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SUBJECT: LER 95-014-00:on 951021,all offsite power lost for over 15 minutes & fire not put out in 15 minutes.Caused by inadequate/ineffective control procedures.Offsite power restored from 230kV sys.W/951120 ltr.

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November 20, 1995

PG&E Letter DCL-95-258

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Docket No. 50-275, OL-DPR-80
Diablo Canyon Unit 1
Licensee Event Report 1-95-014-00
Diesel Generators Started and Loaded as Designed Upon Failure of Auxiliary Transformer 1-1 Due to Inadequate/Ineffective Procedures Related to the Control of Grounding Devices

Gentlemen:

Pursuant to 10 CFR 50.73(a)(2)(iv), PG&E is submitting the enclosed Licensee Event Report concerning auto-start and loading of the diesel generators (ESF actuation) as designed upon failure of Unit 1 auxiliary transformer 1-1, due to inadequate/ineffective procedures related to the control of grounding devices.

This event did not adversely affect the health and safety of the public.

Sincerely,

Gregory M. Rueger

cc: Steve Bloom
L. J. Callan
Kenneth E. Perkins
John Russell
Michael D. Tschiltz
INPO
Diablo Distribution

Enclosure

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280016

# LICENSEE EVENT REPORT (LER)

| FACILITY NAME (1) | DOCKET NUMBER (2) | PAGE (3) |
|---|---|---|
| Diablo Canyon Unit 1 | 0 5 0 0 0 2 7 5 | 1 OF 12 |

TITLE (4) Diesel Generators Started and Loaded as Designed Upon Failure of Auxiliary Transformer 1-1 Due to Inadequate/Ineffective Procedures Related to the Control of Grounding Devices

| EVENT DATE (5) | | | LER NUMBER (6) | | | REPORT DATE (7) | | | OTHER FACILITIES INVOLVED (8) | |
|---|---|---|---|---|---|---|---|---|---|---|
| MON | DAY | YR | YR | SEQUENTIAL NUMBER | REVISION NUMBER | MON | DAY | YR | FACILITY NAMES | DOCKET NUMBER (S) |
| 10 | 21 | 95 | 95 | 0 1 4 - | 0 0 | 11 | 20 | 95 | | 0 5 0 0 0 |
| | | | | | | | | | | 0 5 0 0 0 |

OPERATING MODE (9): 6

POWER LEVEL (10): 0 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR: (11)

X 10 CFR 50.73 (a)(2)(iv)

OTHER -

(Specify in Abstract below and in text, NRC Form 366A)

LICENSEE CONTACT FOR THIS LER (12)

| NAME | TELEPHONE NUMBER AREA CODE | TELEPHONE NUMBER |
|---|---|---|
| Donald H. Behnke- Senior Regulatory Services Engineer | 805 | 545-2629 |

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

| CAUSE | SYSTEM | COMPONENT | MANUFACTURER | REPORTABLE TO NPRDS | | CAUSE | SYSTEM | COMPONENT | MANUFACTURER | REPORTABLE TO NPRDS | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| A | E A | X F M R | W 0 0 5 | N | | | | | | | |
| | | | | | | | | | | | |

SUPPLEMENTAL REPORT EXPECTED (14)

[ ] YES (If yes, complete EXPECTED SUBMISSION DATE) [X] NO

EXPECTED SUBMISSION DATE (15): MONTH | DAY | YEAR

ABSTRACT (16)


On October 21, 1995, at 0938 PDT, with Unit 1 in Mode 6 (Refueling) and Unit 2 in Mode 1 (Power Operation) at 100 percent power, all three Unit 1 diesel generators (DGs) auto-started and loaded, as required, when Unit 1 experienced a loss of all offsite power following the failure of auxiliary transformer 1-1 with the startup bus de-energized for maintenance. On October 21, 1995, at 0951 PDT, an Unusual Event (UE) was declared in accordance with plant procedures when all offsite power was lost for greater than 15 minutes and also for a fire that was not put out within 15 minutes. At 1005 PDT, a 1-hour, emergency report was made to the NRC in accordance with 10 CFR 50.72(a)(1)(i), "the declaration of an emergency class as specified in the emergency plan." On October 22, 1995, at 0129 PDT, the UE was terminated when offsite power was restored. Eight supplemental calls kept the NRC informed of changes in status.

On October 22 at 0128 PDT, the three DGs were separated from their respective vital buses, secured, and returned to standby mode.

This event was caused by inadequate/ineffective procedures related to the control of grounding devices (ground buggies), which resulted in the direct ground of a 12 kV bus and the resulting failure of auxiliary transformer 1-1 with a subsequent transformer oil fire and the loss of all offsite power. Applicable procedures are being revised to provide better controls for ground buggies.

I. Plant Conditions

Unit 1 was in Mode 6 (Refueling) with core reload complete and the reactor head on but not tensioned. Offsite power was being "back fed" through the main transformers (500 kV to 25 kV) (EA)(XFMR) and auxiliary transformers (EA)(XFMR), while the alternate (startup) offsite power (EA) source (230 kV) was cleared for maintenance.

Unit 2 was in Mode 1 (Power Operation) at 100 percent power.

II. Description of Problem

A. Summary:

On October 21, 1995, at 0938 PDT, all three Unit 1 diesel generators (DGs)[EK][DG] auto-started and loaded, as required, when Unit 1 experienced a loss of all offsite power following the failure of auxiliary transformer 1-1 with the startup (SU) bus [EA][BU] de-energized for maintenance. On October 21, 1995, at 0951 PDT, an Unusual Event (UE) was declared in accordance with plant procedures when all offsite power was lost for greater than 15 minutes and also for a fire that was not extinguished within 15 minutes. At 1005 PDT, a 1-hour, emergency report was made to the NRC in accordance with 10 CFR 50.72(a)(1)(i), "the declaration of an emergency class as specified in the emergency plan."

On October 22 at 0128 PDT, the three DGs were separated from their respective vital buses, secured, and returned to standby mode when offsite power was restored. On October 22, 1995, at 0129 PDT, the UE was terminated. Eight supplemental calls kept the NRC informed of changes in status.

B. Background:

Standby offsite power to Diablo Canyon Power Plant (DCPP) is provided from two 230 kV lines and can be provided from three 500 kV lines when the DCPP main generator is not operating.

Auxiliary transformer 1-1 converts 25 kV to 12 kV for non-safety use by the four reactor coolant pumps (AB)(P) and two circulating water pumps (KE)(P). None of these pumps were operating.

Ground buggies are personnel and equipment protecting grounding devices that replace the breaker in the breaker cubicle and can be aligned to ground either the load or the bus side of the breaker.

Breaker 52-VD-4 is the startup feeder breaker to 12 kV bus D (see figure 1).

Breaker 52-VD-8 is the auxiliary feeder breaker to 12 kV bus D (see figure 1).

MP E-57.11B, "Installing and Removing Grounds from De-energized Power Plant Electrical Equipment," requires that the installing technician hang a "Ground Installed" tag on the cubicle door and a "Caution" tag on the ground buggy.

CF4.ID5, "Control of Lifted Circuitry, Process Tubing, and Jumpers During Maintenance," requires the logging of the caution tag on a status sheet attached to the work order unless the caution tag is controlled and documented by an approved written procedure.

OP J-5:IV, "12 kV Breaker Code Order," requires workers to contact the control room to request the required switching orders prior to installing the ground buggy.

C. Event Description:

On October 2, 1995, during the Unit 1 seventh refueling outage, a clearance was hung on 12 kV bus D (EA)(BU) in preparation for routine outage work. The clearance added control board caution tags to the 52-VD-4 and 52-VD-8 breaker switches in the control room, as well as the ground installed tag on the breaker cubicle. Three days later a crew of three Technical Maintenance (TM) workers were assigned the task of installing a grounding device (EA)(57), commonly referred to as a ground buggy (EA)(57), in place of start-up feeder breaker 52-VD-4 (EA)(BKR) (see figure 1). The ground buggy had not been installed when the clearance was hung since ground buggies were not considered to be formal clearance points. One of the workers contacted the control room to request switching orders to install the ground buggy as required by OP J-5: IV.

The Senior Control Operator (SCO) prepared the switching orders on a switching log specifying that the ground buggy be installed on the "load" (12 kV bus D) side of 52-VD-4, and had the log independently verified by a second operator. The switching log was issued to the TM workers, who installed the ground buggy on the "bus" (12 kV bus D) side of the breaker since the load side of the breaker was still energized. PG&E has identified that different terminology was used by the TM and Operations organizations regarding the definition of "bus" and "load" when referring to feeder breakers and cross-ties.

In this situation, all parties involved knew where the ground buggy had to be installed, and it was installed in the correct configuration despite the terminology differences.

MP E-57.11B requires that the installing technician hang a "Ground Installed" tag on the cubicle door and a "Caution" tag on the ground buggy. It then directs the worker to log that caution tag in accordance with CF4.ID5. This procedure requires the logging of the caution tag on a status sheet attached to the work order unless the caution tag is controlled and documented by an approved written procedure. In this instance, the installing technician did not log the caution tag in the work order since it had been issued and documented in accordance with OP J-5:IV, an approved written procedure. Upon the completion of the ground buggy installation, the switching log was returned to the control room for filing. Work requiring this ground buggy was completed on October 11, 1995.

On October 20, 1995, the SU power system clearance was reported on, adding another man-on-line tag to the 52-VD-4 cubicle. This is a separate clearance from the clearance on 12 kV bus D.

On October 21, 1995, Unit 1 was in day 22 of a scheduled 33 day refueling outage. DGs 1-1 and 1-3 were operable and in standby mode. DG 1-2 was available (STPs required for declaring operable were not complete) and in standby mode.

On October 21, 1995, at approximately 0400, a TM Foreman in response to a request from operations, electronically verified that the work was complete and that all red tags had been removed prior to reporting off the bus D clearance, as required by OP2.ID1, "DCPP Clearance Process." It is common practice to physically walk down the clearance, and in doing so, he noted two "Ground Installed" tags. He opened those cubicle doors and verified that the ground buggies were installed on the load side of their associated cubicles. At this time, he did not notice a "Ground Installed" tag on the 52-VD-4 cubicle. He reported off the clearance.

At approximately 0600 on the same day, Operations personnel were sent to remove the bus D clearance man-on-line tags and rack in the necessary breakers. They noted that 52-VD-4 was racked out with an additional man-on-line tag in effect as a result of the startup bus clearance. They do not recall seeing a "Ground Installed" tag on the cubicle door. At 0620, an operator removed the control board caution tags from the 52-VD-4 and 52-VD-8 breaker switches in the control room.

Later that morning, the day shift operating crew made preparations to energize 12 kV bus D in preparation for an uncoupled run of a reactor coolant pump. The Unit 1 SCO, Control Operator (CO), and an assigned extra Reactor

Operator (RO) discussed the evolution prior to closing the auxiliary feeder breaker (52-VD-8) that would provide power to bus D. They noticed the "Ground Installed" lamacoid attached to the switch plate for the startup feeder breaker (52-VD-4) switch. The RO questioned the location of the installed ground buggy, stating that if it were installed on the 12 kV bus D side of the breaker, a direct path to ground would exist when the bus was re-energized. The three operators discussed this issue and concluded (erroneously) that the ground buggy was located on the startup bus side (load side) of 52-VD-4 (see figure 1). The operator's conclusion was based on the facts that the 12 kV bus D clearance had been reported off and the associated control board caution tag had been removed from the 52-VD-4 operating switch. It is a common practice to energize a bus with ground buggies installed on the "load" side of the breakers. The fact that a separate clearance had recently been issued for work on the startup bus was discussed, and having a ground buggy on the "Load" side of 52-VD-4 was an expected condition. The operators did not physically check the 52-VD-4 cubicle to verify their assumptions.

At approximately 0938 PDT, an attempt was made to energize 12 kV bus D. When the auxiliary feeder breaker, 52-VD-8, to this bus was closed to energize the bus, a catastrophic failure of auxiliary transformer 1-1 occurred. All relays and breakers responded to the instantaneous overload condition as designed, but not soon enough to prevent the damage that occurred. The rupture of the transformer case released the contained coolant oil which then ignited. The transformer deluge systems actuated as designed. Newly installed main transformers were slightly damaged by the transformer fire (paint damage and coating of oil and fire fighting foam). The iso-phase bus ducting was ruptured at the transformer and one of the glass viewing ports was blown out at the motor operated disconnect switch. DCPP Unit 2 was not affected, and continued to operate at 100 percent power throughout the event.

The Operations Fire Brigade and the Industrial Fire Officers (IFOs) responded to the fire in a timely and professional manner. Offsite assistance from the California Department of Forestry (CDF) was requested, but due to the effectiveness of the deluge system and the responses of the fire brigade and the IFOs, CDF assistance was not needed. The fire was out in approximately 30 minutes.

Due to the fire, smoke, and loss of lighting; the turbine building, containment and other administrative buildings were evacuated. Some roving fire watches were missed during the evacuation period, but this was not considered significant since potential sources of fires such as most electrical circuits were de-energized and personnel were restricted from the area. In addition, the plant was at an increased state of alertness with the incident command system established and the fire brigade and IFOs ready.

At 0940, the control boards were walked down for equipment alignment.

This event caused a loss of all offsite power for Unit 1. All three DGs on Unit 1 started and loaded on their respective buses. Residual Heat Removal (RHR) pump 1-1 (BP)(P) was restarted following the load shed. This still left the non-vital buses de-energized. Technical Maintenance and Substation Maintenance were allowed to perform initial inspections and to complete maintenance activities that had already begun on the SU transformers and buses prior to initiating switching to restore offsite power to the unit.

At 0949 PDT, component cooling water (CCW) pump 1-2 (CC)(P) was shutdown. At 0950, containment fan cooling units (CFCUs) (BK)(CLR) 1-2, 1-3, and 1-4 were shutdown. Both auxiliary salt water (ASW) (BI) and both CCW pumps and all five CFCUs had autosequenced on when the DG s had loaded onto the vital buses. The pumps and CFCUs not needed were secured.

At 0951 PDT, in accordance with the guidance of Emergency Procedure G-1, following the loss of offsite power for greater than 15 minutes with at least one diesel generator starting and loading onto its vital bus, or a fire that is not out within 15 minutes, an UE was declared. All required notifications were made by 1005 PDT.

At 0954 PDT, ASW pump 1-2 was shutdown.

At 1010 PDT, the fire was reported to be out and the transformer deluge system was secured.

The hazardous materials personnel responded to the transformer bank area to control the oil loss from the auxiliary transformer. A maximum of 4,300 gallons of transformer oil combined with fire water was collected at the north plant weir. With the support of a contract disposal firm the majority of the oil was loaded onto the disposal trucks for offsite transport. The hazardous materials team performed cleanup activities to remove residual oil in the area. A very small amount of oil and/or fire suppression foam flowed to Diablo Creek producing a sheen on the water. All required offsite notifications were made by Environmental Engineering.

At 1345 PDT, a medical emergency was declared and an ambulance was requested for a security guard suffering from smoke inhalation. After being examined at a local hospital, he was released.

At 2200 PDT, permission was given to commence energization of 4 kV buses from the startup system. A tailboard was held to cover the process. The operating procedures for this switching evolution required that all loads be stripped prior to re-energizing the buses. At 2215, switching commenced in accordance with OP J-2:II, J-6B:IV/V/VI, OP J-9:II, and formal communications.

On October 22, 1995, at 0022 PDT, OCB-212 was closed and SU transformer 1-1 was energized. At 0046 PDT, the 12 kV SU bus was energized by closing 52-VU-12.

At 0055 PDT SU transformer 1-2 was energized followed by energization of 4 kV buses D and E from startup power.

At 0118, 0123, and 0128 PDT, DG 1-3, 1-2, and 1-1 respectfully were separated from the bus, shutdown, and returned to standby mode. Buses F, G. and H were now being supplied by startup power.

At 0129 PDT, the UE was terminated.

D. Inoperable Structures, Components, or Systems that Contributed to the Event:

SU transformers 1-1 and 1-2 and their associated buses, were out of service for maintenance.

E. Dates and Approximate Times for Major Occurrences:

1. October 21, 1995, at 0938 PDT: Event Date/Discovery Date, Transformer 1-1 failure and all three DGs started.
2. October 21, 1995, at 0951 PDT: UE Declared.
3. October 21, 1995, at 1005 PDT: A 1-hour emergency report was made to the NRC in accordance with 10 CFR 50.72(a)(1)(i).
4. October 22, 1995, at 0128 PDT: The three DG s were secured and returned to standby mode.
5. October 22, 1995, at 0129 PDT: UE terminated.

F. Other Systems or Secondary Functions Affected:

Due to the fire, smoke and loss of lighting; the turbine building, containment and other administrative buildings were evacuated. Per design, the RHR pump and spent fuel pool cooling pump (DA)(P) did not restart upon re-energization of the vital buses, thus RHR was lost for approximately two minutes during the recovery. The spent fuel pool cooling pump was lost for approximately eight hours.

G. Method of Discovery:

The loss of offsite power and the auto-start of the three DGs was immediately apparent to plant operators due to alarms and indications received in the control room. Eyewitnesses to the transformer fire called in the fire alarm to the control room.

H. Operator Actions:

1.. Equipment designed to auto-start was verified to be running.

2. CCW pump 1-2, ASW pump 1-2 and CFCUs 1-2, 1-3, and 1-4 were returned to normal standby mode

3. RHR pump 1-1 was manually restarted. The pump is not intended to automatically restart after vital bus transfer in Mode 6.

4. Spent fuel pool cooling pump (DA)(P) 1-2 was restarted. The pump is not intended to automatically restart after vital bus transfers.

5. Plant busses were reconfigured to restore offsite power from the 230 kV SU power system.

6. After restoring 230 kV power, the three DG s were secured and returned to standby mode.

I. Safety System Responses:

1. DGs 1-1, 1-2, and 1-3 started and loaded to their respective buses.

2. Both ASW pumps and both CCW pumps and all five CFCUs autosequenced onto their respective buses after the vital buses were powered by the DGs.

III. Cause of the Problem

A. Immediate Cause:

Loss of all offsite power to the Unit 1 vital buses.

B. Root Cause:

This event was caused by a general programmatic failure, in that existing administrative controls were either inadequate or ineffective in preventing the energization of an electrical bus while it was grounded by means of an installed personal protection device (ground buggy).

C. Contributing Cause:

1. The failure to take advantage of previous events and precursors to identify and develop effective process controls is considered to be a prime causal factor in this event. During 2R6, a DG was started with a ground buggy installed in the generator breaker cubicle, grounding the generator. Corrective actions did not consider generic implications in that they addressed only ensuring that ground buggies are removed from the breakers associated with the DGs prior to starting. Actions failed to identify the potential for other situations where the presence of a ground buggy might result in adverse consequences (i.e., feeder or cross-tie breakers). Also, the intent to procedurally require ground buggies to be recorded in work orders was ineffective.

2. One of the major causes of unreliability in transformers is the inability to withstand the mechanical forces produced by through faults. Most transformer manufacturers did not become aware of the internal forces generated during a through fault until the 1960s. Steps to improve the mechanical strength of the conductors, winding insulation, and coil clamping structure were initiated by some manufacturers; however, others did not make any improvements until the late 60's and the early 70's when ANSI standards required transformers to be "self protecting" with no system impedance.

   Axial looseness of windings in older transformers occurs over time from the compaction of the insulation materials by vibration, thermal expansion and contraction, and short circuit forces. When this occurs on units with static clamping structures, the axial clamping force is gone and the coils will move axially during a fault. This movement normally results in conductor insulation damage, arcing and failure. The steel clamping plates do not extend through the core window to provide full circumference clamping pressure on the coils. This lack of clamping pressure in the core window areas allows the winding to move upward during a fault condition. This was evident on the failure of auxiliary transformer 1-1.

IV. Analysis of the Event

Had the need arisen, SU power could have been restored within 30 minutes at any time during this event. The transformer deluge system performed its intended safety function of preventing the spread of the fire to the other transformers.

The loss of all offsite power is an FSAR, Chapter 15, Conditon II previously analyzed event. Three DGs were available and performed their intended safety function. In Mode 6, only one DG is needed to maintain the plant in a safe shutdown condition. The fire did not threaten the DGs.

The spent fuel pool temperature increase from 92 degrees Fahrenheit (F) to 112 degrees F. The alarm setpoint for the spent fuel pool is 130 degrees F. Had the pool temperature reached the alarm setpoint, operators would have taken corrective actions or compensatory measures in accordance with approved plant procedures.

During the two minutes when the RHR pump was not in operation, there was no appreciable increase in the temperature of the reactor coolant system.

Thus, the health and safety of the public were not affected by this event.

V. Corrective Actions

A. Immediate Corrective Actions:

1. A prompt response by the plant fire brigade and the effectiveness of the transformer deluge system combined to limit the extent of the fire and to put the fire out within 30 minutes.

2. With the support of a contract disposal firm the majority of the transformer oil was loaded onto disposal trucks for offsite transport. The hazardous materials team performed cleanup activities to remove residual oil in the area. A very small amount of oil and fire suppression foam flowed to Diablo Creek producing a sheen on the water.

3. After determining the cause of the event, reviewing the status of the startup transformers and their associated buses, offsite power was restored from the 230 kV system.

4. An Event Investigation Team was initiated to investigate this event, coordinate recovery efforts, and determine applicable corrective actions to prevent recurrence.

B. Corrective Actions to Prevent Recurrence:

1. Applicable plant administrative, maintenance, and operations procedures are being revised to:

   a. Change the clearance process to include control of ground buggies. Add ground buggies as formal clearance points

   b. Provide directions on the control of ground buggies. Consolidate all technical requirements for ground buggies in one procedure.

   c. Provide directions for energizing dead buses and transformers. Require formal bus inspections by both maintenance and operations prior to returning a bus to service.

2. New lamicoids for the switchgear door and control room mimic bus will be created to ensure consistency and eliminate confusion in the actual physical location of the ground

3. Provide training to maintenance and operations personnel on the new procedural improvements.

4. Additional corrective actions are being developed and will be tracked by a plant non-conformance report.

VI. Additional Information

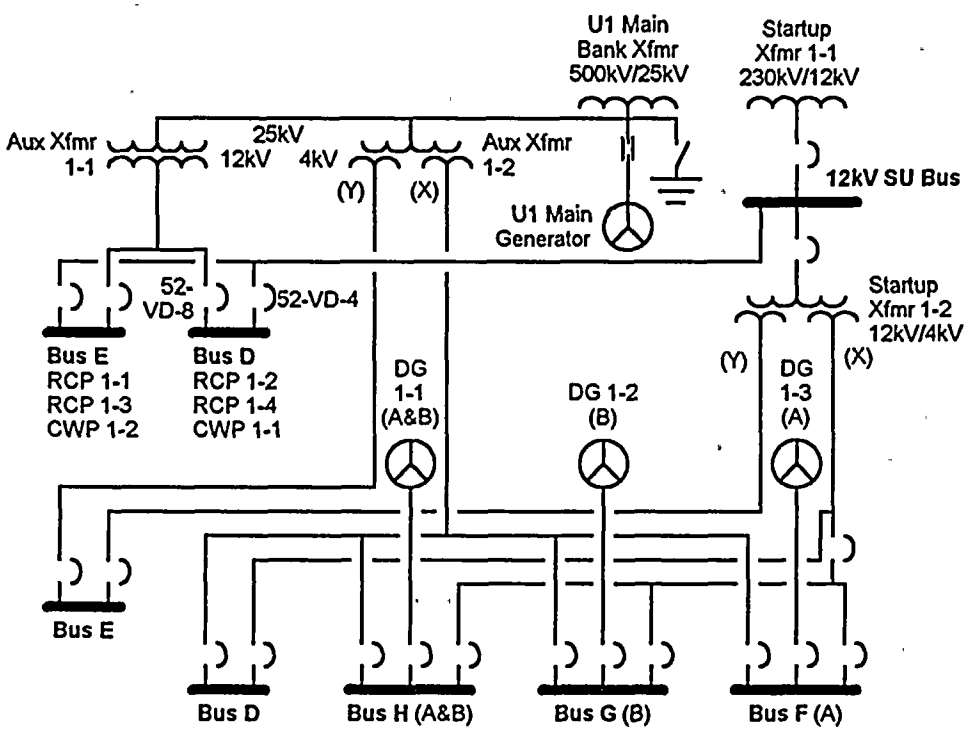
A. Failed Components:

Component: Auxiliary transformer 1-1, Wagner

B. Previous LERs on Similar Problems:

LER 1-94-016 reported the autostart of all six DGs due to the loss of all offsite power to both units. That event was caused by an offsite fire; since the DGs performed as per design, there was no corrective actions deemed necessary to preclude recurrence. Thus, the corrective actions of the previous event could not have precluded the current event.

## FIGURE 1


U1 Main
Bank Xfmr
500kV/25kV
Startup
Xfmr 1-1
230kV/12kV
Aux Xfmr
1-1
25kV
12kV
4kV
(Y)
(X)
Aux Xfmr
1-2
12kV SU Bus
U1 Main
Generator
52-
VD-8
52-VD-4
Startup
Xfmr 1-2
12kV/4kV
(Y)
(X)
Bus E
RCP 1-1
RCP 1-3
CWP 1-2
Bus D
RCP 1-2
RCP 1-4
CWP 1-1
DG
1-1
(A&B)
DG 1-2
(B)
DG
1-3
(A)
Bus E
Bus D
Bus H (A&B)
Bus G (B)
Bus F (A)