UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-8064

June 18, 2001

Gregory M. Rueger, Senior Vice President
and General Manager
Nuclear Power Generation Bus. Unit
Pacific Gas and Electric Company
Nuclear Power Generation, B32
77 Beale Street, 32nd Floor
P.O. Box 770000
San Francisco, California 94177

SUBJECT: DIABLO CANYON INSPECTION REPORT NO. 50-275/01-03; 50-323/01-03

Dear Mr. Rueger:

On May 19, 2001, the NRC completed routine resident inspection at the Diablo Canyon Nuclear Power Plant, Units 1 and 2, facility. The enclosed report documents the inspection findings that were discussed on May 18, 2001, with James R. Becker and 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.

One issue was evaluated under the Significance Determination Process and was determined to be of very low safety significance (Green). The issue involved two sources of offsite power and a diesel generator on Unit 2 being inoperable longer than allowed by the Technical Specifications. This issue has been entered into your corrective action program and is discussed in the summary of findings and in the body of the attached inspection report. This issue was determined to involve a violation of NRC requirements, but because of its very low safety significance and that it has been entered into your corrective action program, the violation is noncited, consistent with Section VI.A of the NRC Enforcement Policy. The noncited violation is described in the subject inspection report. If you contest the violation, 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; the Director, Office of Enforcement, U. S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Diablo Canyon, Units 1 and 2, facility.

Pacific Gas and Electric Company filed for voluntary bankruptcy proceedings during this inspection period. The NRC has exercised communications channels to better understand your planned and implemented actions, especially as they relate to your responsibility to safely operate the Diablo Canyon reactors. NRC inspections, to date, have confirmed that you are operating these reactors safely and that public health and safety is, thus far, assured.

In response to these conditions, there will continue to be two differences in how the Region communicates its inspection findings. First, we will continue the 6-week periodicity of our integrated inspection reports (the other reactors in Region IV implemented a quarterly report frequency, with the exception of San Onofre Nuclear Generating Station). Second, the description of the scope of the individual inspection activities will be more detailed. This is being done to keep the public more fully informed of the breadth and depth of the NRC's inspection and oversight activities.

In accordance with 10 CFR 2.790 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/NRC/ADAMS/index.html (the Public Electronic Reading Room).

Sincerely,

/RA/

William B. Jones, Chief
Project Branch E
Division of Reactor Projects

Docket Nos: 50-275
50-323
License Nos: DPR-80
DPR-82

Enclosure:
NRC Inspection Report No.
50-275/01-03; 50-323/01-03

cc w/enclosure:
David H. Oatley, Vice President
Diablo Canyon Operations and Plant Manager
Diablo Canyon Nuclear Power Plant
P.O. Box 56
Avila Beach, California 93424

Lawrence F. Womack, Vice President, Power
Generation & Nuclear Services
Diablo Canyon Power Plant
P.O. Box 56
Avila Beach, CA 93424

Dr. Richard Ferguson
Energy Chair
Sierra Club California
1100 llth Street, Suite 311
Sacramento, California 95814

Nancy Culver
San Luis Obispo Mothers for Peace
P.O. Box 164
Pismo Beach, California 93448

Chairman
San Luis Obispo County Board of
Supervisors
Room 370
County Government Center
San Luis Obispo, California 93408

Truman Burns\Mr. Robert Kinosian
California Public Utilities Commission
505 Van Ness, Rm. 4102
San Francisco, California 94102

Robert R. Wellington, Esq.
Legal Counsel
Diablo Canyon Independent Safety Committee
857 Cass Street, Suite D
Monterey, California 93940

Ed Bailey, Radiation Program Director
Radiologic Health Branch
State Department of Health Services
P.O. Box 942732 (MS 178)
Sacramento, CA 94327-7320

Steve Hsu
Radiologic Health Branch
State Department of Health Services
P.O. Box 942732
Sacramento, California 94327-7320

Christopher J. Warner, Esq.
Pacific Gas and Electric Company
P.O. Box 7442
San Francisco, California 94120

City Editor
The Tribune
3825 South Higuera Street
P.O. Box 112
San Luis Obispo, California 93406-0112

Robert A. Laurie, Commissioner
California Energy Commission
1516 Ninth Street (MS 31)
Sacramento, CA 95814

Electronic distribution from ADAMS by RIV:
Regional Administrator **(EWM)**
DRP Director **(KEB)**
DRS Director **(ATH)**
Senior Resident Inspector **(DLP)**
Branch Chief, DRP/E **(WBJ)**
Senior Project Engineer, DRP/E **(GAP)**
Section Chief, DRP/TSS **(PHH)**
RITS Coordinator **(NBH)**

<u>Only inspection reports</u> to the following:
Scott Morris **(SAM1)**
NRR Event Tracking System **(IPAS)**
DC Site Secretary **(AAJ)**
Dale Thatcher **(DFT)**

R:_DC\2001\DC2001-03RP-DLP.wpd

RIV:SRI:DRP/E	SPE:DRP/E	C:DRP/E		
DLProulx	GAPick	WBJones		
/RA/	***T-WBJones***	***/RA/***		
6/18/01	6/18/01	6/18/01		

OFFICIAL RECORD COPY T=Telephone E=E-mail F=Fax

ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket Nos:	50-275 50-323
License Nos:	DPR-80 DPR-82
Report No:	50-275/01-03 50-323/01-03
Licensee:	Pacific Gas and Electric Company
Facility:	Diablo Canyon Nuclear Power Plant, Unit 1 and 2
Location:	7 ½ miles NW of Avila Beach Avila Beach, California
Dates:	April 1 through May 19, 2001
Inspectors:	D. L. Proulx, Senior Resident Inspector T. W. Jackson, Resident Inspector G. A. Pick, Senior Project Engineer, Region IV
Approved By:	W.B. Jones, Chief, Project Branch E Division of Reactor Projects

ATTACHMENTS:

Attachment 1 Supplemental Information

Attachment 2 Auxiliary 1-2 Overheated Joint 309

SUMMARY OF FINDINGS

IR 05000-275-01-03, IR 05000-323-01-03, on 4/1/01 to 5/9/01, Pacific Gas and Electric Co., Diablo Canyon Nuclear Power Plant, Units 1 and 2. Resident Inspector Report. Maint. Risk Assess. and Emerg. Work Cont.

This report covers a 7-week routine resident inspection conducted from April 1 through May 19, 2001. One Green finding was identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using IMC 0609 “Significance Determination Process.” Findings for which the Significance Determination Process does not apply are indicated by “No Color” or by the severity level of the applicable violation. The NRC’s program for overseeing the safe operation of commercial nuclear power reactors is described at its Reactor Oversight Process website at http://www.nrc.gov/NRR/OVERSIGHT/index.html.

A. Inspector Identified Findings

Cornerstone: Mitigating Systems

- Green. A violation of Technical Specification 3.0.3 and 3.8.1.1 occurred because operators rendered two sources of offsite power and a diesel engine generator inoperable simultaneously for approximately 7 hours, but did not take the required actions. Because of inadequate planning and procedure guidance, operators placed the load tap changer for Unit 2 Startup Transformer 2-1 to an inappropriate tap setting, but did not declare Startup Transformer 2-1 inoperable. These actions, coupled with 500 kV auxiliary power inoperable for breaker cubicle inspections, and Diesel Generator 2-2 inoperable because of degraded wiring, rendered all three emergency power sources for Vital Bus H inoperable in excess of the Technical Specification 3.0.3 allowed outage time of 1 hour. This violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy. This item was placed in the corrective action program as Action Request A0528007.

  The inspectors evaluated this issue using the Significance Determination Process. The inspectors noted that this finding had potential impact because a total loss of Unit 2 Vital Bus H would have resulted from several initiating events, including a reactor trip. (Vital Busses F and G and their associated diesel engines remained operable.) This finding involved three mitigating systems, the 500 kV Auxiliary Transformer, the 230 kV Startup Transformer, and Diesel Engine Generator 2-2. Using Phase 1 of the Significance Determination Process, this item could be considered an item in which systems were unavailable in excess of the Technical Specification action statement (3.8.1.1), requiring a Phase 2 Significance Determination Process evaluation. However, the inspector noted that although Startup Transformer 2-1 was inoperable as defined by its Technical Specification 3.8.1.1 function to automatically pick up loads following a loss of 500 kV offsite power, operators could have easily recovered Startup Transformer 2-1 and returned the load tap changer to automatic control. Thus, Startup Transformer 2-1 is considered available for most accident sequences (except those involving loss of the startup transformer). Auxiliary power and Diesel Engine Generator 2-2 were readily recoverable. This violation was determined to be of very low risk significance, as evaluated under the transient and loss of offsite power Significance Determination Process worksheets and as independently verified by an NRC senior reactor analyst (Green) (Section 1R13).

Report Details

Summary of Plant Status

Diablo Canyon Unit 1 began this inspection period at 100 percent power. Operators decreased Unit 1 reactor power to 75 percent on April 7, 2001, because of a water leak into the lube oil system for Main Feedwater Pump 1-2. Following swapping of the lube oil heat exchangers for Main Feedwater Pump 1-2 and turbine valve testing, operators returned Unit 1 to 100 percent power later on April 7. Unit 1 continued to operate at 100 percent power until the end of this inspection period.

Diablo Canyon Unit 2 began this inspection period at 100 percent power. On April 28, 2001, operators commenced a reactor shutdown and entered Mode 3 (Hot Standby) for Refueling Outage 2R10. On April 30, operators initiated a plant cooldown and entered Mode 5 (Cold Shutdown). Maintenance personnel detensioned the reactor head on May 3, entering Mode 6 (Refueling). On May 5, operators commenced core offload and the reactor was defueled as of May 7. Following outage work, operators began reloading the core on May 14, re-entering Mode 6. Unit 2 entered Mode 5 on May 19 when mechanics retensioned the reactor head. Unit 2 subsequently remained in Mode 5 until the end of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R05 Fire Protection (71111.05)

Monthly Routine Inspection

a. Inspection Scope

The inspectors performed 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 Update as guidance. Specific risk-significant areas inspected included the intake structure, the radiological controlled area of the auxiliary building, the Unit 1 containment, and the safety-related switchgear rooms in the auxiliary building.

b. Findings

No findings of significance were identified.

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

Risk Assessments

a. Inspection Scope

Throughout the inspection period, the inspectors reviewed daily and weekly work schedules to determine when the licensee had scheduled risk-significant activities. The inspectors reviewed selected activities regarding risk evaluations and overall plant configuration control. The inspectors verified that the licensee established the applicable contingencies, as discussed in the risk assessments. The inspectors used Procedure AD7.DC6, "On-Line Maintenance Risk Management," Revision 5, as guidance and reviewed the activities associated with the following:

- 4 kV Bus H outage and cubicle wire inspections
- Auxiliary Saltwater Pump 2-1 outage and vault drain check valve preventive maintenance
- Residual Heat Removal Pump 2-1 maintenance outage window
- Auxiliary Transformer 2-1 and 2-2 bus bar inspections (refer to Section 4OA2)

b. <u>Findings</u>

Unit 2 operated with two sources of offsite power and one diesel engine generator inoperable in excess of the time allowed by Technical Specification 3.8.1.1, Action J, and Technical Specification 3.0.3. Because Unit 2 was in Technical Specification 3.0.3 for approximately 7 hours without initiating action within 1 hour to place the plant in Mode 3, the licensee violated Technical Specification 3.0.3. This violation was determined to be of very low risk significance (Green), as evaluated under the transient and loss of offsite power Significance Determination Process worksheets and as independently verified by an NRC senior reactor analyst.

On March 23, 2001, the licensee determined that inspection of the feeder breakers from the auxiliary transformers to each of the vital busses was necessary because of degraded wires in other safety-related breaker cubicles. A total of five degraded wires were identified such that the operability of the breakers was in question.

On March 24-25, 2001, the licensee performed emergent inspections of the auxiliary feeder breakers for each unit. The licensee determined that the safest method to perform these inspections was to de-energize the auxiliary feeder breakers and to transfer the safety-related busses to the 230 kV startup transformers. On March 25, 2001 while inspecting Breaker 52HH13 (the Unit 2 Bus H Auxiliary Feeder Breaker), the licensee transferred onsite electrical power to the Startup Transformer. At this time, the startup source provided approximately 107.5 percent over voltage. Operators were concerned that this overvoltage condition could adversely affect the loads on the safety-related busses. Thus, operators placed the Unit 2 startup transformer load tap changer to manual and adjusted the tap setting to Tap 4, so that the 4 kV and 480 V busses would be within their normal operating bands.

Operators reviewed Procedure OP J-2:VIII “Guidelines for Reliable Transmission Service for DCPP,” Revision 2, to determine if this approach was acceptable to maintain the startup transformer operable. Attachment 9.1 of Procedure OP J-2:VIII provided direction as to the operability of the startup transformers during various degraded conditions. For the applicable condition (all offsite lines available and the load tap changer in manual) the table requires compensatory measures to maintain operability, including placing the feature cutout switch for the standby condensate booster pump in

BLOCK (preventing its automatic start) and by blocking the automatic transfer of one 12 kV bus to the startup transformer. Engineering developed these actions to prevent losing startup power because of the starting currents of the large motors (i.e. reactor coolant pumps, circulating water pumps, and condensate booster pumps). In addition, Attachment 9.1 of Procedure OP J-2:VIII recommended placing the load tap changer in Tap 7, 8, or 9 depending on the 230 kV offsite voltage. Operators took the compensatory measures but left the load tap changer in Tap 4, believing that the recommended tap positions were optional, and considered the Unit 2 startup transformer operable.

Following commencement of the wiring inspections, technical maintenance personnel identified degraded control wiring associated with Diesel Engine Generator 2-2. Operators declared Diesel Engine Generator 2-2 inoperable at approximately 2:00 a.m. on March 25, 2001, and cleared Diesel Engine Generator 2-2 to replace the degraded wire. Because the operators considered the Unit 2 Startup Transformer operable, operators believed that Technical Specification 3.8.1.1 Action D applied. Technical Specification 3.8.1.1 Action D, states that with one source of offsite power (auxiliary) and one Diesel Engine Generator (Diesel Engine Generator 2-2) inoperable, restore one of these emergency power sources to operable status within 12 hours, or be in Mode 3 (Hot Standby) within the next 6 hours. Therefore, because technical maintenance personnel estimated that the wire replacement would take about 6 hours, the operators determined that Technical Specification 3.8.1.1 would be met with the work. The degraded wire associated with Diesel Engine Generator 2-2 Breaker Cubicle 52HH7, was replaced and the diesel declared operable at 8:53 a.m. on March 25.

Subsequent design engineering review of this task revealed that the operators improperly interpreted Procedure OP J-2:VIII. Engineering personnel determined that the recommended load tap changer settings of Attachment 9.1 of Procedure OP J-2:VIII were required to maintain operability of the 230 kV offsite power system. Since operators adjusted the load tap setting to Tap 4, Startup Transformer 2-1 should have been declared inoperable for the duration of this event. Thus, the actual condition of the plant was that two sources of offsite power and one diesel engine generator were inoperable. In this case, Technical Specification 3.8.1.1 Action J applied, which required the licensee to enter Technical Specification 3.0.3 immediately. Technical Specification 3.0.3 states that action shall be initiated within 1 hour to place the plant in Mode 3 within the next 7 hours. Because Unit 2 was in Technical Specification 3.0.3 for approximately 7 hours without initiating action within 1 hour to place the plant in Mode 3, the licensee violated Technical Specification 3.0.3.

Failure to restore operability to one Unit 2 emergency power source to Bus H (Diesel Engine Generator 2-2, Auxiliary Transformer, or Startup Transformer) within 1 hour or take action to place the plant in hot standby within the next 7 hours is a violation of Technical Specification 3.0.3. This violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy. This item was placed in the corrective action program as Action Request A0528007 (323/2001003-01).

The inspectors noted that the cubicle inspections of March 24-25, 2001, were performed on a weekend as emergent work. Thus, the appropriate planning personnel were not involved in determining the plant configuration and contingencies for performing the wiring inspection/replacements. In addition, the inspectors noted that Procedure OP J-2:VIII described the required load tap changer settings for the startup transformer as recommendations, misleading the operators into believe that these tap settings were optional to maintain operability. The licensee stated that Procedure OP J-2:VIII, Attachment 9.1, would be enhanced to more precisely define the load tap changer settings as required to maintain operability.

The inspectors evaluated this issue using the Significance Determination Process. The inspectors noted that this finding had potential impact because a total loss of Unit 2 Vital Bus H would have resulted from several initiating events, including a reactor trip. This finding involved three mitigating systems, the 500 kV auxiliary transformer, the 230 kV startup transformer, and Diesel Engine Generator 2-2. Using Phase 1 of the Significance Determination Process, this item could be considered an item in which systems were unavailable in excess of the Technical Specification action statement, requiring a Phase 2 Significance Determination Process evaluation. However, the inspector noted that although Startup Transformer 2-1 was inoperable as defined by its Technical Specification 3.8.1.1 function to automatically pick up loads following a loss of 500 kV offsite power, operators could have easily recovered Startup Transformer 2-1 and returned the load tap changer to automatic control. Thus, Startup Transformer 2-1 is considered available for most accident sequences (except those involving a loss of the startup transformer). Auxiliary power and Diesel Engine Generator 2-2 were also readily recoverable. This condition existed for less than 3-days (7-hours) and Diesel Generator Engines 2-1 and 2-3 remained operable. This finding was determined to be of very low risk significance (Green).

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed operability evaluations and supporting documents to determine if the associated systems could meet their intended safety functions despite the degraded status. The inspectors reviewed the applicable Technical Specification Bases and Final Safety Analysis Report Update sections in support of this inspection. The inspectors reviewed the following action requests:

- A0527329, Broken Wire in Unit 2 Cubicle 52HH9
- A0527392 and Operability Evaluation 2001-01, Operability of Units 1 and 2 Pending Inspection for Degraded Wires in 4 kV to 480 V Cubicles and Startup Crosstie Cubicles.
- A0528337, Investigate for Gas Voids in Unit 1 Safety Injection Line
- A0532661, Material on Centrifugal Charging Pump 2-1 Procured Nonsafety Related

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors evaluated portions of postmaintenance testing to determine if the test adequately demonstrated that the maintenance activity was performed properly. The inspectors reviewed the work orders, the completed data reduction, and witnessed portions of the postmaintenance tests performed in accordance with the following:

- TP TB-9720, "MOV Flow Test - Charging Injection Valves (8803 A/B)," Revision 1
- STP P-CCP-21, "Routine Surveillance Test of Centrifugal Charging Pump 21," Revision 11

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

The inspectors evaluated several outage activities during Unit 2 Outage 2R10 to verify Technical Specification compliance, and to ensure that the licensee appropriately considered risk in developing schedules, plant configurations, mitigation strategies, and protection of key safety functions.

Prior to the start of the outage, the inspectors evaluated the licensee's outage safety plan. The inspectors verified that the licensee optimized availability of key safety functions, such that more than the minimum required equipment was planned to be available throughout the outage. In preparation for the actual outage work, the inspectors witnessed the licensee's shutdown and cooldown of Unit 2 during April 28-30, 2001.

The inspectors provided continuous control room coverage from May 3-4, 2001, when the reactor coolant system was in a condition of reduced inventory (i.e. midloop) to install steam generator nozzle dams, which was a risk-significant evolution. The inspectors used Procedure OP A-2:III, "Reactor Vessel - Draining to Half Loop with Fuel in the Vessel," Revision 18, as guidance. The inspectors evaluated the calibration of the Reactor Vessel Refueling Level Indicating System and the cross-calibration of the incore thermocouples and resistance temperature detectors. The inspectors verified adequate inventory control and contingency plans and verified containment closure and containment closure capability were in accordance with Technical Specifications and outage risk plans.

The inspectors monitored the core offload and core reload activities from May 5-7 and May 14-16, 2001, respectively, to ensure that the licensee complied with Technical Specifications and performed the evolution in a safe manner.

The inspectors walked down several safety-related clearances. The inspectors verified that the tags were placed on the correct components and provided adequate isolation for the work involved. In addition, the inspectors noted that none of the clearances compromised the availability of key safety functions. The inspectors used Procedure OP2.ID1, “Clearances,” Revision 11D, as guidance.

The remaining outage activities will be reviewed as part of the next routine resident inspection.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

Routine Observations

a. Inspection Scope

The inspectors evaluated several routine surveillance tests to determine if the licensee complied with the applicable Technical Specifications requirements. The inspectors performed a technical review of the procedure, observed the test, and reviewed the completed test data. The inspectors evaluated the following:

- STP P-ASW-A, “Performance Test of Auxiliary Saltwater Pumps,” Revision14

- STP V-15, “ECCS Flow Balance Test,” Revision 22

- STP I-38-B.1, “SSPS Actuation Logic Test in Modes 1, 2, 3, and 4," Revision 9

- STP I-38-B.2, “SSPS Train B SI Reset Timer and Slave Relay V-602 Test in Modes 1,2,3, and 4,” Revision 4

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems (71152, 71153)

a. Inspection Scope

The licensee performed inspections of 12 kV Auxiliary Bus 2-1 and 4 kV Auxiliary Bus 2-2 as described in Licensee Event Report 50-275/2000-004-01 and prescribed in Action Request A0510971. (This event was also the subject of NRC Inspection Report 50-275; 323/00-09). During the inspection of 12 kV Auxiliary Bus 2-1, an Overheated Splice Joint (No. 309) was discovered (refer to Attachment 2). The inspectors reviewed work instructions, scope of the planned work activities, and field drawings. The inspectors evaluated the work history for the Unit 2 12 kV bus, evaluated previous corrective actions, and reviewed the design requirements for the 12 kV bus. The inspectors walked down the bus bars prior to disassembly to independently evaluated the condition of the buses. The inspectors interviewed craft personnel performing the work, system engineers implementing the corrective actions, design engineers who performed the root cause evaluation, and management personnel who were responsible for effective resolution of the bus bar work. The inspectors attended management meetings related to resolution of the bus bar deficiency.

b. Assessment

.1 Bus Bar Physical Condition

The licensee determined that an overheated splice joint was located on the center phase of the 12 kV bus bar from Auxiliary Transformer 2-1 to Buses D and E. The splice joint was located outside of the turbine building approximately 10 feet from the transformer. The inspectors verified that there were no other bus ducts in close proximity to the bus duct at the degraded splice joint. The inspectors noted that the adjacent joints on either side of the degraded joint had evidence of overheating, as well as the Raychem insulation on the center phase. As seen in Attachment 2, a second Splice Joint (307A) had also degraded because of overheating.

The inspectors evaluated the condition of additional splice joints inside the switchgear room since this location mirrored the Unit 1 configuration, which had previously failed (refer to Inspection Report 50-275; 323/00-09). The inspectors noted that the aluminum tee had copper bus bar routed to Switchgears D and E after the first joint. The inspectors determined that the zinc-chromate grease remained in good condition, the splice joints had both single and double splice plates, the joints had no evidence of overheating (contrary to the condition found outside the turbine building). Because of the good condition of the bus bar inside the Unit 2 switchgear room, the inspectors concluded that a fault on the Unit 2 12 kV Auxiliary Bus would not have been as severe as Unit 1 and would not have affected the startup buses.

.2 Work History

Unit 1

The inspectors reviewed the scope of work completed during Refueling Outage 1R10, as documented in Action Request A0510961. The inspectors confirmed that the licensee had completed the following work activities:

a. For Startup Bus 1-1 from Startup Transformer 1-1 to the Startup Switchgear (3750A), for nontaped connections full face 3x6" splice plates were installed and torqued to 50 ft-lbs; booted connections had Raychem boots installed to replace the polyvinyl chloride boots and taped connections at 90 degree joints were visually inspected for signs of overheating; and connections had new bolts installed including Belleville washers.

b. For Auxiliary Bus 1-2 from Auxiliary Transformer 1-2 to Switchgears D, E and Vital Buses (F, G, and H), measured the as-found torque on selected joints and torqued all joints to 50 ft-lbs; replaced the straight polyvinyl chloride boots with Raychem boots since 90 degree Raychem boots were not available; and replaced the installed aluminum bus bar with copper bus bar.

c. For Auxiliary Bus 1-1 (replaced in May 2000), the licensee identified, during planned inspection of the bus, that a Raychem boot had discolored because of heat at the bolt locations at the high point. Subsequently, the licensee installed ventilation louvers instead of the breather tube to eliminate heat at this high point.

The inspectors reviewed the completed work packages and noted the following: (1) the as-found torque values for a small number of joints were less than 20 ft-lbs; (2) the licensee identified the as-built configuration of all joints inspected; (3) the licensee identified the joints not inspected so that corrective actions could be implemented during a future inspection; and (4) identified some evidence of overheating as revealed by some leaching of elasticizer from a small number of bus bar joints. The inspectors considered these corrective actions reasonable considering the short period of time allowed to plan the work and procure the necessary parts for the unique configurations. The joints not inspected were either taped (i.e. had an unusual shape that required other than a straight Raychem boot) or were located in a fire barrier.

The inspectors determined that these corrective maintenance activities, combined with the operating conditions for the buses (continuously loaded and heavily loaded), reduced the risk of another fault occurring on Unit 1.

<u>Unit 2</u>

From review of the Unit 2 maintenance records, the inspectors determined that the licensee had worked on the affected joint in April 1996, while replacing the existing insulation with Raychem insulation. As indicated in Action Requests A0400090 and A0400295, the licensee found cracked insulation on the 12 kV buses. The licensee inspected the Unit 2 bus bars after finding cracked insulation pieces in the Unit 1 buses following a 1996 transformer failure. The licensee found hairline cracking of the insulation on the 4 kV bus bars. The licensee taped the 4 kV bus bars with insulating tape in accordance with vendor recommendations since the hair line cracks did not affect the integrity of the bus bar insulation. The inspectors noted that the work order indicated that personnel torqued the joints to 50 ± 5 ft-lbs, which agreed with the vendor manual bolting requirements. The licensee inspected the condition of the 4 kV bus bar insulation cracks during this outage. The licensee noted no significant degradation.

In March 1998, the licensee inspected the protective boots in this bus duct to look for degradation. The records indicated that the inspections found the protective boots in good condition.

From May 3-6, 2001, the inspectors observed disassembly, inspection, and torquing of selected splice plates for the bus bars for Auxiliary Transformers 2-1 and 2-2. The inspectors verified that the scope of the planned work agreed with the commitments contained in Licensee Event Report 50-275/2000-004-01 and Nonconformance Report N0002112. The inspectors reviewed the as-found torque, micro-ohm, and splice joint condition for the joints sampled by the maintenance personnel. The inspectors noted that the joints did not indicate any significant deficiencies other than the joint that had been found overheated.

The inspectors determined that these corrective maintenance activities, once completed, combined with the operating conditions for the buses (continuously loaded and heavily loaded), reduced the risk of another fault occurring on Unit 2.

.3 Design Requirements

As described in Inspection Report 50-275; 323/00-09, the vendor could not provide qualification test reports to demonstrate viability of the various bus bar configurations at Diablo Canyon. The licensee concludes in Nonconformance Report N0002112 that the operating experience at Diablo Canyon provides the best basis for the ampacity ratings of the installed 3750A Bus Bars. This engineering judgement was provided after the licensee could not locate a test report that would support qualification of these bus bars. The licensee found no evidence that the bus bars had experienced any significant degradation. In addition, the 3750A Bus Bars are normally unloaded, rarely loaded, and the maximum design load is 3400A. Because of the lack of identified degradation and establishment of a preventive maintenance task to periodically inspect the bus bars, the licensee concluded that the bus bars could be used. The licensee concluded the preventive maintenance program combined with the refurbished bus bars in Refueling Outages 1R10/2R10, 1R11/2R11, and 1R12/2R12 provide assurance that any future degradation would be identified prior to reaching unacceptable levels.

.4 Corrective Actions

Following the May 2000, bus bar failure, the licensee established a priority for evaluating the buses based upon factors that increased the risk of a splice joint failure, as identified in Nonconformance Report N0002112. The licensee attributed the failure to a heavily loaded bus (relative to the rated load and to the size/area of the splice plates), whether the bus is continuously loaded or normally unloaded (the auxiliary versus the startup buses), and inconsistent silver plating. Other interactions that may have contributed to the failure included off-gassing of the polyvinyl chloride boot. These conditions resulted in the following buses being identified as most susceptible: 12 kV buses from Auxiliary Transformer 2-1, 4 kV auxiliary buses for Units 1 and 2, and the 12 kV startup bus for Unit 1.

The inspectors noted that the licensee expressed surprise at the amount of overheating and degradation identified at Joint 309. The licensee concluded that the joint would not have lasted another operating cycle without failing. The licensee estimated that the joint could have failed within 4-6 months since the failure mechanism (increased resistance resulted in increased heating that increased the degradation/resistance, et cetera) was increasing exponentially. The inspectors concluded that the licensee had missed a failure by a small margin. The inspectors noted that had a failure occurred that the power supply to the reactor coolant pumps and circulating water pumps would have tripped. An anticipatory reactor trip would have occurred. The event would have resulted in a loss of load reactor trip with loss of normal heat removal. This type of failure is tracked by the performance indicators.

Following the failure of the Unit 1 bus bar in May 2000, the inspectors agreed with the licensee decision to delay inspecting Unit 2 since: (1) the bus bars had been recently torqued (5 years on Unit 2 versus 20+ years on Unit 1) and (2) an inspection 2 years previously had identified no degradation.

As of the end of this inspection, the licensee had not received the analysis results from their offsite vendor for the likely cause of Joint 309 overheating. The inspectors determined that the licensee had provided portions (e.g., bus bar pieces, splice plates, boot, and insulation) of both the overheated joints and a good joint for analysis. The inspectors will review the results of this analysis once completed for any additional regulatory response that may be required.

Work activities outstanding that need to be completed in Refueling Outages 1R11/2R11 include: (1) Startup Transformer 1-1 replace taped connections and use larger splice plates; (2) Auxiliary Transformer 1-2(2-2) to Buses D and E and vitals replace taped connections; (3) Startup Transformer 1-2(2-2) to Buses D and E and vitals replace taped connections; and (4) 12 kV startup switchgear to Startup Transformer 1-2(2-2) replace taped connections. The licensee documented the work scope for the Unit 1 and 2 outages on Action Requests A0510972 and A05100973, respectively.

.5 Risk Assessment

Had this degraded condition not been corrected, a failure would have resulted in a loss of load reactor trip with a loss of the power conversion system. This event would have been captured by the performance indicators for reactor scram with loss of the power conversion system.

c. Observations and Findings

No findings of significance were identified.

4OA5 Other

Evaluation of Diablo Canyon Safety Condition in Light of Power and Financial Conditions

a. Inspection Scope

Because of the energy situation in California, Region IV initiated special review processes for Diablo Canyon. The residents evaluated the following factors each week to determine whether the financial condition and power needs of the station impacted plant safety. The resident inspectors briefed the responsible managers in Region IV on these factors. The factors reviewed included: (1) impact on staffing, (2) corrective maintenance backlog, (3) changes to the planned maintenance schedule, (4) reduction in outage scope, including risk-significant modifications, (5) availability of emergency facilities and operability of emergency sirens, and (6) grid stability (i.e., availability of offsite power to the switchyard, status of the operating reserves especially onset of rolling blackouts, and main generator VAR loading.)

Additionally, the resident inspectors provided status daily on the energy supply situation, operating reserves, and availability in the California market. Managers have increased their presence by performing monthly visits to assess site conditions, including employee morale, licensee initiatives, and specific technical issues.

4OA6 Management Meetings

Exit Meeting Summary

The inspectors presented the inspection results to Mr. J. Becker, Station Director, and other members of licensee management at the conclusion of each regional inspection during the inspection period. The resident inspection results were presented on May 18, 2001. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT 1

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. R. Becker, Station Director
D. D. Christensen, Engineer, Nuclear Quality Assurance and Licensing
R. E. Hite, Director, Radiation Protection
S. C. Ketelsen, Supervisor, Regulatory Services
D. B. Miklush, Director, Engineering Services
P. T. Nugent, Director, Regulatory Services
D. H. Oatley, Vice President
J. W. Tompkins, Director, Nuclear Quality Analysis and Licensing
R. A. Waltos, Director, Maintenance Services

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Opened and Closed During this Inspection

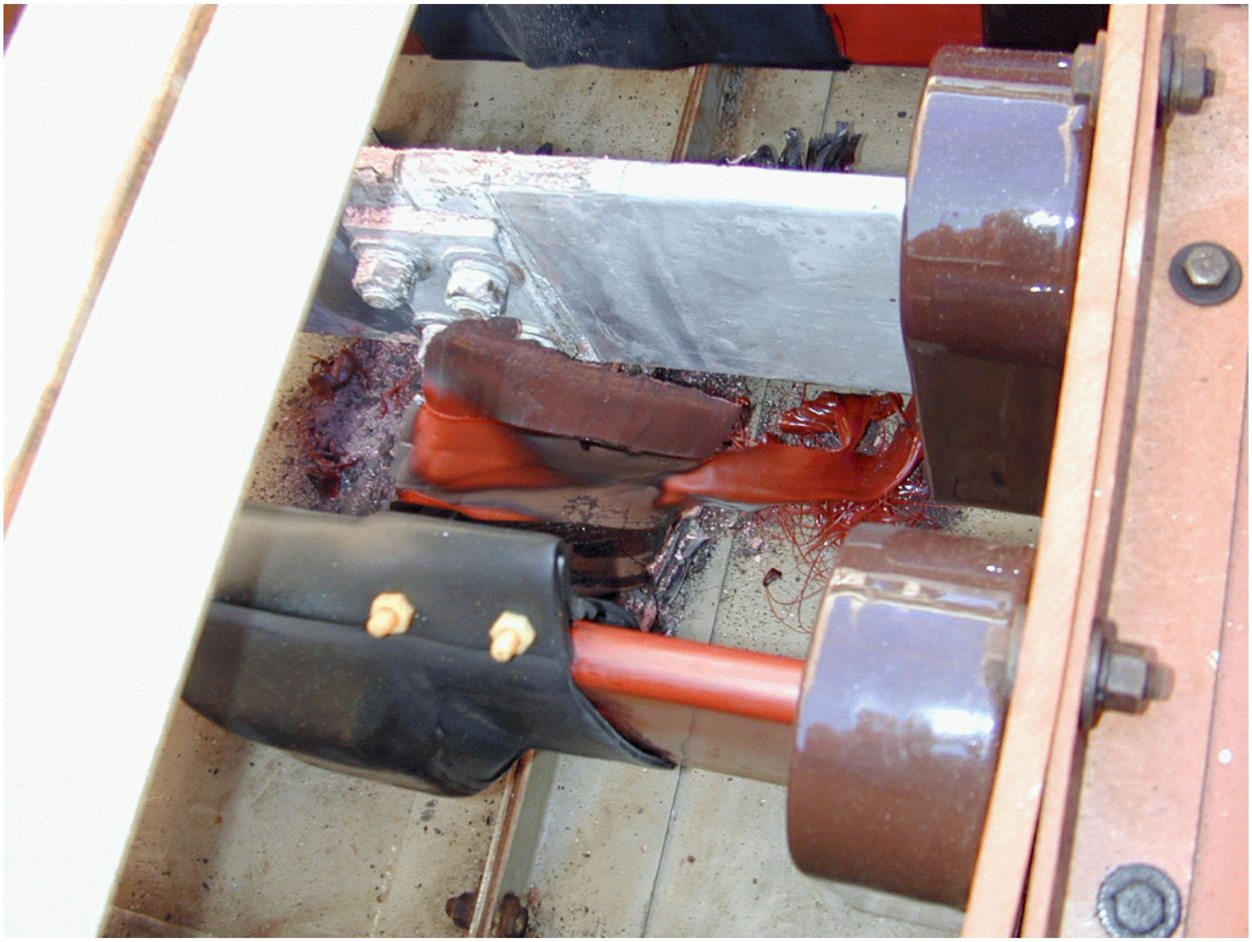
323/2001003-01	NCV	Technical Specification 3.0.3 violation for rendering all three emergency power sources for Unit 2 Vital Bus H inoperable (Section 1R13)

Previous Items Closed

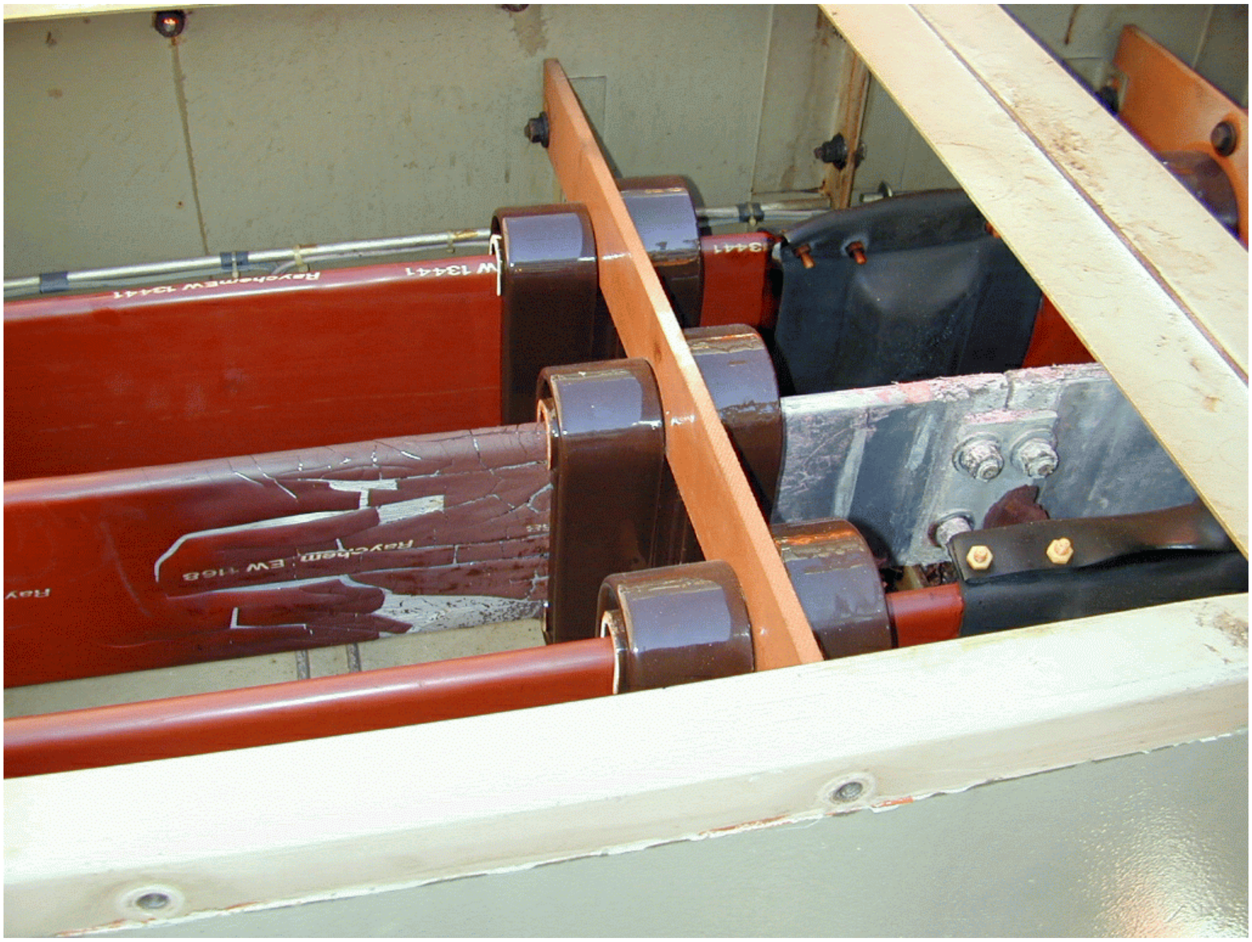
None

LIST OF ACRONYMS USED

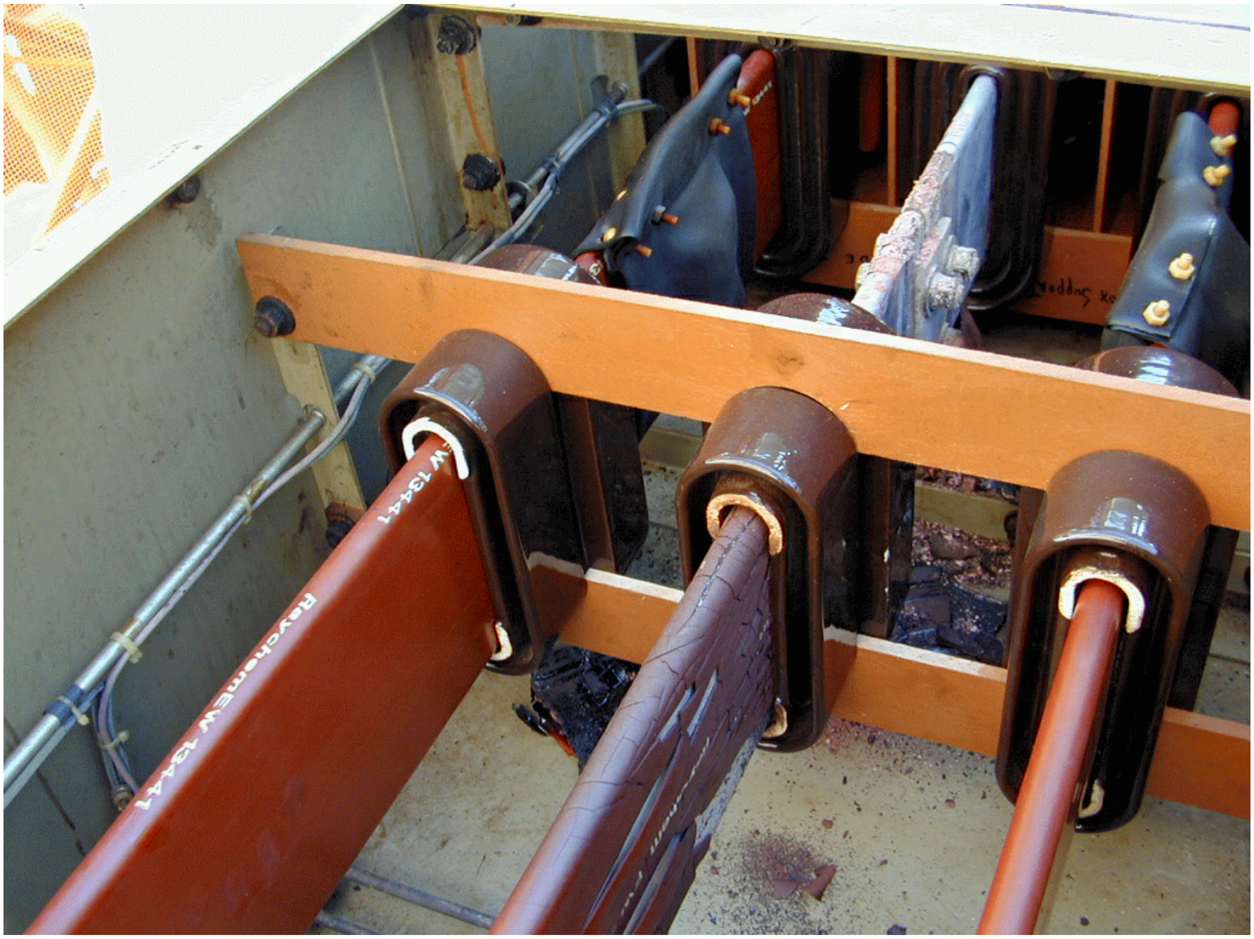
CFR	Code of Federal Regulations
ft-lbs	foot-pounds
kV	kilovolts
NCV	noncited violation
NRC	Nuclear Regulatory Commission
VAR	volt-amperes reactive



View 1 of BUS 309 Showing degraded Insulation on Bus Bar.



View 2 of BUS 309 Showing degraded Insulation on Bus Bar



View 1 of BUS 309 Showing degraded Insulation on Bus Bar