ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-275/95-06
50-323/95-06

Licenses: DPR-80
DPR-82

Licensee: Pacific Gas and Electric Company (PG&E)
77 Beale Street, Room 1451
P.O. Box 770000
San Francisco, California

Facility Name: Diablo Canyon Nuclear Power Plant, Units 1 and 2

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

Inspection Conducted: February 19 through April 1, 1995

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Inspection Summary

Areas Inspected (Units 1 and 2): Routine announced inspection of operational safety verification, plant maintenance, surveillance observations, onsite engineering, plant support activities, followup maintenance, followup engineering, and in-office review of licensee event reports (LERs).

Results (Units 1 and 2):

Operations:

- The control room demeanor and communications were found to be excellent. Operators in the control room were observed throughout the period to maintain clear communications and a quiet, professional demeanor. This showed clear, consistent adherence to management expectations in this area.

- Operator support during the Notice of Unusual Event (NOUE) conditions and minimum control room staffing situation were very well implemented.

Operators ensured rest periods were observed and operator turnover was excellent. Unit 1 was reduced to 50 percent power as a precaution during the period of heavy Pacific Ocean swells during the NOUE, to account for the potential operational limitations which could have been encountered due to rising condenser differential pressure. These actions demonstrated an excellent safety awareness during the event.

- Operations sometimes lacked attention to detail in identifying minor control board anomalies and minor plant anomalies.

- Restoration of the positions of two valves following slave relay surveillance testing was not performed in accordance with licensee procedures.

- Operator errors caused inadvertent draindown of an accumulator and overpressurization of the Unit 2 condensate resin regeneration system.

Maintenance:

- Planning of the Safety Injection (SI) Pump 2-2 replacement was well coordinated. Multiple activity paths accommodating potential scenarios were planned thoroughly in advance to anticipate potential conditions. This demonstrated excellent planning and organization. As a result of the effectiveness of the planning and maintenance preparations, replacement of the pump was accomplished within the 72 hour limiting condition for operation action statement.

- Quality Control (QC) involvement during troubleshooting and replacement of a component cooling water (CCW) heat exchanger inlet valve identified a spacer ring configuration not documented in design drawings. QC also appropriately questioned the lack of systematic troubleshooting in the identification of the root cause of valve stroke time problems.

- The replacement of a turbine-driven auxiliary feedwater (AFW) pump drain valve did not start until 6 hours after the pump was made inoperable for the clearance. This demonstrated unnecessary outage time for safety-related equipment.

- The careful excavation and attention to administrative details during the diesel fuel oil (DFO) storage tank pitting evaluation work was strong.

Engineering:

- Engineering activities to prepare the design change for SI Pump 2-2 pump replacement appeared to have been well coordinated. The safety evaluations addressing lowered pump performance for the old SI Pump 2-2, and addressing the emergency core cooling system (ECCS) flow conditions

following installation of the new SI Pump 2-2, appeared to have appropriately addressed the complex issue.

- Engineering involvement in the SI Pump 2-2 surveillance testing was weak, in that several violations of plant administrative procedures occurred.

- System engineer involvement in the investigation and corrective actions for auxiliary seawater (ASW) Flow Control Valve (FCV) 603 stroke time was considered proactive. QC involvement and interface with engineering in the technical evaluation was considered effective.

- Engineering support of the investigation and corrective action of DFO storage tank pitting was strong and timely in the area of operability analysis and inspection planning. However, the proposed design change to repair a through-wall pit did not include dedication activities for Belzona, a material specified to be used during the repair.

- Engineering attention to detail could be improved as indicated by NRC identified inconsistencies between the installed and the documented system configurations.

Plant Support:

- Emergency planning activities associated with the heavy rains and winds, mud slides, and flooding conditions were excellent, including the areas of communications with state and local governments and the Federal Emergency Management Agency (FEMA), evaluation of site access, assessment of site conditions, and Emergency Operations Facility (EOF) staffing.

- Plant Security response to heavy rains and winds, mud slides, and flooding conditions was strong and timely. Security was promptly reduced to minimum manning required for the security plan. Security personnel managed disciplined turnover and rest times in an excellent manner. Throughout the event, security personnel appeared alert and cognizant of responsibilities.

Summary of Inspection Findings:

- Violation 275/9506-01 was identified (Sections 2.1, 4.1, and 4.4).

- Followup Item 275/9220-05 was closed (Section 7.1).

- Followup Item 275/9506-02 was opened (Section 7.1).

- Violation 323/9217-03 was closed (Section 7.2).

- Followup Item 275/9322-02 was closed (Section 7.3).

- Unresolved Item 275/8802-01 was closed (Section 8.1).
- LERs 275/94-012, Revision 1; 275/95-001, Revision 0, and 323/94-003, Revision 1 were closed (Section 9).

Attachments:

- Attachment 1 - Persons Contacted and Exit Meeting
- Attachment 2 - Acronyms

DETAILS

1 PLANT STATUS (71707)

1.1 Unit 1

Unit 1 began the report period at 100 percent power. On March 13, power was curtailed for approximately 5 hours to 83 percent power in response to low power demand. On March 10, 1995, during heavy rains and winds, mud slides, and flooding conditions, power was reduced to 50 percent as a precautionary measure due to high seas and increased sea growth fouling of the condenser. Power was increased to 100 percent on March 11 when differential pressures stabilized and more staffing was available on site. Unit 1 operated at 100 percent for the remainder of the report period.

1.2 Unit 2

Unit 2 began the report period at 100 percent power. On March 12, power was reduced to approximately 90 percent power for several hours for the performance of periodic turbine valve testing. The unit returned to 100 percent power after testing. Unit 2 operated at 100 percent for the remainder of the report period.

1.3 NOUE Due to Restricted Access to the Plant Background

On March 9, 1995, a severe storm system with heavy winds and rain caused mud slides and flooding throughout the Central California coastal area. On March 10, at 2 p.m. (PST), the licensee released all nonessential employees to leave the site. From 5 to 6 p.m. (PST), several mud slides and flooded road conditions occurred, blocking access to the site on several roads, including site access roads. Efforts to clear roads continued, but were unable to keep up with road closures.

Licensee Action

At 6:50 p.m. (PST), a NOUE was declared at licensee management discretion due to the inability to travel to and from the Diablo Canyon site. This condition was caused by closure of all roads leading to the plant due to mud slides and flooding. The storm continued through the evening, with 8.5 inches of rain in a 24 hour period, high winds, and heavy seas.

The decision to declare a NOUE was made based on licensee management's assessment of the loss of offsite emergency response capabilities (10 CFR 50.72(b)(1)(v)) and inability to relieve operations and security shift personnel (10 CFR 50.72(b)(1)(iii)). Additionally, 42 of the 131 emergency sirens were inoperable due to the severe weather and local power outage conditions.

Two sources of offsite 230 kV power were threatened by flooding in an underground portion of the common Morro Bay switching center. PG&E received water removal assistance from local fire agencies and from the Coast Guard. Three other sources of offsite power (delayed 500 kV backfeed) were unaffected. At no time were any of the sources of offsite power lost. The NRC notifications by the licensee detailed these conditions.

Operations. Security, and licensee management response was timely and appropriate and will be discussed in the applicable sections later in this report.

Licensee management onsite throughout the event included: the Plant Manager, the Manager of Operations Services, the Manager of Engineering Services, the Manager of Maintenance Services, the Manager of Outage Services, the Manager of Nuclear Quality Services and several directors. In addition to the operation and security shift personnel, approximately 125 licensee staff members remained on site.

Since, during the night, the extent of road damage was unknown in several areas due to mudslide and flooding blockages, licensee management prepared to transport Operations and Security crews via helicopter at daylight.

At daylight, around 6:30 a.m. (PST), onsite personnel assessed storm damage to the site and access roads. Minor mud slides and water damage were identified onsite. Several mud slides and hazardous driving conditions due to debris were identified. No major damage was identified.

After road clearing operations provided a route into the site, operations and security crews were relieved on March 11 at 8:30 a.m. (PST). Later that morning the remaining staff were allowed to leave the site. However, the licensee continued to provide 24 hour management coverage onsite to facilitate damage repairs and preparations for potential of storms in the near future.

The storm damaged several radio repeaters and telecommunications installations. Telephone communications remained available. As many as 62 of 131 emergency sirens were inoperable during the event; however, plant pagers remained functional throughout the event. Telecommunications and radio equipment were repaired, and all but 15 sirens were fixed by 11 a.m. PST on March 11. An assessment of offsite power and transmission lines found no major damage.

The EOF was manned continuously during the storm conditions by the licensee and San Luis Obispo County until the NOUE was exited. The licensee and county officials, in cooperation with FEMA, assessed emergency evacuation route status throughout the event and provided a continuing assessment that an evacuation of the public could have been performed if required by a plant event.

The licensee exited the NOUE on March 11, at 1 p.m. (PST), based on satisfactory resolution of the concerns causing entry into the NOUE. At

3 p.m. (PST), Unit 1 returned to 100 percent power. On March 12, at 12 noon (PST), licensee management terminated 24 hour onsite management coverage due to continued good weather and successful repair of storm damage on site. The licensee notified the California State Office of Emergency Services and the media.

NRC Action Both NRC resident inspectors were onsite for the duration of the event. NRC resident inspectors initiated shift rotation and maintained 24 hour coverage throughout the event. The inspectors observed Operations and Security watchstanders, Plant Staff Review Committee (PSRC) activities, Emergency Planning activities, damage assessment, and licensee management oversight activities throughout the event. Discussion of the observations are included in applicable sections of this report.

Safety Significance Throughout the event, the licensee continued to evaluate safety significance of the current conditions and anticipate potential problems. Specific concerns included the threat to 230 kV offsite power, which would have required entry into a Technical Specification (TS) action statement and would have resulted in an expected delay of 10 to 20 minutes to backfeed offsite power from the 500 kV offsite source, if a trip had occurred. This condition was analyzed and was within the design basis. The reduction of Unit 1 power when condenser differential pressures were observed to be rising averted the potential of a plant trip due to high condenser differential pressure. Evaluation of the safety significance of other conditions is included in applicable sections later in this report.

NRC Conclusion The NRC concluded that the response to the event was well managed, and individual as well as integrated decision making displayed excellent safety awareness.

1.4 Replacement of Safety Injection Pump 2-2

Background Since the outage of October, 1995, the Unit 2 SI Pump 2-2 total developed head (TDH) had appeared to decrease, although data was not conclusive due to scatter in the test measurements. Licensee engineering performed an analysis of the pump performance data and made plans, contingent upon pump test results, to either replace the pump or allow lower pump performance via a license amendment.

Licensee Action On March 28, 1995, at 2:02 a.m. (PST), during the routine scheduled SI Pump 2-2 surveillance, the licensee declared the pump inoperable and entered the applicable 72 hour TS action statement, when the pump developed only 1450 psid head vice 1455 psid required by TS. Based upon the surveillance test results, the licensee decided to replace the pump, and replacement activity started immediately.

The pump was replaced, tested, and declared operable within the 72-hour action statement.

Safety Significance and Conclusion Since detailed discussions of various aspects of the pump replacement are included later in this report, the safety significance and NRC conclusions will also be addressed in applicable sections later in this report.

1.5 Overpressurization of Unit 2 Condensate Resin Regeneration System

On April 1 at 9 a.m. (PST), during transfer of resin between vessels, an operator incorrectly cross-connected the condensate resin regeneration system with the higher pressure condensate system. As a result, the Unit 2 resin regeneration system (a 150 psig system) was overpressurized when it was inadvertently connected to the discharge of the condensate booster pumps (approximately 430 psig).

Damage caused by the overpressurization included a 4-foot split in the seam of the anion regeneration tank and leakage of various gaskets throughout the system. Several diaphragm type valves were overpressurized and transmitted pressure throughout the resin regeneration system. At least one of the relief valves designed to protect the system did not lift. Repairs to the system are in process. The licensee has conducted an engineering evaluation and is conducting a root cause investigation into several aspects of the event.

In order to regenerate Unit 2 demineralizer anion resin, operators manually transferred the anion resin to and from the Unit 1 regeneration system. Additionally, at several times during the repair of the Unit 2 system, anion resin was shipped offsite to be regenerated. This manual activity was expected to continue until the Unit 2 system was repaired and returned to service.

Safety Significance There is no direct safety significance associated with the overpressurization of the resin system. Evaluation of operator actions and NRC conclusions are included in applicable sections later in this report.

2 OPERATIONAL SAFETY VERIFICATION (71707)

2.1 Operator Errors

During this inspection period, several operator errors were observed by the NRC or the licensee or became self-evident. The instances are as follows:

Accumulator Draindown During routine fill of accumulators, a licensed operator in the control room operated an incorrect valve, resulting in partial draining, rather than filling, of Accumulator 1-2. The operator promptly identified the error, took immediate corrective action, and documented the problem. The error occurred using Procedure OP B-3B:I, Revision 10, "Accumulators - Fill and Pressurize," when Valve SI-1-8876B was opened, rather than Valve SI-1-8878B. The control switch for Valve SI-1-8876B is located directly beneath the control switch for Valve SI-1-8878B. The accumulator was drained to approximately the 60 percent level, which is below the normal

67 percent level and below the TS required level. The low level condition was in effect for approximately 5 to 10 minutes.

Resin Regeneration System Overpressurization Overpressurization of the resin regeneration system occurred as a result of manipulation of incorrect valves by an operator and failure of the operator to use an automatic control system which would have performed the desired operation and required minimal operator actions.

The condensate demineralizers are connected to the resin regeneration system to periodically perform regeneration of the resin beds. During an evolution which involved the transfer of resin to a condensate demineralizer, an operator manipulated valves associated with the incorrect condensate demineralizer, resulting in aligning an in-service demineralizer to the resin regeneration system. The operator manipulation of the incorrect valves resulted in the damage to the system. The system has an automatic transfer capability; however, the operator chose to perform the transfer operation manually. Licensee review of the manual procedure, OP C-7C:III, Revision 8, "Condensate Polishing System Transferring Resin Beds," revealed that the operator had also failed to perform a 25-minute draindown of the demineralizer required by the procedure. The failure to follow the draindown requirements did not result in any additional damage to the system.

Incorrect Restoration of AFW Steam Supply Valves After NRC observation of Surveillance Test Procedure (STP) M-16N, Revision 11A, "Operation of Trains A and B Slave Relays K632 and K634," Valves FCV-37 and FCV-38 were observed to be closed. Their required position for operability of the AFW turbine-driven pump is open. One valve was returned to the open position during the performance of a subsequent surveillance which was accomplished immediately following the completion of STP M-16N. The other was returned to the open position when the operator noted the valve needed to be opened prior to performing the valve stroke timing test in the closed direction. The specific details of the error are discussed in the Surveillance Test section of this report.

Safety Significance The safety significance of each of these occurrences is low, since the mispositioned valves were returned to proper position immediately after mispositioning, and the concern was corrected. In the case of the resin system, the event was confined to systems outside the condensate and feedwater systems. The regulatory significance, however, is high, since mispositioning of valves by operators can have great impact on the safety of the plant.

Conclusion Proper operation of valves and correct implementation of procedures are basic requirements for safe plant operation. The above examples are indications that operator attention to detail during procedure use has been inadequate in some cases. These events are considered to be a violation of TS 6.8.1., which states, in part, that written procedures shall be established, implemented, and maintained covering applicable procedures recommended in Appendix A of Regulatory Guide (RG) 1.33, Revision 2, dated

February 1978. Appendix A of RG 1.33, Revision 2, recommends procedures covering the operation of ECCSs, surveillance testing of safety systems required by TS and chemical control. Contrary to these requirements, operators failed to perform the required actions of quality related Procedures OP B-3B:I, OP C-7C:III, and STP M-16N. These correspond to Examples 1, 4, and 2, respectively, of a violation of TS 6.8.1 as identified in Enclosure 1 of this report (275/9506-01).

2.2 Operator Attention to Detail

On March 21, 1995, the inspector observed the following plant and control room deficiencies, which the licensee had not previously noted.

- Recorder RR-31 The inspector noted the recorder for the Unit 1 Train B Containment High Range Radiation Monitor on Postaccident Monitoring (PAM) Panel 1 was not operable. There was no paper in the recorder and the pen was tracking directly on the plastic roller, which provided no trace. The PAM panels are in the main control room. The inspector notified the Shift Supervisor and the licensee installed paper.

- Recorder TR-65A The inspector noted that Recorder TR-65A, for Unit 1 Train A Core Exit Thermocouples on PAM Panel 1, was not operable. The pen was tracking on paper that already had a trace that indicated temperatures oscillating approximately 50 degrees, which made the trace unusable. The inspector notified the Shift Supervisor and the licensee installed new paper.

- Emergency Diesel Generator (EDG) 2-2 Tubing Support The inspector noted that a tubing support on EDG 2-2 was not attached to the appropriate structural member. The inspector noted the equivalent support on EDG 2-1 was attached. The support was for an approximate 4-foot length of tubing connecting turbocharger air pressure to a local meter. This portion of the EDG appeared to have been recently painted. The inspector concluded that the tubing had not been attached after the painting. The clamp was on the tubing, but not bolted to any supporting piece. The licensee generated maintenance plans to reattach the tubing.

- Valve FCV-128 The inspector noted an air leak on Unit 1 Charging to Reactor Coolant System (RCS) Flow Control Valve FCV-128. The licensee was evaluating repair of this leak.

- Flow Indicator 533 On March 11, the inspector noted that Flow Indicator 533, Unit 2 Steam Generator 2-3 Steam Flow, had failed low. The inspector informed the operator on watch, who documented the problem on an Action Request (AR), and initiated maintenance planning to correct the failure.

Safety Significance In each case, the safety significance of the finding was low.

The PAM recorders are to be used as trending points following an accident and were installed per RG 1.97. The inspector reviewed TS and determined, although these indications were included in TS 3.3.3., the licensee had sufficient redundancy such that no action statement needed to be entered, even if these particular recorders were inoperable.

Regarding the diesel pipe support, licensee evaluation indicated that the mass of the pipe support and tubing was sufficiently low, and nearby supports secured the tubing, such that the effects of seismic forces would not be significant on the tubing.

Conclusion The inspector concluded that the licensee's response to the inspector's concerns were appropriate and timely in each instance. The inspector also concluded, however, that both Operations and Engineering personnel had missed opportunities to identify these deficiencies prior to the inspector's doing so, particularly the deficiencies on the PAM panel.

2.3 Control Room Decorum

During the report period, several observations by inspectors during all shifts indicated that the control room decorum throughout the inspection period was exemplary. Noise levels in the control room were very low, both routine and unusual control room activities were conducted in a calm, professional manner. Inspector observations and questions to the operators were addressed promptly and accurately. Turnovers were conducted promptly and effectively. Activities associated with maintenance and clearances were performed with minimal disruption to operators responsible for monitoring plant conditions. In particular, during stranded plant conditions of March 10 and 11, professionalism by operators and management of control room activities was excellent, and turnover of plant conditions to the relief crew was thorough and timely. Briefing of the relief crew was conducted in a calm, thorough manner.

Safety Significance Conduct of control room operations in an environment of professionalism, coupled with management of plant work activities in a manner least likely to disrupt routine control room activities, provides an excellent environment for appropriate control of a reactor plant, as well as avoidance of conditions which could lead to distractions and confusion of operators.

Conclusion Although the licensee's control room decorum is typically very professional, during this inspection period, the control room operations and management of control room work activities has been of especially high quality. The control room staff and management performed in a particularly professional manner during the mud slides and flooded road conditions and the subsequent recovery from those conditions.

2.4 Operations Response to Mud Slides and Flooding Conditions

Background As described earlier in this report, on March 10 and 11, the licensee declared an NOUE due to closure of several roads which cut off all vehicle access to the site. Operators at Diablo Canyon work 12-hour shifts, with turnover at 7 a.m. and 7 p.m.. The NOUE was declared at 6:50 p.m. on March 10.

At the time the event was declared, there were 4 Senior Reactor Operators, 5 Reactor Operators and 11 nonlicensed Nuclear Operators on site. All but one of these operators had been on shift since 7 a.m. The licensee reduced crew manning for operations watchstanders to the minimum TS control room manning requirements in order to minimize operator fatigue until a relief crew would be available. This allowed approximately half the operators to be on rest while still complying with minimum TS crew manning.

The licensee verified that greater than a 3-day supply of consumables (such as diesel fuel, steam generator chemicals, and condensate resin regeneration chemicals) were available on site.

At 7:30 p.m. on March 10, as a result of high seas and high winds, condenser differential pressures on Unit 1 were steadily increasing. Since condenser cleaning would be difficult, although not impossible, given the staff available on site, the licensee curtailed Unit 1 to 50 percent power as a precautionary measure. Since Unit 2 differential pressures remained stable, Unit 2 was maintained at 100 percent power.

Since the extent of road damage was unknown in several areas due to mudslide and flooding blockages, licensee management prepared to transport Operations and Security crews via helicopter at daylight if necessary.

Safety Significance The extension of shift duties for the Operations and Security crews did not appear to have resulted in lowering of shift performance. Because operators on shift remained alert and maintained professional decorum, turnovers between operators were thorough, and the operators taking rest breaks were immediately available if conditions warranted; the safety significance of this reduced staff condition appeared minimal. The proactive decision to reduce Unit 1 power to 50 percent upon rising condenser differential pressure reduced the safety significance of the high seas.

Conclusion Reduced operations shift manning was performed in an excellent manner. Decision making and planning during the NOUE showed excellent safety awareness. Operations management and Control Room staff maintained excellent communication throughout the period of the NOUE.

2.5 Safety System Walkdown

2.5.1 SI Pump Test Connection

During a routine walkdown of portions of the safety injection system, inspectors noted that the test connections installed on some of the SI pump suction and discharge lines were different from the other similar pumps in that, instead of the pipe cap typically used, the connection appeared to have a swagelock-type fitting installed on the end of the cap.

Licensee Action After discussions with plant engineering and investigation by the licensee, the licensee determined that the reference Piping Drawing 063930, "Vents, Drains, and Test Connections, Two Inches and Smaller," Revision 7, applied and did not reflect the installed configuration. The licensee initiated an AR to document the problem. A Quality Evaluation (QE) will be issued to resolve the deficiency and determine the root cause of the condition.

Safety Significance The licensee concluded that this configuration resulted in no operability concerns. The licensee's evaluation appeared to have considered the appropriate factors.

2.5.2 CCW Heat Exchanger Drawing Code Breaks

During a routine walkdown of portions of a Unit 2 CCW heat exchanger and associated piping, the inspector identified that, on the end bell of the CCW heat exchanger, a 1/4-inch tubing connector upstream of an ASW flow differential pressure sensor isolator appeared to be rusting, indicating a material other than stainless steel. Further inspection identified the similar configuration on Unit 1. The inspector noted that no valve was installed between the CCW heat exchanger and the isolator and questioned if the connector material was consistent with the ASME code requirements for that system.

Licensee Action The licensee documented this concern on AR A0366721. Investigation revealed that the code break for the tubing should have been at the bellows isolator between the ASW system and the cap fill connection for the sensor downstream of the rusting connectors. A design change will be necessary to reclassify the isolators as Class I. The connector should have been of stainless steel, a material not subject to rust. The licensee determined that the isolators had been procured as Class I components and, therefore, the situation could be rectified by a documentation change. The licensee plans to correct the configuration the next time the isolator is disconnected from the heat exchanger.

Safety Significance The rust on the fitting is minimal, the material properties of the fitting are adequate for the service in which it is installed. As a worst case analysis, assuming a break in the 1/4-inch line at the location of the fitting, the ASW system fluid leakage would not result in any significant effect on heat exchanger performance, since it is at the

outlet of the heat exchanger and typically exposed to 15 psi to vacuum. Additionally, any possible leakage from the fittings is within the design basis of the leakage removal required for larger piping breaks in that area. There is no safety significance directly associated with this improper material in use.

Conclusion The installation of a swagelock fitting at the end of a pipe cap on the SI system did not appear to be significant. Similarly, the use of incorrect material in the ASW system was not of significance. The NRC inspectors noted a lack of licensee attention to detail concerning equipment configurations which are inconsistent with system requirements.

3 PLANT MAINTENANCE (62703)

During the inspection period, the inspector observed and reviewed selected documentation associated with the maintenance and problem investigation activities listed below to verify compliance with regulatory requirements, compliance with administrative and maintenance procedures, required quality assurance/QC department involvement, proper use of safety tags, proper equipment alignment and use of jumpers, personnel qualifications, and proper retesting. Specifically, the inspector witnessed portions of the following maintenance activities:

Unit 1

- SI Pump 1-1 Oil Cooler Heat Exchanger Gasket Replacement
- SI Pump 1-1 Seal Cooler Temperature Switch Preventative Maintenance
- Valve SI-1-8923A Preventative Maintenance of Limitorque Motor Operator
- Troubleshooting and Replacement of Valve SW-1-FCV-603
- DFO Storage Tank Corrosion Investigation and Repair

Unit 2

- SI Pump 2-2 Replacement
- Excavation and Inspection of DFO Storage Tanks
- Unit 2 Turbine Driven AFW Manual Drain Valve Repair

3.1 Unit 2 SI Pump Replacement

3.1.1 Design Change Installation

The SI Pump 2-2 replacement appeared to have been thoroughly planned and coordinated several days before the job started. Schedules and key parallel

activities were included in work schedule charts. Vendor experts had been consulted for pump installation details, materials were staged, and procedures were written. The licensee determined that the goal of complete replacement and testing of the pump within the 72-hour TS action statement was within the capability of the crews.

During the replacement activity, technicians identified several additional instances in which work could proceed in parallel since more physical space was available for workers to gain access to complete tasks. Additionally, maintenance work was being completed without errors. This resulted in a much faster completion of work.

After installation of the new pump, pump seal leakage was initially high, and inspections of the pump followed by discussions with the vendor determined that the seals had not been adjusted properly. The vendor manual did not specify that the pump seal adjustment be verified during installation. The seals were tightened and, subsequently, prior to returning the pump to service, the adjustments made were verified with the vendor to have been appropriate.

Management and foremen were observed at the work site during all hours of the activity. Maintenance technicians appeared well trained and observant of procedural requirements for the replacement work as well as radiation protection processes.

Safety Significance The proper planning and execution of urgent, nonroutine work such as an SI pump replacement is safety significant. The failure to properly tighten the pump seal was considered minor, since it was self-evident, and was fixed quickly. Appropriate management and supervisory involvement was significant, since the coordination of work crews was essential to timely completion of the pump replacement within the action statement.

Conclusion Maintenance planning and work activities were well executed. Management and supervisory involvement was a noteworthy strength. The level of management involvement was appropriate for this significant work activity.

3.2 Excavation and Inspection of DFO Storage Tanks

Background On February 22, 1995, during activities in preparation for the installation of a flexible coupling on the DFO transfer piping to increase seismic margin, the licensee identified pits on the surface of one of the DFO storage tanks, under the tank's protective coating. The licensee then began to investigate the nature and extent of DFO storage tank corrosion. On March 7, the licensee identified a through-wall pit of about 1/8 inch diameter near the top of DFO Storage Tank 0-1. The licensee covered the hole with tape as a temporary measure, performed an operability evaluation, and initiated a design change to repair the hole. The inspection plan, design change, and operability evaluations will be discussed later in the engineering section of this report.

Work Activity The licensee developed an inspection plan and, on March 1, initiated excavation of portions of both tanks in accordance with the inspection plan. The inspectors observed portions of the planning, excavation, and inspection of the pitting of the surfaces of the buried DFO storage tanks. Root cause investigation determined the most likely areas of pitting attack, and maintenance planning minimized exposure of the tank walls to damage by excavation activities. Inspectors observed that inservice testing and materials evaluation engineers worked closely with maintenance and excavation teams to minimize potential of damage to tanks during the excavation process. Security plan activities were properly implemented, confined space permits were issued, and work order (WO) requirements were implemented to exclude items which could drop into the pits and potentially damage the tanks. Shoring plans for protection of the tanks and personnel were followed closely. Soil evaluation was required to determine if contamination was present. Pit locations were promptly transmitted to engineering to evaluate tank operability.

Quality Services Involvement On March 10, the manager of Quality Services pointed out to the PSRC that the locations of the pitting had been evaluated, and the conclusion was that the extent of damage for both tanks was well quantified. Therefore, the urgency to excavate portions of the tanks as quickly as possible for inspection was no longer required. Therefore, before repair operations were conducted with both tanks partially exposed, the need to re-bury one of the tanks should be considered, to minimize the potential of a common mode failure. The PSRC agreed to re-bury one of the tanks while repairs were completed on the other tank.

Safety Significance The exposure of DFO Storage Tanks is safety significant, and the licensee appeared to have properly implemented precautions over and above the minimum requirements. Timeliness of excavation and assessment was strong, as was the balance of the need for rapid assessment of the condition of tanks with the need to minimize the time when the tanks were vulnerable to a common mode failure.

Conclusion The excavation and assessment of the DFO Storage Tanks was performed in a timely and safety conscious manner. The multiple requirements during excavation activities were followed properly and were well coordinated. The involvement of Quality Services was a noteworthy strength.

3.3 Replacement of CCW Heat Exchanger 1-2 Saltwater Inlet Valve (SW-1-FCV-603)

Background On February 2, 1995, the licensee determined that Valve SW-1-FCV-603 would not smoothly stroke open, and that its stroke time had increased significantly. The licensee replaced the actuator on February 9 after troubleshooting activities, when it's stroke time exceeded the acceptance criteria. QA involvement pointed out that the troubleshooting could have been more systematic.

Replacement of Valve The licensee later determined that the delay in stroke time was due to a problem in the valve rather than the actuator, since the stroke time problems recurred on March 9. The licensee performed a prompt operability assessment and concluded that the system would remain operable. This assessment was based upon the knowledge that Valve FCV-603 stroked within the specified time after it was exercised, the stroke time limit does not support any timed engineered safety features functions, and the valve was to remain in the open position except for daily exercise as a compensatory measure. The licensee replaced the valve on March 14, and the excessive stroke time appeared to be corrected. Root cause evaluation is underway.

QC Involvement QC inspectors observing the troubleshooting pointed out that systematic investigation of the problem had not been performed. QC inspectors identified that a spacer was installed in the piping downstream of the valve, which was not shown on the drawing, and initiated an AR and an operability review.

Safety Significance The valve is designed to fail open upon loss of air. The stroke time degradation was in the open direction. Therefore, the safety significance was low. The Prompt Operability Assessment appeared appropriate. The spacer found in the piping was found to not affect the operability of the system.

Conclusion The replacement of the valve was timely and addressed the degraded stroke time. The involvement of QC in recommending more systematic troubleshooting, and in questioning a configuration not reflected in design drawings was an example of excellent questioning attitude and a noteworthy strength.

3.4 Unnecessary Outage Times for Turbine Driven AFW Pumps During Maintenance

The inspector observed that, after clearing the Unit 2 turbine-driven AFW pump around 7 a.m. for replacement of a manual drain valve, the work on the pump did not start until after 1 p.m. that day. The inspector communicated to licensee management that greater than necessary safety-related equipment outage times may be continuing. The licensee concluded that the pump outage time could have been reduced and is continuing efforts to reduce overall safety equipment outage times.

Conclusion The licensee's response was prompt and appropriate to continue efforts for minimizing equipment outage times.

4 SURVEILLANCE OBSERVATIONS (61726)

Selected surveillance tests required to be performed by the TS were reviewed on a sampling basis to verify that: (1) the surveillance tests were correctly included on the facility schedule; (2) a technically adequate procedure existed for performance of the surveillance tests; (3) the surveillance tests had been performed at a frequency specified in the TS; and (4) test results satisfied acceptance criteria or were properly dispositioned.

Specifically, portions of the following surveillances were observed by the inspector during this inspection period:

Unit 1

- STP P-SIP-11 "Routine Surveillance Test of Safety Injection Pump 1-1"
- STP P-CSP-12, "Routine Surveillance Test of Containment Spray Pump 1-2"

Unit 2

- STP P-SIP-22, "Routine Surveillance Test of Safety Injection Pump 2-2"
- STP M-16N, Operation of Trains A and B Slave Relays K632 and K634
- STP V-3R6, Exercising Steam Supply to AFW Pump Turbine Isolation Valves, FCV-37 and FCV-38
- STP R-10C, Water Inventory Balance (WIB)

4.1 SI Pump 2-2 Surveillance

Background The licensee analysis of SI Pump 2-2 performance indicated that the TDH during recirculation conditions was decreasing, with significant data scatter. The licensee concluded that the pump may be degrading but considered the pump to be operable. The licensee had difficulty in discerning the decrease in pump performance from the data scatter.

Observations On March 28, the inspector observed the performance of Revision 1XPR of STP P-SIP-22, "Routine Surveillance Test of Safety Injection Pump 2-2." Members of the licensee's engineering staff, as well as the Engineering Services Manager, were involved in or observing the testing. The system engineer read the procedure, and the operator operated valves according to the engineer's instructions. The inspector noted some concerns as discussed below.

Step 12.6 of STP P-SIP-22 required that the pump recirculation flow must be established between 29 and 30 gpm as read on the installed gage. A prerequisite in this procedure requires a high accuracy gage be installed to provide additional accuracy beyond that of the installed gage. The high accuracy gage indicated a recirculation flow rate of 28.5 gpm, while the installed gage indicated 29.2 gpm. After proceeding past this point in the procedure, after the pump failed to meet the TDH required by TS, the engineer directed an operator supporting the test to adjust manual Valve SI-2-8920B to attempt to increase the recirculation flow. This valve operation was not specified at this point in the procedure, although adjustment of this valve was implied to achieve the required recirculation flow previously during the performance of Step 12.6. The operator attempted to increase flow by

throttling the valve in the closed direction, since the valve was fully open. Pump recirculation flow increased slightly, but the valve adjustment did not increase the flow to a rate above 29 gpm, as read on the high accuracy gage. The inspector noted that the manipulation of the valve at this point in the test without direction by the procedure or shift foreman approval was inappropriate.

The valve which was throttled, SI-2-8920B, was secured with a seal and was initially manipulated without breaking the seal. Later, when throttling was increased, the seal was broken. Neither the system engineer nor the operator informed the control room that a sealed valve had been manipulated. Later that morning, the inspector informed the Unit 2 Shift Foreman that the sealed valve had been operated. The licensee's administrative procedure which covers sealed valves, OP1.DC20, Revision 1, "Sealed Components," required that a sealed valve form be filled out and authorized by the Shift Foreman prior to manipulation of the valve since the procedure did not clearly indicate that a component seal was to be broken.

Safety Significance The immediate safety significance of the above concerns is low, since the pump failed the surveillance test and pump replacement activities commenced promptly after the test was concluded. However, the failure to follow the surveillance and administrative procedures is of concern.

Conclusion The failure of engineering directing the surveillance, to follow the surveillance procedure as written, and to follow administrative procedures controlling plant valve operation is a noteworthy weakness and is a violation of TS 6.8.1, which states, in part, that written procedures shall be established, implemented, and maintained covering applicable procedures recommended in Appendix A of RG 1.33, Revision 2, dated February 1978. Appendix A of RG 1.33, Revision 2, recommends procedures for surveillance testing required by TS and for administrative procedures equipment control. Contrary to these requirements, on March 28, 1995, the inspector observed that engineering and operations personnel deviated from the required actions of STP P-SIP-22, Revision 1XPR, "Routine Surveillance Test of Safety Injection Pump 2-2," and of plant administrative Procedure OP1.DC20, Revision 1, "Sealed Components." This was identified as Example 3 of a violation of TS 6.8.1 (275/9506-01).

4.2 RCS Leakage Calculation Error Not Properly Included

On March 21, 1995, the inspector observed performance of a Unit 2 WIB using a computer program that monitored reactor coolant parameters and calculated leak rate. The inspector observed the surveillance, reviewed the results, reviewed the procedure, and interviewed cognizant personnel. The inspector noted the following:

- STP R-10C, Revision 12, "Water Inventory Balance (WIB)," called for using the program for 50 minutes. The program sampled leak rate each

minute and generated an average leak rate. A leak rate was calculated using beginning and end time values only, and a leak rate was calculated based on standard deviation of the 1-minute interval data points which provided a calculated leakage with a 95 percent confidence that actual leakage was below the calculated value. If any of these numbers were at or above 1 gpm (the TS limit) the operator was directed to perform a "not less than 2, and preferably 4-hour" manual WIB. The manual calculation did not incorporate any values for process or instrument uncertainty.

- The Unit 2 leak rate performed yielded a calculated WIB of 0.09 gpm, an average of -0.065 gpm, and a 95 percent confidence WIB of 0.39 gpm.

The inspector concluded that the data scatter that resulted in a 95 percent confidence WIB greater than the calculated WIB could have been due to either instrumentation uncertainty or from lack of repeatability of the process, or a combination of both.

The inspector was concerned that no factor to account for instrument uncertainty or process error was included in the manual calculation, which would be used to calculate the WIB if the computer program WIB value was at or above the TS limit of 1 gpm unidentified leakage. This was despite the computer program results, which indicated data scatter from minute to minute, and a measurable error band with 95 percent confidence. The licensee generated AR A0366852 to evaluate this concern and assess a means to quantify the instrument uncertainty in this application.

Safety Significance The cognizant licensee engineers explained that the error was insignificant, that error values in plant procedure acceptance criteria were under a generic review by Engineering, and that past occurrences of leak rate increases had been addressed in a timely and conservative manner, up to and including plant shutdown before leakage rates exceeded TS limits.

Conclusion The inspector considered this an adequate but not proactive course of action, which met requirements and was not safety significant.

4.3 STP P-CSP-12, Revision 1, "Routine Surveillance Test of Containment Spray (CS) Pump 1-2"

On March 22, 1995, the inspector observed performance of routine inservice testing of Unit 1 CS Pump 1-2 in accordance with STP P-CSP-12, "Routine Surveillance Test of Containment Spray Pump 1-2." The inspector noted that the pump was operated for 45 minutes with reduced flow through a test line to the Refueling Water Storage Tank (RWST). The inspector noted that most of this operating time, approximately 40 minutes, was used to vent a discharge flow detector, which was required by the procedure prior to reading flow. Flow was 287 gpm both before and after the venting. The inspector noted that the pump shaft was moving horizontally back and forth from the pump approximately 1/4 of an inch, as a result of forces on the impeller caused by the low flow.

Safety Significance The inspector reviewed a letter from Westinghouse to the licensee dated October 27, 1989, which described minimum flow requirements for pump operation for the CS pumps. Minimum flow required was 146 gpm for periods up to 3 hours. The inspector considered the 45 minutes at 287 gpm was acceptable, but that wear and tear on the pump could be minimized by more efficient use of time to vent the detector.

Conclusion The inspector concluded that, overall, the inservice test had been performed adequately. The inspector did note one bearing vibration that was in the alert range. However, the licensee had also noted this and appeared to be taking appropriate action.

4.4 Failure to Restore Valves FCV-37 and -38 to Proper Position

Background Valves FCV-37 and -38 are normally open valves supplying steam to the turbine driven AFW pump. During testing they are closed to allow cycling of FCV-95, a downstream valve.

Observation After performance of Revision 11A of STP M-16N, "Operation of Trains A and B Slave Relays K632 and K634," the licensee proceeded to perform STP V-3R6, Revision 4, "Exercising Steam Supply to AFW Pump Turbine Isolation Valves, FCV-37 and FCV-38." The inspector noted that the operator using STP V-3R6 followed the step requiring opening or checking open Valve FCV-38. The operator opened the valve and, in checking the panel, also noted that FCV-37 was closed. The operator opened Valve FCV-37, returning it to it's normal position, and informed the Shift Foreman. The operator continued with the procedure.

The NRC inspector questioned why the valves had not been returned to their proper positions during STP M-16N restoration. Further review concluded that the operator performing the test incorrectly checked "N/A" (meaning that step was not applicable) for the step which restored the valves to the proper position. Use of the "N/A" for that step was limited to situations where repeated slave relay testing was expected, which was not the case in this instance.

Safety Significance Valves FCV-37 and -38 are safety system valves supplying steam to the turbine-driven AFW pump. Although the incorrect positioning was promptly identified, the error had resulted in improper restoration of a safety system.

Conclusion The failure to restore Valves FCV-37 and -38 to their normal positions after slave relay testing is a violation of TS 6.8.1, which states, in part, that written procedures shall be established, implemented, and maintained covering applicable procedures recommended in Appendix A of RG 1.33, Revision 2, dated February 1978. Appendix A of RG 1.33, Revision 2, recommends procedures for the performance of surveillance testing required by TS. Step 12.10.3 of Procedure STP M-16N required that Valves FCV-37 and -38 be restored to their normal position after testing. This step was incorrectly marked as not applicable and, as a result, Valves FCV-37 and 38 were not

restored to their normal position at the completion of the test. This was identified as Example 2 of a violation of TS 6.8.1 (275/9506-01).

5 ONSITE ENGINEERING (37551)

5.1 SI Pump Replacement Analysis

Background As discussed earlier in this report, SI Pump 2-2 had experienced performance degradation. The licensee planned to evaluate and obtain a license amendment to lower the required TS acceptance criteria for TDH or replace the SI pump and provide analyses which demonstrated that a flow balance would not be necessary, because the flow characteristics would not have changed, in compliance with the TS requirements. Both of these analyses were provided to the Office of Nuclear Reactor Regulation (NRR) for review.

5.1.1 Reduction of TS TDH from 1455 to 1430 psid

The licensee performed an analysis which evaluated a 2 percent reduction of pump performance across the entire pump curve. The resulting lower flows affected only small break loss of coolant accident analysis. The inspector identified that the dual pump interaction discussed in NRC Bulletin 88-04, "Potential Safety Related Pump Loss," had not been addressed. After analysis, the licensee determined that Bulletin 88-04 pump-to-pump interaction would not occur.

Safety Significance The licensee concluded that the TDH reduction from 1455 to 1430 psid would result in a peak centerline temperature (PCT) increase of 35°F, resulting in a PCT of 1281°F. The maximum allowable PCT is 2200°F.

Conclusion The NRC staff of NRR was in the process of evaluating this license amendment request at the time the decision was made by the licensee to replace the pump. The licensee plans to formally withdraw the amendment request.

5.1.2 Analysis of ECCS System Characteristics and Flow Balance

Flow Balance Calculation To support replacement of the SI pump, the TS requirement for assurance of balanced ECCS flow was addressed. The inspectors reviewed Calculation N-180, dated March 22, 1995. The calculation addressed the various cases of injection flow conditions, including varying RCS pressure with line break, one or two SI pumps running, and one line spilling or intact. The licensee obtained system resistances from testing performed during the last outage and applied fluid flow computer code "PEGISYS," Version 3.0, with Diablo Canyon specific ECCS model, verified and validated by Westinghouse. This model is used for calculating ECCS injection profiles as input to Westinghouse safety analyses. This determined the expected system resistances. Calculation N-180 had been verified. The inspectors asked what the instrument error and acceptable range of pump performance were. Errors of +/-0.3 psi, and pump range of +/-50 ft of TDH were assumed. This appeared reasonable.

The inspectors questioned if the flow balance testing performed each outage resulted in significant changes in injection valve positions, an indication of unstable system resistances. The licensee provided surveillance test data which indicated that system resistances had been stable throughout the life of the plant. Inspectors examined flow balance data obtained after replacement of SI Pump 2-2 in 1988 and found that valve positions changed dramatically after installation of the new pump. Successful flow balance was not possible until after installation of an orifice at the outlet of the new pump, since the replacement pump was much stronger than SI Pump 2-1. Since several unsuccessful flow balances were attempted at that time, valve positions were adjusted significantly. In most cases of flow balance, the adjustments resulted in less than 2 gpm change in flow. Some outages did not require adjustments.

Adjustment of Balance Valves The inspectors noted that the ECCS flow balance valves had been adjusted with SI Pump 2-2 as the weaker pump. In the case of the replacement pump, SI Pump 2-2 will now be the stronger pump. The most recent outage indicated that SI Pump 2-1 had line flows about 3 to 4 gpm more than SI Pump 2-2. When asked to address the difference between old and new pumps, the licensee calculations indicated significant flow margin in flow balance, including instrument error, and concluded that no significant change in the flow balance would occur, given the pump curve for the new pump.

Pump Performance Measurement The new pump, installed as SI Pump 2-2, was tested at the vendor shop, and the curve transmitted to the licensee. These pump curve values, corrected by 50 foot head for a small change in pump speed, were used in the computer code, as well as in the Calculation N-180.

Validation of the installed capacity of the pump was measured at recirculation conditions to address the TS required head of 1455 psid. The pump pressure was found to be within one psid of the predicted pump differential pressure.

Safety Significance The replacement of a SI pump is highly safety significant. The licensee concluded that substantial safety margin exists in the various safety analyses used. The replacement pump performance during recirculation was within 0.07 percent of the predicted pump performance.

Conclusion The licensee appeared to have performed the complex analyses in a meticulous manner. The inspectors did not identify any problems during the review of the analysis, and the analysis appeared valid.

5.2 Inspection and Analysis of DFO Storage Tank Pitting

Background Preparations for installation of a flexible coupling in a DFO transfer line resulted in identification of pitting on the surface of the DFO storage tanks.

5.2.1 Inspection Plan for DFO Storage Tanks

After discovery of pitting on the surface of a DFO storage tank, the licensee initiated planning to inspect a sample of the surfaces of the DFO storage tanks to determine the extent of damage, the safety significance, and the root cause of the pitting. The inspection scope included the areas around piping penetrations, all at the tops of the tanks, and a segment of the surface of the tanks not near a penetration, extending partially down the sides of the tanks in that area. Based on the findings of the inspections, the scope could be increased.

The inspectors questioned whether the inspection scope included portions of the tanks attached to structural supports, level indication piping, and electrical connections. The licensee noted that these types of attachments would be inspected since the areas were already included in the inspection plan. The inspectors asked what special precautions would be in effect with tanks exposed and if both tanks would be exposed simultaneously. The licensee stated that security, confined space entry, and basic life safety precautions would be observed.

The licensee completed the inspection plan during this inspection period and implemented repairs.

Safety Significance The inspection plan appeared thorough and flexible, and the risks of common mode failure of exposed tanks appeared to have been addressed in the need for timely assessment of tank conditions. The safety significance of exposed tanks from a seismic perspective will be addressed in the next section of this report.

Conclusion The inspection plan appeared to have been well thought out and safety and security requirements addressed. The timeliness of the inspection activity was excellent.

5.2.2 Analysis of DFO Storage Tank Pitting

After discovery of the pitting on the DFO storage tanks, engineering analysis concluded that the tanks were operable. Discovery of additional pitting as new portions of the tanks were exposed resulted in new analysis. Each analysis concluded that the tanks were operable. The inspectors reviewed portions of the operability analyses.

The licensee performed a finite element analysis for those areas in which significant pitting was identified. The inspectors asked if the analysis was valid for configurations with varying volumes of fuel in the tanks and in the state of partial excavation as well as buried. The licensee stated that the tanks had been analyzed for varying fuel levels from full to almost empty and in the partially excavated state, which was most limiting. The inspector's questions regarding several of the assumptions of the analysis were satisfactorily addressed by the licensee.

Safety Significance The analysis concluded that the tanks remained operable, although much of the seismic margin was used, and portions of the tank and pipe nozzle exceeded ASME Code allowable stresses by a small amount while the tanks were excavated. The licensee concluded that deformation in the plastic range would be limited, and the tanks would not rupture in a design basis seismic event. This appeared reasonable.

Conclusion The analysis was timely and updated promptly in light of new information. Analysis assumptions were appropriately broad and several potential configurations were adddressed.

5.3 Through-Wall Pit in DFO Storage Tank

On March 6 at approximately 11 p.m., workers excavating a portion of the DFO storage tank identified a through-wall pit with a 1/8-inch through-wall hole. The workers treated the through-wall hole as a foreign material boundary, made the excavation area a foreign material exclusion area, and taped the hole with tape qualified as foreign materials exclusion tape.

5.3.1 Operability Evaluation

Engineering analysis and operability evaluation started promptly, and was underway at 2:30 a.m. the next morning. The licensee determined that the tank was operable with compensatory measures to keep foreign material from the hole.

This inspectors reviewed the assumptions and analysis of the operability evaluation and the compensatory measures. At 7:30 a.m. on March 7, the inspector questioned the lack of consideration of potential flooding due to the potential for tank ruptures or other internal or external flooding events in the turbine building adjacent to the tank with the through-wall pit.

The licensee responded that morning with installation of sandbags around the excavation area and provided pumps and training to operations and maintenance personnel to remove liquid from the excavated area over and alongside the tank in order to maintain the liquid below the level of the hole. The inspector observed that 2 days later, on March 9 and 10, the pumps were used to maintain the water level below the hole during heavy rains.

5.3.2 Design Change to Repair the Through-Wall Pit

The licensee prepared the design change to repair the through wall pit and discussed it in the PSRC meeting on March 10. After the meeting, the inspectors questioned many aspects of the repair, such as potential for foreign material, seismic performance under design basis conditions, and other areas. The only area not adequately addressed was a failure to dedicate a commercial grade filler substance, "Belzona," used to fill the air gap under the patch support. The licensee performed the dedication, obtained PSRC approval of the design change, and installed the change on March 11.

Safety Significance The lack of commercial grade dedication of Belzona was not consequential to the adequacy of the design change repair, since it neither was exposed to the internal surface of the tank, nor provided structural support.

Conclusion The design change was well implemented and considered all but one aspect questioned by the inspectors. The lack of dedication activities was not of consequence and was corrected within 3 hours. The design change was installed in a timely fashion, a few hours after PSRC approval.

5.3.3 Root Cause of DFO Storage Tank Pitting

The licensee concluded that the cathodic protection system for the tanks had been inoperable for several years. This condition had been discovered some time ago and was determined to have not been significant. The more likely cause of the pitting was determined to have been degradation of the corrosion resistant coating around the piping penetrations on the tanks due to work activities which allowed personnel to stand on the coating while performing work.

The licensee also noted some corrosion of fasteners and concluded this was the result of inadequate corrosion resistant coating adherence or application. The licensee had previuosly initiated a task force to evaluate buried commodities throughout the site, since several cases of corrosion of underground equipment have been observed.

The licensee replaced the corrosion protection coating in all areas where the tanks and fasteners were exposed and ensured personnel did not disturb the coating after installation.

The inspectors reviewed the root cause evaluation and corrective actions and did not identify any concerns with the licensee's actions.

Conclusion The tank excavation, root cause evaluation, and corrective actions were performed in a timely and proactive manner.

6 PLANT SUPPORT ACTIVITIES (71750)

The inspectors evaluated plant support activities based on observation of work activities, review of records, and facility tours. The inspectors noted the following during these evaluations.

6.1 Emergency Planning Response to Heavy Rains and Winds, Mud Slides, and Flooding Conditions

At 6:50 p.m. (PST) on March 10, 1995, a NOUE was declared at licensee management discretion due to the inability to travel to and from the Diablo Canyon site. This condition was caused by closure of all roads leading to the

plant due to mud slides and flooding. Additionally, 42 of the 131 emergency sirens were inoperable due to the severe weather and local power outage conditions.

The storm damaged several radio repeaters and telecommunications installations. Telephone communications remained available. As many as 62 of 131 emergency sirens were inoperable during the event; however, plant pagers remained functional throughout the event.

Emergency Planning Response The EOF was manned continuously by the licensee and San Luis Obispo County after 2 a.m. on March 10 due to storms and flooding. The licensee and county officials, in cooperation with the FEMA, assessed emergency evacuation route status throughout the event and provided a continuing assessment that an evacuation of the public could have been performed if required by a plant event. The licensee notified the California State Office of Emergency Services and the media.

Emergency Planning management continued in close communication with plant management throughout the event, providing recommendations and assessments.

Conclusion The declaration of an NOUE was a proactive response to county and site conditions. The Emergency Planning activities were proactive and thorough and included continuing communication with all involved public and private organizations. Emergency Planning management remained involved in all aspects of response throughout the event.

6.2 Security Response to Mud Slides and Flooding Conditions

During the event, relief crews for security personnel were unable to reach the site. Security management implemented rest schedules to maintain security personnel alert, as well as comply with minimum manning allowed by the site security plan. Security management coordinated with site management to obtain relief crews by helicopter in the event roads could not be cleared in a timely fashion.

Inspector observations of security personnel throughout the event indicated that the personnel remained alert, observed rest times and turnover requirements, and performed in a professional and responsible manner.

Conclusion The response to mud slides and flooding conditions was well coordinated and implemented, and security crews and management performed duties in an excellent manner.

7 MAINTENANCE FOLLOWUP (92902)

7.1 (Closed) Inspection Followup Item 275/9220-05: Auxiliary Saltwater Crosstie Valves

This item involved six issues that were identified by the NRC during inspection of a corrosion problem that had developed with ASW Train Crosstie

Valve 1-FCV-496. Some of the issues were related to Nonconformance Report (NCR) DCO-91-EM-N009, which had been issued to investigate the corrosion problem. The six issues are discussed below along with licensee actions:

(1) The nonconformance report (NCR) did not address the timeliness of corrective actions. NCR DCO-91-EM-N009 failed to address the fact that licensee actions to correct the corrosion problem with Valve 1-FCV-496 were not timely. As a result, this valve had experienced repetitive problems, including remote electric failures and difficulties in manual operation. The original quality evaluation that had been issued following the initial failure on May 23, 1989, had not been aggressively pursued.

The ASW crosstie valves are safety-related as pressure boundaries, and with respect to their manual operation, but have nonsafety related motor operators. The licensee stated that the safety-related functions of the valve were not defeated by the corrosion binding problem because, in all cases, the pressure boundary was maintained and, with relubrication and considerable force, the valve was always able to be manually operated. Nevertheless, it was clear that some loss of immediate function had occurred.

The licensee revised Procedure OM7.IDE, "Quality Evaluations," to include a requirement to identify Quality Evaluations (QEs) that are delinquent by more than 30 days and to establish a new due date. As due dates are repetitively revised, a progressively higher level of management approval is needed.

The inspectors reviewed the procedure change and concluded that the licensee had taken appropriate action.

(2) The NCR did not address why Procedure OP C-9, "Control of Safety-Related Equipment Not Required By Technical Specifications," was not implemented for the failure of Valve 1-FCV-496.

The licensee stated that Procedure OP C-9 (which has since been superseded by Procedure OP1.DC16, "Control of Plant Equipment Not Required by the Technical Specifications," Revision 1A) was used for equipment in service, not when maintenance discovers a problem with cleared equipment, as in this case. Consequently, approved WOs and maintenance procedures are used in lieu of the operations procedure to control any safety impact.

The inspectors accepted the licensee's position.

(3) The ASW pump room floor drains are small, which may affect the flooding evaluation for the ASW pump vaults. One of the drains is blocked by a leakoff hose.

The licensee stated that Calculation M-270, "Auxiliary Saltwater Pump Vault Drain System," Revision 2, adequately accounted for the as-found drain configuration. This calculation originally predicted that the ASW pump motor would become submerged and subsequently inoperable following a pipe crack in the ASW discharge piping inside the pump vault, but a later revision (Revision 3) removed conservatisms and incorporated drainline modifications in the calculation and concluded that the motor would remain dry.

The inspectors toured the ASW pump vaults and reviewed Calculation M-270. The inspector concluded that the drain configuration was consistent with the assumptions in Calculation M-270, but also noted that the calculation predicted a drain capacity of 500 gallons per minute into a sump tank that had two sump pumps each rated at only 50 gallons per minute. The calculation did not address the limited capacity of the sump pumps. The inspectors questioned the licensee whether the drain rate assumption in the calculation would be affected by the apparently inevitable overflow of the sump tank during a moderal energy line break (MELB). The licensee indicated that additional review would be necessary to determine whether the conclusions of Calculation M-270, Revision 3, would be affected by the increased backpressure that would be exerted on the drain line from a flooded sump. The inspectors were also concerned, from a quality perspective, that the calculation did not address what may have been an important element in the analysis. This item will be reviewed further during a future inspection and will be tracked as an inspection followup item (IFI 275/9506-02).

(4) The ASW design criteria memorandum (DCM) did not discuss design for a MELB.

The inspectors reviewed DCM T-12, "Pipe Break (HELB/MELB), Flooding, and Missiles," Revision 1, and DCM S-17B, "Auxiliary Saltwater System," Revision 2, and verified that these documents contained an evaluation of the ASW pump compartment flooding associated with an MELB.

(5) The crosstie valves, being not seismically qualified, may stroke to a nonconservative position during a seismic event.

The licensee clarified that the ASW crosstie valve operators are seismically qualified. The inspectors verified that the equipment database was consistent with this position.

(6) Could the ASW crosstie valves or other safety-related valves with nonsafety-related valve operators malfunction due to improper switch settings in a way such that the pressure boundary would be breached?

The inspectors concurred with the licensee's position that the four valves per unit in this category were set such that a pressure boundary breach caused by this mechanism was not credible.

7.2 (Closed) Enforcement Item 323/9217-03: Failure to Check Containment Fan Cooler Unit Damper Counterweights

During February 1992, inspections of the freedom of motion of the backdraft damper counterweights on containment fan cooler unit Backdraft Dampers 2-2 and 2-4 backdraft dampers, as prescribed by Work Order (WO) C0096321, were not performed properly. Subsequent inspections revealed that the counterweights on these backdraft dampers were overtightened.

The licensee stated that the workers who performed this work used knowledge of previous inspections and did not actually perform a complete inspection, in that not all of the backdraft damper counterweights were inspected. The workers were counseled regarding verbatim compliance with work orders. Additional training was provided to engineers, supervisors, and plant operators in evaluating degraded plant conditions. The licensee corrective actions appeared to have been appropriate.

7.3 (Closed) Inspection Followup Item 275/9322-02: Improper Torquing of Operator Bolts

In response to industry information concerning the failure of power-operated relief valves (PORVs) due to improper actuator installation, the licensee obtained information from the vendor, including actuator bolt torque. Previous torquing of these bolts was accomplished using a turn-of-the-nut method. The licensee desired and received a more precise torquing specification. However, the vendor had changed bolting material since the PORVs were installed at Diablo Canyon. The new bolting material was of higher strength and, therefore, the torque specification provided by the vendor was too high for the bolt material used at Diablo Canyon. As a result, several of the PORV actuator bolts were overtorqued, theoretically beyond yield strength. However, subsequent testing and analysis indicated that the bolts were not made inoperable by the torque levels applied. The additional concern was that the erroneous torque values were used in the field before the vendor information had been completely reviewed. An initial evaluation by maintenance engineering of the adequacy of the vendor-supplied torque valves did not identify the potential for an overtorque condition. However, a later review by design engineering identified the overtorque concern. The concern was that the design engineering review was not completed prior to use of the vendor information.

In QE Q0010795, the licensee stated that the maintenance engineering review was the review of record with regard to clearing the vendor information for use in work instructions. The design engineering review was in response to a field change transmittal, which is only a vehicle to incorporate new or revised information into drawings or vendor manuals. However, in discussions with the inspectors, the licensee stated that future receipts of vendor information will receive a more complete design review before being used. As a result of these discussions, the licensee realized that current procedural guidance in this area was confusing and issued AR A0367362 to clarify procedures that control the processing of vendor information.

The inspectors concluded that, although the original concern expressed by this item was not an actual problem as defined by the licensee's program, the licensee had nevertheless taken proactive steps to provide additional assurances against the use of erroneous vendor information.

8 FOLLOWUP ENGINEERING (92903)

8.1 (Closed) Unresolved Item 275/8802-01: RG 1.97 Open Issues

In February 1988, the NRC identified three areas where Diablo Canyon had deviated from the recommendations of RG 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," Revision 3. The areas were:

(1) The use of resistor networks as isolation devices

(2) The lack of power supply redundancy for steam generator (SG) wide-range instrumentation

(3) The lack of a recording device for neutron flux monitoring

Numerous telephone conversations and meetings were conducted between the plant and the NRC's NRR in an effort to reach an agreement regarding actions that should be accomplished. In letters dated May 27, 1989, October 25, 1991, February 7, 1992, December 17, 1993, and December 27, 1993, the licensee provided additional information and proposed plant modifications addressing the three areas of concern. The licensee and NRR came to resolution on all issues. The unresolved item was left open pending completion of the licensee's committed actions. During this inspection, the inspectors verified that the licensee had completed these actions, as discussed below.

Concerning issue (1) above, the inspectors in 1988 had identified that the RCS pressure information was transmitted to the emergency response facility display system and the plant computer through resistor networks. Similar resistor networks existed between the Category 1 and non-Category 1 portions of the SG wide-range level and RCS cold leg temperature channels. The NRR determined that resistor networks were not acceptable isolation devices unless satisfactory testing could demonstrate this function. The licensee committed to replace the resistor networks with appropriate isolation devices in the affected RG 1.97 circuits.

In AR A0258234-01, the licensee documented the replacement of the resistor isolation devices. During the sixth refueling outages on both units, some of the HAGAN process control racks were replaced with the EAGLE 21 protection system upgrade racks. The new racks included acceptable electrical isolation devices. For those circuits not affected by the upgrade, the licensee implemented Design Change Notices 1-EJ-47400 and 2-EJ-48400 during the fifth refueling outages. These changes replaced the resistor-type isolation devices with transformer-type devices. The inspectors discussed this information with the licensee and reviewed supporting plant documentation and the referenced

design changes. As a result of this review, the inspectors concluded that the licensee had satisfactorily completed actions to address issue (1).

Concerning issue (2) above, the inspectors in 1988 had identified that the wide-range SG level instrumentation circuit did not meet the redundancy criteria for Category 1 instrumentation as recommended by RG 1.97. The licensee used a single Class 1E power source for all wide-range SG level instrumentation. The licensee committed to install a separate Class 1E power supply for two of the four wide-range SG level loops.

In AR A0258234-02, the licensee documented completion of Design Change Packages (DCPs) E-47460 and E-48690, for Units 1 and 2, respectively. These changes caused two of the SG wide range loops to be powered from a separate vital instrument AC power source. Based on discussions with the licensee and review of the listed DCPs, the inspectors concluded that the licensee had satisfactorily addressed issue (2).

Concerning issue (3) above, the inspectors in 1988 had identified that, contrary to RG 1.97 guidance, no device had been installed to record at least one channel of neutron flux monitoring instrumentation. The licensee committed to install a neutron flux recorder in the control room.

In AR A0258234, the licensee documented the completion of DCPs E-47689 and E-48689. which added neutron flux recorders to control room Panel PAMI in Units 1 and 2, respectively. Based on review of these DCPs, the inspectors concluded that the licensee had satisfactorily addressed issue (3).

9 IN OFFICE REVIEW OF LERs (90712)

The inspectors performed a review of the following LERs associated with operating events. Based on the information provided in the report, review of associated documents, and interviews with cognizant licensee personnel, the inspectors concluded that the licensee had met the reporting requirements, addressed root causes, and taken appropriate corrective actions. The following LERs are closed:

- 275/94-012, Revision 1, Containment Airlock Electrical Circuit Backup Over-Current Protection Outside of Design Basis Due to Personnel Error

- 275/95-001, Revision 0, Engineering Safety Features Actuation System Outside design Basis due to High Energy Break Interaction with Solid State Protection System Circuits

- 323/94-003, Revision 1, Auxiliary Building Outside Design Basis Due to Previous Nonconservative Americal Society for Testing and Materials Testing

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Licensee Personnel

*G. M. Rueger, Senior Vice President and General Manager, Nuclear Power Generation Business Unit
*W. H. Fujimoto, Vice President and Plant Manager, Diablo Canyon Operations
*L. F. Womack, Vice President, Nuclear Technical Services
*M. J. Angus, Manager, Regulatory and Design Services
*J. R. Becker, Director, Operations
*K. J. Condron, Engineer, Nuclear Safety Engineering, Reliability Engineering
W. G. Crockett, Manager, Engineering Services
*R. N. Curb, Manager, Outage Services
*R. D. Glynn, Senior Engineer, Quality Assurance
*T. L. Grebel, Supervisor, NRC Regulatory Support
*C. R. Groff, Director, Engineering Services
C. D. Harbor, Engineer, Regulatory Support
K. A. Hubbard, Engineer, Regulatory Support
*D. B. Miklush, Manager, Operations Services
*J. E. Molden, Manager, Maintenance Services
*P. T. Nugent, Engineer, Regulatory Support
D. H. Oatley, Director, Mechanical Maintenance
*L. M. Parker, Engineer, Independent Safety Engineering
*B. H. Patton, Sr. Power Production Engineer, System Engineering
H. J. Phillips, Director, Technical Maintenance
*R. P. Powers, Manager, Nuclear Quality Services
J. A. Shoulders, Director, Engineering Services
*D. A. Taggart, Director, Nuclear Safety Engineering
*R. L. Thierry, Supervisor Engineer, Nuclear Safety Assessment
*D. A. Vosburg, Director, NSSS Systems Engineering
*R. A. Waltos, Director, Engineering Services
*J. C. Young, Director, Nuclear Quality Services

1.2 NRC Personnel

*M. D. Tschiltz, Senior Resident Inspector
*M. H. Miller, Senior Resident Inspector, Cooper
J. R. Russell, Resident Inspector, San Onofre
M. F. Runyan, Reactor Inspector

*Denotes those attending the exit meeting on March 30, 1995.

In addition to the personnel listed above, the inspectors contacted other personnel during this inspection period.

2 EXIT MEETING

An exit meeting was conducted on March 30, 1995. During this meeting, the Resident Inspectors reviewed the scope and findings of the report. The

licensee acknowledged the inspection findings documented in this report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.

ATTACHMENT 2

ACRONYMS

AFW	auxiliary feedwater
AR	action request
ASME	American Society of Mechanical Engineers
ASW	auxiliary feedwater
CCW	component cooling water
CS	containment spray
DCM	design criteria memorandum
DCP	design change package
DFO	diesel fuel oil
ECCS	emergency core cooling system
EDG	emergency diesel generator
EOF	emergency operations facility
FCV	flow control valve
FEMA	Federal Emergency Management Agency
LER	licensee event report
MELB	moderate energy line break
NCR	noncomformance report
NOUE	notice of unusual event
NRR	Nuclear Reactor Regulation
OP	operations procedure
PAM	postaccident monitoring
PCT	peak centerline temperature
PORV	power operated relief valve
PSRC	plant staff review committee
QC	Quality Control
QE	Quality Evaluation
RG	Regulatory Guide
RCS	reactor coolant system
SI	safety injection
SG	steam generator
STP	surveillance test procedure
TDH	total developed head
TS	technical specification
WIB	water inventory balance
WO	work order