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

July 31, 2000

Gregory M. Rueger, Senior Vice President
and General Manager
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Nuclear Power Generation, B32
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San Francisco, California 94177

SUBJECT: DIABLO CANYON INSPECTION REPORT NO. 50-275/00-09; 50-323/00-09

Dear Mr. Rueger:

From May 15 through June 29, 2000, the NRC conducted a special inspection at your Diablo Canyon Power Plant facility. The enclosed report presents the results of this inspection. The inspection evaluated your response to the fire in the Unit 1 nonvital 12 kV nonsegregated electrical bus and the loss of offsite power to certain 4 kV vital and nonvital buses. The results of this inspection were discussed on June 29, 2000, with you and members of your staff during a public exit meeting.

This inspection was chartered to review the root cause and extent of condition of the event, the corrective actions taken to remedy the damage, and your staff's actions following the discovery of the fire and the resultant loss of offsite power. The inspectors reviewed selected procedures and records, observed restoration and evaluation activities, and interviewed plant personnel. The inspectors also performed several related baseline inspections as documented in the enclosed report. As a result of this inspection, the NRC has developed a sequence of events, determined the risk significance of the event, and assessed the quality of response of your plant staff and managers. The long-term actions to prevent recurrence will be evaluated separately. We will evaluate the design issues identified during this inspection as information for generic communications to the industry.

We have determined that, after the main generator trip, offsite power was unavailable to the vital electrical buses. Even though all vital equipment operated as required, the risk associated with this event was significant. The turbine trip was initiated by a short circuit in the 12 kV nonvital bus bars from Unit Auxiliary Transformer 1-1 to Switchgear D and E. This resulted in a fire followed by a loss of offsite power to the vital buses for 33 hours. Because the fire burned for greater than 15 minutes, the shift manager declared an Unusual Event (the first level of emergency action in the NRC-required emergency response plan). After the fire was extinguished, the shift manager remained in the Unusual Event because of the loss of offsite power. The inspectors noted that no radioactivity was released offsite above normal background levels and that the event did not impact public health and safety.

Your staff acted expeditiously to assure that the health and safety of the public was maintained. Specifically, operators promptly and appropriately completed the actions specified in the emergency operating procedures to place the reactor in a stable configuration. The fire brigade responded in a timely manner and quickly extinguished the fire, as specified in the firefighting preplans. Operators appropriately notified the NRC Operations Center and state and local government officials and properly classified the event, as specified by regulations and required by your emergency plan.

The inspectors found that your staff thoroughly evaluated the electrical bus failure, identified the most probable root causes, and identified the extent of conditions on Units 1 and 2. Your staff took prudent actions to ensure that the failure would not likely recur until your long-term actions can be implemented (during each of the upcoming refueling outages). The inspectors verified your immediate corrective actions prior to restart of the unit and will evaluate your long-term actions during a later inspection.

Based on the results of this inspection, the NRC has identified two issues, for which their risk was evaluated in accordance with the significance determination process, as having very low safety significance (Green). In the first instance, in order to bound the risk associated with the bus fault, the inspectors assumed that the root cause could be attributed to a failure to torque electrical splice joint bolts (Note: the root cause analysis actually identified several potential factors, none of which could be determined to be the single cause of failure). A qualitative/quantitative assessment of the risk associated with this finding identified that the error had very low risk significance. In the second instance, your staff determined that operators had failed to follow the requirements of their Technical Specifications. This second issue was also determined to have very low risk significance. The NRC has determined that, for this second instance, a violation of Technical Specification 3.5.1 occurred. It is being treated as a noncited violation, consistent with Section VI.A of the Enforcement Policy. The noncited violation is described in the subject inspection report. If you contest the violation or significance of the noncited 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 a copies to the Regional Administrator, Region IV, the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, and the NRC Resident Inspector at Diablo Canyon.

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).

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

/RA/

Ken E. Brockman, Director
Division of Reactor Projects

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

Enclosure:
NRC Inspection Report No.
50-275/00-09; 50-323/00-09

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket Nos.:	50-275 50-323
License Nos.:	DPR-80 DPR-82
Report No.:	50-275/00-09 50-323/00-09
Licensee:	Pacific Gas and Electric Company
Facility:	Diablo Canyon Nuclear Power Plant, Units 1 and 2
Location:	7 ½ miles NW of Avila Beach Avila Beach, California
Dates:	May 15 - June 29, 2000
Inspectors:	G. A. Pick, Senior Project Engineer, Division of Reactor Projects (DRP) D. L. Proulx, Senior Resident Inspector, DRP D. G. Acker, Resident Inspector, DRP W. B. Jones, Senior Reactor Analyst, Division of Reactor Safety (Regional Assistance)
Approved By:	L. J. Smith, Chief, Branch E, DRP

ATTACHMENTS:

1. Supplemental Information
2. NRC'S Revised Reactor Oversight Process
3. Diablo Canyon Electrical Distribution
4. Bus Bars and Switchgear Cubicle Damage
5. Chronological Sequence of Events Diablo Canyon Unit 1 12 kV Bus Fault
6. Diablo Canyon Unit 1 Special Inspection Charter
7. Public Exit Slides
8. Switchgear Room Bus Duct Proximity

SUMMARY OF FINDINGS

Diablo Canyon Nuclear Power Station
NRC Inspection Report 50-275/00-09; 50-323/00-09

The report covers a special inspection that assessed the licensee response to a fire in a 12 kV nonsegregated electrical bus and a subsequent loss of offsite power to the vital 4 kV buses. The inspectors performed onsite inspection from May 15 - 26, and June 26 - 29, 2000. In addition, the inspectors performed several baseline inspections, as appropriate, during their review of licensee activities. This executive summary summarizes the results of the individual items listed in the inspection charter (Attachment 6) and summarizes any findings identified during implementation of related baseline inspection procedures. NRC will evaluate the design issues identified during this inspection as information for generic communications to the industry

Background

Diablo Canyon Unit 1 has a normal supply of power to the onsite loads from the main generator to the 25/12 kV and 25/4 kV Unit Auxiliary Transformers 1-1 and 1-2, respectively. After a reactor trip, the power supply for the onsite loads transfers to Startup Transformers 1-1 and 1-2 for the 12 kV and 4 kV loads, respectively. The Diablo Canyon Electrical Distribution is displayed in a schematic in Attachment 3.

Event Overview/Significance

On May 15, an electrical fault (short circuit) isolated the normal supply to the 12 kV nonvital loads supplied by Unit Auxiliary Transformer 1-1 and a fire in the 12 kV bus to nonvital Switchgear D and E (refer to Attachment 4 for photographs of damaged bus and breaker cubicles). The transfer to Startup Transformer 1-1 properly occurred and the 12 kV onsite loads remained operating. The initial fault caused a secondary fault in the bus bars from Startup Transformer 1-2 Winding X that supplied 4 kV nonvital Bus D and 4 kV Vital Buses F, G, and H. A circuit breaker immediately before Startup Transformer 1-2 opened on differential current. This resulted in the loss of offsite power to all vital and nonvital 4 kV buses, a condition that was not corrected for 33 hours. The diesel generators and all other vital equipment operated as designed. Operators entered their emergency operating procedures and appropriately responded to the event.

The licensee performed the necessary actions to mitigate this event, which included declaring an Unusual Event, extinguishing the fire, cooling down the reactor coolant system, and restoring offsite power. The inspectors noted that no radioactivity was measured offsite in excess of normal background levels. Although this event did not impact the health and safety of the public, the Senior Reactor Analyst determined that the conditional core damage probability (the risk associated with this loss of offsite power under the existing plant conditions) reflected a risk significant event. This evaluation identified the increase in risk given that offsite power to the 4 kV vital buses was lost for 33 hours with all vital power and equipment available.

Emergency Classifications and Notifications

The inspectors determined that operators properly classified this event as an Unusual Event in accordance with their emergency plan. The licensee provided a timely initial notification;

however, the inspectors noted that the licensee incorrectly reported that Unit Auxiliary Transformer 1-1 had exploded and that a main steam safety valve had stuck open. The inspectors determined that the licensee and the NRC had been aware early on that the transformer had not exploded and that the main steam safety valve had not stuck open. Eventually, the licensee formally provided an updated notification that corrected this misinformation. The inspectors concluded that this misinformation did not affect the operators' response to the event or the NRC's understanding of the event.

Fire Brigade Notification and Response

The inspectors determined that the fire brigade was notified in a timely manner of a fire in the 12 kV switchgear room. The inspectors determined that the fire brigade responded quickly to the report of a fire and effectively implemented the fire fighting preplan strategy.

Root Cause Analysis/Extent of Condition Determination

Based on the inspectors' observation of the damaged areas and review of the design for the bus bars, the inspectors concluded that the initial root cause review had identified the most likely causes. The inspectors concluded that the design of the 12 kV and 4 kV electrical systems at Diablo Canyon did not violate any licensing requirements. However, the inspectors also concluded that the vendor acceptance testing was marginal to support that some of the bus bars had adequate current carrying capacity within allowed heat rise standards and that the design for some of the bus bars did not meet some general industry guidance.

The inspectors found that the licensee performed a detailed evaluation of the damage that resulted from the fire in the 12 kV bus duct. The licensee repaired and refurbished all damaged components, inspected and torqued accessible splice joints on the 12 kV auxiliary bus and 4 kV startup bus, and performed postmaintenance tests to ensure that the bus bars were properly restored. In addition, the licensee evaluated whether a similar defect was likely to occur on Unit 2. Because the licensee had previously inspected and torqued the splice plates for the Unit 2 bus, similar to the one that failed in Unit 1, the inspectors agreed that Unit 2 was not likely to experience a similar failure.

Cornerstone: Mitigating Systems

- Green. During the reactor coolant system cool down from normal operating pressure and temperature to Mode 4 (Hot Shutdown), operators energized the safety injection accumulator discharge isolation valves with reactor coolant system pressure at 1500 psig. With the valves energized, operators could have inadvertently isolated the safety injection accumulators. Approximately 3 hours later, with reactor coolant system pressure at 1122 psig, the operators recognized that Technical Specification 3.5.1 prohibited these valves from being energized and entered Technical Specification 3.0.3. Reenergizing the safety injection accumulator discharge isolation valves violated Technical Specification 3.5.1. This violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy.

The inspectors assessed the risk significance of this finding using the significance determination process and determined that this event had very low risk significance. The inspectors used the Phase I worksheet and determined that this event affected a mitigating system. The inspectors assumed that the operators had closed the safety injection accumulator isolation valves and would not be able to recover the components. With this conservative assumption, the Phase 1 screening required a Phase 2 review because of the inability to inject water using the accumulators. From the Phase 2 review, the inspectors identified one sequence affected in the large break loss of coolant accident and one sequence affected in the small break loss of coolant accident. These evaluations resulted in very low risk significance based on the low initiating event frequency for loss of coolant events and availability of other mitigating equipment. The licensee included this item in their corrective action program as Action Request A0508060 (Section 1R14.1).

- Green. The inspectors found that this event likely resulted from a combination of design deficiencies and the potential failure to properly torque the failed joint following the 1995 Unit Auxiliary Transformer 1-1 explosion. In order to determine the increase in risk associated with this event, the inspectors assumed the bus bar failure resulted from inadequate torquing of the joint (inadequate corrective actions) following the 1995 transformer explosion.

  Using the significance determination process, the Senior Reactor Analyst found that this performance issue of inadequate corrective actions had very low risk significance. The Phase 2 risk assessment determined that there was no appreciable change in the core damage frequency. However, the worksheets for Transient and Loss of Offsite Power did not fully account for the loss of the nonvital bus bars from the unit auxiliary and startup transformers. In addition, the fire contribution needed to be considered. Consequently, the Senior Reactor Analyst conducted a Phase 3 evaluation, using site specific probabilistic risk assessment information related to the mitigating capability of and initiating frequency contribution to the 12 kV nonvital switchgear. From evaluation of the accident sequences that this event impacted, the Senior Reactor Analyst again concluded that minimal change in the core damage frequency occurred. The minimal changes in core damage frequency resulted because the licensee had already modeled that this event had a high likelihood of occurring. This event did not disable any vital equipment and all vital equipment operated as designed (Section 4AO3.3).

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Report Details

Summary of Plant Status:

On May 15, 2000, following a fault in the nonvital (nonsafety-related) switchgear room, the reactor tripped and operators stabilized the plant in Mode 3. Operators restarted the plant on May 26. The plant achieved 100 percent power on May 29 and maintained that level throughout the remainder of the inspection period.

Unit 2 operated at 100 percent power throughout this inspection.

Introduction

Following the 12 kV nonvital bus fire and loss of offsite power to the 4 kV vital buses on May 15, the licensee declared an Unusual Event. The inspectors responded to the site and provided continuous coverage until the offsite power was restored and the diesel generators were secured. The inspectors evaluated the event and licensee mitigating actions as specified in Inspection Procedure 71153, "Event Followup." Based on communications with the licensee, NRC knowledge of the plant response, and an initial determination that this was a risk significant event, NRC dispatched a special inspection team of three inspectors. The inspectors evaluated licensee activities following the guidance in Inspection Procedure 93812, "Special Inspection." The inspectors performed several baseline inspection procedures in conjunction with this special inspection. In addition, the inspectors evaluated the items listed in the Inspection Charter (refer to Attachment 6). The report sections that address the points of the Inspection Charter are 1R05, 1EP1, and 4OA3.

Event Description

On May 15, at 12:25 a.m. (PDT), a differential relay detected an electrical fault, which tripped Unit 1 from 100 percent power, tripped associated offsite supply circuit breakers, and tripped a field breaker supplying current to the voltage regulator for the generator field. The electrical fault occurred on the 12 kV bus bars from Unit Auxiliary Transformer (UAT) 1-1 that supplied the 12 kV nonvital Buses D and E (refer to Attachment 3) and resulted in a fire in the nonvital switchgear room. The fault on the 12 kV bus bar continued to be fed for 4-8 seconds by the decay of the main generator electrical field during generator coast down; this contributed to the catastrophic failure of the bus bars. This additional energy feeding into the fault resulted in a secondary phase-to-phase fault on the Startup Transformer (SUT) 1-2 bus from Winding X (upstream of the split to nonvital Bus D and vital Buses F, G, and H). Breaker 52VU14 in the 12 kV switchgear that supplied SUT 1-2 tripped on high differential current, which resulted in a loss of preferred offsite power to 4 kV vital (safety-related) Buses F, G, & H and nonvital Buses D & E. As designed, all diesel generators started and the vital loads sequenced on automatically.

Operators appropriately implemented the emergency operating procedures and ensured that the plant was in a safe, steady-state condition. After completing the actions specified in the emergency operating procedures, operators transitioned into procedures that provided instructions for cooling down the plant. At 8:54 a.m. operators initiated a plant cool down to 390°F. The operators identified this hold point for reactor coolant system chemistry concerns and to get below a temperature limit in the reactor cavity area, which was a concern because of the loss of control rod drive mechanism cooling. Operators stabilized the reactor at 380°F, 900 psig at 3:35 p.m. and maintained these conditions for approximately 26 hours. At 5:03 p.m. the plant process computer failed because of a loss of battery power. On May 16, at 8:52 a.m., plant personnel energized the 4 kV and 480 Vac nonvital buses by back feeding through UAT 1-2. At 9:59 a.m. the shift manager exited the Unusual Event since offsite power had been restored to the vital buses and the diesel generators had been secured.

1 REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness

1R04 Equipment Alignments (71111.04)

Partial System Walkdowns (Unit 1)

a. Inspection Scope

While offsite power to Unit 1 was unavailable, the inspectors verified equipment alignment of the operating diesel generators and evaluated whether any discrepancies could impact the function of the equipment. Specifically, the inspectors walked down the fuel oil trains of the three operating diesel generators, observed the operating parameters of these diesel generators, reviewed the clearances that isolated the diesel generators from the faulted offsite power, observed control board circuit breaker line-ups for operating safety-related equipment, and observed clearance changes for restoring offsite power.

b. Issues and Findings

The inspectors identified no findings during this inspection.

1R05 Fire Protection (71111.05, 71153, 93812)

Annual Drill

a. Inspection Scope

The inspectors evaluated the readiness of personnel to fight fires, including the fire brigade notification, onsite response, and offsite response to the report of fire in the 12 kV switchgear room. In addition, the inspectors evaluated the effectiveness of the fire brigade response as it related to the fire fighting preplan strategy, command and control of the fire brigade leader during fire fighting efforts, availability of personnel and equipment, radio communications with plant operators and among fire brigade members, smoke removal operations, and the method of entry into the fire area.

The inspectors interviewed fire brigade members; evaluated personnel statements of operators, fire brigade members, and security officers; reviewed Procedures CP M-6, “Fire,” Revision 24 (provided actions taken in response to a fire), and CP M-6B, “Fire

Fighting Pre Plans - Turbine Building and Transformer Areas," Revision 1 (provided fire fighting strategies);" reviewed Updated Final Safety Analysis Report Chapter 9.5; reviewed sequence of event printouts; reviewed card reader transaction and zone alarm histories for the doors into the room; and reviewed Action Request A0508047.

b. Assessment

Following reports by security officers of a fire at UAT 1-1, operators notified the fire brigade. At 12:43 a.m., the fire brigade arrived at the 12 kV switchgear room, contacted the control room and informed the control room that the fire was internal to the switchgear room and not associated with UAT 1-1. Given the large amount of smoke, the Fire Brigade Captain requested help from the California Department of Forestry. Because of the request for offsite fire fighting assistance, the large amount of smoke being reported and knowledge that a fire had been ongoing for at least 18 minutes, the shift manager declared an Unusual Event and contacted the California Department of Forestry, as requested.

The inspectors determined that the fire brigade was notified within 2 minutes and responded to the 12 kV switchgear room within 18 minutes following the reactor trip. The fire brigade had extinguished a small fire in the 12 kV nonsegregated bus duct with a carbon dioxide extinguisher within 17 minutes of arriving at the switchgear room. The fire brigade effectively ventilated the room using the fire preplan. The inspectors concluded that the fire brigade and security officers worked effectively.

The California Department of Forestry arrived on site at 1:39 a.m., within 51 minutes of being notified. The shift manager declared the fire out at 1:43 a.m. Since the fire was out, the offsite assistance was not required. Consequently, the Fire Brigade Captain released the California Department of Forestry at 2:30 a.m.

c. Issues and Findings

The inspectors identified no findings during this inspection.

1R12 Maintenance Rule Implementation (71111.12)

Routine Reviews

.1 12 kV system

a. Inspection Scope

The inspectors reviewed licensee evaluations of the 12 kV system failure that occurred to determine if the failure was properly classified, what components were scoped, and if the components were in (a)1 or (a)2, as specified in the Maintenance Rule and the licensee program. The inspectors reviewed the maintenance history, reviewed vendor information, reviewed the Maintenance Rule classification data, and interviewed engineering personnel.

b. Assessment

The licensee had included the 12 kV system under the Maintenance Rule. Selected parts of the 12 kV system had specific performance criteria; however, the 12 kV bus bars that failed were monitored using plant level criteria because the licensee had concluded that the only risk from bus failure was a reactor trip. In addition, the 12 kV busing was not considered risk significant by the expert panel. The inspectors found that the licensee did not have any preventive maintenance requirements for the bus bars. The licensee stated that the vendor did not recommend any preventive maintenance.

Based on the vendor information and internal review, the licensee decided that the bus bars would operate satisfactorily without maintenance until the next refueling outage. Even though the exact failure mechanism was not known, the inspectors observed that preventive maintenance such as torque checks, visual inspections, and micro-ohm tests could have eliminated some of the potential causes for the failure.

c. Issues and Findings

The inspectors identified no findings during this inspection.

.2 Additional Component Reviews

a. Inspection Scope

The inspectors reviewed licensee evaluations of selected component failures that occurred during the event to determine if the failures were properly classified, if the components were scoped, and if the components had performance goals or performance criteria, as specified in the Maintenance Rule and the licensee program. Components evaluated included:

- Component Cooling Water Pump 1-2 shaft driven oil pump failure - The inspectors reviewed this failure as documented in Action Requests A0508243, discussed the failure with licensee personnel, and reviewed the Maintenance Rule functional failure determination.

- Train A Central Control Unit for main annunciators lockup - The inspectors reviewed the failure of Main Annunciators Train A during the event as documented in Action Requests A0508282 and A0508045. The inspectors reviewed Action Request A0506562 that had resulted in the main annunciators being placed in (a)1 on April 19.

b. Issues and Findings

The inspectors identified no findings during this inspection.

1R13 Maintenance Risk Assessment and Emergent Work Control (71111.13 and 93812)

Current Activities

a. Inspection Scope

The inspectors evaluated risk assessments performed following the 12 kV fire and loss of offsite power. The inspectors reviewed whether the licensee took necessary steps to control the contribution to risk of emergent work activities and to reassess planned work activities because plant conditions had changed.

The inspectors verified that the licensee complied with the requirements of Procedure AD7.DC6, “On-line Maintenance Risk Assessment,” Revision 4A. The inspectors evaluated the coordination of the work planners and control room operators with risk assessment personnel. The inspectors ensured that the licensee implemented the activities with a maximum amount of precaution and at as low a level of risk as possible. The inspectors reviewed the following activities:

- The risk associated with the clearance of the main electrical bank transformers so that back feeding could be initiated.

- The risk associated with operating each diesel generator on May 16 in accordance with Technical Specification 3.8.1.1.a. Operators ran the diesel generators in accordance with Procedure STP M-9A, “Diesel Engine Generator Routine Surveillance Test,” Revision 55.

- The risk related to testing the diesel generators in accordance with Technical Specification 3.8.1.1.c on May 25, combined with SUT 1-2 being out of service for testing. This combination of components out-of-service resulted in probabilistic risk assessment allowed outage times of 12, 9, & 13 hours for Diesel Generators 1-1, 1-2, and 1-3, respectively. Each diesel generator was operated for approximately 5 minutes in accordance with Procedure STP M-9X, “Diesel Generator Operability Verification,” Revision 12.

b. Issues and Findings

The inspectors identified no findings during this inspection.

1R14 Personnel Performance During Nonroutine Plant Evolutions (71111.14, 71153, 93812)

Reactor Scram Response, Plant Cool Down, and Post-trip Review

.1 Operator Performance

a. Inspection Scope

The inspectors evaluated the operator response to the reactor trip and loss of offsite power, including the post-trip review. The inspectors evaluated the response against the requirements of Emergency Operating Procedures E-0, “Reactor Trip or Safety Injection,” Revision 24, E-0.1 “Reactor Trip Response,” Revision 22, and the Technical Specifications. The inspectors interviewed operators who had been on duty during the event, reviewed control room logs, and reviewed plant process computer printouts. The inspectors had responded to the event and were able to monitor operator performance after the reactor had been stabilized. The inspectors reviewed the Operations Incident Summary for this event and the additional lessons learned for Procedure AP-26, “Loss of Offsite Power,” Revision 3.

b. Assessment

Initial Response

At 12:25 a.m., operators promptly entered Procedure E-0 in response to the reactor trip. Numerous smoke detectors in the 12 kV switchgear room alarmed annunciators in the control room, and operators received a report of fire in the 12 kV switchgear room from a security officer. Operators gained control of the reactor coolant system cool down by throttling auxiliary feedwater flow. At 12:30 a.m., operators transitioned to Procedure E-0.1. Operators took the necessary actions to transfer the pressurizer heaters to their backup vital power supply. An equipment operator at the intake structure reported that circulating water pump motor temperatures were rising. At 12:37 a.m., operators secured Circulating Water Pump 1-2 (because of a loss of cooling water to the motor), closed the main steam isolation valves and adjusted the setpoints for the 10 percent atmospheric relief valves. Main Steam Safety Valve RV-7 lifted at approximately 1047 psig (low end of operating band).

At 12:45 a.m., operators shut Valve LCV-8, hotwell makeup from the condensate storage tank, since it had failed open on a loss of power, as designed. At 1:06 a.m., operators noticed that the level in Steam Generator 1-2 continued to drop while the level in the other steam generators had begun to stabilize. Operators manually opened Valve MS-1-PCV-20, 10 percent atmospheric relief valve, to lower the steam line pressure and, by 1:52 a.m., reseated Main Steam Safety Valve RV-7. At 2 a.m., operators entered Procedure OP L-7, “Plant Stabilization Following Reactor Trip,” Revision 6. At 4:20 a.m., operators powered normal lighting to the Unit 1 side of the control room from Unit 2. At 5:45 a.m., high temperature alarms occurred in the reactor cavity area because the cooling fans had lost their 4 kV power source. Procedure AR-PK-03-22, “Control Rod Drive Mechanism Fans Suction Temperature Hi/Lo,” Revision 8B, required that the unit be cooled down below 392°F to prevent overheating the control rod drive mechanism coils and control cables.

Plant Cooldown

At 8:54 a.m., operators transitioned to Procedure OP L-5, “Plant Cooldown From Minimum Load to Cold Shutdown,” Revision 52, to cool down the unit to 390°F. At 12:07 p.m. with reactor coolant system pressure at 1500 psig, operators restored power to safety injection accumulator discharge isolation valves. At 2:55 p.m., the shift foreman recognized the safety injection accumulator discharge isolation valves were energized with reactor coolant system pressure at 1122 psig and entered Technical

Specification 3.0.3. The operators promptly lowered reactor coolant system pressure below 1000 psig, as required to comply with Technical Specification 3.5.1.a.

During the cool down, operators restored power while implementing Procedure OP L-5, step 6.2.17. This step had operators close the breakers, close the accumulator isolation valves, and open the breakers once primary pressure decreased to about 900 psig. Because of a high subcooling margin, the shift foreman had directed that equipment operators rack-in the breakers for the safety injection accumulator valves and make preparations to close the valves to ensure an orderly cool down. Initially, the shift foreman failed to recognize the Technical Specification requirement to be below a reactor coolant system pressure of 1000 psig before energizing the valves.

c. Issues and Findings

Operators restored power to all of the safety injection accumulator discharge valves when pressurizes pressure was above 1000 psig. The inspectors assessed the risk significance of this finding using the significance determination process and determined that this event had very low risk significance. The inspectors used the Phase I worksheet and determined that this event affected a mitigating system. The inspectors assumed that the operators had closed the safety injection accumulator isolation valves and would not be able to recover the components. With this conservative assumption, the Phase 1 screening required a Phase 2 review because of the inability to inject water using the accumulators. From the Phase 2 review, the inspectors identified one sequence affected in the large break loss of coolant accident and one sequence affected in the small break loss of coolant accident. These evaluations resulted in very low risk significance based on the low initiating event frequency for loss of coolant events and availability of other mitigating equipment. The inspectors found that the licensee attributed this violation of Technical Specification 3.5.1.a to personnel error. This violation is being treated as a noncited violation, consistent with Section VI.A of the Enforcement Policy. The licensee entered this problem in the corrective action program as Action Request A0508060 (275/0009-01).

.2 (Closed) Licensee Event Report 50-275/00-005-00: entry into Technical Specification 3.0.3 after power restored to reactor coolant system accumulator valves because of personnel error.

The deficiency described in this licensee event report is documented in Section 1R14.1. The inspectors identified the failure to comply with Technical Specification 3.5.1 as a noncited violation.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the operability evaluations for the mitigating system components described below to ensure that the evaluation properly justified operability and that no unrecognized increase in risk occurred.

- Residual Heat Removal Pump 1-2 excessive shaft seal leakage documented in Action Request A0435047. The inspectors verified that the pump remained operable and capable of injecting water. In addition, the inspectors evaluated whether the leakage exceeded the limits specified in the Final Safety Analysis Report Update, Section 15.5.17.8.1 for exposure to operators. The inspectors independently verified the calculations performed to determine the leakage as documented in Procedure STP M-87, “Operational Leak Inventory of ECCS Systems Outside Containment Likely to Contain Highly Radioactive Fluids Following an Accident,” Revision 10.

- Valve PCV-455C stroked open in 4.3 seconds, which exceeded the limit of 2.9 seconds. The licensee evaluated this slow stroke time in Action Request A0508069. The inspectors reviewed the steps the licensee took to troubleshoot the slow stroke time. The inspectors evaluated the testing performed in Procedure STP V-3J2, “Exercising Pressurizer Power Operated Relief Valves PCV-455C, 456 and 474,” Revision 7. The inspectors reviewed the past operability evaluation for the as-found slow stroke time of Valve PCV-455C related to the steam generator tube rupture accident, spurious safety injection, and for low temperature overpressure protection.

b. Issues and Findings

The inspectors identified no findings during this inspection.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors observed and evaluated postmaintenance tests on UAT 1-1 and SUT 1-2 to verify that the transformers were capable of providing reliable electrical power to plant equipment after being subject to fault current. The postmaintenance tests measured turns ratios and winding resistance, analyzed oil samples, and performed high potential tests on the insulation in accordance with the following work orders:

- R0208252, R0192472 and C0167217 for UAT 1-1
- R0208252, R0192802 and C0167259 for SUT 1-2

b. Issues and Findings

The inspectors identified no findings during this inspection.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the tests below to ensure the equipment remained capable of performing its safety function. The inspectors reviewed the procedures to ensure that the test measured the required parameters and that the data was within specifications. The inspectors reviewed the routine operability test for Diesel Engine Generator 1-3 and the check valve leakage tests for the safety injection check valves that had been repositioned.

- Procedure STP M-9A, “Diesel Engine Generator Routine Surveillance Test,” Revision 55, performed on May 23.
- Procedure STP V-5A2, “Emergency Core Cooling System Check Valve Leak Test, Post-Refueling/Post-Maintenance Valves 8948 A-D and 8818 A-D,” Revision 7, performed on May 23.

b. Issues and Findings

The inspectors identified no findings during this inspection.

1R23 Temporary Plant Modifications (71111.23)

Periodic Evaluations

.1 Temporary Power to Plant Process Computer (Unit 1)

a. Inspection Scope

The inspectors evaluated the installation of temporary power to the plant process computer on May 15. The inspectors reviewed Jumper Log Entry 00-11, “Provide Unit 2 Power to Plant Process Computer Inverter Loads,” that implemented this temporary modification. The inspectors reviewed control room drawings and operator logs. In addition, the inspectors used Procedures OP AP-26 and CF4.ID7, “Temporary Modifications - Plant Jumpers and Measuring and Test Equipment,” Revision 7A as reference material.

The plant process computer provides indications and alarms in the control room to aid the operators and is normally powered through an inverter from Battery Charger 1-7 in the 125 Vdc nonvital distribution system. Upon loss of the battery charger, a static switch automatically transfers power from the inverter to a 480 Vac power supply, which is stepped down to 120 Vac. If the transfer fails, Battery 1-7 supplies power to the inverter for a finite period of time.

b. Assessment

When all nonvital 4 kV power was lost, Battery Charger 1-7 tripped off line and the alternate 480 Vac source also lost power, thereby causing the plant process computer to be powered from Battery 1-7. Procedure OP AP-26 listed the plant process computer, among other components, as an important load that required temporary power. However, the procedure did not provide direction for installing temporary power to any of the affected loads.

The system engineer evaluated the available options for providing temporary power to the plant process computer. Initially, the system engineer considered connecting a portable battery charger to the 125 Vdc bus, to supply power to the inverter. Subsequently, the licensee noted that the capacity of the portable charger was far less than the inverter loads (100 versus 140 amps) and was not a viable option. Secondly, the system engineer noted that 480 Vac power could be provided to the bypass circuit through the inverter static switch to provide power to the 120 Vac loads. The 480 Vac source could be provided from a weld receptacle on Unit 2; therefore, the system engineer commenced preparation of Jumper 00-11. While the system engineer prepared the package for Jumper 00-11, Inverter IY 1-7 tripped on low voltage after being supplied by Battery 1-7 for 16.5 hours.

Upon energizing, the plant process computer would not start because of a hard drive failure. The hard drive was replaced on May 17. Operators manually monitored the parameters normally tracked by the plant process computer while the plant process computer was unavailable during the transition from Mode 3 to Mode 5.

The inspectors concluded that the lack of specific, planned guidance in Procedure OP AP-26 for providing temporary power for the nonvital loads in the event of a loss of offsite power contributed to the loss of the plant process computer. The loss of the plant process computer, although an operator burden, did not affect operator performance and was not risk significant. The licensee properly installed Jumper 00-11. The inspectors noted that the licensing basis impact evaluation (10 CFR 50.59 screening) was performed properly, the second verifications were performed, and the control room drawings were properly annotated.

c. Issues and Findings

The inspectors identified no findings during this inspection.

.2 Temporary Power to Chemical Addition Pumps

a. Inspection Scope

The inspectors reviewed drawings, Procedure CF4.ID7, the temporary modification package, the licensing basis screening documentation, and the clearance order.

b. Issues and Findings

The inspectors identified no findings during this inspection.

1EP1 Drill Evaluation (71114.06, 71153, 93812)

Drill (Unit 1)

a. Inspection Scope

The inspectors evaluated the emergency classification and notifications that occurred as a result of this fire in the 12 kV switchgear room and loss of offsite power to the vital buses. The inspectors reviewed the official notification documents prepared by control room personnel; reviewed control room logs; interviewed operators; reviewed Action Request A0508416; reviewed the critique of the emergency response by the emergency planning organization; and reviewed procedures that specified notification and classification requirements. Specific procedures reviewed included: (1) EP G-1, “Emergency Classification and Emergency Plan Activation,” Revision 28; (2) EP G-2, “Activation and Operation of the Interim Site Emergency Organization,” Revision 21; (3) EP G-3, “Notification of Off-Site Agencies and Emergency Response Organization Personnel,” Revision 33; and (4) EP RB-10, “Protective Action Recommendations,” Revision 7.

b. Assessment

The inspectors concluded that the licensee appropriately classified this as an Unusual Event. The shift manager knew that vital equipment had operated properly without any additional indications that there existed a threat to equipment operability. The shift manager had conservatively declared the Unusual Event without waiting for fire fighting efforts to begin. The inspectors assessed whether an Alert classification would have been more appropriate (i.e., fire fighting efforts greater than 15 minutes and vital equipment threatened). The inspectors determined that vital equipment in the 12 kV switchgear room could not be threatened because of the fire protection design features.

From a review of the Appendix R safe shutdown evaluation, the inspectors determined that the combustible loading for all combustibles in the room, if concentrated in a single area, would not result in a fire lasting longer than 30 minutes. In addition, the inspectors determined that the vital equipment was separated by trains and protected by 2 hour fire barriers or, if not protected, had a redundant train available as described in the Final Safety Analysis Report Update, Fire Hazards Analysis.

The licensee initially reported to the NRC that UAT 1-1 had exploded and that Main Steam Safety Valve RV-7 had stuck open. The event had been ongoing for 19 hours before the licensee corrected the initial inaccurate 10 CFR 50.72 notification. The operators understood that UAT 1-1 had not exploded within 10 minutes of the initial report and that the Main Steam Safety Valve RV-7 was not stuck open within 30 minutes; nevertheless, the initial notification at 39 minutes into the event communicated incorrect information. The inspectors determined that the licensee self critique identified this as a deficiency that required corrective action as part of Action Request A0508416. In addition, the inspectors noted that the communications on the continuously open bridge with Region IV personnel had reflected the correct information after a short period of time, thereby, negating any adverse impacts from the inaccurate report. Also, the licensee maintained a Senior Reactor Operator qualified person in continuous communication with the NRC, which helped assure the accuracy and quality of communications between the NRC and the licensee as the event progressed. The inspectors determined that the notifications to state and local officials met timeliness requirements.

c. Issues and Findings

The inspectors identified no findings during this inspection.

4OA3 Event Follow-up (71153 and 93812)

Inspection Scope

The inspectors responded to the site, monitored operator response, and collected data to perform risk evaluations. In addition, NRC dispatched a special inspection team to review all aspects of the event and address the items in the Inspection Charter (Attachment 5). The inspectors developed a detailed sequence of events (Attachment 4), reviewed information that supported assumptions used in determining the conditional core damage probability (CCDP), reviewed component failures, assessed the potential root causes, evaluated whether the licensee addressed the extent of condition, and identified that the licensee had initiated a review for actions to prevent recurrence. NRC will evaluate the design issues identified in the following sections as material for generic communication to the industry.

.1 Onsite Electrical Supply System Design

Diablo Canyon Unit 1 has two sources of offsite electrical power, a 230 kV system and a 500 kV system, as shown in Attachment 3.

500/25 kV system

A delayed source of offsite power, the 500 kV system, is backfed from the 500/25 kV main transformers after the main generator is separated from the system. Operators must open the main generator disconnect switch before power can be restored following loss of the main generator. During normal power operations 25/12 UAT 1-1 supplies nonvital 12 kV loads such as reactor coolant pumps and 25/4 kV UAT 1-2 supplies 4 kV vital and nonvital loads. UATs 1-1 and 1-2 are located at the northeast corner of the turbine building.

230 kV system

An immediate source of offsite power, the 230 kV system, supplies 230/12 kV SUT 1-1. SUT 1-1 supplies Unit 1 startup power to 12 kV nonvital loads and to 4 kV vital and nonvital loads through 12/4 kV SUT 1-2 when auxiliary power is not available. The output of SUTs 1-1 and 2-1 can be provided to the opposite unit during an emergency situation through a cross-tie circuit breaker. During power operation, the 230 kV system is normally unloaded. SUTs 1-1 and 1-2 are located north of the turbine building.

Electrical power transfer following a reactor trip

During power operation, all plant loads are normally powered by the UATs with the SUTs unloaded. After a reactor trip, or other event, that would cause loss of auxiliary power, nonvital 12 kV loads are fast transferred to startup 12 kV power and vital 4 kV loads are slow (dead bus) transferred to startup 4 kV power.

Unit 1 12 kV and 4 kV bus design

SUTs 1-1 and 1-2 and UATs 1-1 and 1-2 are connected to their associated distribution switchgear by bus bars. All the bus bars are completely enclosed in aluminum ducts, with all three phases in the same duct (nonsegregated). All Unit 1 startup and auxiliary 12 kV and 4 kV nonvital switchgear is located within a common room at the northeast corner of the turbine building.

All the bus bars were supplied by General Electric. The bus bars were a combination of aluminum and copper. Individual bus bars were connected with splice plates that were secured to the bus bars by four ½-inch bolts. The bus bars and splice plates were silver plated at the connection points. For the 12 kV bus bars, the air gap between the conductors was approximately 6 inches, which is slightly below the required air gap for uninsulated conductors, so all the bus bars and connections were insulated with a combination of sleeves and wraps. The 4 kV bus bars were also insulated.

Bus duct proximity

The 12 kV busing exits UAT 1-1 northeast of the turbine building, penetrates the east turbine building wall, and connects to 12 kV nonvital Switchgear D and E. The 4 kV busing exits UAT 1-2 northeast of the turbine building, penetrates the east turbine building wall, and connects to 4 kV nonvital Switchgear D and E. In addition, the SUT 1-2 4 kV Winding X bus splits and exits the ceiling of the room, where it eventually connects to vital Switchgear F, G and H. Because of the need for two sources of power to multiple switchgear within the room, there are many crossing bus ducts above the switchgear (refer to Attachment 8).

The licensee evaluated the extent of nonvital bus duct proximity to each other in each nonvital switchgear room. The licensee determined that for each nonvital 4 kV switchgear the bus ducts for auxiliary power and startup power remained in close proximity for extended stretches. The inspectors noted that a fault on a startup bus duct would be limited and likely result in little damage because of the presence of breakers to interrupt the current flow. However, the inspectors noted that a fault in the 4 kV auxiliary bus duct had no similar breakers to quickly sense and interrupt the fault and would likely affect the adjacent startup bus duct.

The licensee indicated that their approach to prevent a similar exposure of a failure in one nonvital bus duct from affecting an alternate nonvital bus duct would be to ensure preventive maintenance activities were implemented to prevent overheating of the bus duct.

Power to switchyard components and switchyard control room

The licensee has two sources of nonvital power to the switchyard control room and other switchyard components. Nonvital Bus D provides power to the 230 kV switchyard, and nonvital Bus E provides power to the 500 kV switchyard. Each switchyard bus has a cross-connect breaker that can be closed to allow for either Bus D or Bus E to provide power to the switchyard. During the accident the loss of nonvital 4 kV Buses D and E resulted in a loss of power to the switchyard control room and other components. When the lights in the control room and the electronic protective relays lose preferred power, batteries can supply power for up to 36 hours.

The switchyard control room operator promptly requested a temporary generator from offsite. The temporary generator was obtained and connected to the switchyard control room within 13 hours.

.2 Fault Location, Mechanism, and Description of Damage

The fault was located on 12 kV bus bars from UAT 1-1 to Switchgear D and E, 3 feet upstream of a tee connection (refer to Attachment 4). The tee connected perpendicular bus bars running between Switchgear D and E. The fault occurred above the passageway between 12 kV Switchgear D and E. From review of the event sequence, the inspectors concluded that the fault was initially a phase-to phase fault because of the absence of any ground fault alarms.

At approximately 12:25:47 a.m., a Type 87 differential relay that monitored current conditions for UAT 1-1 and associated busing actuated a unit trip. The unit trip opened supply breakers for the 500 kV system, tripped the turbine, and tripped power to the main generator field. Since there were no circuit breakers on the main generator output, the main generator continued to supply current to the fault as the generator field collapsed. The inspectors verified from review of alarm printouts that this trip was supported by a sequence of relay actuations.

After normal entry to the area was allowed, a detailed inspection of the damage was performed. The center 12 kV bus bar was missing for approximately 1 yard, with the two exterior bus bars missing for approximately 6 and 9 inches. One bus bar had a 3 inch diameter hole in it. The bottom and top of the bus duct was melted for several feet, along with sections of the duct work on the perpendicular 12 kV bus sections at the tee connection. In addition, the fire had burned an approximate 1 foot square hole in the bottom of the SUT 1-2 Winding X 4 kV bus duct, which was 4 inches above the 12 kV bus duct. Although the 4 kV bus bars and duct were covered with black soot, the only conductor damage was a small piece of metal missing from the center bus bar and one outer bus bar, which the inspectors considered to be indicative of a single phase-to-phase fault.

The floor beneath the fault contained a large slag pile, and a great deal of metal had splattered on the face of 12 kV nonvital Switchgear D and E. However, no missiles penetrated the switchgear, and they remained energized throughout the event, supplying power to reactor coolant pumps. Later, when the switchgear doors were opened, no internal damage was observed.

.3 Root Cause

a. Inspection Scope

The inspectors reviewed the initial root cause determination, independently inspected the damaged equipment, and evaluated the equipment design.

b. Assessment

The licensee determined that the exact cause would never be known, in that the physical evidence was destroyed by the fault and resultant fire. The licensee ruled out sabotage, animals, foreign materials, and insulation failure. The licensee concluded that a center bus bar overheated at a splice joint, which caused insulation over the splice joint, a poly vinyl chloride boot, to begin to smoke. Eventually the heat and smoke caused failure of fiberglass insulation on adjacent phases, which resulted in phase-to-phase arcing. Although the specific cause of the overheating was not confirmed, the inspectors determined that the following factors contributed to the failure:

- Inconsistent silver plating
- Heavy bus loading
- Splice plate connections that may operate in excess of capacity
- Undetected damage from a 1995 fault of UAT 1-1

Silver plating

The inspectors observed that many of the removed bus bars and splice plates had minimal silver plating. The silver plating was brushed on in lieu of being dipped and had thin spots. The vendor had required only 0.002-inch thickness for the silver plating. The licensee sent one partially destroyed bus splice connection to a laboratory for analysis. The analysis determined that the silver plating on the splice plate had partially separated from the base aluminum, with corrosion products on the aluminum surface. The laboratory stated that they were unable to determine whether the corrosion was present prior to the fault. If the separated silver was present prior to the fault, it would have created higher resistance and, therefore, heat at the connection. The laboratory stated that the most likely source of corrosive compounds was the poly vinyl chloride insulating boot. The inspectors observed that silver plating was flaking off the aluminum bus bars at two other splice joints that were not directly affected by the fault.

Bus loading

The inspectors observed that the 12 kV 6 inch aluminum bus bars that failed were purchased for a rated design load of 2250 amps. The inspectors observed that this bus was routinely loaded to 2100 amps, with a worst case maximum design load of 2293 amps. The licensee stated that the value of 2293 amps was for initial design planning and that actual worst case operating loads were lower than 2250 amps.

The inspectors reviewed the installation drawings and observed that Drawing 663339, “Installation Details for Indoor and Outdoor Bus Duct,” Revision 4, indicated that 6 inch aluminum bus bars were rated for 2000 amps. The licensee contacted the bus bar vendor, who stated that they had tested the Diablo Canyon bus bars to design requirements using IEEE 37.20-1969, “IEEE Standard for Switchgear Assemblies Including Metal-Enclosed Bus,” paragraph 8.2.2.2, and that the heat rise met the limit of 65 C. The vendor further stated that all the bus bars provided to Diablo Canyon met the design requirements for maximum heat rise testing as specified in IEEE 37.20-1969.

The inspectors reviewed the test data supplied by the vendor for the various bus bar arrangements, including the bus bar that failed. The vendor was unable to locate a specific test for the bus bar that failed. The vendor had provided test data that demonstrated a maximum heat rise for the bus bar configuration between UAT 1-1 and the 12 kV switchgear as 46 C at 2000 amps and 63 C at 2200 amps. Given that the temperature rise increased 17 C for a current increase of 200 amps, the inspectors concluded that the data did not support a maximum temperature increase less than 2 C for an additional load increase of 50 amps.

The test for a design load of 2530 amps was performed at 2500 amps with a heat rise of 64 C. The inspectors concluded that the data did not support that the maximum temperature would not increase more than 1 C for a load increase of 30 amps. However, the inspectors observed that this was a design control problem since these bus bars currently had a worst case design loading of less than 1400 amps.

The vendor was unable to locate test data for design loads of 3750 amps, the bus bars from the output of SUT 1-1 and SUT 2-1 to their respective startup switchgear. The licensee listed the worst case running loads as 3339 and 3300 amps, respectively. The vendor supplied test data for 3000 amp bus bars of the correct size and 4000 amp bus bars of a different size and concluded that it was their judgement that the data supported the design for 3750 amps. Since the 4000 amp test used larger bus bars and had a heat rise of 64 C, the inspectors concluded that the data did not support the conclusion of the vendor. However, the inspectors noted that the startup power bus bars were rarely fully loaded and were normally unloaded.

The inspectors observed that the vendor heat rise tests of aluminum bus bars for 2200 amps were conducted with two bus bars (one splice joint) for each phase, with two splice plates. From review of the test details, the inspectors determined that the tests had used 3 x 4 inch copper splice plates. The inspectors questioned the adequacy of this testing to validate the 2½ x 4 inch aluminum splice plates used at Diablo Canyon. The vendor responded that prior to 1979 “standard” splice plates were used and that after 1979 copper plates were used.

Splice joints

The inspectors noted that the splice plates connecting the bus bars were considerably smaller than the bus bars themselves. Some splice connections had two aluminum splice plates (on both sides at each bus bar joint) 2½ x 4 inches x ⅜ inch thick. Each splice plate had four ⅝-inch holes drilled in it, with the size of the holes varying slightly.

The inspectors concluded that some holes were made larger to allow specific connections to be made. The inspectors observed that there was nominally a 3/16 inch gap between the bus bars to allow for thermal expansion. The inspectors noted that the splice plates were not always centered between the bus bars so that the contact surface on one side of a bus bar was smaller than the other. The inspectors observed several locations where contact between one bus piece and the splice plates was 1 inch wide or less. Therefore, the contact area was 4 inches by 1 inch (minus bolt holes) times two plates or about 6.6 square inches of contact surface.

UL 891, “Dead-Front Switchgear,” January 1982 recommended a maximum of 200 amps per square inch (surface contact area) for aluminum bus bar with silver-plated, bolted contacts. Using the UL 891 guidance, the as-installed bus bars would only be adequate for 1320 amps, or about one-half the vendor rated value. In addition, the inspectors considered that if the Vendor test had centered the splice plates, then the Diablo Canyon installation with uneven plate coverage of the bus bars would tend to be hotter.

Because the vendor qualification testing provided to date was not always accomplished at the maximum load required, combined with testing accomplished with splice plates that were not the same size as installed at Diablo Canyon and several of the tests resulted in maximum heat rises near the 65 C limit, the inspectors determined the testing did not ensure compliance with IEEE 37.20. In addition, the inspectors concluded that some as-installed joints would be subject to higher temperatures than the test results because the splice plates were not centered between bus bars.

The inspectors noted that the as-found torque values for many of the ½ inch splice plate connecting bolts were found to be in the range of 10 to 20 foot-pounds (marked, broken loose, then re-torque to the mark) indicating thermal relaxation from initial installation torque values of approximately 40 foot-pounds.

<u>Undetected damage from 1995 UAT 1-1 explosion</u>

The inspectors reviewed the 1995 explosion of UAT 1-1, and observed that the 12 kV busing had been moved several feet into the building by the explosion. Licensee records indicated that most of the bus bar connections from the transformer to the failed connection were disassembled and repaired as necessary. Records for the failed connection were not complete. However, the licensee indicated from review of existing records that the insulation had been removed from the failed joint for visual inspection and micro-ohm testing. The licensee based this conclusion on the fact that they had micro-ohm data listed for an adjacent joint (number eight), which was an undisturbed, vendor-supplied wrapped joint. The inspectors agreed with the assertion that the joint had been micro-ohmed. However, the inspectors disagreed with the licensee conclusion that the joint had been retorqued since the documentation stopped at joints one through seven (outside of the turbine building) without the similar confusion of an eighth joint.

The inspectors determined that the root cause could be attributed to a combination of vendor supplied equipment design deficiencies and potential failure to torque the failed joint properly following the 1995 UAT 1-1 transformer explosion. However, to determine the worst case risk associated with a performance issue, the inspectors assumed that the joint failed solely because personnel did not properly tighten the joint. This assumption resulted in inadequate corrective action as the performance issue. In addition, since this fault initiated a turbine trip and may have impacted the initiating event frequency, the Senior Reactor Analyst performed a risk evaluation in accordance with the significance determination process.

The Phase I risk assessment indicated that the performance issue should be evaluated using Phase 2. A review of the worksheets for Transient and Loss of Offsite Power did not account for the loss of the nonvital buses from the auxiliary and startup transformers. In addition, the initiating event frequencies from Table 1 of Manual Chapter 0609 for a turbine trip and loss of offsite power were found to bound the initiating event frequency. There was no change in the core damage frequency based on the Phase 2 review.

However, the Senior Reactor Analyst determined that a more comprehensive review (Phase 3) of the licensee's probabilistic risk assessment should be performed to ensure that the mitigating capability (reliability of the busses and transformers) as well as the initiating frequency for a fire in the turbine building 12 kV switchgear room were appropriately considered. The Phase 3 evaluation considered three initiating events to determine whether the performance issue resulted in a change to the core damage frequency. Specifically, the Senior Reactor Analyst considered the initiating event frequency for loss of offsite power, reactor trip without the power conversion system, and fire in the turbine building 12 kV switchgear room. The reliability of the transformers and buses was considered for mitigating systems.

The event itself was best characterized by a fire in the turbine building 12 kV switchgear room. A fire in this area is assumed to cause a loss of offsite power to the nonvital and vital buses. The diesel generators are assumed to remain available as well as other safety-related equipment. A loss of offsite power and transient with loss of power conversion system were also considered to assure that these initiators bounded this occurrence. In addition the reliability of the transformers and electrical buses as specified in the probabilistic risk assessment were considered.

Based on the Phase 2 and 3 assessments, it was determined that the performance issue resulted in a delta core damage frequency that had very low risk significance. From evaluation of the accident sequences that this event impacted, the Senior Reactor Analyst concluded that minimal change in the core damage frequency occurred. The changes in core damage frequency were minimal because initiating event frequencies and mitigating equipment failure rates, established in the licensee's probabilistic risk assessment and the significance determination process worksheets, bounded the equipment failures. This event did not disable any vital equipment and all vital equipment operated as designed.

Licensing requirements

The inspectors observed that 10 CFR Part 50, Appendix A, General Design Criterion 17 and IEEE 765-1983, “IEEE Standard for Preferred Power Supply for Nuclear Power Generating Stations,” specify that the design minimize the simultaneous failure of both sources of offsite power. IEEE 765-1983, Paragraph 5.1.3.2 states that the design shall minimize their [both sources of offsite power] simultaneous failure as a result of failure of a single breaker, switchyard bus, switchgear bus or cable. However, the inspectors observed that Diablo Canyon was licensed before the General Design Criteria were issued and was not committed to IEEE 765. Therefore, the inspectors concluded that the existing Diablo Canyon bus design, which has multiple metal bus ducts running in close proximity, did not violate any licensing or design requirements. In addition, the licensee stated that they believed the use of separate metal buses met the criteria for minimizing the loss of offsite power from a single fault.

The inspectors observed that the requirements of IEEE 37.20-1969 were now contained in ANSI/IEEE 37.23 (1987), “Guide for Metal-Enclosed Bus and Calculation Losses in Isolated-Phase Bus.” This requirement was also referenced in NEMA SG 5-1995, “Power Switchgear Assemblies.” The inspectors concluded that the test methods of IEEE 37.20-1969 were still valid industry standards. The inspectors did not identify any licensing requirements or commitments to industry standards that addressed the design details for the 12 kV and 4 kV systems, beyond the requirement for two separate sources of offsite power. The inspectors identified no failure of the licensee to comply with NRC requirements in the design, maintenance, or procurement of these nonvital components.

Licensee Review of Design

The licensee reviewed the various design issues associated with the 12 kV and 4 kV buses and concluded that the existing installations were acceptable until long range corrective actions could be implemented. The licensee documented their conclusions in Nonconformance Report N0002112. The main basis for the conclusions were:

- For the buses with current near the design limits, the vendor heat rise tests were based on an ambient temperature of 40 C, while the temperature at the Diablo Canyon site is always considerably lower.

- Many of the buses were operated at much lower current than specified by design.

The inspectors agreed with the licensee that the ambient temperature at Diablo Canyon would provide conservatism in the predicted heat rise testing and that the buses would remain operable. However, because of potential differences in splice configurations and materials, differences in test currents, and differences in bus sizes tested, the inspectors still considered the vendor validation testing marginal to support that the Diablo Canyon bus design met IEEE 37.20-1969 requirements.

c. Conclusions

Based on the inspectors observation of the damaged areas and review of the bus bars design the inspectors concluded that the initial root cause review had identified the most likely causes. The inspectors concluded that the design of the 12 kV and 4 kV systems at Diablo Canyon did not violate any licensing requirements. The inspectors concluded that the vendor acceptance tests supporting the current carrying capacity of some of the bus bars at Diablo Canyon did not meet some general industry guidance. However, with the expected environmental conditions cooler than the tested conditions, the licensee was able to demonstrate that the bus bars remained within the allowable heat rise standards.

.4 Equipment Restoration To Address Extent of Condition

a. Inspection Scope

The inspectors reviewed the actions to define the scope of damage, correct the damage, and test the new or repaired equipment.

For the nonvital Switchgear D and E, the inspectors found that the licensee had tested relays located near to the fault, had visually inspected all the breaker cabinet internals, removed circuit breakers for inspection, replaced exterior lamps and relay covers, and repainted the exterior panels.

b. Assessment

The licensee removed a large section of 4 kV bus bars, including the faulted section, and sent to a local vendor for repair and cleaning. The licensee replaced insulators as necessary, smoothed out the small damaged areas, and replaced the damaged bus ducts.

The licensee inspected all the bus bars that supply 12 kV power between the fault and UAT 1-1. The licensee removed all the aluminum bus bars and splice plates from this section of 12 kV busing and replaced them with copper. The licensee had all the replacement pieces silvered to a minimum of 0.02 inch by dipping to provide a better connection surface and replaced the bus ducts as necessary. Electricians torqued the accessible 4 kV and 12 kV bus bars splice plate connections to 50 ± 5 foot-pounds and high potential tested the replaced bus bars.

The licensee inspected and tested protective relays and circuit breakers subject to the fault and either replaced/calibrated or calibrated, as necessary. As discussed in Section 1R19, the licensee performed numerous maintenance activities on SUT 1-2 and UAT 1-1.

The inspectors determined that the bus bars and splice joints on UAT 2-1 to the 12 kV switchgear had been inspected, reinsulated, the splice joints torqued and resilvered in 1997, following replacement of the bus bar insulation because the insulation had cracked.

c. Conclusions

The inspectors concluded that the scope and performance of immediate repair actions were adequate.

.5 Risk Evaluation (71153 and 93812)

a. Inspection Scope

The NRC dispatched a special inspection, consisting of three inspectors, to evaluate this loss of offsite power event. The level of NRC response was decided by assessing the actual risk posed by this loss of offsite power, as characterized by the CCDP combined with knowledge of plant conditions and the licensee response. The CCDP accounted for the actual plant configuration. NRC has developed guidance for the required level of agency response. For a CCDP less than 5E-6 no additional reactive inspection is required. For CCDP in the range of 1E-6 to 1E-4 a special inspection is authorized since this is considered to be a risk significant event. This threshold overlaps a response that allows for both no reaction and an Augmented Inspection Team. For CCDP ranging from 1E-5 to 5E-3 an Augmented Inspection Team response is recommended with overlap for both a special inspection and an Incident Investigation Team. The preliminary numbers identified for this event fell in the range from 3E-5 to 3E-4.

b. Assessment

CCDP determination

The Senior Reactor Analyst performed an initial CCDP assessment while the fire and loss of offsite power event progressed. The Senior Reactor Analyst used the Diablo Canyon 1997 probabilistic risk assessment model and considered the loss of offsite power as the initiating event. The loss of offsite power contribution to the conditional core damage frequency was approximately 1.6E-6/yr. An updated loss of offsite power frequency (Bayesian Update, 0.03) was used to calculate a preliminary CCDP on the order of 5E-5.

Offsite power was not restored until 33 hours after the initiating event occurred. Following a review of the initiating event and plant response, the licensee and NRC staff determined that the initiating event was better characterized as a turbine/reactor trip followed by a loss of offsite power. Changing the initiating event was important for the risk assessment because (1) the pressurizer power operated relief valves would not be challenged by a pressure transient and (2) the condenser would be available for only a short period to remove decay heat. In addition, the inspectors determined that offsite power could have been recovered within 8 hours of the fire event, as described below.

The licensee performed a detailed risk assessment of the event. This assessment included modifying their probabilistic risk assessment model to calculate the core damage frequency for the period this event occurred. The licensee developed three case studies based on turbine trip with subsequent diesel engine generator mission times of 6 and 24 hours and a loss of offsite power with a mission time of 24 hours. This later assessment provided a bounding risk analysis for the loss of offsite power event. An additional assessment was performed to determine the actual core damage frequency and CCDP for the configuration the plant operated in during the 33 hour period.

The core damage frequency and resulting CCDP for operating the plant in the configuration without offsite power for 33 hours were calculated at 9.6E-5/ry and 3.6E-7, respectively. The sensitivity study for a loss of offsite power initiators during a 24 hour period was calculated to be 4.5E-6/ry and 7.2E-5, respectively. This later calculation included the more challenging plant response to the loss of offsite power initiator and a mission time of 24 hours, which exceeded the time the inspectors determined was necessary for the recovery of offsite power.

Validation of assumptions

The inspectors validated the licensee assertion that the links could have been removed and offsite power restored in less than 33 hours. The licensee used an estimate of 6.5 hours. The inspectors discussed the readiness of maintenance personnel and reviewed the availability of emergency equipment to determine whether the tasks could be completed as planned. The inspectors reviewed the following procedures to determine whether the licensee had authorization to take the actions planned:

Procedure	Title	Revision
ECA-0.0	Loss of All Vital AC Power	13
ECA-0.3	Restore 4KV Buses	9
OP1.DC11	Conduct of Operations-Abnormal Plant Conditions	15

The inspectors found that the licensee had authorization to take the actions planned. In addition, the inspectors estimated the licensee would be able to restore offsite power within 8 hours, which would not result in an event of increased risk significance.

c. Issues and Findings

The turbine trip with subsequent loss of offsite power best reflected the fire event and subsequent plant response. The mission times evaluated at 6 and 24 hours bounded the conditional assessments. The core damage frequencies and CCDPs for these two cases were 1.1E-5/yr and 1.8E-5 for 6 hours and 4.2E-5/yr and 7E-5 for 24 hours. The inspectors and the Senior Reactor Analyst found the assessments to be detailed and included the risk associated with reactor coolant pump seal loss of coolant accident. Based on the preliminary assessment performed by the Senior Reactor Analyst and the revised model analysis of this fire event, the resulting CCDP was determined to be 3E-5.

.6 Actions to Prevent Recurrence

The licensee established a prioritization scheme to evaluate and identify the most susceptible buses. The prioritization considered, in decreasing order of importance,

(1) buses where the normal load has little margin relative to the continuous duty design rating, (2) locations that have the auxiliary buses in close proximity to the startup buses, and (3) buses that are hard wired to the main generator (i.e., have no breaker to quickly sense and interrupt the fault). These conditions resulted in the following buses being identified as most susceptible: 12 kV UAT 2-1, 4 kV auxiliary buses for Units 1 and 2, and the 12 kV startup bus for Unit 1. The licensee will also factor into their corrective actions to prevent recurrence industry operating experience, construction of the busing, maintenance program requirements, and aging issues (torque relaxation and insulation breakdown).

As of the end of this inspection, the licensee was considering the following preliminary corrective actions to prevent recurrence. During the upcoming Unit 1 refueling outage, the licensee planned to: (1) inspect and torque the booted connections on the 3750 amp bus for SUT 1-1 and replace splice plates on the booted connections with full face copper splice plates; (2) inspect and torque splice plate connections on the 4 kV auxiliary buses; and (3) upgrade the 2250 amp 12 kV buses from aluminum to copper bars. The same inspection and replacement activities will occur on taped connections during the subsequent Unit 1 refueling outage.

Similarly, during the next Unit 2 refueling outage, the licensee planned to: (1) upgrade UAT 2-1 to 12 kV switchgear bus bars from aluminum to copper and install double splice plates and (2) inspect and torque splice plate connections on the 4 kV auxiliary buses.

By August 30, the licensee will provide the final, planned corrective actions in an update to Licensee Event Report 50-275/00-004-00.

4OA4 <u>Other (71111.14)</u>

<u>(Closed) Licensee Event Report 50-275/00-004-00</u>: Unit 1 Unusual Event because of 12 kV bus fault.

This special inspection report evaluates and documents in detail the issues and content of Revision 0 of this licensee event report. Followup of the long term corrective actions will occur during evaluation of the later revision. The licensee indicated that a revision to this licensee event report will be issued by August 30, 2000.

4OA5 <u>Exit Meeting Summary (93812)</u>

The inspectors presented the inspection results to Mr. Greg Rueger and members of the Diablo Canyon staff on June 29, 2000, during a meeting open to public observation. Mr. Rueger acknowledged the findings presented.

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

Attachment 1
Supplemental Information

PARTIAL LIST OF PERSONS CONTACTED

Licensee

Jim Becker, Manager, Operations Services
*Pete Bedesmen, Engineer, Nuclear Quality Services
Rick Burnside, Engineer, Nuclear Quality Services
*Steve Chestnut, Director, Engineering Services - Balance of Plant
Dwight Christensen, Engineer, Nuclear Safety and Licensing
Pat Colbert, Supervisor, Engineering Services - Design
*Bill Garret, Director, Operations
Cal Gillies, Director, Chemistry and Environmental Operations
Bob Hanson, Engineer, Engineering Services - Balance of Plant
*Stan Ketelsen, Supervisor, Nuclear Safety and Licensing
*Mark Lemke, Supervisor, Emergency Planning
Dave Miklush, Manager, Engineering Services
David Oatley, Vice President and Plant Manager
Steve Pratt, Coordinator, Emergency Planning
*Greg Rueger, Senior Vice President Generation
*Jack Shoulders, Director, Engineering Services
David Taggart, Director, Nuclear Quality Services
Lynn Walter, Team Leader, Maintenance Services
*Bob Waltos, Manager, Maintenance Services and Acting Plant Manager
Bob Washington, Engineer, Engineering Services - Balance of Plant
*Larry Womack, Vice President, Power Generation and Nuclear Services

NRC

*Dyle Acker, Resident Inspector, Diablo Canyon
*Ken Brockman, Director, Division of Reactor Projects
*Bill Jones, Senior Reactor Analyst, Division of Reactor Safety
*David Lange, Senior Coordinator for Region IV, Office of Executive Director for Operations
*Greg Pick, Senior Project Engineer, Branch E, Division of Reactor Projects
*David Proulx, Senior Resident Inspector, Diablo Canyon
*Linda Smith, Chief, Branch E, Division of Reactor Projects

* Identifies those personnel who attended the public Exit Meeting on June 29, 2000

LIST OF INSPECTION PROCEDURES PERFORMED

The following procedures were used to perform inspections during this report period. Documented findings are contained in the body of the report.

71111.04	Equipment Alignments
71111.05	Fire Protection
71111.12	Maintenance Rule Implementation
71111.13	Maintenance Risk Assessment and Emergent Work Control
71111.14	Personnel Performance During Nonroutine Plant Evolutions
71111.15	Operability Evaluations
71111.19	Postmaintenance Testing
71111.22	Surveillance Testing
71111.23	Temporary Plant Modifications
71114.06	Drill Evaluation
93812	Special Inspection

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

50-275/0009-01	NCV	Failure to comply with the requirements of Technical Specification 3.5.1.a (Section 1R14.1)

Closed

50-275/00-004-00	LER	Unit 1 Unusual Event Because of a 12 kV Bus Fault (Section 4AO4)
50-275/00-005-00	LER	Entry into Technical Specification 3.0.3 After Power Restored to Reactor Coolant System Accumulator Valves Because of Personnel Error (Section 1R14.2)

LIST OF ACRONYMS USED

ANSI	American National Standards Institute
CCDP	conditional core damage probability
CFR	Code of Federal Regulations
DEG	diesel engine generator
IEEE	Institute of Electrical and Electronics Engineers
LER	licensee event report
NCV	noncited violation
NEMA	National Electrical Manufacturers Association
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
SUT	startup transformer
UAT	unit auxiliary transformer
UL	Underwriters Laboratories

DOCUMENTS REVIEWED

Calculations -

License updated Probabilistic Risk Assessment 1997

CALCULATION FILE NO. PRA00-02, Revision 0, "Calculation of the Conditional Core Damage Probability For the Fire Event of May 15, 2000"

Action Requests -

A0508040	Unit 1 Reactor Trip From Fault on Auxiliary Transformer 1-1 Leads
A0508041	Fault on Leads Exiting Auxiliary Transformer 1-1
A0508042	Steam Generator 1-2 RV-7 Lifted After Unit 1 Reactor Trip
A0508043	Investigate Reason for 52VU14 Opening
A0508044	Steam Generator 1-1 RV-4 Is Simmering
A0508045	Unit 1 Main Annunciator X-6000 CRT and Printer Failed

Action Requests -

A0508055	Install Temporary Power for Unit 1 Unscheduled Outage
A0508067	Plant Process Computer Inverter Automatic Shutdown
A0508091	BP2 - Loose Belt on Booster Pump
A0508092	BP3 - Loose Belt on Booster Pump
A0508152	MS-1-PCV-20, Evaluate Necessity to Operate Manually Following Reactor Trip
A0508166	CWP 1-2 Ran for 13 Minutes Without ICW
A0508172	Main Annunciator Failure to Print - Alarm Summary
A0508186	Evaluate LCV-8 Failure Mode
A0508188	Evaluate EDG 1-2 Undervoltage Start
A0508243	CCW Pump 1-2 Shaft Driven Oil Pump Not Working
A0508282 & A0506562	Unit 1 Train A CCU Lockup During 5/15 Reactor Trip Maintenance Rule Performance Criteria Goal Setting Review
A0508300	Plant Process Computer Subsystem Disk Drives Dead and SYDKA Problems
A0508371	Evaluate Degraded Bus and Update Drawings as Required
A0508383	Derate 4 kV Bus Due to Damage Sustained During Fire
A0508564	Poor Fireground Communications During Fire on 5/15/00
A0508565	Personnel Accountability System Lacking During Fire on 5/15/00
A0508618	Tee Section of New 12 kV Bus Phasing Incorrect
A0508783	Evaluate the Aux 1-1 Bus Bar Connection Boot Insulation
A0508914	Provide Vital Power Supply to Clearance Coordinator Office
A0509579	480 Vac Vital Bus Loading Lesson Learned From LOOP Event of 5/15

Nonconformance Reports -

N0002005	Unit 1 Reactor Trip Due to Electrical Fault
N0002112	Auxiliary Transformer 1-1 Fault on the 12 kV Leads to Buses D & E

NRC'S REVISED REACTOR OVERSIGHT PROCESS

The federal Nuclear Regulatory Commission (NRC) revamped its inspection, assessment, and enforcement programs for commercial nuclear power plants. The new process takes into account improvements in the performance of the nuclear industry over the past 25 years and improved approaches of inspecting safety performance at NRC licensed plants.

The new process monitors licensee performance in three broad areas (called strategic performance areas): reactor safety (avoiding accidents and reducing the consequences of accidents if they occur), radiation safety (protecting plant employees and the public during routine operations), and safeguards (protecting the plant against sabotage or other security threats). The process focuses on licensee performance within each of seven cornerstones of safety in the three areas:

Reactor Safety	**Radiation Safety**	**Safeguards**
•Initiating Events	•Occupational	•Physical Protection
•Mitigating Systems	•Public	
•Barrier Integrity		
•Emergency Preparedness		

To monitor these seven cornerstones of safety, the NRC used two processes that generate information about the safety significance of plant operations: inspections and performance indicators. Inspection findings will be evaluated according to their potential significance for safety, using the significance determination process, and assigned colors of GREEN, WHITE, YELLOW or RED. GREEN findings are indicative of issues that, while they may not be desirable, represent very low safety significance. WHITE findings indicate issues that are of low to moderate safety significance. YELLOW findings are issues that are of substantial safety significance. RED findings represent issues that are of high safety significance with a significant reduction in safety margin.

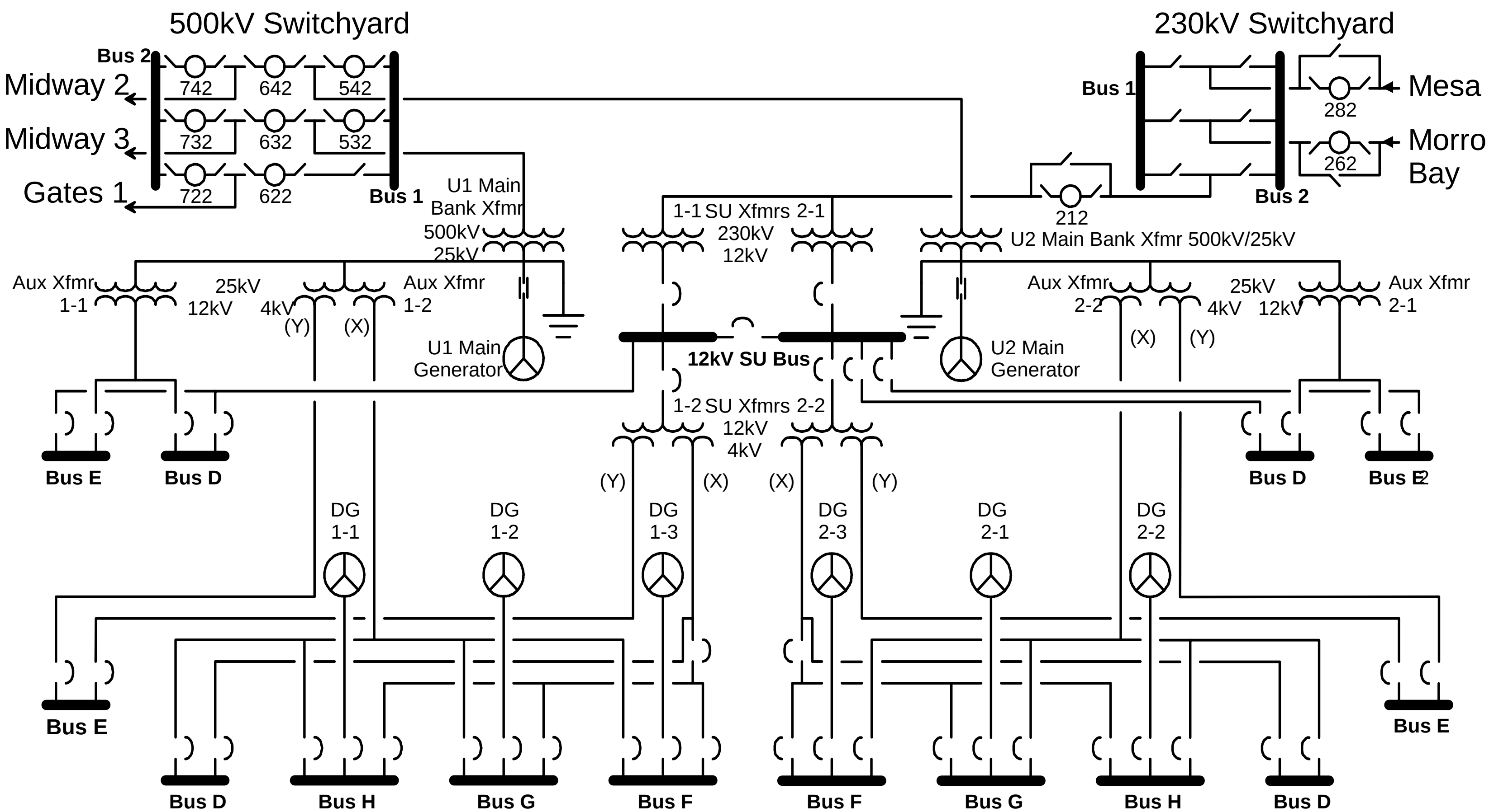
Performance indicator data will be compared to established criteria for measuring licensee performance in terms of potential safety. Based on prescribed thresholds, the indicators will be classified by color representing varying levels of performance and incremental degradation in safety: GREEN, WHITE, YELLOW, and RED. GREEN indicators represent performance at a level requiring no additional NRC oversight beyond the baseline inspections. WHITE corresponds to performance that may result in increased NRC oversight. YELLOW represents performance that minimally reduces safety margin and requires even more NRC oversight. And RED indicates performance that represents a significant reduction in safety margin but still provides adequate protection to public health and safety.

The assessment process integrates performance indicators and inspection so the agency can reach objective conclusions regarding overall plant performance. The agency will use an Action Matrix to determine in a systematic, predictable manner which regulatory actions should be taken based on a licensee's performance. The NRC's actions in response to the significance (as represented by the color) of issues will be the same for performance indicators as for inspection findings. As a licensee's safety performance degrades, the NRC will take more and increasingly significant action, which can include shutting down a plan, as described in the Action Matrix.

More information can be found at: http://www.nrc.gov/NRR/OVERSIGHT/index.html.

Diablo Canyon Electrical Distribution

Attachment 3



Attachment 4 - Bus Bar and Switchgear Cubicle Damage

Attachment 4 - Bus Bar and Switchgear Cubicle Damage

Attachment 5

Chronological Sequence of Events Diablo Canyon Unit 1 12 kV Bus Fault

Time	Description
May 15	
0025:47	A phase-to-phase fault developed on the 12 kV side of Unit Auxiliary Transformer 1-1, igniting a small fire that releases bus bar and duct material to nearby equipment. The fault resulted in a differential trip of Relay 87AT11, causing a unit trip. The unit trip signal opened the 500 kV output breakers (PCB 532 and 632), initiated transfer of the 12 kV and 4 kV plant loads to the startup transformer, and initiated a turbine trip. With reactor power greater than the P-9 setpoint, the turbine trip resulted in a reactor trip. All control rods properly inserted to shutdown the reactor. Operators entered Emergency Operating Procedure E-0, “Reactor Trip or Safety Injection,” Revision 24
0025:48	Because vital Bus G was lightly loaded, it initially transferred to the startup transformer. Diesel Engine Generator (DEG) 1-2 received an automatic start signal but did not load onto vital Bus G.
0025:52	Fire alarms were received in the control room.
0025:55	Multiple grounds were received on the 4 kV side of the startup transformer. Because the 4 kV bus duct was directly above the 12 kV bus fault, secondary damage was induced to the 4 kV bus.
0025:58	Breaker 52VU14, which supplied the 4 kV buses from Startup Transformer 1-1, tripped open because of high differential current that resulted from a phase-to-phase fault. This deenergized nonvital Buses D and E, and vital Buses F, G, and H, which started DEGs 1-1 and 1-3 on bus undervoltage. Unit 1 control room lighting was powered from emergency lighting.
0026:03	DEG 1-2 assumed all loads on vital Bus G.
0026:06	DEGs 1-1 and 1-3 assumed all loads on vital Buses H and F, respectively. Because 4 kV nonvital Buses D and E were not powered by DEGs, the 4 kV nonvital buses remained deenergized. 12 kV nonvital loads (reactor coolant pumps and “selected” Circulating Water Pump 1-2) continued to be powered from Startup Transformer 1-1
0026:36	All vital loads such as auxiliary saltwater pumps, auxiliary feedwater pumps, component cooling water pumps, containment fan cooler units, and centrifugal charging pumps were powered by the DEGs.
0030	Operators exited Procedure E-0 and entered Emergency Operating Procedure E-0.1 “Reactor Trip Response,” Revision 22
0037	Because of the loss of the intake cooling system (powered from 4 kV nonvital power), the windings for the circulating water pumps were no longer being cooled. Operators tripped Circulating Water Pump 1-2 since the pump did not trip. The relay “energized” to trip whenever a circulating water pump was in operation and power was available.

Attachment 5

Chronological Sequence of Events Diablo Canyon Unit 1 12 kV Bus Fault

Time	Description
	Because of the loss of condenser vacuum that resulted from tripping Circulating Water Pump 1-2, as directed by Procedure E-0.1, operators closed the main steam isolation valves and adjusted the setpoints for the steam generator 10 percent atmospheric steam dumps to 1005 psig to remove decay heat from the reactor.
	Main Steam Safety Valve RV-7 lifted at approximately 1047 psig (lower end of allowable range).
0043	The fire brigade arrived at the scene and noted that thick smoke created very low visibility in the 12 kV switchgear room.
	The shift manager declared a Notification of Unusual Event (Unusual Event) based on a fire in the protected area lasting greater than 15 minutes.
0045	Operators closed Valve LCV-8, hotwell makeup from the condensate storage tank, that had failed open, as designed, on a loss of 4 kV nonvital power.
0048	The shift manager contacted the California Department of Forestry at the request of the incident commander to assist in fire fighting efforts.
0049	The fire brigade opened doors and initiated ventilation to clear smoke from the 12 kV switchgear room.
0056	The shift manager informed the state and local authorities of the Unusual Event.
0103	The fire brigade extinguished the small fire in the 12 kV bus duct using a hand-held carbon dioxide fire extinguisher.
0104	The shift manager informed the NRC Headquarters Operation Center of the Unusual Event. The Headquarters Operations Officer requested a continuously open line between the NRC and the licensee.
0106	Operators recognize Main Steam Safety Valve RV-7 open because Steam Generator 1-2 level continues to decrease
0139	The California Department of Forestry firemen arrived on site. Their assistance was not required in that the fire had already been successfully extinguished.
0143	Shift manager declares fire out
0152	Steam Generator 1-2 Main Steam Safety Valve RV-7 reseated since operators had manually opened Valve PCV-20 earlier.
0200	Operators exited Procedure E-0.1 and entered Procedure OP L-7, “Plant Stabilization following Reactor Trip,” Revision 6, since plant conditions were stable with reactor coolant system temperature at 547°F and pressure at 2235 psig.
0205	NRC entered Monitoring Phase of Normal Operation because of the sustained loss of offsite power to the vital buses.
0245	Chemistry sampled steam generators and reported that radioactivity levels were below the minimum detectable.

Attachment 5

Chronological Sequence of Events Diablo Canyon Unit 1 12 kV Bus Fault

Time	Description
0300	The fire brigade restored normal access to the 12 kV switchgear room so that an inspection could be performed.
0322	NRC Senior Resident Inspector arrived on site to monitor licensee response to event.
0400	The inspection team reported that the fault blew a hole through the 12 kV bus duct and caused collateral damage to the 4 kV bus and several electrical panels. Management determined that Breaker 52VU14 could not be closed and that a loss of offsite power to the vital buses had occurred.
0420	Operators restored power to the Unit 1 side of the control room by cross-connecting power from Unit 2.
0545	Operators received a high temperature alarm in the reactor cavity area because the control rod drive mechanism fans had tripped when Breaker 52VU14 opened. Procedure AR-PK-03-22, "Control Rod Drive Mechanism Fans Suction Temperature Hi/Lo," Revision 8B, required that the plant be shut down and temperature reduced below 392°F.
0700	The day shift crew arrived to turnover and assume the watch.
0854	Operators commenced reactor coolant system cool down using the steam generator 10 percent atmospheric steam dumps.
1207	Operators restored power to the safety injection accumulator isolation valves with reactor coolant system pressure at 1500 psig. Technical Specification 3.5.1 required power to be removed from these valves whenever pressure exceeded 1000 psig.
1238	Operators transferred power for Diesel Fuel Oil Transfer Pump DFO-PP 0-1 to Unit 2.
1335	Switchyard personnel connected an emergency generator to the 500 kV and 230 kV switchyards to provide power to the switchyard air compressors. The air compressors, which provided control air to the 500 kV and 230 kV switchyard pneumatic breakers, received power from the deenergized Unit 1 4 kV nonvital buses and had been running on battery power for 13 hours
1455	Operators entered Technical Specification 3.0.3 at 1122 psig reactor coolant system pressure when they recognized that all four of the accumulator isolation valves had been energized with reactor coolant system pressure greater than 1000 psig.
1505	Operators exited Technical Specification 3.0.3 because reactor coolant system pressure was decreased below 1000 psig.
1535	Operators stabilized the reactor coolant system at 380°F and 900 psig for a chemistry hold to aid in radioactivity cleanup.
1703	The plant process computer failed because of loss of battery power. The plant process computer uninterruptible power supply was powered from the 4 kV nonvital buses, with backup power supply from a nonvital battery via an inverter. When the 4 kV nonvital bus was lost, the licensee attempted to provide a jumper to the inverter but was unsuccessful. Operators manually trended plant parameters.

Attachment 5

Chronological Sequence of Events Diablo Canyon Unit 1 12 kV Bus Fault

Time	Description
1730	Maintenance personnel provided temporary power to the auxiliary building sump pumps, which had tripped because of the loss of the 4 kV nonvital buses.
May 16	
0129	Valve PCV-455C, pressurizer power operated relief, failed its stroke time test and was declared inoperable. This valve would be needed for low temperature overpressure protection in Mode 5 (Cold Shutdown).
0441	Maintenance personnel removed disconnect links from 25 kV side of Unit Auxiliary Transformer 1-1. Operators commenced restoration of 500 kV back feed capability.
0808	Breakers PCB-532 and PCB-632 were closed, the plant was able to back feed the Unit 1 4kV buses from the 500 kV system. Operators commenced restoration of the 4 kV nonvital buses.
0852	Operators energized all 4 kV and 480 V nonvital buses through Auxiliary Transformer 1-2, by back feeding from the 500 kV system.
0918	Operators paralleled Vital Bus H with Auxiliary Transformer 1-2, and shutdown DEG 1-1.
0937	Operators paralleled Vital Bus G with Auxiliary Transformer 1-2, and shutdown DEG 1-2.
0959	Operators paralleled Vital Bus F with Auxiliary Transformer 1-2, and shutdown DEG 1-3.
0959	The shift manager exited the Unusual Event
1006	The licensee notified the state and local officials of termination of the Unusual Event
1008	The licensee terminated the continuous communications with NRC Region IV on the ENS line and informed NRC that the Unusual Event had been terminated at 0959.
1058	Licensee notified the NRC Headquarters Operators Center that the Unusual Event had been terminated at 0959
1733	Operators commenced the reactor coolant system cool down to 290°F.
1736	Residual Heat Removal Pump 1-2 started for chemistry sample.
1749	Residual Heat Removal Pump 1-2 secured. Operators noted excessive leakage from pump seal.
1817	Unit 1 entered Mode 4 (Hot Shutdown) with reactor coolant system temperature less than 350°F.
May 17	
0141	Following repairs, Valve PCV-455C passed its stroke time test. This allowed operators to commence cool down to Mode 5 (Cold Shutdown).
1513	With the reactor coolant system at 290°F, operators commenced the cool down to Mode 5.

Attachment 5

Chronological Sequence of Events Diablo Canyon Unit 1 12 kV Bus Fault

Time	Description
1855	Unit 1 entered Mode 5 with reactor coolant system temperature less than 200°F.
2000	Reactor coolant system cool down secured with reactor coolant system temperature at 180°F.

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

Attachment 6

May 17, 2000

MEMORANDUM TO: Greg Pick, Senior Project Engineer, Project Branch E

FROM: Ken Brockman, Director, Division of Reactor Projects
/RA/ Elmo Collins acting for

SUBJECT: DIABLO CANYON UNIT 1 SPECIAL INSPECTION CHARTER

On May 15, 2000, the licensee declared an unusual event when a fire in a 12 kV switchgear room lasted longer than 15 minutes. Based on a preliminary review of the circumstances surrounding this event, it was determined that this event was potentially one of moderate risk significance. Accordingly, a special inspection is being chartered for the NRC to better understand this event. This memorandum designates you as the lead inspector for the special inspection. Mr. Dyle Acker, Resident Inspector, will support you in the inspection efforts.

Mr. David Proulx, the Senior Resident Inspector, initially responded to the site to monitor licensee response. He will provide inspection report input related to his initial response. Specifically, he will provide an initial evaluation of both the operator and the broader site response to the event. These inspection activities were conducted under the emergency response program, Section 9A1E (Event Response), and baseline Inspection Procedures 71153 (Event Followup) and 71111.04 (Equipment Alignments). After you arrive on site, Mr. Proulx's responsibilities will return to his roll managing implementation of the baseline inspection program.

The objectives for your inspection should, at a minimum, include the following:

1. Develop a detailed sequence of events.

2. Confirm the adequacy of the licensee's extent of condition determination and the associated corrective action plans prior to restart of Unit 1.

3. Confirm the adequacy of the licensee's root cause analysis and any associated corrective actions needed to prevent recurrence of a similar condition.

4. Evaluate the effectiveness of the fire brigade notification and response.

5. Evaluate the adequacy and timeliness of the licensee's emergency classifications and the associated notifications.

Greg Pick

These inspection activities should be conducted using Inspection Procedure 93812 (Special Inspection) and any appropriate baseline inspection procedures. You should coordinate with the Chief, Project Branch E, in defining the appropriate baseline inspection procedures to use.

The inspection activities commenced on May 15, 2000, when Mr. Proulx responded to the site in response to this event. A report documenting the results of the inspection should be issued within 30 days of the completion of the inspection (tentatively scheduled for May 19, 2000).

This charter will be modified should the team develop significant new information that warrants review by the special inspection team. Should you have any questions concerning this charter, contact Linda Smith, Chief, Project Branch E, at 817-860-8137.

cc via ADAMS E-mail:
E. Merschoff
T. Gwynn
A. Howell
L. Smith
J. Melfi
D. Proulx
D. Acker
D. Powers
G. Good

Attachment 7 - Public Exit Slides

- **SCOPE**
- **RESULTS**
- **CORRECTIVE ACTIONS**
- **RISK DETERMINATION**
- **SUMMARY**

SAFETY SIGNIFICANCE

A single short circuit in a Unit 1 12 kilovolt (kV) non-vital power circuit caused a temporary loss of all vital and non-vital offsite 4kV power and the extended loss of almost all non-vital power in the unit.

EVENT SEQUENCE

MAY 15, 2000

0025 PDT	A short circuit in the station 12kV power system normal feeder caused a reactor trip from 100%. The consequent fire also caused the failure of the immediately adjacent 4kV standby feeder into the unit thus disabling all offsite power in the unit except for one 12kV feeder for reactor coolant pumps and circulating water pumps.

0043 The licensee declared an unusual event based on a fire that lasted greater than 15 minutes.

0103 Fire is extinguished.

0854 Operators commenced reactor coolant system cool down to cold shutdown.

1535 Operators stabilized the reactor coolant system at 380°F and 900 psig for chemistry hold.

May 16, 2000

0852 After disconnecting the faulted auxiliary transformer, restored offsite power to the unit using a back-feed through the unit main transformer from the 500kV switchyard.

0959 After supplying vital buses from offsite power source, operators secured diesels and unusual event terminated.

OPERATIONAL CHALLENGES

Factors that complicated the event and made operations more difficult:

1. Loss of normal station lighting and ventilation - vital lighting and ventilation not affected;
2. Loss of power to unit process computer charger and eventual loss of computer;
3. Loss of power supply to switchyard air compressors/control room - air compressors charged accumulators for breakers; gasoline generators from offsite provided replacement power.

RESPONSE

Region IV activated emergency response center for monitoring and provided inspector coverage in control room around the clock and provided additional inspectors for support.

Three person special inspection team chartered during event.

Generic communications of event being evaluated

ROOT CAUSE

Overheating at splice joint caused poly vinyl chloride (PVC) smoldering and eventual failure of fiberglass insulation and arcing to other phases on 12kV bus.

POTENTIAL CONTRIBUTORS

1. Inconsistent silver plating of joints
2. High normal current
3. Splice Construction
4. Undetected damage from 1995 transformer explosion

SHORT TERM CORRECTIVE ACTIONS

1. 12kV aluminum bus duct to switchboard replaced with copper
2. 12kV aluminum splice plates replaced with larger copper splice plates
3. 12kV bus bar ends and plates resilvered
4. Torqued joints
5. Verified that similar bus bars for Unit 2 had maintenance performed in past 3 years and were not as susceptible

LONG TERM ACTIONS

1. Analyze adequacy of other bus duct based on

    a. service and fault duties
    b. proximity to other bus duct
    c. fault protected or hard wired to main generator

2. Evaluate

    a. bus construction
    b. bus maintenance program
    c. relaxation of bolt torque
    d. industry experience with aluminum bus

FINDINGS

PERSONNEL PERFORMANCE

1. Operators performed well
2. Noncited violation; isolating safety injection accumulators early
3. Good fire brigade response

CORRECTIVE ACTION PROGRAMS

Effective at incorporating immediate corrective actions and identifying tasks that required long term evaluation.

Potential inadequate corrective actions from 1995 Auxiliary Transformer 1-1 explosion

AGENCY LESSONS LEARNED

Need to clearly communicate to licensee that official communications must go to the Headquarters Operations Officer.

RISK DETERMINATION

NRC staff assessed the risk in terms of the likelihood of core damage given that the event occurred (CCDP), as well as the "change" in the annualized estimate of core damage (CDF).

Inspectors concluded that, if station blackout had occurred during the event, back-feed access to 500kV could have been restored in 8 hours versus actual 33 hours.

SUMMARY

Attachment 8 - Switchgear Room Bus Duct Proximity