UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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May 13, 2005

Gregory M. Rueger, Senior Vice
President, Generation and Chief Nuclear Officer
Pacific Gas and Electric Company
Diablo Canyon Power Plant
P.O. Box 3
Avila Beach, California 93424

SUBJECT: DIABLO CANYON POWER PLANT - NRC INTEGRATED INSPECTION REPORT 05000275/2005002 AND 05000323/2005002

Dear Mr. Rueger:

On March 31, 2005, the U.S. Nuclear Regulatory Commission completed an inspection at your Diablo Canyon Power Plant, Units 1 and 2, facility. The enclosed integrated report documents the inspection findings that were discussed on April 15, 2005, with Mr. James R. Becker and other members of your staff.

This inspection examined activities conducted under your licenses as they relate to safety and compliance with the Commission's rules and regulations, and with the conditions of your licenses. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

There were two NRC-identified findings and two self-revealing findings of very low safety significance (Green) identified in this report. The two NRC identified findings and one self-revealing finding involved violations of NRC requirements. However, because of their very low risk significance and because they are entered into your corrective action program, the NRC is treating these three findings as noncited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Diablo Canyon Power Plant.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

William B. Jones, Chief
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Division of Reactor Projects

Dockets: 50-275
50-323
Licenses: DPR-80
DPR-82

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Inspection Report 05000275/2005002
and 05000323/2005002
w/attachment: Supplemental Information

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Dockets:	50-275, 50-323
Licenses:	DPR-80, DPR-82
Report:	05000275/2005002 05000323/2005002
Licensee:	Pacific Gas and Electric Company (PG&E)
Facility:	Diablo Canyon Power Plant, Units 1 and 2
Location:	7 ½ miles NW of Avila Beach Avila Beach, California
Dates:	January 1 through March 31, 2005
Inspectors:	D. L. Proulx, Senior Resident Inspector T. W. Jackson, Senior Resident Inspector T. A. McConnell, Resident Inspector V. G. Gaddy, Senior Project Engineer D. R. Carter, Health Physicist
Approved By:	W. B. Jones, Chief, Projects Branch E Division of Reactor Projects

CONTENTS

SUMMARY OF FINDINGS

IR 05000275/2005-002, 05000323/2005-002; 01/01/05 - 03/31/05; Diablo Canyon Power Plant Units 1 and 2; Equipment Alignments, Fire Protection, Personnel Performance Related to Non-routine Plant Evolutions and Events, and Other.

This report covered a 13-week period of inspection by resident inspectors and an announced inspection in radiation protection. A self-revealing Green finding, a self-revealing Green noncited violation and two NRC identified Green noncited violations were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609 "Significance Determination Process." Findings for which the Significance Determination Process does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A self-revealing finding was identified for operators failing to follow Procedure OP J-4A:IV, "Generator Stator Cooling Water-Heat Exchanger Removal from and Return to Service," Revision 5, for isolation of flow to the Unit 1 stator cooling water-heat exchangers by operating isolation valves out of sequence. This finding resulted in an unplanned transient involving a main generator runback from 50 to 15 percent power and has human performance crosscutting aspects for failing to follow the procedure when removing the stator cooling water-heat exchanger from service.

  The failure to follow Procedure OP J-4A:IV affects the initiating events cornerstone and is more than minor because it resulted in an actual impact to the facility (unplanned rapid power reduction) that upset plant stability. This finding screened as very low safety significance (Green) because no loss of safety functions or other adverse impacts to the facility occurred (Section 1R14.1).

Cornerstone: Mitigating Systems

- Green. The inspectors identified a noncited violation of Technical Specification 5.4.1.d for failure to implement procedures for Fire Protection Implementation, because of failure to provide adequate training for operations fire responders. Procedure OM8, "Fire Protection Program," Revision 2B, Section 7.8 states, in part, that quality problems associated with the Fire Protection Program shall be documented and resolved in accordance with Procedure OM7 "Corrective Action," Revision 2B. Section 9.5.1 of the Final Safety Analysis Report states that measures are established to ensure conditions adverse to fire protection are identified, reported and corrected, and that administrative procedures are established to implement this requirement. Specifically, Pacific Gas & Electric Company failed to adequately resolve a condition adverse to fire protection in accordance with Procedure OM7. As of March 1, 2005, operations responders were not required to participate in fire drills for initial qualification or maintenance of qualification, as was noted as a qualification deficiency in Noncited Violation 50-275;323/2003-08-01, and Action Request A0600934. This finding has problem identification and resolution crosscutting aspects for failure to correct operations responder training deficiencies.

The performance deficiency associated with this finding is a failure to adequately implement the fire protection program with respect to the qualifications of the fire brigade operations responder. The finding impacted the mitigating systems cornerstone and was more than minor since there was an adverse impact to a fire protection defense-in-depth element. This finding is greater than minor because the reactor safety mitigating systems cornerstone objective attribute to provide protection against external factors was affected. Manual Chapter 0609, Appendix F, "Fire Protection Significance Determination Process," does not address fire brigade performance deficiencies. Regional management review concluded this finding was of very low safety significance because it affected the fire prevention and administrative controls category and represented a training deficiency (Section 1R05.2).

- Green. The inspectors identified a noncited violation for the failure to promptly correct a cracked lube oil instrument sensing line, as required by 10 CFR Part 50, Appendix B, Criterion XVI. On August 29, 2004, operators observed a lube oil leak from the weld connecting the outlet of Valve DEG-2-1084 to instrument tubing. Approximately one month later, the leak had increased and it was discovered that the circumferential crack was 180 degrees through-wall on the weld. As a result, there was an increased potential for diesel engine generator 2-3 to trip on low lube oil level. The finding had problem identification and resolution crosscutting aspects associated with operations and engineering personnel not recognizing the significance of the degraded condition and not implementing timely corrective actions.

  This finding impacted the Mitigating Systems Cornerstone for reliability of systems that respond to initiating events to prevent undesirable consequences, and it affects the equipment performance attribute. The finding was more than minor using Example 4.f of Inspection Manual Chapter 0612, Appendix E. Similar to Example 4.f, the inspectors determined that there was impact to DEG 2-3 operability. Using the SDP Phase 1 screening worksheets in Appendix A of Inspection Manual Chapter 0609, the finding was determined to have potentially greater than very low safety significance because the failure could have resulted in an actual loss of diesel engine Generator 2-3 during a loss of offsite power event. An NRC Senior Reactor Analyst performed a Phase 3 significance determination and the estimated conditional core damage frequency was 1.2E-7/yr. This violation was of very low safety significance (Section 4OA5.1).

Cornerstone: Barrier Integrity

- Green. Two examples of a self-revealing violation of Technical Specification 5.4.1.a were identified for failure to adequately plan maintenance associated with the Control

Room Ventilation System. On January 4, 2005, and February 1, 2005, both trains of the Control Room Ventilation System were inadvertently rendered inoperable for short periods of time when the system boundary was opened for maintenance. In each case the maintenance activity was not appropriately planned to ensure the administrative controls prescribed by Technical Specification 3.7.10 were met and/or the appropriate components were identified. Human performance crosscutting aspects were identified for the inadequate planning and communications involving the work activities on the Control Room Ventilation System.

This issue is more than minor because the issue affects the Barrier Integrity Cornerstone and represented a partial losses of function of the Control Room Ventilation System for both train boundaries being open. This issue was evaluated utilizing Inspection Manual Chapter 0609, Significance Determination Process, Appendix A, Item 1 for the Containment Barriers Cornerstone. The Phase 1 review identified that the finding only represents a degradation of the radiological barrier function for the control room and was therefore of very low safety significance (Section 1R04.2).

B. Licensee-Identified Violations

Violations of very low significance were identified by Pacific Gas & Electric Company and have been reviewed by the inspectors. Corrective actions taken or planned by Pacific Gas & Electric Company appear reasonable. The violations are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Diablo Canyon Unit 1 began this inspection period at 100 percent power. On January 5, 2005, Unit 1 was curtailed to 51 percent power to support main condenser cleaning. Following completion of this evolution, Unit 1 was returned to 100 percent power on January 7, 2005. On February 7, 2005, Unit 1 was curtailed to 51 percent power to support circulating water system tunnel cleaning. On February 8, 2005, Unit 1 experienced a turbine runback to 15 percent power because of a low flow condition in the stator cooling water system. After the condition was corrected, Unit 1 was returned to 51 percent power. Following completion of the circulating water system tunnel cleaning evolution, Unit 1 was returned to 100 percent power on February 11, 2005. Unit 1 remained at 100 percent power for the duration of the inspection period.

Diablo Canyon Unit 2 began this inspection period at 100 percent power. On January 8, 2005, Unit 2 was curtailed to 84 percent power for main turbine valve testing. Following completion of the testing, Unit 2 was returned to 100 percent power on January 8, 2005. Unit 2 remained at 100 percent power for the duration of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignments (71111.04)

The inspectors performed one partial and one complete system walkdown during this inspection period.

Partial System Walkdown

.1 Unit 1 Auxiliary Feedwater (AFW) Pump 1-1

a. Inspection Scope

The inspectors performed a partial system walkdown of Unit 1 AFW Pump 1-1. The inspectors observed valve alignment, the availability of electrical power and cooling water, labeling, lubrication, ventilation, structural support, and material condition. The inspectors used Drawing 106703, “Feedwater,” Sheet 3, Revision 61, and Procedure OP D-1:I, “Auxiliary Feedwater System - Make Available,” Revision 25, during the inspection.

b. Findings

No findings of significance were identified.

Complete System Walkdown

.2 Units 1 and 2 Control Room Ventilation System (CRVS)

a. Inspection Scope

The inspectors performed a complete system walkdown of the control room ventilation system to verify that the system was aligned, operated and maintained in accordance with NRC requirements.

During this inspection period Pacific Gas and Electric Company (PG&E) performed maintenance on the CRVS. The inspectors reviewed PG&E's response to the two occasions in which both trains of the CRVS were inadvertently rendered inoperable. The maintenance was performed utilizing Action Requests (ARs) A0629238 and A0631325.

b. Findings

Introduction. A self-revealing violation of Technical Specification 5.4.1.a was identified for inadequate maintenance planning which resulted in both CRVS trains being rendered inoperable without compensatory measures for restoration of a train of CRVS being established. The Technical Specifications permit both trains of CRVS to be inoperable for up to 24 hours provided compensatory measures are established.

Description. On January 4, 2005, and again on February 1 both trains of CRVS were rendered inoperable because of inadequate maintenance planning that opened the boundaries of both trains without compensatory measures being established. Technical Specifications 3.7.10 states that the control room boundary may be opened intermittently under administrative controls, and that if both trains of CRVS are inoperable because of the control room boundary being open, then the system must be restored to operable within 24 hours. Technical Specification Bases 3.7.10 states that the proper administrative controls to invoke this aspect of the Technical Specification consists of stationing a dedicated individual who is in continuous communication with the control room, who has a method of rapidly closing the control room boundary, and has been specifically trained on these duties.

On January 4, 2005, work began on the Unit 1 CRVS. This maintenance outage was scheduled to work on several dampers and other planned maintenance on one train of the Unit 1 CRVS. Maintenance personnel required that Damper VAC-1-MOD-1C be opened to perform inspections, and that the associated conduit be opened to inspect the seat. This required removal of a blind flange (spectacle flange) to support the work and opened the CRVS boundaries. The maintenance activity was not adequately planned and communicated to the operators which resulted in the failure to identify that both CRVS train boundaries would be open.

Following completion of the work, the shift manager noted that the sequence of the work opened the CRVS boundaries. Maintenance personnel stated that this condition existed for approximately 15 minutes. The shift manager entered this occurrence into the corrective action program as AR A0629238. The inspectors noted that the failure to appropriately plan the work activity to identify and establish the required work controls to restore the CRVS, if needed, while both trains boundaries were open was a violation of Technical Specification 5.4.1.a.

Subsequently, on February 1, 2005, maintenance personnel identified the incorrect motor operated damper for maintenance. Maintenance personnel identified that Damper VAC-1-MOD-1A was stuck in the partially opened condition. However AR A0631129 was generated to work on Damper VAC-1-MOD-1. Because the wrong damper was communicated to the control room operators, the clearance included Damper VAC-1-MOD-1A. Operators then approved the clearance to work on Damper VAC-1-MOD-1, using Damper VAC-1-MOD-1A as the boundary. When maintenance personnel began work on Damper VAC-1-MOD-1A and opened the CRVS to inspect and repair this damper, both trains of CRVS were rendered inoperable. This resulted in a second occurrence where both trains of the CRVS were rendered inoperable without having identified and established compensatory measures. PG&E initiated AR A0631325 to enter this item into the corrective action program.

In each case the CRVS boundary could have closed to returned the system to service in a prompt manner if required. Human performance crosscutting aspects were identified for the inadequate planning and communications involving the work activities on the CRVS.

<u>Analysis</u>. This issue is more than minor and affects the Barrier Integrity Cornerstone, because it represents partial losses of function of the CRVS. On January 4, 2005, (for 15 minutes) and February 1 (four hours) both trains of CRVS were rendered inoperable because of an opening in the CRVS boundary which would have prevented pressurization of the control room. This issue was evaluated utilizing Inspection Manual Chapter 0609, Significance Determination Process, Appendix A, Item 1 for Containment Barriers Cornerstone. Specifically, the Phase 1 review identified that the finding only represents a degradation of the radiological barrier function for the control room and was therefore of very low safety significance (Green).

<u>Enforcement</u> Technical Specification 5.4.1.a states, in part, that procedures shall be established, implemented and maintained for the items listed in Regulatory Guide 1.33, Appendix A, Revision 2. Section 9.a. states, in part, that maintenance that can affect the performance of safety-related equipment shall be properly pre-planned and performed in accordance with written procedures appropriate to the circumstances. Contrary to the above, on January 4, 2005, and February 1 maintenance activities associated with the CRVS system were not appropriate to the circumstances to ensure the requirements associated with Technical Specification 3.7.10 were met and/or the scope of the work activity was identified. Because these two examples of failure to

properly pre-plan and perform maintenance on the CRVS were of very low safety significance, and have been entered into the corrective action system as ARs A0629238 and A0631325, these two examples of a violation are being treated as an noncited violations (NCV), consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-275;323/05-02-01, Failure to Adequately Plan CRVS Maintenance that Involved Opening the Control Room Boundary.

1R05 Fire Protection (71111.05)

The inspectors performed ten fire protection walkdowns during this inspection period.

.1 Routine Observations

a. Inspection Scope

The inspectors performed ten fire protection walkdowns to assess the material condition of plant fire detection and suppression, fire seal operability, and proper control of transient combustibles. The inspectors used Section 9.5 of the Final Safety Analysis Report (FSAR) Update as guidance. The inspectors considered whether the suppression equipment and fire doors complied with regulatory requirements and conditions specified in Procedures STP M-69A, “Monthly Fire Extinguisher Inspection,” Revision 34, STP M-69B, “Monthly CO2 Hose Reel and Deluge Valve Inspection,” Revision 1, STP M-70C, “Inspection/Maintenance of Doors,” Revision 9, and OM8.ID4, “Control of Flammable and Combustible Materials,” Revision 12. Specific risk-significant areas inspected included:

- Units 1 and 2, Diesel Engine Generator Rooms of the Turbine Building
- Units 1 and 2, Emergency Core Cooling Pump Rooms of the Auxiliary Building
- Units 1 and 2, Auxiliary Saltwater Pump Vaults of the Intake Structure
- Units 1 and 2, DC Switchgear/Battery Rooms of the Auxiliary Building
- Units 1 and 2, 4 kV Switchgear Rooms of the Turbine Building

b. Findings

No findings of significance were identified.

.2 Operations Responder Qualifications

a. Inspection Scope

The inspectors reviewed the corrective actions identified for operations responders which were taken stemming from noncited Violation 50-275; 323/03-08-01. This issue involved failure to establish, implement, and maintain procedures for fire protection, a violation of Technical Specification 5.4.1.d. Specifically, PG&E implemented a change to Procedure CP-6, "Fire," Revision 2, that provided for non-licensed operators to be operations responders in a fire, without qualifications appropriate to the circumstances.

The non-licensed operators were provided with a two-hour classroom training session, that omitted several important aspects of the operations responder responsibilities. The inspectors reviewed corrective actions related to the issue identified in NCV 50-275; 323/03-08-01, to determine if the issues were adequately addressed through the corrective action process (AR A0597355).

b. Findings

Introduction. The inspectors identified a violation of Technical Specification 5.4.1.d for failure to implement procedures for Fire Protection Implementation involving a failure to provide adequate training for operations fire responders. Procedure OM8, "Fire Protection Program," Revision 2B, Section 7.8 states, in part, that quality problems associated with the Fire Protection Program shall be documented and resolved in accordance with Procedure OM7 "Corrective Action," Revision 2B. Section 9.5.1 of the Final Safety Analysis Report states that measures are established to ensure conditions adverse to fire protection are identified, reported and corrected, and that administrative procedures are established to implement this requirement. Contrary to the above, PG&E did not adequately implement and maintain a procedure for fire protection. Specifically, PG&E failed to adequately resolve a condition adverse to fire protection in accordance with Procedure OM7. As of March 1, 2005, operations responders were not required to participate in fire drills for initial qualification or to maintain their qualification. This issue was noted as a qualification deficiency associated with NCV 50-275;323/2003-08-01, and AR A0600934.

Description. Per License Condition 2.C.5.b to License Nos. DPR-80 and DPR-82 (Diablo Canyon Power Plant), PG&E may make changes to the approved fire protection program, without prior approval of the NRC, only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire. Prior to 1998, the fire brigade leader was a senior control operator and the fire brigade members were licensed and non-licensed operators. The senior control operator possessed knowledge of fire protection systems, safe shutdown equipment, and other plant equipment, and also acted as a liaison to the control room. Following the change to a professional fire brigade in 1998, senior control operators were assigned to be the operations responder to a fire event. In this position, they primarily acted as a liaison between the control room and the fire brigade and provided limited recommendations for protecting safe shutdown equipment.

On August 29, 2003, PG&E instituted an additional change to the operations responder position. In addition to using the senior control operators, licensed control operators and non-licensed, Level 8 nuclear operators could be used as operations responders. A two-hour training session was provided to nuclear operators on the duties of an operations responder, prior to August 29, 2003. The training session was outlined in Lesson Number R032C12, “Operations Responder Responsibilities.” Procedure CP - 6, “Fire,” Revision 2, included a checklist for the operations responder duties in Attachment 4.2, “Operations Responder Checklist”. This training did not include participation in a fire drill for qualification.

The inspectors interviewed various control operators and nuclear operators and identified that "the control operators and nuclear operators had not participated in drills with the fire brigades and identified a lack of interaction with the brigades." In addition to interviews, the inspectors compared Attachment 4.2 of Procedure CP - 6, “Fire,” Revision 26, to Lesson Number R032C12, “Operations Responder Responsibilities.” The inspectors noted that a number of important items were omitted from the lesson plan as well.

Section 9.5 of the FSAR Update outlines PG&E’s compliance with NRC Branch Technical Position APCSB 9.5-1. Table B-1, of Appendix 9.5B, “Regulatory Compliance Summary,” states, in part, the following aspects of Branch Technical Position APCSB 9.5-1 which PG&E is committed to comply with:

a. Personnel

> “...the FSAR should discuss the training and the updating provisions such as fire drills provided for maintaining the competence of the station fire fighting and operating crew,...

C Fire Brigade Organization, Training, and Equipment

> “Basic training is a necessary element in effective fire fighting operation. In order for a fire brigade to operate effectively, it must operate as a team. All members must know what their individual duties are.”

The inspectors observed that PG&E did not consider the operations responder as part of the fire brigade, and therefore, they provided little or no training to the operations responders. Prior to the implementation of the professional fire brigade in 1998, the operations responder duties were performed by the fire team leader who was a senior control operator. When PG&E implemented the professional fire brigade, the operational knowledge was separated out from the fire brigade and given to the operations responder. Therefore, without the presence of a competent operations responder, the fire brigade’s capability would be adversely impacted following the 1998 fire brigade change. Since senior control operators had performed the function of the fire brigade leader prior to the professional fire brigade implementation, the senior control operators indicated they were comfortable with filling the operations responder position. However,
operators who had no prior experience on the fire brigade indicated they were not comfortable with performing the operations responder duties. This conclusion had not been acted upon with respect to participation in drills, and indicates that this violation was not corrected.

AR A0600934 was written on February 19, 2004, and noted that operations responders were not required to participate in site fire drills. The corrective actions for this AR stated that operations responders would participate in future drills, but did not include a tracking mechanism as to which operations responder participated in drills or that participation in drills was necessary for an operations responder's initial or maintenance of qualifications. Action Request A0600934 was closed out on July 29, 2004, with no further action. The inspectors noted that PG&E designated approximately 100 individuals as operations responders. In conducting quarterly fire drills, it would take several years for all of the designated operations responders to have experienced a fire drill on a routine basis. As of March 1, 2005, PG&E had no tracking mechanism to ensure operations responders were participating in drills or had drill experience as part of the initial qualifications. As of March 1, 2005, approximately 90 percent of the non-licensed operations responders had no drill experience. The inspectors concluded that PG&E took inadequate corrective action related to the issues identified as apart of NCV 50-275;323/2003-08-01, AR A0600934, and failed to adequately implement Procedure OM8.

Analysis. The performance deficiency associated with this finding is a failure to adequately implement the fire protection program with respect to the qualifications of the fire brigade operations responder. The finding impacted the mitigating systems cornerstone and was more than minor since there was an adverse impact to a fire protection defense-in-depth element. This finding is greater than minor because the reactor safety mitigating systems cornerstone objective attribute to provide protection against external factors was affected. Manual Chapter 0609, Appendix F, "Fire Protection Significance Determination Process," does not address fire brigade performance deficiencies. Regional management review concluded this finding was of very low safety significance because it affected the fire prevention and administrative controls category and represented a training deficiency.

Enforcement. The inspectors identified a violation of Technical Specification 5.4.1.d for failure to implement procedures for Fire Protection Implementation, because of a failure to provide adequate training for operations fire responders. Procedure OM8, "Fire Protection Program," Revision 2B, Section 7.8 states, in part, that quality problems associated with the Fire Protection Program shall be documented and resolved in accordance with Procedure OM7 "Corrective Action," Revision 2B. Section 9.5.1 of the Final Safety Analysis Report states that measures are established to ensure conditions adverse to fire protection are identified, reported and corrected, and that administrative procedures are established to implement this requirement. Contrary to the above, PG&E did not adequately implement and maintain a procedure for fire protection. Specifically, PG&E failed to adequately resolve a condition adverse to fire protection in accordance with Procedure OM7. As of March 1, 2005, operations responders were not required to participate in fire drills for initial qualification or maintenance of qualification, as was noted as a qualification deficiency associated with NCV 50-275;323/2003-08-01, and AR A0600934. Because the failure to correct a condition adverse to fire protection was determined to be of very low safety significance, and has been entered into the corrective action program as AR A0633376, this violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-275; 323/05-02-02, Failure to Correct Fire Program Violation Concerning Qualifications of Operations Responders in Support of the Fire Brigade.

1R06 Flood Protection Measures (71111.06)

.1 Internal Flood Protection

a. Inspection Scope

The inspectors reviewed PG&E's flood protection measures for Unit 1 to ensure that adequate precautions had been taken to mitigate internal flood risks. In particular, the inspectors reviewed the Unit 1 component cooling water-heat exchanger room.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

On January 11, 2005, the inspectors witnessed one operator requalification examination in the simulator. The scenario involved a steam generator tube rupture coupled with a main steam line break. The inspectors verified the crew's ability to meet the objectives of the training scenario, and attended the post-scenario critique to verify that crew weaknesses were identified and corrected by PG&E staff.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors performed two inspections of PG&E's Maintenance Rule implementation for equipment performance problems. The inspectors assessed whether the equipment was properly placed into the scope of the rule, whether the failures were properly characterized, and whether goal setting was recommended, if required.
Procedure MA1.ID17, "Maintenance Rule Monitoring Program," Revision 13, was used as guidance. The inspectors reviewed the following Action Requests.

- AR A0629702, "Maintenance Rule Performance Criteria, Goal Setting Review," for Unit 1 Residual Heat Removal System

- AR A0630073, Maintenance Rule Performance Criteria, Goal Setting Review," for Unit 1 Radiation Monitoring System

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

The inspectors performed five inspection samples of maintenance risk assessments and emergent work control.

.1 Risk Assessments

g. Inspection Scope

The inspectors reviewed daily work schedules and compensatory measures to confirm that PG&E had performed proper risk management for routine work. The inspectors considered whether risk assessments were performed according to their procedures and whether PG&E had properly used their risk categories, preservation of key safety functions, and implementation of work controls. The inspectors used Procedure AD7.DC6, "On-line Maintenance Risk Management," Revision 7, as guidance. The inspectors specifically observed the following work activities during the inspection period.

- (Unit 1) 230 kV switchyard power supply breaker 52-HD-11 overcurrent trip on March 3, 2005

- (Unit 2) Diesel Engine Generator 2-3 coincident with Reactor Coolant Loop 3 Low Flow Bistable Trip on March 23, 2005

b. Findings

No findings of significance were identified.

.2 Emergent Work

a. Inspection Scope

The inspectors observed emergent work activities to verify that actions were taken to minimize the probability of initiating events, maintain the functional capability of mitigating systems, and maintain barrier integrity. The scope of work activities reviewed includes troubleshooting, work planning, plant conditions and equipment alignment, tagging and clearances, and temporary modifications. The following activities were observed during this inspection period:

- (Unit 1) Reactor Coolant Pump 1-2 No. 2 seal leakoff flow high alarm on January 14, 2005

- (Unit 2) Filter air leak repair for radiation monitor RM-11 on January 16, 2005
- (Unit 2) Repair to valve CVCS-2-8514 on March 1, 2005

b. Findings

No findings of significance were identified.

1R14 Personnel Performance Related to Non-routine Plant Evolutions and Events (71111.14)

The inspectors observed two non-routine plant evolutions/events during this inspection period.

.1 Unit 1 Main Turbine Runback

a. Inspection Scope

The inspectors reviewed PG&E's response to a Unit 1 main turbine runback from 50 to 15 percent power, on February 8, 2005. The inspectors responded to the control room, observed operator response and reviewed PG&E's assessment of the event in accordance with AR A0631613.

b. Findings

Introduction. A self-revealing finding was identified for operators failing to follow Procedure OP J-4A:IV, "Generator Stator Cooling Water-Heat Exchanger Removal From and Return to Service," Revision 5. Operators isolated flow to both of the stator cooling water-heat exchangers by operating valves out of sequence. This resulted in an unplanned transient from a main turbine runback from 50 to 15 percent power.

Description. On February 8, 2005, Unit 1 was at 50 percent power for circulating water system tunnel cleaning. The stator cooling water system was in its normal alignment, with both of the heat exchangers in service in series. To support replacement of a relief valve stator cooling water-heat Exchanger 1-1 was required to be cleared. Operators held a briefing that emphasized that stator cooling water-heat Exchanger 1-1 would be cleared using Procedure OP J-4A:IV and that temperatures would be carefully monitored.

Section 6.1 of Procedure OP J-4A:IV provided the steps to remove stator cooling water-heat exchanger from service. Because the two heat exchangers in the system were aligned in series, the steps were sequenced such that to isolate a single heat exchanger, the bypass valve must be opened first to maintain cooling water flow to the other heat exchanger (1-2). Step 6.1.4 required operators to open Valve GSC 1-408 (the bypass valve for stator cooling water-heat Exchanger 1-1). Step 6.1.5 directed the operators to then close Valve GSC 1-409 (the inlet valve for stator cooling water-heat Exchanger 1-1). Although the operators were briefed on the procedure steps, and had the procedure in their possession, they did not perform self-verification or place keeping and performed Steps 6.1.5 and 6.1.4 out of sequence, isolating all flow to both of the stator cooling water-heat exchangers.

As a result, a low flow condition on the stator cooling water was sensed, this resulted in an automatic main turbine runback from 50 to 15 percent power. Reactor power followed steam demand as designed and reactor power stabilized at 15 percent. Control room operators stabilized the plant and monitored the applicable parameters. The operators performing Procedure OP J-4A:IV backed out of the procedure steps to return heat Exchanger 1-1 to service until the transient was understood. PG&E initiated AR A0631613 to enter this item into the corrective action program. Operators determined that the failure to follow Procedure OP J-4A:IV resulted in the unplanned transient. This finding has human performance crosscutting aspects associated with procedural implementation.

Analysis. The failure to follow Procedure OP J-4A:IV affected the initiating events cornerstone and was more than minor because it resulted in a reactor transient from 50 to 15 percent reactor power. Using Inspection Manaual Chapter 0609, Significance Determination Process, Appendix B, Phase 1 initiating event, this finding screens to Green because no loss of safety functions or other adverse impacts to the facility occurred.

Enforcement. The failure to follow Procedure OP J-4A:IV is not a violation of NRC Requirements. Procedure OP J-4A:IV is not a safety-related procedure and is not required by Technical Specification 5.4.1.a Regulatory Guide 1.33. However, the failure to follow Procedure OP J-4A:IV resulted in an unplanned reactor transient and is considered a finding, FIN 50-275/05-02-03, Failure to Follow Procedure Resulted in Unplanned Transient. This finding is in the corrective action system as AR A0631613.

.2 Unit 2 Restoration of Letdown System While At Power

a. Inspection Scope

On March 1, 2005, operators and maintenance personnel performed maintenance on the letdown system cation resin bed and valve CVCS-2-8514 that required the system to be isolated. The inspectors observed the pre-evolution brief, the restoration activities, and a post evolution debrief.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed nine inspection samples of operability evaluations. These reviews of operability evaluations and/or prompt operability assessments and supporting documents were performed to determine if the associated systems could meet their intended safety functions despite the degraded status. The inspectors reviewed the applicable Technical Specifications, Codes/Standards, and FSAR Update sections in support of this inspection. The inspectors reviewed the following AR's and operability evaluations:

- (Units 1 and 2) Velan valve yokes not assembled as seismically tested (AR A0604776)
- (Unit 1) Low Recirculation Flow for Auxiliary Feedwater Pump 1-1 (AR A0631269)
- (Units 1 and 2) Water in Diesel Fuel Oil Tank 0-2 (AR A06333368)
- (Unit 2) Fault in Auxiliary Saltwater Pump 2-1 Circuitry (AR A0634925)
- (Units 1 and 2) Evaluate Single Failure through AC Meter- Operating Experience (AR A0 631353)
- (Unit 1)Voiding in Unit 1 Safety Injection/Charging Pump Suctions (AR A0634065)

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed two postmaintenance tests for selected risk-significant systems to verify their operability and functional capability. As part of the inspection process, the inspectors witnessed and/or reviewed the postmaintenance test acceptance criteria and results. The test acceptance criteria were compared to the Technical Specifications and the FSAR – Update. Additionally, the inspectors verified the tests were adequate for the scope of work and were performed as prescribed, jumpers and test equipment were properly removed after testing, and test equipment range, accuracy, and calibration were consistent for the application. The following selected maintenance activities were reviewed by the inspectors:

- (Unit 1) Viper testing for auxiliary feedwater level control valves FW-1-LCV-110 and FW-1-LCV-111 on January 12 (Work Orders C0190784 and C0190785)

- (Unit 2) Inspect/Repair Valve Actuator for Valve VAC-2-FCV-681 (Work Order C0194234)

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors evaluated four routine surveillance tests to determine if PG&E complied with the applicable Technical Specification requirements to demonstrate that equipment was capable of performing its intended safety functions and operational readiness. The inspectors performed a technical review of the procedure, witnessed portions of the surveillance test, and reviewed the completed test data. The inspectors also considered whether proper test equipment was utilized, preconditioning occurred, test acceptance criteria agreed with the equipment design basis, and equipment was returned to normal alignment following the test. The following tests were evaluated during the inspection period:

- (Unit 1) Procedure STP M-8F2, “PLTM Leak Rate Testing of Personnel Air Lock Seals,” Revision 5, on January 20, 2005

- (Unit 1) Procedure STP P-AFW-11, “Routine Surveillance Test of Turbine Driven Auxiliary Feedwater Pump 1-1,” on February 2, 2005

- (Unit 1) Procedure STP M-10A, “Diesel Fuel Oil Storage Tank Inventory,” Revision 16, on March 3, 2005

- (Unit 1) Procedure STP M-89A, "Void Volume Measurement in SIP/CCP Crosstie Piping," Revision 8A, on March 12, 2005

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed one temporary plant modification during this inspection period to verify that it did not affect safety system functions. Temporary plant modifications may include jumpers, lifted leads, temporary systems, repairs, design modifications, and procedure changes which can introduce changes to plant design or operations. As part of the inspection effort, the inspectors verified aspects of the temporary plant modification that include energy requirements, material compatibility, structural integrity, environmental qualification, code and safety classification, system timing constraints, reliability, cooling requirements, control signals, equipment protection boundaries, water flow paths, pressure boundary integrity, procedures, drawings, and tests. During this inspection period, the following temporary plant modifications were reviewed:

- (Unit 1) Temporary ultrasonic level indicator on Line 4296 (AR A0612988)

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS2 ALARA Planning and Controls (71121.02)

The inspectors completed 7 samples of ALARA planning and controls.

a. Inspection Scope

The inspectors assessed PG&E's performance with respect to maintaining individual and collective radiation exposures as low as is reasonably achievable (ALARA). The inspectors used the requirements in 10 CFR Part 20 and PG&E's procedures required by Technical Specifications as criteria for determining compliance. The inspectors interviewed PG&E personnel and reviewed:

- Five work activities from previous work history data which resulted in the highest personnel collective exposures

- Site specific trends in collective exposures, plant historical data, and source-term measurements

- Assumptions and basis for the current annual collective exposure estimate, the methodology for estimating work activity exposures, the intended dose outcome, and the accuracy of dose rate and man-hour estimates

- Method for adjusting exposure estimates, or re-planning work, when unexpected changes in scope or emergent work were encountered

- Records detailing the historical trends and current status of tracked plant source terms and contingency plans for expected changes in the source term due to changes in plant fuel performance issues or changes in plant primary chemistry

- Radiation worker and radiation protection technician performance during work activities in radiation areas, airborne radioactivity areas, or high radiation areas

- Self-assessments, audits, and special reports related to the ALARA program since the last inspection

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA3 Event Followup (71153)

.1 (Closed) License Event Report (LER) 50-323/2003-004-001: Manual Reactor Trip Due to a Random Fuse Failure.

On March 17, 2003, with Unit 2 in Mode 3 (Hot Standby) operators initiated an manual reactor trip in accordance with plant procedures. During control rod testing of Control Bank B, operators noticed a difference of greater than 12 steps between demanded position and the Digital Rod Position Indication for Control Bank B. PG&E determined that a single random fuse failure for the moveable coil circuitry prevented rod F2 from movement with the associated Control Bank B demand. Operators correctly initiated a reactor trip in accordance with plant procedures.

The inspectors reviewed this LER and determined that no violations of NRC requirements occurred and that the LER provided adequate description and corrective actions for the event. This LER is closed.

.2 (Closed) LER 50-323/2003-005-00 and -01: Technical Specification Required Shutdown due to Personnel Error.

On April 4, 2003, a Technical Specification 3.7.5.C required shutdown was initiated because an Auxiliary Feedwater System check valve was installed backwards. This issue was discussed in detail in NRC Inspection Report 50-275; 323/2003-06. A Green NCV was identified.

The inspectors reviewed this LER and determined that no new information was provided that would change the original disposition. This LER (and subsequent Revision 01) is closed.

4OA4 Other Crosscutting Aspects of Findings

Section 1R04.2 identified a human performance aspect for failure to pre-plan maintenance associated with the CRVS that resulted in the control room boundary being opened without administrative controls.

Section 1R05.2 identified a problem identification and resolution crosscutting aspect for failure to correct operations responder training deficiencies.

Section 1R14.1 identified a human performance crosscutting aspect for failing to follow procedures when removing a stator cooling water-heat exchanger from service.

Section 4OA5.1 identified a problem identification and resolution crosscutting aspect associated with operations and engineering personnel not recognizing the significance of the degraded condition and not implementing timely corrective actions.

4OA5 Other

.1 (Closed) Unresolved Item (URI) 05000323/2004005-06: Failure to Promptly Correct Diesel Engine Generator Lube Oil Instrument Line Crack.

Introduction. The inspectors identified a Green NCV for the failure to promptly correct a cracked lube oil instrument sensing line, as required by 10 CFR Part 50, Appendix B, Criterion XVI. As a result, there was an increased potential for DEG 2-3 to trip on low lube oil level.

Description. On August 29, 2004, operators discovered a lube oil leak coming from the welded connection of Valve DEG-2-1084 to the downstream 3/8 inch instrument line. The instrument line connected the lube oil system to pressure Switch PS-237. The pressure switch provided a low pressure alarm for the pre-circulation lube oil pump. PG&E decided to correct the leak in the next available maintenance outage window, which would be in Refueling Outage 2R12. Additionally, as documented in AR A0617419, engineering personnel did not consider the leak to affect the operability of DEG 2-3 and no formal prompt operability assessment was performed at that time.

Following the Parkfield earthquake on September 28, 2004, operators initiated a test run of the Unit 1 and 2 DEGs to verify their capability start and run. During the pre-firing checks for DEG 2-3, it was noted that the oil leak had grown significantly (approximately 12 drops per minute). Following discussions between operations, maintenance, and engineering personnel, DEG 2-3 was declared inoperable. Operators subsequently closed Valve DEG 2-1084, which isolated the leak. Diesel engine Generator 2-3 was again considered operable under a prompt operability assessment documented in AR A0617419. The cracked instrument line was replaced on October 2, 2004.

PG&E personnel performed a failure analysis of the cracked tubing and determined that the crack initiated at the toe of the weld and was the result of high-cycle fatigue. The crack was circumferential at the toe of the weld, and was through-wall for half of the tubing's outer diameter. The source of the stress that created the crack was the unsecured mass of Valve DEG-2-1084 and vibration from the pre-circulation lube oil pump at standby and the DEG when it was in operation. PG&E personnel evaluated the crack and determined that it would have minor impact on DEG 2-3 operation. This evaluation was based on the estimated force to completely break the cracked tubing (30 to 40 pounds) and the calculated leakrate at an operating lube oil pressure of 90 psig, as compared to a standby lube oil pressure of 15 psig. Engineers calculated the leakrate to be 0.0015 gph at a lube oil pressure of 90 psig. Based on this leakrate, and the lube oil low level alarm setpoint of 110 gallons, engineers estimated 107,000 hours of operation before the alarm would activate.

The inspectors performed an independent evaluation of the cracked tubing's impact on DEG 2-3. Since DEG 2-3 only operated approximately 2 hours between the time the leak was discovered and the time DEG 2-3 was declared inoperable, the inspectors observed that the crack had propagated quickly; primarily from the vibration of the pre-circulation lube oil pump only. The inspectors surmised that there was an increased probability that the instrument tube would completely severe under several hours of DEG 2-3 operation. The inspectors, and PG&E personnel, calculated that if the tubing severed, and was not obstructed, then the leakrate would become 10 to 15 gpm. However, based on the mounting of the tubing it was determined that if the tubing were to completely severe, the flow out of Valve DEG-2-1084 would be obstructed by instrument tubing and the resulting flow would be 1 to 3 gpm. PG&E estimated that DEG 2-3 could sustain a loss of 200 gallons of lube oil before damage to the engine began and/or the engine shutdown on low-low lube oil pressure. The low lube oil level alarm would become active after DEG 2-3 lost 170 gallons of lube oil. Assuming no operator intervention before the low lube oil level alarm became active, operators would have 10 to 30 minutes to respond to DEG 2-3 and isolate Valve DEG-2-1084. The inspectors determined that operators would be able to respond to such a scenario in a timely manner to prevent damage to DEG 2-3.

A problem identification and resolution crosscutting aspect associated with operations and engineering personnel not recognizing the significance of the degraded condition and implementing timely corrective actions.

Analysis. The performance deficiency associated with this event is the failure to correct a cracked lube oil instrument tubing downstream of Valve DEG-2-1084. This deficiency impacted the mitigating systems cornerstone for reliability of systems that respond to initiating events to prevent undesirable consequences and affects the equipment performance attribute. The finding was more than minor using Example 4.f of

Inspection Manual Chapter 0612, Appendix E. Similar to Example 4.f, the inspectors determined that there was impact to DEG 2-3 operability. Using the SDP Phase 1 screening worksheets in Appendix A of Inspection Manual Chapter 0609, the finding was determined to be potentially greater than very low safety significance because the failure could have resulted in an actual loss of safety function of DEG 2-3.

An NRC Senior Reactor Analyst performed a Phase 3 significance determination. The following assumptions were made:

- A bounding assumption was made that DEG 2-3 would have failed to run at all times between August 29 and September 28, 2004 (exposure period = 30 days), absent operator recovery actions, as a result of lubricating oil depletion following failure of the degraded weld. The weld failure was assumed to occur at the start of DEG 2-3 due to engine vibration.

- The postulated failure of DEG 2-3 to run is considered to be an independent failure mechanism, not to impact the other two DEGs.

- A fire would not have occurred in conjunction with the postulated oil spill. The location of the oil leak was not close to any hot surfaces and would not have been expected to create a fire.

- A bounding assumption was made that operators would fail to detect the leak for the one-hour period before the low level alarm activates and that irrecoverable engine damage would occur if the diesel engine was not shut down within 10 minutes. In reality, it is likely that the leak would be detected prior to the alarm.

- Using the worst-case flowrate of 3 gpm, as calculated by the resident inspectors, the low level alarm would activate approximately 57 minutes after engine start. Operators would have 10 minutes to isolate the cracked instrument tubing line based on 30 gallons margin between the low level alarm and a diesel engine shutdown on the low lube oil pressure. It is presumed that the engine would shutdown automatically on low lube oil pressure, or operators would need to shut down the engine manually in order to isolate the instrument line due to the presence of hot spewing oil. In the latter case, operators would also have to de-energize the pre-circulating lube oil pump to prevent the hot lube oil from spewing in the vicinity of the isolation valve. The pre-circulating lube oil pump can be de-energized locally and operators are knowledgeable regarding this expected action.

Calculation

Using the SPAR-H Human Reliability Analysis Method (INEEL/EXT-02-01307), the total estimated failure probability for operators to diagnose the problem and then take all actions necessary to restore the function of the diesel generator was 0.42.

The Diablo Canyon SPAR model, Revision 3.11 was used to estimate the change in risk resulting from the performance deficiency. In this model, the nominal value assigned to the failure of DEG 2-3 to run is 2.117E-2. To account for the performance deficiency, the analyst added to this value the probability associated with failure to isolate the postulated worst-case oil leak. Therefore, the new probability of DEG 2-3 failing to run was set to 2.117E-2 + 0.42= 0.44.

The SPAR model result was a Î-CDF of 1.433E-6/yr. The analyst verified that all cutsets contributing to this figure were associated with LOOP sequences and that the distribution of risk within the various sequences was within expectations. With an exposure period of 30 days, the impact on risk of the performance deficiency is estimated as a Î-CDF of 1.433E-6/yr. (30 days exposure/yr./365 calendar days/yr.) = 1.2E-7/yr.

External Events

The analyst was aware that Diablo Canyon lies in an active seismic area and that an earthquake could result in a concurrent loss of offsite power and failure of the flawed instrument tubing welded connection. It was determined by the analyst that the subject welded connection would not be particularly susceptible to a failure mode specific to seismic loadings because of the skid-mounted configuration (everything moves as a unit and little sheer stress would be applied to the cracked weld). Therefore, the risk contribution from seismic events for this finding is primarily a function of the increased frequency of loss of offsite power events.

The analyst determined that the frequency of seismic events that cause a loss of offsite power without also causing a loss of diesel generators is 1.07E-3/yr. The analyst ran two cases in the SPAR model to determine the contribution of seismic initiating events to the risk significance of the performance deficiency. In the first case, the LOOP initiating frequency was set to 1.07E-3/yr, as stated above. All operator recovery of offsite power basic events was set to TRUE (because recovery of offsite power would not be expected prior to postulated core damage). The result in SPAR was 4.41E-6/yr. In the second case, all of the changes above were made in addition to raising the fail-to-run of DEG 2-3 to 0.44 and adjusting the common cause failure to its nominal value, as was done in the internal events analysis. The result was 4.611E-6/yr. The difference between these two values is 2.0E-7/yr. Taking into account the exposure period of the finding, the estimated risk contribution from seismic events is 1.6E-8/yr.

Other external initiating events were determined not to be significant when compared to the loss-of-offsite power event frequency as used in the SPAR model (3.3E-2/yr.), or they were already included in the SPAR model frequency. These initiating events include fire-induced loss-of-offsite power and severe weather.

Based on the above considerations, the analyst concluded that the contribution from external initiators would not be sufficient to change the risk characterization of the finding.

Large Early Release Frequency:

The analyst determined that the finding required assessment of large early release because the Phase 3 result provided a risk significance estimation of greater than 1×10^{-7}. All of the sequences contributing to a change in risk from the base case are LOOP sequences that involve, in some cases, a station blackout. Diablo Canyon has a large, dry containment structure. Using Manual Chapter 0609, Appendix H, Table 5.1, "Phase 1 Screening Type A Findings at Power," the analyst concluded that none of the sequences of interest contributed to the risk of a large early release.
Based on the resulting conditional core damage probability of 1.2E-7/yr., the finding was determined to be of very low safety significance.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformance are promptly identified and corrected. Contrary to the above, PG&E failed to promptly correct the cracked lube oil instrument tubing on DEG 2-3. Specifically, PG&E observed the crack, but did not adequately assess the growth rate of the crack or its potential impact on DEG 2-3 operability. Because this failure to promptly correct the lube oil instrument tubing is of very low safety significance and has been entered into the corrective action system as AR A0617419, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-323/05-02-04, Failure to Promptly Correct Diesel Engine Generator Lube Oil Instrument Line Crack.

40A6 Management Meetings

Exit Meeting Summary

The resident inspection results were presented on April 15, 2005, to Mr. James Becker, Vice President and Station Director, and other members of PG&E management. PG&E acknowledged the findings presented.

The inspectors asked PG&E whether any materials examined during the inspection should be considered proprietary. Proprietary information was reviewed by the inspectors and left with PG&E at the end of the inspection.

4OA7 Licensee Identified Violations

The following finding of very low safety significance was identified by PG&E as a violation of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as an NCV.

- Technical Specification 5.4.1 requires, procedures be established, implemented, and maintained covering access control to radiation areas including a radiation work permit system. Station procedure RP1.ID9, “Radiation Work Permits,” Revision 7, Section 4.3, required individuals signing in on a radiation work permit to be responsible for reading, understanding, and following the applicable requirements. On November 18, 2004, PG&E identified that a crew tasked to install steam generator inserts and manways on the 2-2 Steam Generator failed to get permission prior to entering the steam generator platform and prior to removing the cold leg shield door. Radiation Work Permit 04-2041 required radiation protection be contacted prior to moving or adjusting shielding. The finding was documented in the corrective action program as AR-0624425. The finding was found to have very low safety significance because it was not an ALARA finding, there was no overexposure or substantial potential for an overexposure and the ability to assess dose was not compromised.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

PG&E personnel

J. Becker, Vice President - Diablo Canyon Operations and Station Director
C. Belmont, Director, Nuclear Quality, Analysis, and Licensing
S. Chesnut, Director, Engineering Services
S. David, Manager, Operations
D. Jacobs, Vice President, Nuclear Services
S. Ketelsen, Manager, Regulatory Services
M. Lemke, Manager, Emergency Preparedness
D. Oatley, Vice President and General Manager, Diablo Canyon
J. Purkis, Director, Maintenance Services
P. Roller, Director, Operations Services

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Opened and Closed

50-275;323/2005-002-01	NCV	Failure to properly pre-plan CRVS maintenance when opening the control room boundary (Section 1R04.2)
50-275;323/2005-002-02	NCV	Failure to Correct Fire Program violation concerning qualifications of Operations Responders in support of the fire brigade (Section 1R05.2)
50-275/2005-002-03	FIN	Failure to follow procedure resulted in unplanned transient (Section 1R14.1)
50-323/2005-002-04	NCV	Failure to Promptly Correct Diesel Engine Generator Lube Oil Instrument Line Crack (Section 4OA5.1)

Closed

50-323/2004-005-06	URI	Failure to Promptly Correct Diesel Engine Generator Lube Oil Instrument Line Crack (Section 4OA5.1)
50-323/2003-004-00	LER	Manual Reactor Trip Due to a Random Fuse Failure (Section 4OA3.1)
50-323/2003-005-00 and -01:	LER	Technical Specification 3.7.5.C Required Shutdown due to Personnel Error. (Section 4OA3.2)

LIST OF DOCUMENTS REVIEWED

Section 1R06: Flood Protection Measures

Action Requests

A0615938 A0630181 A0630182 A0606275

Other

DCI-EA-41313-Appendix I, “Rational For Not Requiring Flood Protection Covers Over FCV-602, -603 Valve Pits in CCW HX Rooms in Units 1 & 2"

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Action Requests

A0630067 A0630230 A0445633 A0630068 A0445541 A0020366

Section 2OS2: ALARA Planning and Controls (71121.02)

Corrective Action Documents

A0610617, A0624425, A0626349, A0626321, A0626979, A0627869, A0629640

Audits and Self-Assessments

040630025 1R12 Radiation Protection Assessment Report - Outage Coverage

Radiation Work Permits

04-2002-00	2R12 Scaffolding in Containment
04-2027-00	2R12 Reactor Reassembly
04-2042-00	2R12 Steam Generator Nozzle Dam Installation and Removal
04-2044-00	2R12 Primary Steam Generator Eddy Current Inspection and Tube Work
04-2049-00	2R12 Steam Generator Chemical Cleaning and Support Work

Procedures

RP1.ID1	Requirements for the ALARA Program, Revision 2B
RP1.ID9	Radiation Work Permits, Revision 7
RCP D-200	Writing Radiation Work Permits, Revision 30
RCP D-205	Performing ALARA Reviews, Revision 14A

Miscellaneous Documents

ALARA Advisory Council Charter

LIST OF ACRONYMS

AFW	auxiliary feedwater
AR	action request
CFR	*Code of Federal Regulations*
CRVS	Control Room Ventilation System
FIN	Finding
FSAR	Final Safety Analysis Report
IMC	Inspection Manual Chapter
LER	Licensee Event Report
NCV	noncited violation
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
PG&E	Pacific Gas and Electric Company
RWP	Radiation Work Permit
SDP	Significance Determination Process
URI	Unresolved Item