2 hours. On October 12, 1989 a similar, but shorter (approximately 15 minutes), event occurred while the telephone company completed repairs on the line. Although 50.72 notifications were made in both cases, the licensee determined that a follow-up LER was not required. The residents reviewed the licensee's non-conformance report and found it to be acceptable. Included in the licensee's actions was a commitment to revise emergency procedures to provide a more thorough list of communication options.

d. Condensate Spill

On September 23, 1989, the licensee had a 25,000 gallon spill of condensate storage tank water into the auxiliary boiler sump. The problem was caused when a planned isolation of instrument air to the turbine building occurred. Although clearance personnel had checked affected air operated valves for their "failed" position, one valve the makeup valve to the deaerator actually failed open vice closed when the air was isolated. This allowed a drainage path from the condensate storage tank to the deaerating heater which overflowed onto the floor and sump.

The spill was found by security personnel on rounds. The spill had no direct safety significance since the condensate storage tank tap

for the auxiliary boiler is physically above the point where the required volume/level for safety related water inventory is.

Licensee personnel are reviewing the accuracy of their information for failed valve positions and have committed to take appropriate corrective action.

e. Actuation of Protection Bistables by Two-way Radio

On September 23, 1989, Unit 1 high steam flow bistables were actuated and steam dumps armed when general construction forces performing pre-outage work used a two-way radio in the component cooling water heat exchanger room. The room was posted as a prohibited radio area. No event occurred because no other coincident bistables were in a tripped condition at the time. Operators quickly deduced the cause of the bistable trip and then cleared the bistables.

Operator on shift management acted aggressively and denied use of two-way radios by construction forces for the remainder of the weekend.

f. NRC Management Visit

On September 25, 1989, plant staff and plant management met independently with senior NRC management consisting of the regional administrators of Regions I, II, and III and two division managers from NRR. The purpose of the meeting was the commencement of a nationwide survey of licensee perceptions and suggestions regarding regulatory effectiveness.

g. Unit 1 Reactor Trip and Safety Injection from 100% Power Due to Instrumentation Problems

On October 6, 1989, at 1:02 p.m., Unit 1 experienced a reactor trip and steam line differential pressure safety injection. The licensee was conducting multiple pre-outage work tasks, while at power, in preparation for a scheduled shutdown for refueling on October 14, 1989. The pre-outage work being conducted contributed at least in part to the event and to some subsequent complications in recovery.

Prior to the event, initial plant conditions included steam flow and steam pressure bistables in the tripped condition (for one of four protection set logics). The bistables were tripped to allow performance of a calibration of the channels to gather data for a feedwater control design modification (the channel calibration was not due). Additionally, two of the four atmospheric steam dump valves were isolated in preparation for routine testing of their control circuits to ensure correct operation for the upcoming shutdown scheduled in about one week.

The event occurred at a time when I&C technicians were physically closing the isolation valve for one of the pressure transmitters which provides the control signal for one of the atmospheric steam

dump valves which were to receive this routine testing for the pending plant shutdown. This transmitter does not provide the safeguards signal, but shares a common pressure tap on the main steamline and is physically adjacent to a safeguards steam pressure transmitter (an adjacent panel). It was speculated and subsequently shown that the repositioning of this valve initiated a false pressure spike on the steamline pressure instrumentation which when combined with other channels in trip gave the necessary coincidence for safety injection/reactor trip. The event sequence showed a reactor trip and safety injection at 1:02 p.m..

All safety systems actuated normally. Operators responded promptly in accordance with plant procedures. The resident inspectors were in the control room immediately after the trip and monitored plant status and operator actions. Several complications were appropriately responded to by operators:

The unit lost both circulating water pumps (the seawater for condenser cooling). Only one circulating water pump should be lost per design. Hence, the steam dumps valves to the condenser were prevented from opening. The licensee's investigation subsequently revealed a timer relay failure caused the trip of the circulating water pump.

Reactor coolant system lo-lo Tave was reached due to the injection of the BIT and the relatively cold refueling water storage tank, and the injection of cold auxiliary feedwater to the steam generator. Main steam isolation valves closed when Lo-Lo Tave was reached. Main steam isolation does not ordinarily occur on reactor trip, but did so because of the tripped condition of the steam flow bistables in conjunction with the actual Lo-Lo Tave.

At 1:07 p.m. operators shut pressurizer spray valves in response to decreasing pressurizer pressure in accordance with their emergency procedure. At about the same time auxiliary feedwater flow was reduced and reactor coolant cooldown was terminated.

At 1:08 p.m. the operator turned off pressurizer heaters in response to increasing pressurizer pressure. A rapid turn around of RCS pressure was being experienced.

At 1:10 p.m. one pressurizer power operated relief valve lifted. Initial indications were that it lifted at a lower pressure than it should have by about 85 psi. The valve continued to intermittently lift and caused an increase in the pressurizer relief tank level and pressure. Pressure increased to about 19 psi (the rupture disk is rated at 100 psi).

From 1:15 to 1:21 p.m. operators reduced charging flow by stopping one of the two centrifugal charging pumps and stopping the positive displacement charging pump. Pressurizer level was at 70% and increasing.

At 1:22 p.m. a circulating water pump was manually restarted to begin to reestablish condenser vacuum.

At 1:24 p.m. RCS letdown was reestablished.

At 1:25 p.m. the turbine driven auxiliary feedwater pump was stopped with steam generator levels reestablished.

At 1:27 p.m. charging pump suction was realigned from the RWST to the volume control tank.

At about 1:30 p.m. pressurizer level was 90% and increasing.

At 1:30 p.m. operators attempted to open the two in service atmospheric steam dumps. Neither valve responded to initial demands.

At 1:31 p.m. a condenser vacuum pump was started to restore condenser vacuum.

At 1:35 p.m. a second attempt to open the attempt to open to atmospheric steam dumps was attempted. One valve opened.

At 1:41 p.m. excess letdown was placed in service to reduce RCS inventory.

At 1:41 p.m. main steam isolation bypass valves were opened to prepare to open to main steam isolation valves.

At 1:44 p.m. RCS temperature started to decrease due to the atmospheric steam dump and the main steam isolation bypass valves being open. Lo-Lo Tave signals caused another main steam isolation.

At 1:45 p.m. Operators shut down reactor coolant pumps 1-1 and 1-3 to reduce RCS heat input and pressurizer swell.

At 1:46 p.m. the pressurizer swell was terminated at 97% (Note that at 100% indicated level a substantial volume of pressurizer steam space remains before the pressurizer goes solid).

At 1:48 p.m. the tripped steam pressure and steam flow bistables were returned to service to prevent additional steam line isolations.

At 1:48 p.m. the main steam isolation bypass valves were reopened and the two out of service atmospheric dumps were returned to service and one was opened.

At 2:11 p.m. cooldown was transferred to the condenser steam dumps.

At 2:30 p.m. the plant was stable in Mode 3 and the unusual event was terminated.

The licensee decided to begin the scheduled refueling outage early and not attempt restart. The licensee formed a comprehensive event response plan to determine the cause of the event and corrective actions for the event and the complicating factors.

The results of licensee investigations were followed by the resident inspectors and regional personnel. The detailed results are reported in the licensee's LER 1-89-09 and are not repeated here.

The licensee's corrective actions were reported in the LER. The licensee's LER was reviewed and found to be generally thorough with the exception of the analysis of the pressurizer power operated relief valve (PORV) actuation. The licensee reported that the repetitive lifting of the valve was due to a capacitor not connected in the controller which eliminated controller dead band. The licensee's LER did not explain the cause of the unconnected capacitor nor corrective action, nor address whether continued cyclic actuation would have been harmful.

Secondly, the early lift of the PORV by 85 psig was explained in the LER by that fact that operators had the pressure controller set at 2210 psig versus the normal 2235 psig in order to maintain boron concentration in the pressurizer within 50 ppm of the reactor coolant boron concentration. The LER did not address why such actions were necessary, whether a revised control scheme is required. The licensee committed to issue an LER revision to address these areas.

The most important apparent conclusions drawn by the licensee appear to be

- the need to implement administrative controls similar to technical specifications for non-technical specification equipment such as atmospheric steam dumps. The new administrative controls would include a limit on the number of components that could be taken out of service and the length of time.

- the need to be more conservative in the selection of concurrent work which might cause an inadvertent plant trip. The specific licensee lesson from this event was to prevent future work on a non-safety instrument that shares a common root valve with a safety instrument if any coincident bistables are tripped at the time.

h. <u>Noble Gas Release</u>

On October 7, 1989, the licensee experienced an approximate 10 psi reduction in a waste decay gas tank pressure and experienced an actual noble gas release in the 140 foot elevation of the auxiliary building which is a roof structure.

The residents followed up this event initially and subsequently related the event to regional health physics inspectors and their management. A separate inspection was conducted by those personnel and will be reported separately.

i. Thimble Tube Thinning

Background

NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors," dated July 26, 1988, identified a concern with reactor incore neutron monitoring system thimble tube integrity. The concern regards the fretting wear of the thimble tubes resulting in degradation of the RCS pressure boundary and the potential of a non-isolable leak of reactor coolant.

In response to the bulletin, the licensee, in a letter dated August 26, 1988, committed to an inspection program for DCPP Units 1 and 2 which established the initial inspection at each unit's third refueling outage, respectively. The Unit 1 outage started on October 6, 1989, and the Unit 2 third refueling outage is scheduled to start in February, 1990.

This Inspection

On October 10, 1989, the licensee completed eddy current inspection of the Unit 1 incore neutron monitoring system thimble tubes during the third refueling outage. All 58 tubes were inspected. The Unit 1 thimble tubes are of two sizes: 0.201 inch ID (45 tubes) and 0.210 inch ID (13 tubes).

The inspection results identified 20 tubes which exceeded 60% wall degradation with 3 tubes with greater than 80% wall degradation including 1 with greater than 90% degradation.

An acceptance criteria of 60% through-wall was established by a finite element analysis performed by Westinghouse using ASME Code material allowable values. Nineteen of the identified tubes were 0.201 inch ID and 1 was 0.210 inch ID. Also, there were 8 additional tubes with indications between 50 and 60%. All 8 are 0.201 inch ID tubes. Since all measured values are increased by 10% to account for measurement uncertainties, these 8 tubes were also considered as not meeting the 60% acceptance criteria, giving a total of 28 tubes not meeting acceptance criteria. An additional 17 tubes were found to have wear scars between 35 and 49% through-wall.

The licensee concluded that there was no indication of tube leakage based on the following:

1. Physical inspection of the area did not show any evidence of boric acid crystal buildup indicative of a tube leak.

2. There was no increase in radiation levels in the area during power operation.

3. Surveillance Test Procedure (STP) R-8A, "Reactor Coolant System Operational Pressure Leak Test," performed at the conclusion of the refueling indicated no leakage.

Based on the above, the licensee concluded that no degradation had progressed completely through the tube walls.

PG&E reported the above condition on October 20, 1989, in accordance with 10 CFR 50.72 as recommended by NRC Bulletin 88-09. The licensee also initiated a non-conformance report. The following corrective actions were taken:

1. An operations shift order was issued to discuss identification of and actions to be taken following thimble tube failure. Additionally, the operator round sheet was modified to require inspection of the seal table during routine containment walkdowns.

2. The 33 thimble tubes (including all tubes above the replacement criteria and 5 which were in the 35-49% wear category) were replaced.

3. Since the wearing appears to be location dependent, 12 additional tubes were repositioned.

4. The licensee committed to initiate a surveillance program to track further tube degradation in future outages.

Additionally, the licensee completed a Justification for Continued Operation (JCO) for Unit 2. In the JCO it was concluded that Unit 2 thimble tube condition could not be predicted from Unit 1 data.

Westinghouse identified another plant which has a lower internals design similar to Unit 2 and was subject to a recent 100% inspection of the thimble tubes. The licensee concluded that the data obtained from that plant would provide a more meaningful basis for comparison than Unit 1. The results from the other plant inspection show a total of 19 thimble tubes with indications greater than 60% including measurement accuracy. The indications were over a range with the largest being 91%. Although the inspection was performed after 11 fuel cycles, since the tubes were repositioned after cycle 4, the indicated wear could be conservatively assumed to have occurred over the four cycles. The four cycles of operation (12 month cycle) is slightly longer operating time than Unit 2 (three 15 month cycles). The licensee supported their conclusion that Unit 2 tubes had not degraded to the extent of Unit 1 with the following; the plant did not experience any leakage prior to inspection, had experienced less degradation than Unit 1 and had operated slightly longer than Unit 2.

The inspector reviewed the corrective actions for Unit 1 and the JCO for Unit 2 and found them to be acceptable.

j. Crosstie of Diesel Generators Between Units

On October 10, 1989, the inspector was informed by plant management that an apparently erroneous statement had been made by PG&E in requesting a license amendment to extend the allowed outage time of diesel generator 1-3 (the swing diesel) from 72 hours to 7 days allowed outage time.

In response to NRC questions, PG&E had stated in a letter dated July 3, 1989, that Diablo Canyon had the ability to crosstie diesel generators between the units and a specific operating procedure was named in the letter which supposedly performed that operation.

Plant personnel in preparing to commence the 7 day diesel generator outage noted the prerequisite and the absence of instructions for crosstieing in the procedure.

Subsequent discussions were held between PG&E, the resident, and NRC headquarters personnel.

The licensee devised a plan whereby diesels could be crosstied through the startup transformers in the event of a loss of all offsite power. The licensee analyzed the voltage drops through such a scheme and found them acceptable. Procedures were appropriately revised and approved and the 7 day diesel outage was commenced.

The apparently weak connection between PG&E licensing personnel and plant operations was discussed at the exit interview. Licensee action will be followed up through the non-conformance which the licensee committed to write.

k. Control Room Ventilation Mode Change

On October 12, 1989, the licensee made a 10 CFR 50.72 report based on an engineering safety feature actuation. Specifically the control room ventilation system switched to pressurization mode when a bag of radioactive waste was brought out of containment and placed near the control room monitors.

This event and licensee corrective actions will be followed up through the licensee's event report.

l. Containment Sump Not Per Design and Lacking in Cleanliness

On October 17, 1989, the resident inspector examined the Unit 1 containment sump as part of a preplanned inspection. The sump is an important safety feature and is used as the source of reactor cooling water subsequent to a LOCA.

The sump was found to contain debris including a hacksaw blade. Additionally, the sump was not built in accordance with its design drawing in that an inner screen mesh was not in place.

On November 1, 1989, while Unit 2 was in Mode 4, the inspector examined visually accessible portions of its containment sump and found some debris, including a utility knife, inside the outer screen. The licensee performed follow-up inspection, including radiography of Unit 2 RHR containment sump suction piping, and found additional debris, including a small nut in the suction piping. The licensee performed an analysis and determined that the debris found did not affect the operability of the system.

The analysis of these finding, the licensee's actions including Unit 2, will be reported in a separate special report.

m. San Francisco Earthquake

On October 17, 1989, at 5:03 p.m., an earthquake of about 6.9 magnitude occurred with its epicenter just south of San Jose, California, approximately 150 miles from Diablo Canyon. The earthquake was physically barely perceptible to some plant personnel and the Senior Resident Inspector. Additionally, the strong motion alarm was received in the control room. The strong motion alarm is actuated by a relative motion change of around 0.001 G by either of two detectors. In addition to the alarm, the detectors start recordings on 20 additional monitors.

In accordance with Emergency Procedure M-4, a "moderate" earthquake was declared based on the actuation of the strong motion detector and the perception of motion by plant personnel. Also in accordance with EP M-4, an Unusual Event was declared, plant inspections were initiated, and Unit 1 core offload, which had been in progress, was halted. Inspections conducted in the hour following the earthquake include walkdowns of the containments and fuel handling buildings and a walkdown of various plant tank level indicators. No damage was found and core offload recommenced at 6:05 p.m..

Follow-up inspection was performed by the Onsite Project Engineering Group (OPEG) on October 21. Because of the low level of ground motion, the team focused efforts on plant features such as ventilation ducting, gaps between buildings and switchyard equipment; all areas which would provide the first indications of damage. In addition, instrumentation of the Unit 1 generator rotor, which is temporarily placed on a support during the refueling outage and is instrumented because of close tolerances, were read. It was found that there was a maximum vertical displacement of 0.002 inches and a maximum horizontal displacement of 0.011 inches. These small displacements are indicative of the extremely low level of excitation experienced by the turbine building.

The resident inspectors, on subsequent plant walkdowns, found no indications of plant damage resulting from the earthquake.

n. Spent Fuel Pool Radiation Monitor Alarms

On October 18, 1989, the resident inspector was informed on spent fuel radiation monitor alarms being received in the Unit 1 spent fuel pool during fuel movement.

The radiation monitor in question (RM58) is located near the spent fuel pool and its alarm setpoint is 15 mr/hr. The monitor alarms and shift ventilation to iodine removal mode on actuation. The alarm setpoint is specified by technical specifications but different plants have requested and received higher setpoint values. The alarms being received were false from the standpoint of identifying problems vice background radiation level swings. The licensee made an interpretation of technical specification regarding the need to include instrument inaccuracies in setting the alarm setpoint. The resident examined the licensee's rationale, briefed regional and NRC headquarters management and considered the interpretation acceptable.

Further information revealed that spent fuel pool personnel had received up to 15 alarms per hour during fuel inspection on October 17, 1989, and had ceased to respond unless the alarm persisted. The job was stopped by a health physics supervisor that morning. The licensee was asked to conduct an investigation into the unacceptable response to the alarm problem.

Regional health physics inspectors were informed by the resident and conducted a full inspection which will be reported separately.

o. Drug Abuse Allegation

On October 20, 1989, the resident received an allegation regarding a named individual who was suspected of controlled substance use.

Regional security inspectors were notified by the resident who in turn notified licensee security personnel. Subsequent feedback showed that the accused individual had not been granted unescorted access to the plant and had not passed pre-employment screening.

p. Employee Concern on Containment Isolation Valves

On October 21, 1989, the resident received a call from a worker who was concerned that the licensee's method of testing the containment isolation valves for primary water supply to the containment was not proper.

The test in question was the measurement of the time it took for the valve to close. The closure time is specified in technical specifications. The licensee tests the valves at 55 psig which is lower than the normal system pressure (on the order of 100 psi). The licensee does this because the nature of the rubber diaphragm Grinnell valves causes them to not close quickly in a solid water system due to rubber valve seat deformation. The licensee's test at 55 psi is a conservative estimate of containment pressure in

accident conditions (nominally 47 psig). If the closed primary water system is pressurized to 100 psi, then no out-leakage will occur. If the line is violated, then the the maximum pressure it would see would be 47 psi under accident conditions and the valve would close under these conditions within technical specification closure times.

The inspectors opinion was related to the employee who seemed satisfied.

q. Inadvertent Unit 1 Containment Ventilation Isolation

On October 24, 1989, at 12:30 a.m., while defueled, Unit 1 received an inadvertent Containment Ventilation Isolation (CVI) when the input AC power to Train A of the Solid State Protection System (SSPS) input relay cabinet was momentarily grounded.

When performing Temporary Procedure (TP) TB-8930, as part of design change package for the installation of seismic trip into the SSPS it was noted the fuse holder for fuse 2FU1 had the upper clip spread open such that contact was intermittent, causing the input relays to chatter. The technician removed the fuse and attempted to squeeze the clip closed so that it would tightly hold the fuse. In doing so, his pliers slipped, causing a momentary arc between the hot and neutral legs of the inverter supply.

This momentary ground of the inverter supply fed through instrument AC distribution panel 12 which also supplies AC power to radiation monitoring rack "E". Rack "E" includes radiation monitors 1RM-14A and IRM-28A. The momentary ground caused the output relays for these radiation monitors to deenergize and actuate a CVI.

The containment ventilation isolation system performed as designed. The licensee made a four hour non-emergency report at 3:44 p.m., October 24, 1989.

The licensee will follow-up with a non-conformance report and a LER. The inspector will review the licensee's actions as described in the LER in a future inspection.

r. Feedwater Spill

On October 25, 1989, Unit 1 experienced an estimated 5000 gallon spill of steam generator water out of a disassembled auxiliary feedwater check valve. The problem occurred due to concurrent work of check valve inspection and filled steam generators.

Although the work clearance for the valve had a precaution to not fill steam generators above a certain level (the feed ring level), no specific actions were specified to preclude operators from filling above this level. Operations personnel approving the clearance earlier in the outage had not noted the need to provide some means of alerting operators on following shifts.

There were no environmental or radiological consequences to the spill.

The licensee has written a quality evaluation on the spill which will be followed up by the inspector in the normal course of future inspection.

s. Manual Unit 2 Turbine/Reactor Trip on Indication of Arcing in Main Generator Exciter

At 6:55 a.m. on October 27, 1989, operators manually tripped Diablo Canyon Unit 2 on indication of arcing in the main generator exciter. The reactor trip was normal and all systems responded as required.

The licensee's fire brigade responded to the exciter area. In accordance with emergency procedures, the licensee declared an Unusual Event when fire fighting assistance was requested from California Department of Forestry since arcing continued to be observed in the exciter after the trip. The California Department of Forestry responded to the site, but no further action was required as there was no fire. Based on this assistance request the licensee declared an Unusual Event. The licensee secured from the Unusual Event at 8:28 a.m. based on the assessment that there was no further fire hazard. The California Department of Forestry was released from the site and a fire watch was stationed at the exciter area.

The licensee precautionarily vented hydrogen gas from the generator cooling system and purged the system with carbon dioxide. Further, the licensee precautionarily evacuated the turbine building until conditions were considered stable. An apparent spurious spike in the air ejector radiation monitor was observed. The indication rapidly trended to normal and subsequent steam generator samples did not substantiate the indication. The licensee included an investigation of the phenomenon in their event response plan.

The licensee determined the root cause of the event to be the grounding of the normally electrically insulated 11 turbine shaft bearing. The path to ground was subsequently determined to be at a temperature indicator for the #11 bearing lube oil return. A bushing, which normally electrically insulates the temperature indicator's support from the grounded main housing, was found to have degraded and allowed the indicator to lean over and contact the grounded support. Since the temperature indicator is not insulated from the #11 bearing, the bearing was grounded as well. It is theorized that the generator shaft, which normally operates with an induced voltage of 150 volts, began to arc to the #11 bearing shaft labyrinth seal. This event coincides with other indications such as a dramatic increase and slow fall off of generator radio frequency (RF) noise, a lowering of bearing temperature (indicative of greater seal clearances allowing more flow), and increasing bearing vibration. At some point, the bearing (a babbit bearing) became the point of arcing. The bearing basically melted and reformed a number of times, each time with greater clearances.

At approximately 6:00 a.m. RF noise sharply increased, which apparently was the point where the permanent magnet generator (PMG), which supplies voltage to the exciter voltage regulator and is physically at the end of the turbine/generator shaft, began to contact the stator. At 6:50 a.m. a maintenance individual on the turbine deck noted smoke and a burning odor from the exciter housing and called the control room. After operators verified the information, the plant was manually tripped.

The PMG and stator were damaged during the event and the bearing was wiped. In recovery, the licensee shipped the bearing offsite to be refurbished and took the Unit 1 PMG/stator assembly for use on Unit 2.

The licensee conducted an "Event Response Plan" which tracked various corrective maintenance and cause investigation actions. A non-conformance report (NCR) was also initiated. It was determined in the preliminary investigation that in 1983 the turbine-generator vendor had recommended that the #11 bearing lube oil return temperature indicator be removed because it supplied a potential grounding path. The recommendation was not implemented. Continued investigation by the licensee will be conducted in the NCR and will be followed by the inspector during routine reviews.

No violations or deviations were identified.

5. Maintenance (62703)

The inspectors observed portions of, and reviewed records on, selected maintenance activities to assure compliance with approved procedures, technical specifications, and appropriate industry codes and standards. Furthermore, the inspectors verified maintenance activities were performed by qualified personnel, in accordance with fire protection and housekeeping controls, and replacement parts were appropriately certified. Maintenance activities observed are described in the events section of this report. In addition, the following maintenance items are discussed in detail.

a. Maintenance Personnel Overtime

On October 25, 1989, in discussion with a mechanical maintenance journeyman working a Unit 1 safety related valve, the inspector discovered that the journeyman was on a work schedule of 12 hours a day for all 7 week days (7-12s). The inspector discussed this with both the foreman on the job and the assistant outage manager and discovered that some craft were indeed on a 7-12 schedule. The inspector presented this to plant management and requested time accounting sheets.

Technical Specification 6.2.2, "Plant Staff", paragraph f. requires that plant staff who perform safety-related functions shall work no more than 16 hours straight, no more than 16 hours in any 24 hours period, not more than 24 hours in any 48 hour period, no more than 72 hours in any 7 day period, all excluding shift turnover break.

To exceed these limits an individual or group during an extended shutdown period must have the authorization of the Plant Manager of his designee including a basis for granting the deviation.

Plant procedure NPAP A-8, "Overtime and Emergency Relief Restrictions" restates the above requirement without providing specific guidance on how the policy is to be implemented and who it is applicable to.

On November 20, 1989, the maintenance manager had confirmed that several individuals in the electrical and mechanical shops, who had performed safety related maintenance activities, had exceeded 72 hours in a 7 day period without obtaining the Plant Manager's, or his designee's approval. This is an apparent violation (Enforcement Item 50-275/89-23-01).

As immediate action, the maintenance manager issued a memo to maintenance foremen establishing a work policy more stringent than the TS criteria. Specifically, permission was required to work more than 12 hours in a 24 hour period and more than six consecutive days. As discussed below, this guidance was not entirely effective.

The licensee's specific data was requested on October 27, 1989, and provided on November 20, 1989, delaying the completion of this report. Additionally, although the inspectors findings were brought to the attention of plant management on October 27, individuals in the electrical maintenance shop exceeded the 72 hour maximum as late as November 3, 1989. The issue of licensee responsiveness to identified problems was discussed at the November 21 exit meeting.

Additionally, the inspectors requested that the licensee review compliance with Technical Specification 6.2.2.f of other organizations performing safety related functions with respect to who the TS is applicable to, and how and if it has been implemented for the Unit 1 refueling outage. The licensee should discuss their findings in the response to the notice of violation.

b. <u>Flow Instrument 1-FI-928A</u>

The inspector observed portions performed on flow instrument rotameter used in the filling of accumulators from the charging pumps. The maintenance was performed to inspect and clean the rotameter, a flow instrument which operates in the flow path. The inspector noted two problems discussed below:

- o The instrumentation and controls (I&C) technician, hired for the outage, had not signed off any steps in his work package, although he had already removed the rotameter and had begun to clean it. The steps he had not signed off included obtaining permission from the shift foreman, verifying he was at the right unit, a clearance walkdown, and hanging an out-of-service sticker or tag. The inspector verified that although not signed off, the steps had been completed.

- o Although the rotameter is part of the pressure boundary and that the flange used flexitaltic gaskets, the work order did not specify that new gaskets were needed nor torque values required for reassembly. It stated "Re-install FI-928A." The technician recognized the omissions and requested that the package be revised.

These findings were discussed with I&C management and were characterized as poor attention to detail by the technician and an inadequate work package. I&C management committed to stress compliance with work step sign off and the need to issue thorough work orders.

One violation was identified.

6. <u>Surveillance (61726)</u>

By direct observation and record review of selected surveillance testing as documented in paragraph 3, 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.

No violations or deviations were identified.

7. <u>Engineering Safety Feature Verification (71710)</u>

The inspector performed a walkdown of the Unit 1 and Unit 2 Auxiliary Saltwater (ASW) systems. Cosmetically, the ASW pump vaults were in poor condition with all having some amount of standing water (from the seals) and dirt on the floor. Adverse conditions in these rooms has contributed to equipment failures in the past and, as noted in this inspection, conditions have not been notably improved.

The issue of plant aging in adverse conditions has been previously discussed with plant management who committed to review the maintenance program (follow-up item 50-323/89-21-05).

The inspector also found, on two occasions, seals missing on ASW pump discharge valves; although the valves were found in the correct positions. On both occasions, the inspector reported the findings to the shift foreman. In follow-up, it was discovered that no action requests (AR) had been initiated to document the discovery. As a result of similar findings discussed in Inspection Report 50-275/88-26 and 50-275/88-31, it was the inspector's understanding that in addition to a six month walkdown of accessible seals, ARs would be initiated for all inadvertently broken seals. The ARs were to be a tracking method for broken seals. Operations management committed to re-emphasize the policy.

No violations or deviations were identified.

8. Radiological Protection (71707)

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

No violations or deviations were identified.

9. Physical Security (71707)

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

No violations or deviations were identified.

10. Licensee Event Report Follow-up (92700)

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.)
9/21/89 Both Units	DCO-89-RC-90
10/12/89 Both Units	DCO-89-RC-90

No violations or deviations were identified.

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

a. Containment Hydrogen Purge Penetration Isolation (Unresolved Item 50-275/89-14-03, Closed)

This unresolved item concerned containment hydrogen purge containment penetration isolation valves FCVs 658, 668, 669, and 659 and the requirement for administrative controls to verify that the valves are closed when not in use.

Technical Specification 4.6.1.1, states that primary containment integrity shall be demonstrated by;

> "At least once per 31 days by verifying that all penetrations* not capable of being closed by OPERABLE containment automatic isolation valves and required to be closed during accident conditions are closed by valves, blind flanges, or deactivated automatic valves secured in their positions,..."

The above requires that inside containment isolation valves FCVs 658 and 659 and outside containment isolation valves FCVs 668 and 669 be maintained closed and deactivated by opening and sealing the respective motor breakers. This conclusion is based on the following since some licensee confusion exists due to the double usage of the work "automatic":

- o The valves are not signaled to close by a Phase A or B automatic containment isolation signal nor a containment ventilation isolation (CVI) signal. Therefore, they are not "OPERABLE containment automatic isolation valves."

- o The penetrations are required to be closed during an accident condition (classified as "nonessential") as shown in the licensee's February 2, 1980, response to NUREG 0578.

- o The valves are remotely operated motor operated valves intended by the TS to be "deactivated automatic valves secured in their positions."

The above is also consistent with the General Design Criteria (GDC) of 10 CFR 50 Appendix A. FSAR table 6.2-39 states that these penetrations meet GDC 56. GDC 56 requires the use of either "locked closed isolation valves" or "automatic isolation valves" on both the inside and outside of containment. Since neither the inside nor outside containment valves receives automatic isolation, GDC 56 requires that they be "locked closed."

Further, the licensee's June 26, 1981 response to NUREG 0737 stated that "All nonessential systems use either manually-sealed closed valves or else the valves are automatically isolated on a Phase A containment isolation signal." Since the hydrogen purge penetrations are classified as "nonessential" and do not receive an automatic isolation signal, it was inferred from this that they would be sealed closed.

The licensee initiated a NCR on the issue, which at the end of the inspection report had not yet been reviewed and approved by the Plant Safety Review Committee, that determined that the absence of seals on the hydrogen purge valve breakers was an acceptable configuration. The NCR argument that the valves do not need to be sealed is based on control room position indication lights fulfilling the function of the seal. The NCR quoted NUREG 0737 which states in item II.E.4.2;

"Sealed-closed purge isolation valves shall be under administrative control to assure that they can not be inadvertently opened. Administrative control includes mechanical devices to seal or lock the valve closed, or to prevent power from being supplied to the valve operator. Checking the valve position light in Control Room is an an adequate method for verifying every 24 hours that the purge valves are closed."

It is apparent from the above that administrative control to seal the valve and verification of position are meant as redundant means of assuring the penetrations remains closed.

The NCR also sited the previously reviewed use of control room position lights to verify the position of the Safety Injection valves. This, however, is not a good comparison since the Safety Injection valves are used for accident mitigation and cannot be sealed closed whereas the hydrogen purge penetrations are required to be closed at the beginning of an design basis event. Additionally, the inspector could find no document where the licensee took or was given credit for the use of position indication lights in lieu of seals for the hydrogen purge penetrations. In fact, position indication lights were recommended in the NRC Standard Revision Plan (SRP 6.2.4) for all remote operated containment isolation valves. The licensee committed to this recommendation in the FSAR.

Based on the above, the licensee should have had containment hydrogen purge valves FCVs 658, 659, 668, and 669 closed with their respective motor breakers sealed in the open position. The failure to do so, as discovered by the inspector on May 9, 1989, is an apparent violation (Enforcement Item 50-275/89-23-02).

Immediately following the inspector discovery of the valves breakers in the closed position, the breakers were opened and subsequently sealed. The licensee has discussed plans to install key locks on some of the valve position switches as a permanent fix. The licensee should discuss their permanent solution in the response to the notice of violation.

b. Impaired Fire Barrier (Enforcement Item 50-323/89-21-02, Closed)

The inspector reviewed the licensee's October 27, 1989, response to a notice of violation issued in Inspection Report 50-275/89-21 regarding the discovery by the inspector of impaired fire barriers. The corrective actions to prevent recurrence were found to be acceptable. These actions included the development of a video tape on the recognition of fire barrier impairments to be presented to onsite craft during upcoming safety meetings and to all new employees during general employee training. This item is closed.

c. <u>Safety Injection System Heat Tracing (Unresolved Item 50-323/89-21-03, Closed)</u>

Inspection Report 50-275/89-21 discussed findings related to the quality classification of the safety injection system boric acid heat tracing. In summary, a July 1988 Quality Assurance (QA) audit found that the Q-List (a quality classification list maintained by Nuclear Engineering and Construction Services (NECS)) did not list all heat trace which was required to be safety related. Where as the Q-List at the time specified that only portions of the heat trace system between the BIT (boron injection tank) and RCS (reactor coolant system) were safety related, the 1982 Design Criteria Memorandum (DCM) for heat trace, which represents the licensee's current understanding, specified that all portions of the heat trace system associated with safety related piping be classified safety related. This includes the piping from the boric acid tanks (BATs) to the BIT.

In response to the Audit Finding Report (AFR 88-843), in November 1988, the Q-List was revised to classify as safety related, "Boric Acid between Boric Acid Tanks, BIT and RCS." The root cause identified in the AFR was that an engineering memorandum had not been entered into the Q-List correctly. What NECS and QA failed to address is that since the Q-List, and not the DCM, was the document used by plant personnel in planning work, the portion of heat trace between the BATs and the BIT had not been treated by maintenance as safety related. Therefore, in effect, NECS upgraded that portion of heat tracing which had been treated as non-safety related (no QA program, seismic criteria not applicable) to safety related without any review of the installed condition of the heat tracing.

As discussed above, the 1987 and 1988 Q-Lists break down heat tracing into two categories, described as safety and non-safety related above. The first is classified as Design Class 1, which requires it withstand a safe shutdown earthquake, is supplied by a Class 1E vital power supply, and is subject to the requirements of the Quality Assurance Program in accordance with 10 CFR Appendix B.

The non-safety related heat trace is classified Design Class II and is subject to none of the above.

In addition to the finding that the November 1988 revision to the Q-List had not been appropriately reviewed prior to implementation, inspection report 50-275/89-21 also noted that a plant organization, independent of NECS, maintains a Component Data Base (CDB) which contains classification information on the component level which was not updated in a timely manner following the revision to the Q-List. When the inspector raised questions on the accuracy of the CDB it was found that eight data entry errors had been made in the classification of heat tracing. This may have contributed to the issuance of work orders, after November 1988, on safety related heat sections of heat trace, as Design Class II.

In response to the inspector's finding, NECS initiated an NCR. The NCR identified related problems. Heat tracing was designed and built as Design Class I. In June 1984, in revision 4 to the Q-List, heat trace was listed as Design Class II with the QA program applicable to only the heat trace between the BAT to the BIT to the RCS. In July 1985, the reference to the QA program was deleted. In March 1987, revision 7 to the Q-List reclassified the heat traces between the BIT and RCS as Design Class I. The bases for these changes were not documented sufficiently to determine why they were made.

NECS conducted a review of the existing heat tracing configuration to ensure it conformed with current quality standards. They found the following:

- Heat trace maintenance procedures are standard for both safety related and non-safety related heat tracing.

- Although non-safety related heat trace is not subject to the same procurement and dedication process as safety related, the hardware is the same commercial grade material.

- Since portions of safety related heat tracing is required to be seismically qualified, a complete walkdown was initiated to ensure that all heat tracing required to be safety related met appropriate seismic qualification. At the time of the report more than half of the system had been walked down and no discrepancies identified which would have compromised seismic qualification.

- Temperatures in all heat traced lines have been monitored on a 24 hour period. All problems, whether they are on safety related or non-safety related heat trace have been treated expediently due to the consequences of low temperatures in highly borated lines.

As corrective actions, NECS revised the Q-List procedure to require evaluation of all classification changes for their effect on the design basis and plant maintenance and operations. Additionally, Q-List changes that change the design basis or have impact on plant operations or maintenance must be implemented by the design change process.

While the above demonstrates that the failure to maintain the Q-List accurate with respect to heat tracing was of minor consequence, the issue of NECS failure to recognize the effect the revision to the Q-List may have had on plant conditions is of concern. The failure to maintain heat tracing in accordance with the design basis is an apparent violation (50-275/89-23-03). In response to the notice of violation, the licensee should also address the control and revision process for the component data base to ensure that accurately reflects the information contained in the Q-List

Two violations were identified.

12. Follow-up of Enforcement Action 89-85 and Team Inspection 50-275/89-01 Open Items (92703, 92702)

a. Based on a review of the licensee response to inspection report 50-275/89-01, associated action requests, quality evaluations, and non-conformance reports, the following enforcement items are closed:

Unit 1

89-01-10	Deviation from FSAR on Control Room Carbon Dioxide Build-up
89-01-05	Control Room Switch Relocated Without Post-maintenace Test
89-01-08	Remote Shutdown Procedures Not Issued in a Timely Manner
89-01-07	Inadequate Design Review on Control Room Ventilation Modifications

Unit 2

89-01-04	Discrepancies of Installation and Maintenance on SI Pump 2-2
89-01-05	Improper Thread Engagement On Pump Motor End Cooling Line
89-01-11	Failure to Adhere to Modification Requirement Regarding Hanger Installation

b. Auxiliary Building Ventilation System Modification Enforcement Items

The inspector reviewed the licensee's response, associated action requests, and non-conformances addressing the following enforcement actions concerning a modification to the Unit 2 auxiliary building ventilation system;

89-01-06	Field change issued for a temporary cover on ventilation system after work was complete.
89-01-07	Valve diagrams not updated in a timely manner.
89-01-08	Field welds not receiving QC inspection prior to returning system to operable status.
89-01-09	Replacement of seismic bolts completed contrary to plant maintenance program.

Based on the review, the above items are closed.

c. Auxiliary Saltwater System Open Items

The inspector reviewed open items associated with the Auxiliary Saltwater (ASW) system. These included:

- Enforcement Item 50-275/89-01-02
- Unresolved Item 50-275/88-11-02
- Follow-up Item 50-275/89-01-01
- Enforcement Item 50-323/89-01-03
- Enforcement Item 50-323/89-01-01

Based on the following review, these items are closed.

1. Understanding and Implementation of the ASW System Design

The first three items listed addressed the lack of understanding of the design of the ASW system and the failure to implement the design into operation. The inspectors had a number of individual concerns which are addressed below.

Capacity of An Individual ASW Train to Meet Design Basis Loads: The Team inspection identified a 1983 design requirement that showed that under certain conditions a second component cooling water heat exchanger was required to be placed in service to meet post LOCA heat load conditions. The requirement had not been implemented into plant procedures and on numerous occasions, CCW heat exchangers were removed from service to facilitate their cleaning.

The licensee subsequently performed had a refined calculation which showed that the a second heat exchanger would not have been needed in the event of a LOCA (it assumed an initial CCW temperature of 75 degrees versus the 80 degrees assumed in the original calculation). In addition, the licensee implemented administrative limits to rack out the breakers for two of five containment fan cooler units (CFCUs), which are the primary post-LOCA heat loads on the CCW and ASW, when one CCW heat exchanger is taken out of service. The licensee also retained Westinghouse to perform further calculations to better define design basis requirements so that the removal from service of two CFCUs is unnecessary. At the time of the inspection this calculation had not been completed. A review of the licensee's implementation of the calculation into plant procedures will be the subject of routine follow-up.

In addition to the above, the licensee's August 4, 1989 response to the enforcement action listed a number of corrective actions including a review of 3000 items of design correspondence, a review of the FSAR for similar commitments, and revisions to operations and engineering procedures. The licensee also referred to the configuration management program and establishing design basis information documents as part of the long term corrective action program. The inspector found these actions to be acceptable.

ASW Requirements With a CCW Pump Out of Service: In a finding similar to the one discussed above, the team inspection found a licensee memo which stipulated that with either the 1-1 or 1-2 CCW pumps out of service, a second CCW heat exchanger is required to be in service to meet design basis heat loads. This requirement had not been implemented into plant procedures. The licensee's corrective actions pertaining to this item were similar to those discussed above except that there is no further actions to refine calculations. The licensee's actions are documented in LER 50-275/84-40 and the licensee's August 4, 1989 enforcement action response. The inspector found these actions to be acceptable.

ASW Flow Measurement: In response to the inspection report 50-275/88-11, it was determined that one critical aspect of ASW operability was the flow through the heat exchangers. However, prior to the inspection, the licensee did not have continuous flow monitoring capability and used a temporary instrument on a quarterly basis to determine system flow. Subsequently, in mid-1988, ultrasonic flow detectors were installed on both units. Due to calibration difficulties, these flow instruments were not used as reliable instrumentation until August 1989.

CCW Heat Exchanger Differential Pressure (dP) Measurement: Prior to the inspection described in inspection report 50-275/88-11, the licensee had adjusted the setpoint for CCW heat exchanger dP without an adequate engineering analysis. The inspectors concern had been that with a quarterly measurement of system flow, if the system had been set up in favorable conditions (such as high tide and a recently cleaned heat exchanger), system flow and thus heat removal capability could degrade below design requirements.

As corrective actions, the licensee issued a procedure for setpoint control which establishes a method for justification, review and approval of all setpoint changes. Additionally, the setpoint for the CCW heat exchanger dP was revise to a lower value and continuous flow indication was installed. The inspector found these actions to be acceptable.

ASW Performance Test: One of the team inspection open items (50-275/89-01-01) concerned a commitment by the licensee to do an ASW system performance test to verify that the CCW heat exchangers remained "full" (flow through all tubes) in all configurations including with one pump and two heat exchangers in service. As documented in inspection report 50-275/89-05, the inspector observed the performance of the test and found it acceptable.

2. Adequacy of Engineering Design Work

The Team inspection found two examples of inadequate engineering design work, both which resulted from the design change. The design change was for the replacement of the ASW

pump impeller with an impeller which required greater power from the pump motor. The design change neglected to considered raising the motor breaker overcurrent trip setpoint or revising the required diesel fuel storage requirement. The inspector reviewed the licensee's assessment of root cause and the corrective actions contained in the August 4, 1989 licensee response to the enforcement action. Corrective actions included engineering design change control procedure revisions and training for engineers. These actions were found to be acceptable.

d. Enforcement Items Associated with the Turbine Driven Auxiliary Feedwater Pump

The inspector reviewed the licensee's August 4, 1989 response and associated corrective actions to the follow enforcement items concerning the Unit 2 turbine driven auxiliary feedwater pump;

89-05-01 Unauthorized design change to the overspeed trip mechanism.

The inspector reviewed the licensee's April 24, 1989, response to the notice of violation and found it acceptable.

89-13-02 Pump inoperable with one steam supply inoperable.

The failure of operators to declare the turbine driven auxiliary feedwater pump inoperable with one of its two steam supply valves inoperable resulted from a failure to incorporate the design basis into plant procedures. The licensee's corrective actions were basically those discussed in their response to the failure to implement ASW CCW design requirements (section 12.c.), specifically an initial review of the FSAR and design correspondence and the long term configuration management program. These actions were found to be acceptable.

89-13-03 Inadequate maintenance on overspeed trip mechanism.

The licensee's August 4, 1989, response to Enforcement Action 89-85 acknowledged that the failure of the turbine driven auxiliary feedwater overspeed trip mechanism resulted from a failure to incorporate vendor maintenance recommendations into procedures. The licensee took a number of corrective actions, including increased maintenance on the overspeed trip mechanism, an initial sample review of vendor maintenance recommendations on 51 significant components, the initiation of a review of maintenance recommendations for all safety-related components and a commitment to develop a "reliability centered

maintenance approach." These actions were found to be acceptable.

e. Enforcement Items Associated with Timeliness of Corrective Actions

1. Equipment Lineup Problems (Enforcement Item 50-323/89-13-01, Closed)

The licensee's August 4, 1989, response discussed corrective actions in response numerous equipment lineup errors including the failure to close a turbine driven auxiliary feedwater pump steam supply vent valve. The inspector found the actions to be comprehensive in nature. The success of the corrective actions will be covered during routine inspection. This item is closed.

2. Diesel Fuel Oil Transfer Pump Vault Drain Check Valves (Enforcement Item 50-275/89-05-01, Closed)

The licensee's August 9, 1989, response discussed corrective actions in response to the enforcement action concerning the failure to recognize and take timely corrective actions following the discovery that check valves had not been installed in the diesel fuel oil transfer pump vaults. The corrective actions addressed both the individual event and the larger issue of corrective action timeliness. The actions were found to be acceptable and will be followed to assess effectiveness in the course of future routine inspection.

f. Follow-up Items

1. Improper Thread Engagement on ASW Pump 2-1 Packing Studs (50-323/89-01-02, Closed)

The SSFI team identified ASW pump 2-1 packing studs having 1/2 to 3/4 full stud to nut engagement. As a result, a design change was initiated by the licensee to install larger studs. In addition, an analysis was performed to address the improper thread engagement.

The analysis noted that there is little expected loading of the packing gland nut and that as a rule of thumb, full strength of a bolt is developed with a bolt engaged about half way into a nut. The inspector found the analysis acceptable for bolts used in this application.

A corrective action, the maintenance procedure for bolting was revised to provide guidance on thread engagement, requiring the bolt to be, at a minimum, flush with the nut.

2. Component Cooling Water System Temperature (50-275/89-01-04, Closed)

The SSFI team identified a CCW system design change requirement that had not been implemented with its design change. The design change was to lower the CCW heat exchanger outlet temperature low temperature alarm from 75 to 45 degrees F. An accompanying requirement was that an inspection for the collection of moisture would be performed on safety-related pump and motor lubricating oil systems cooled by CCW every 90 days.

The inspector reviewed the action request (AR) tracking the design change and found that the setpoint change it had been completed in June 1988. One part of the AR, required to be closed prior to completion of the AR, was an action to establish a lube oil sampling program. Mechanical maintenance began to actively pursue the sampling program in early January 1989. The first sampling was done in February 1989.

Since the change was an alarm setpoint change and not a modification to operating practices, CCW temperatures had routinely been below 75 degrees F (providing a standing alarm) prior to the implementation of the design change. Therefore, if it was felt that an oil sampling program was necessary at these lower temperatures, it should have been implemented as soon as practical, independent of the design change. This was considered a weakness in the licensee's resolution of the problem.

Based on the above, follow-up item 50-275/89-02-04 is closed.

3. Safety Related Pipe Support Discrepancies (Follow-up Item 50-275/89-01-09, Closed)

The team inspection report identified three cases where pipe support installation did not meet the requirements of maintenance procedures. In response, the licensee initiated engineering evaluations of all the discrepancies. In all cases it was determined that the supports would have performed their design function. The licensee also initiated either work orders to correct the discrepancy or field changes to reflect the as found condition. This item is closed.

4. Inadequate Trending of Failures of Diesel Fuel Oil Transfer Pump Discharge Guage (50-275/89-01-03, Closed)

The team found on a walkdown that the diesel fuel oil transfer pump pressure indicator PI-594 was reading approximately 10 psig when the pump was not running. In follow-up it was discovered that the gauge had a long history of failures. The team questioned the licensee's program for trending of maintenance problems.

In follow-up, the inspector discussed the above with the Instrumentation and Controls (I&C) Manager. In the time since the team inspection I&C has required that a Quality Evaluation (QE) be generated to review cause and corrective actions for all failed quality related instrumentation such as PI-594. The QE process requires a history search on the instrument. Based on the above, this item is closed.

No violations or deviations were identified.

13. Exit (30703)

On November 21, 1989, a final exit meeting was conducted with the licensee's representatives identified in paragraph 1. Previous exit meetings had been conducted by the inspectors on September 29, October 6 and 13, and November 3, 1989. The inspectors summarized the scope and findings of the inspection as described in this report.