228460

Transformer Recovery Options Team

TECHNICAL BASIS SUPPORTING OPERATION OF UNIT 1 12 kV BUSES D AND E FROM 230 kV STARTUP POWER

Revision 1

November 18, 1995

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I. Executive Summary

The 12 kV system is comprised of Buses D and E. Each bus provides the power for two Reactor Coolant Pumps (RCPs) and one Circulating Water Pump (CWP). Three sources of power are normally available for the 12 kV system (see Figure 1): the main generator, the 500 kV system, and the 230 kV system. The 12 kV system is normally aligned to the main generator via Auxiliary Transformer (AT) 1-1. On October 21, 1995, during the seventh refueling outage for Unit 1, AT 1-1 failed due to a short to ground. Restart of Unit 1 is dependent on re-establishing acceptable power to the 12 kV system. Nuclear Technical Services (NTS) management proposed that startup and operation could be accomplished by keeping the buses energized from startup power. This evaluation examines the option of operating Diablo Canyon Power Plant (DCPP) Unit 1 12 kV Buses D and E from the 230 kV startup power via Startup Transformer 1-1. The purpose of startup power (230 kV system) is to start up the 12 kV loads after shutdown (for both Units), to provide power for normal site loads, and to provide an immediate source of offsite power during an accident or normal shutdown.

A multi-disciplined team from NTS was formed to scrutinize the viability of the startup power option. The team's goal was to establish whether the plant could operate safely and reliably in this configuration. The NTS Transformer Recovery Options Team consisted of individuals with the following expertise: Design and Licensing Bases, Electrical Design, System Transient Analysis, Probabilistic Risk Assessment (PRA), Operations, and Quality Services. To ensure that the review was thorough and complete, an independent review was performed by an Expert Evaluation Team.

The proposed change in operating configuration was analyzed in a safety analysis with input provided by Westinghouse. The safety analysis focused on impacts to FSAR Update Chapter 15 accident analyses, PRA, and plant operations. The safety analysis showed that no new accidents were created and that the probability of occurrence and the consequences of previously analyzed accidents were within defined criteria. The risk analyses for all accidents were bounded by a "loss of offsite power" (LOOP) (both LOCA and non-LOCA accidents). A LOOP is defined as a loss of both the 500 kV system and the 230 kV system. The defense-in-depth philosophy at DCPP credits three emergency diesel generators in a LOOP incident. The conclusion reached was that operation of DCPP Unit 1 from startup power was safe and would not introduce undue risk to the health and safety of the public.

PRA review determined that a loss of startup power was a new reactor trip initiating event. The annual risk to core damage was increased by approximately 2%, if DCPP Unit 1 operates for six months (November 1995 to May 1996) in this configuration. This level of risk increase is considered non-risk significant per EPRI guidelines. This increase was offset by implementation of risk management practices (e.g., minimize maintenance on 230 kV system and key safety systems) and compensatory measures (e.g., shutting down due to external events and enhancing 230 kV system availability). Other actions include revising operations procedures, training operators (licensed and non-licensed), and implementing design changes.

Numerous computer simulations were run by Transmission Planning and NTS Electrical Engineering. The simulations were performed to model the dynamic and steady state effects caused by adding DCPP unit loads on the 230 kV System. The computer runs provided information on whether the 230 kV system voltage could recover within the protective relay time setting and not load the emergency diesel generators (EDGs). The acceptance criteria was that loads would remain connected to the 230 kV System, and not transfer to the EDGs. If voltage did not recover in the required time, additional computer runs were completed with reduced transfer of loads onto the 230 kV System.

The base computer case takes credit for a complete 230 kV transmission system which includes the following:

- The Diablo Loop; consisting of transmission lines from:
  Diablo - Morro Bay
  Diablo - Mesa
  Mesa - Morro Bay

- The Morro Bay Outlet lines; consisting of transmission lines from:
  Morro Bay - Gates (2 lines)
  Morro Bay - Midway (2 lines)

Local generation for the 230 kV system is supplied from the four units at Morro Bay Power Plant (MBPP). Units 3 and 4 at MBPP are presently unavailable. With only MBPP Unit 1 or 2 in operation, additional compensatory measures are required to maintain adequate voltage. These additional measures are:

- Reset the tap on the Unit 1 and 2 12/4 kV Startup Transformers to boost the 4 kV voltage by 2.5%
- In Unit 2, block the automatic transfer of one 12 kV bus (either D or E)
- Maintain a minimum voltage of 226 kV at the DCPP switchyard

Other compensatory measures are being implemented to help reduce overall plant risk. These measures include the control of maintenance, and training of operators, and are described in more detail in the body of the report. Each compensatory measure required to be completed before starting Unit 1 is tracked in PIMS as a Mode 4 constraint.

A last set of computer runs were completed to deal with single contingencies, such as the loss of a 230 kV transmission line or no generation at MBPP. These studies show that a single contingency will <u>not</u> cause the trip of Unit 1. However, additional compensatory measures are needed to continue operation of DCPP Units 1 and 2 if these events occur. These additional measures are described in the report.

The present electrical analysis uses autumn/winter peak loading for the Los Padres area (405 MW) and for the total PG&E System (16,400 MW). These numbers are valid only through May 1, 1996. By that time, MBPP Units 3 or 4 should be back in service. With MBPP 3 or 4 in service, additional local generation is available and that benefit will be evaluated.

Based on its reviews and the implementation of compensatory measures, the NTS team concluded that restart of Unit 1 was warranted.

230 kV BASE CASES
Unit 1 on 230 kV/ Unit 2 Operating

Cases	Event	Results
Case 1A	Unit 1 Startup (4 kV loads on 25 kV) Normal startup	The 12 kV loads can be started sequentially at any time.
Case 1B	Unit 1 Startup (4 kV loads on 25 kV) Light load Los Padres & PG&E system No MBPP No Tap Change	Four reactor coolant pumps (only) can be started sequentially at any time.

230 kV CONTINGENCY CASES
Unit 1 on 230 kV with 4 kV Loads Supplied by 25 kV

Cases	Event	Trip U1: Result	Trip U2: Result
Case 2	Units 1 and 2 Normal Operation	Unit 1 EDGs do not load	Unit 2 EDGs/do not load
Case 3	Lose MBPP #2	EDGs load LCO	No EDG loading Unit 2 EDGs start No LCO
Case 4	Lose DCPP - Mesa Line	No LCO	No EDG loading Unit 2 EDGs start No LCO
Case 5	Lose MB - Mesa line (put line back in service or implement comp measures for Unit 2)	EDGs load LCO	EDGs load LCO
Case 6	Lose DCPP-MB line (put line back in service)	EDGs load LCO	EDGs load LCO
Case 7	Lose one MB outlet line	EDGs load LCO	No EDG loading No LCO
Case 8	Trip DCPP Units 1 & 2	230 kV remains stable EDGs may load	230 kV remains stable SLUR actuation unlikely on Unit 2

II. Background

On October 21, 1995, during the seventh refueling outage for DCPP Unit 1, Auxiliary Transformer AT 1-1 failed due to a short-to-ground fault that occurred during a test on 12 kV Bus D. Bus D was being energized in preparation for an uncoupled test run of RCP 1-4. A previously installed personnel protection device (ground buggy) was not removed prior to energizing the bus which caused a direct short to ground. The transformer case ruptured and released coolant oil. Oil that remained in the transformer ignited. The fire was contained in approximately 30 minutes; and there was no radiological release and no threat to the health and safety of the public. The automatic fire suppression system actuated and a timely response was provided by the Fire Brigade, Security, and Hazardous Materials personnel.

The failure of AT 1-1 resulted in a loss of offsite power since the 500 kV backfeed was out of service. All three emergency diesel generators started and picked up the electrical loads. Unit 1 was supplied by on-site power for 15 hours, and offsite power was subsequently restored to Unit 1 from the 230 kV system. An Event Investigation Team (EIT) was formed and created the Transformer Recovery Team to determine the root cause and corrective actions to prevent recurrence. The Transformer Recovery Team was divided into three sub-teams to address the following tasks:

- Evaluation of Main and Auxiliary Bank conditions, removal, and required repairs
- Analysis and replacement of the auxiliary transformer
- Options for returning Unit 1 to power.

This report documents the results of the team responsible for the third task (Transformer Recovery Options Team). The technical bases for restarting and operating Unit 1 from startup power are provided in this report.

III. Report Organization

Although energizing the 12 kV Buses from 230 kV startup power was a routine evolution during past startups, continuous plant operation in this mode is not normally done. A number of factors were considered to assess the effect this would have on operation in this configuration. The following sections of this report are organized by the topics analyzed by the team. The results of the review are summarized under each topic heading.

The following issues were researched and responded to by the NTS team:

- 230 kV System Loading and Reliability
- Electrical Analysis and Equipment Capability
- Licensing and Design Bases
- Safety Analysis (Accident Analysis)
- Probabilistic Risk Assessment (PRA)
- Impact on Operations

A. 230 kV SYSTEM LOADING AND RELIABILITY

Power for the 230 kV system is obtained from the DCPP-Mesa transmission line or the DCPP-Morro Bay transmission line. The purpose of startup power (230 kV system) is to start up the 12 kV loads after shutdown (for both Units), to provide power for normal site loads, and to provide an immediate source of offsite power during an accident or normal shutdown. Prior to the transformer failure, required maintenance on the 230 kV system identified the need to qualify elements necessary for a fully capable 230 kV system. Operability Evaluation (OE) 95-06 (Ref. 23) documents operability of the 230 kV startup power system with incoming feeder lines from Morro Bay Power Plant (MBPP) and the Mesa substation in service, combined with various operating configurations of MBPP units. The safety assessment of the OE discusses the effect of double sequencing of engineered safety features (ESF) equipment. No compensatory measures associated with double sequencing were identified. To assure that the 230 kV system is capable of supplying the DCPP Unit 2 loads without starting and loading the diesels, the following compensatory measures were implemented in OE 95-06 for DCPP Unit 2 when MBPP Units 3 or 4 are unavailable and when only MBPP Units 1 or 2 are operating at a maximum capability of 105% voltage:

- One Unit 2 12 kV bus D or E (with two RCPs) is prevented from auto transferring to the 230 kV system.

- The time delay settings for the condensate and condensate booster pump undervoltage start for both DCPP Units have been changed per DCPs E-49228 and E-50228.

For the purpose of evaluating the proposed 230 kV Startup Option, PG&E Transmission Planning evaluated several scenarios to determine the transient and steady-state response of the 230 kV Diablo Loop (Ref. 17 and 18). The 230 kV Diablo Loop is defined as the transmission line encompassing the following: (1) MBPP - DCPP 230 kV, (2) MBPP - Mesa 230 kV, and (3) DCPP - Mesa 230 kV. The results of the scenarios are shown below.

The base condition for each run is that all transmission lines are in service and Morro Bay Power Plant Unit 2 is operating. The important Plant constraints for each case include:

- Reset the tap on the Unit 1 and Unit 2 12/4 kV Startup Transformers to 2.5% boost.
- Block the transfer of one Unit 2 12 kV bus D or E. (Cutout the feature cutout switch on the Main Control Board).
- Maintain 226 kV minimum voltage at the DCPP Switchyard.

The results are given as Pass or Fail. Pass means that the 230 kV loop response is acceptable. Fail means that the 230 kV loop response is unacceptable. The key acceptance criterion is that the Emergency Diesel Generators (EDGs) in either Unit DO NOT LOAD. To ensure the EDGs do not load, The 4 kV vital bus voltage must recover to greater than 93% (of 4160V) at 16 seconds after initiation of the transient. The EDGs may start as a result of the transient.

A trip of a DCPP Unit is the worst case transient and encompasses a LOCA. On a Unit trip, the condensate / condensate booster set is assumed to start. This is a more severe loading than the start or transfer of the additional ECCS loads in response to a LOCA. Thus a successful Unit trip demonstrates a successful response to a LOCA.

On the loss of a transmission line in the Diablo Loop due to a transient disturbance, the ETAP results indicated that the voltage at Unit 1 12 kV Buses will depress to zero for 22 cycles. A fault clearing time of 22 cycles represents the worst case condition which assumes that the primary protection has failed and the backup protection is then used to clear the fault. The normal fault clearing time for primary protection is 6 cycles. The fault will cause the RCPs to experience undervoltage and subsequently cause a reactor trip of DCPP Unit 1. The RCP undervoltage trip setting is 8050 volts with no time delay. A 30 cycle time delay in the 12 kV undervoltage relay will need to be implemented to prevent a reactor trip as a result of a fault on either line (Ref. 24 and 42). This will allow the RCPs to "ride through" the voltage transient and fault clearing time caused by the disturbance (loss of a line). A 30 cycle time delay on the RCP trip will allow an 8 cycle margin for worst case fault clearing time.

1) Unit 1 Startup, Unit 2 Operating

Case 1A - Start 12 kV Loads

Startup DCPP Unit 1 via the 230 kV loop using 4 RCPs and 1 CWP running at steady-state. Start the second CWP from a locked rotor condition. The system parameters are as follows:

- Generation at MBPP is limited to Unit 2 (1.05 per unit)
- DCPP Unit 2 is operating at full output, 1.0 per unit terminal voltage.
- DCPP Unit 1 is off-line
- All 230 kV loop lines are in service.
- Los Padres Peak loading: 385 MW
- Los Padres Off-peak loading: 250 MW

RESULTS: For this scenario only, the results indicate that Unit 1 can be safely started any time of the day in the Autumn/Winter peak and off-peak periods.

Case 1B - Special Unit 1 Startup Case

With 12 kV loads on Unit 1 (4 RCPs only) supplied via the 230 kV loop, transfer DCPP Unit 2 auxiliary loads due to a non-LOCA trip. The startup bank tap setting for Unit 2 is 12/4 kV (no tap change). It is assumed that Unit 2 standby condensate pump and condensate booster pump will start from a locked rotor condition during the auxiliary transfer. The system parameters are as follows:

- Generation at MBPP is limited to Unit 2 (1.05 pu)
- DCPP Unit 2 is operating at full output, 1.0 pu terminal voltage.
- DCPP Unit 1 is off-line
- All 230 kV loop lines are in service.
- Los Padres Peak loading: 385 MW

RESULTS: Unit 2 Trip

Case	12 kV tap	Standby Condensate Set	Results
reduced aux transfer	0% (no tap change)	Started	Pass

2) Unit 1 Operating, Unit 2 Operations

With Unit 1 12 kV loads (4 RCPs and 2 CWPs) supplied via the 230 kV loop, transfer DCPP Unit 2 auxiliary loads due to a Non-LOCA trip. It is assumed that Unit 2 standby condensate pump and condensate booster pump will start from a locked rotor condition during the auxiliary transfer. The system parameters are as follows:

- Generation at MBPP is limited to Unit 2 (1.05pu)
- DCPP Unit 2 is operating at full output, 1.0 pu terminal voltage.
- DCPP Unit 1 is operating at full output, 1.0 pu terminal voltage.
- All 230 kV loop lines are in service.
- Los Padres Peak loading: 385 MW (and sensitivity at 405 MW)
- DCPP 230 kV Pre-Transfer Voltage: 226 kV @ 405 MW

RESULTS: Unit 2 Trip

Case	12 kV tap	Standby Condensate Set	Results
Full aux transfer	0%	Started	Fail
Reduced transfer	0%	Started	Fail
Reduced transfer	0%	*CUT-OUT	Pass
Reduced transfer	2.5%	Started	Pass

* Prevent standby condensate/booster pump set from starting on low pressure.

RESULTS: Unit 1 Trip

Bus Name	16-second voltage	Results
Unit #1 4 kV F, G & H	93.1% (2.5% tap)	Pass
Unit #1 4 kV F, G & H	95.7% (5.0% tap)	Pass

3) No Generation at Morro Bay Power Plant

- ZERO GENERATION AT MORRO BAY POWER PLANT.
- All Morro Bay outlet lines are in service.
- DCPP #1 at full power output to the 500 kV grid.
- DCPP #1's 4 kV vitals and non vitals served via the 25 to 4.16 kV aux. bank.
- DCPP #1's 12 kV loads (43MW) served via the Diablo 230 kV loop power source.
- DCPP #2 at full power output to the 500 kV grid.
- All Diablo 230 kV loop lines are in service.
- Non-LOCA, reduced transfer of DCPP Unit #2.
- DCPP #2 12 to 4 kV startup transformer tap: 2.5%.
- Los Padres load: 405 MW
- Condition: 1995 Autumn peak.
- Diablo 230 kV pre-transfer voltage: 222.5 kV

RESULTS: Unit 2 Trip

Bus Name	16-second voltage	Results
Unit #1 12 bus E	95.5%	Pass
Unit #1 12 bus D	95.5%	Pass
Unit #2 12 bus E	95.1%	Pass
Unit #2 12 bus D	95.1%	Pass
Unit #2 4 kV F, G & H	93.7%	Pass

The above results indicate that the present compensatory actions (2.5% tap change, reduced 12 kV transfer) are sufficient for success for a Unit 2 trip.

RESULTS: Unit 1 Trip

Bus Name	16-second voltage	Results
Unit #1 4 kV F, G & H	2.5 % tap	Fail
Unit #1 4 kV F, G & H	93.8% (5.0% tap)	Pass

If MBPP Unit 2 trips during periods of high load, the DCPP 230 kV voltage will drop about 4 kV to 221 kV. Thus, the resultant 12 kV voltage would be 11.5 kV. This voltage is adequate because the CWP motors are rated at 11.5 kV and are designed to operate at 90% of rated voltage 10.35 kV.

4) Diablo - MESA 230 kV Line Outage

- DIABLO - MESA 230 kV LINE OUTAGE

- Generation at Morro Bay Power Plant: Unit #2 at 100 MW, 1.05 pu
- All Morro Bay outlet lines are in service.
- DCPP #1 at full power output to the 500 kV grid.
- DCPP #1's 4 kV vitals and non vitals served via the 25 to 4.16 kV aux. bank.
- DCPP #1's 12 kV loads (43MW) served via the Diablo 230 kV loop power source.
- DCPP #2 at full power output to the 500 kV grid.
- Morro Bay - Mesa 230 kV line is in service.
- Morro Bay - Diablo 230 kV line is in service.
- Non-LOCA, reduced transfer of DCPP Unit #2.
- DCPP #2 12 to 4 kV startup transformer tap: 2.5%.
- Los Padres load: 405 MW
- Condition: 1995 Autumn peak.
- Diablo 230 kV pre-transfer voltage: 225.7 kV

RESULTS: Unit 2 Trip

Bus Name	16-second voltage	Results
Unit #1 12 bus E	97.2%	Pass
Unit #1 12 bus D	97.2%	Pass
Unit #2 12 bus E	96.9%	Pass
Unit #2 12 bus D	96.9%	Pass
Unit #2 4 kV F, G & H	95.7%	Pass

The above results indicate that the present compensatory actions (2.5% tap change, reduced 12 kV transfer) are sufficient for success.

RESULTS: Unit 1 Trip

Bus Name	16-second voltage	Results
Unit #1 4 kV F, G & H	93.0% (2.5% tap)	Pass
Unit #1 4 kV F, G & H	95.6% (5.0% tap)	Pass

5) Morro Bay - MESA 230 kV Line Outage

- MORRO BAY - MESA 230 kV LINE OUTAGE
- Generation at Morro Bay Power Plant: Unit #2 at 100 MW, 1.05 pu
- All Morro Bay outlet lines are in service.
- DCPP #1 at full power output to the 500 kV grid.
- DCPP #1's 4 kV vitals and non vitals served via the 25 to 4.16 kV aux. bank.
- DCPP #1's 12 kV loads (43MW) served via the Diablo 230 kV loop power source.
- DCPP #2 at full power output to the 500 kV grid.

- Diablo - Mesa 230 kV line is in service.
- Morro Bay - Diablo 230 kV line is in service.
- Non-LOCA, reduced transfer of DCPP Unit #2.
- DCPP #2 12 to 4 kV startup transformer tap: 5%.
- Los Padres load: 405 MW
- Condition: 1995 Autumn peak.
- Diablo 230 kV pre-transfer voltage: 219.4 kV

RESULTS: Unit 2 Trip

The results indicate that the present compensatory actions (2.5% tap change, reduced 12 kV transfer) will fail. The following compensatory actions are required for a pass:

- 5% tap on the Unit #2's 12 to 4 kV startup transformer bank.
- Continue 12 kV reduced load transfer.

Below are the results of the new compensatory actions:

Bus Name	16-second voltage	Results
Unit #1 12 bus E	94.1%	Pass
Unit #1 12 bus D	94.1%	Pass
Unit #2 12 bus E	93.8%	Pass
Unit #2 12 bus D	93.8%	Pass
Unit #2 4 kV F, G & H	95.0%	Pass (5% tap)

RESULTS: Unit 1 Trip

Bus Name	16-second voltage	Results
Unit #1 4 kV F, G & H	92.0% (5.0% tap)	Fail

6) Diablo - Morro Bay 230 kV line outage

- DIABLO - MORRO BAY 230 kV LINE OUTAGE
- Generation at Morro Bay Power Plant: Unit #2 at 100 MW, 1.05 pu
- All Morro Bay outlet lines are in service.
- DCPP #1 at full power output to the 500 kV grid.
- DCPP #1's 4 kV vitals and non vitals served via the 25 to 4.16 kV aux. bank.
- DCPP #1's 12 kV loads (43MW) served via the Diablo 230 kV loop power source.
- DCPP #2 at full power output to the 500 kV grid.
- Diablo - Mesa 230 kV line is in service.

- Morro Bay - Mesa 230 kV line is in service.
- Non-LOCA, reduced transfer of DCPP Unit #2.
- DCPP #2 12 to 4 kV startup transformer tap: 2.5%.
- Los Padres load: 405 MW
- Condition: 1995 Autumn peak.
- Diablo 230 kV pre-transfer voltage: 208.4 kV

RESULTS: Unit 2 Trip

The results indicate that the present compensatory actions (2.5% tap change, reduced 12 kV transfer) will fail. The following compensatory actions are required for a pass:

- 5% tap on the Unit #2's 12 to 4 kV startup transformer bank.
- Block both Unit #2 12 kV Buses from transferring
- Block Unit #2 standby condensate and booster pump from transferring
- Run Morro Bay Unit #1 at 160 MW and 1.05 pu terminal voltage
- Run Morro Bay Unit #2 at 100 MW and 1.07 pu terminal voltage

Below are the results of the new compensatory actions:

Bus Name	16-second voltage	Results
Unit #1 12 bus E	90.3%	Pass
Unit #1 12 bus D	90.3%	Pass
Unit #2 12 bus E	92.3%	Pass
Unit #2 12 bus D	92.3%	Pass
Unit #2 4 kV F, G & H	93.8%	Pass (5% Tap)

RESULTS: Unit 1 Trip

Bus Name	16-second voltage	Results
Unit #1 4 kV F, G & H	------------------------>	Fail

7) Morro Bay - Gates 230 kV Outlet Line Outage

The outlet lines are defined as the Morro Bay to Gates 230 kV and the Morro Bay to Midway 230 kV transmission lines. For the purpose of this analysis, it has been determined that the system response for the outage of the Morro Bay to Gates 230 kV transmission line is identical to the system response for the outage of the Morro Bay to Midway 230 kV transmission line. Therefore, the results of the Morro Bay to Gates 230

kV transmission line outage will bound the results of the Morro Bay to Midway 230 kV transmission line outage.

The predisturbance system conditions analyzed are as follows:

• PG & E area load including losses:	16326.2 MW
• Los Padres Load:	405 MW
• DCPP 500 kV Voltage:	531.7 kV
• DCPP 230 kV Voltage:	222.2 kV
• Gates 230 kV Voltage:	236.8 kV
• Midway 230 kV Voltage:	235.9 kV
• MESA 230 kV Voltage:	218.9 kV
• MBPP 230 kV Voltage:	225.3 kV
• Diablo 230 kV Loop lines:	In service
• Morro Bay Generation Unit 2:	On-line 1.05 pu voltage, 100 MW
• Morro Bay Generation Unit's 1,3 & 4:	Off-line
• Morro Bay - Gates 230 kV line:	1 line out of service
• Morro Bay - Midway 230 kV lines:	In service

DCPP Plant Status:

Unit 1 Generation:	supplying 1100 MW to the 500 kV grid
Unit 1 4 kV vital and non-vital loads:	served via the 25/4.16 kV aux bank #12
Unit 1 12 kV loads (4 RCPs, 2CWPs):	served via the Diablo 230 kV loop
Unit 2 Generation:	supplying 1100 MW to the 500 kV grid
Unit 2 Auxiliary Loads (all):	served via the Unit #2 generator bus
Unit 2 Transfer disturbance:	Non-LOCA trip
Unit 2 standby condensate/booster set:	Start and transfer on non-LOCA trip
Unit 2 Transfer Scheme:	(Reduced) Two 12 kV RCPs are cut out
Unit 2 startup bank (#12) tap:	2.5 percent boost position

RESULTS: Unit 2 Trip

With the Morro Bay to Gates 230 kV line out-of-service, the voltage response caused by the transfer of DCPP Unit 2 is as follows:

Bus Name	16-second voltage	Results
Unit #1 12 bus E	95.3%	Pass
Unit #1 12 bus D	95.3%	Pass
Unit #2 12 bus E	94.9%	Pass
Unit #2 12 bus D	95.9%	Pass

Unit #2 4 kV F, G & H	93.5	Pass

RESULTS: Unit 1 Trip

Bus Name	16-second voltage	Results
Unit #1 4 kV F, G & H	93.7% (5.0% tap)	Pass

8) Simultaneous Loss of Both DCPP Units:

DCPP Unit 1 pumps were already assumed to be powered from the 230 kV source during this configuration. Therefore, this case only differs from the trip of DCPP Unit 2 due to an additional transfer of DCPP Unit 1 4 kV loads. There is no indication that the system was approaching voltage instability. Therefore, the addition of the 4 kV loads would not result in voltage instability. If the transformer tap change option is implemented, the analysis showed a Unit 2 4 kV load at 95.3% at 16 seconds. With this level of margin, it is likely that even SLUR actuation would be avoided. (with tap change on Unit 1)

Reliability of the 230 kV System

To ensure the continued reliability of the grid supplying the DCPP 230 kV system, the following actions are being taken by the Grid Maintenance & Construction (GM&C) Group (Ref. 39):

- Develop an action plan for avoiding extended outages on the 230 kV line components

- Develop an action plan for emergency restoration and repairs following failures on the 230 kV line components

- Develop a plan for condition monitoring and inspection to ensure that the 230 kV line sections are in good condition

- Use Operating Instruction 0-23 when coordinating and scheduling immediate and routine maintenance work to provide safe working conditions, minimize exposure, and maintain 230 kV service requirements at DCPP.

Summary of Transmission Planning Results

1995-6 Heavy Autumn/Winter Analysis Summary
(Aux Bank 1-1 out-of-service)

MBPP Units	230 kV lines	230 kV Starting Voltage	Los Padres Load	Tap Change Unit 1	Tap Change Unit 2	Reduced Transfer Unit 2	DCPP Units Tripped	4 kV Voltage
1 or 2	All In	226 kV	405 MW	2.5%	2.5%	Yes	U1	93.1%[1]
1 or 2	DCPP-Mesa	226 kV	405 MW	2.5%	2.5%	Yes	U1	93.0%
1 or 2	DCPP-Mesa	226 kV	405 MW	5.0%	2.5%	Yes	U1	95.6%
1 or 2	MB-Gates	222 kV	405 MW	2.5%	2.5%	Yes	U1	*FAIL*
1 or 2	MB-Gates	222 kV	405 MW	5.0%	2.5%	Yes	U1	93.7%
0	All In	223 kV	405 MW	2.5%	2.5%	Yes	U1	*FAIL*
0	All In	223 kV	405 MW	5.0%	2.5%	Yes	U1	93.8%
1 or 2	MBPP-Mesa	219 kV	405 MW	2.5%	2.5%	Yes	U1	*FAIL*
1 or 2	MBPP-Mesa	219 kV	405 MW	5.0%	2.5%	Yes	U1	*FAIL (92%)*
1 or 2	MBPP-DCPP	208 kV	405 MW	5.0%	2.5%	Yes	U1	*FAIL*
1 or 2	All In	226 kV	405 MW	2.5%	2.5%	Yes	U2	95.3%[2]
1 or 2	DCPP-Mesa	226 kV	405 MW	2.5%	2.5%	Yes	U2	95.7%
1 or 2	MB-Gates	222 kV	405 MW	2.5%	2.5%	Yes	U2	93.5%
0	All In	223 kV	405 MW	2.5%	2.5%	Yes	U2	93.7%
1 or 2	MBPP-Mesa	219 kV	405 MW	2.5%	2.5%	Yes	U2	*FAIL*
1 or 2	MBPP-Mesa	219 kV	405 MW	2.5%	5.0%	Yes	U2	95.0%
1 or 2	MBPP-DCPP	208 kV	405 MW	2.5%	2.5%	Yes	U2	*FAIL*
1 or 2	MBPP-DCPP	208 kV	405 MW	2.5%	5.0%	Yes[3]	U2	93.8%

1. All analysis for Unit 1 were done using ETAP only without the interface with the WSCC model. This is conservative. A comparison between just ETAP and ETAP with WSCC showed the following in this case:
   ETAP = 93.1 %
   ETAP + WSCC = 94%
   Therefore, there is more margin for Unit 1 than what is shown here.

2. Unit 2 analysis were done with ETAP interfaced with WSCC.

3. Block both U2 12 kV buses, block U2 standby condensate and booster pump, commit MBPP #1 & #2 at high generation levels.

Bounding Analysis

To determine the computer simulations that are bounding, the NTS Team examined the results to determine the worst case conditions. The cases included the following bounding conditions for 230 kV and 500 kV system loading:

- Los Padres load at 405 mw
- PG&E system load at 16,400 mw

The limiting cases were the successful (pass) runs of the following cases:

- Non-LOCA trip of Unit 1 with Unit 2 operating (on 500 kV)
- Non-LOCA trip of Unit 2 with Unit 1 operating (12 kV loads on 230 kV)
- Unit 1 normal operations with Unit 2 in startup (all 12 kV and 4 kV loads on a 230 kV). A non-LOCA trip on Unit 1 from this configuration was not considered for limiting case because it requires two low probability conditions to occur simultaneously (see Licensing Basis discussion)

Each of these cases was then examined for a single contingency loss of a 230 kV transmission line or single loss of a MBPP unit. For example, with a 2.5 percent tap, there are only two successful cases for a trip of Unit 1. These two are: 1) the normal case with all lines available and MBPP Unit 2 in service, and 2) the loss of the DCPP-Mesa line. The pre-event voltage for this scenario is 226 kV. For the Unit 2 trip runs, there are four successful cases: 1) normal, 2) loss of DCPP - Mesa, 3) loss of MBPP - Gates, and 4) loss of MBPP generation. The limiting pre-event voltage for the Unit 2 scenarios is 222 kV.

Finally, the Unit 2 startup case was evaluated. This case was successful only with all lines and MBPP Unit 2 in service. The pre-event voltage for this scenario was 226 kV.

LOCA Vs Non-LOCA Transfer

When the analysis of a DCPP unit transfer was initiated, both LOCA and Non-LOCA were studied in parallel. These studies of the 1995 summer peak conditions included sensitivity analysis of critical variables such as Morro Bay PP unit commitment, DCPP unit commitment, and various 230 kV lines out-of service. The table below contains a comparison of the 4 kV voltages for LOCA and Non-LOCA transfers. In each comparison, similar compensatory measures have been modeled. For every case, the Non-LOCA transfer resulted in lower voltages on the 4 kV bus 16 seconds after the transfer and therefore was used as the bounding case.

MBPP Commitment	230 kV Lines Out	DCPP Commitment	4 kV Voltage LOCA	4 kV Voltage Non-LOCA
Shut Down	None	#2	95.4%	94.8%
Shut Down	None	#1, #2	95.0%	93.1%
Unit #3	MBPP-Gates	#1, #2	94.6%	94.1%
Unit #3	DCPP-Mesa	#1, #2	96.4%	95.3%
Unit #3	MBPP-Mesa	#1, #2	94.5%	93.3%
Unit #3	MBPP-DCPP	#1, #2	94.7%	94.5%

Margin and Uncertainty Analysis

The 230 kV system is a class II system that is the immediate off-site supply to the 4 kV class I busses along with the other Class II buses. The intent of the analysis of the 230 kV system is to show that all plant loads will be supplied from the 230 kV system without loading the diesels. The resetting of the SLUR relay in 16 second after a LOCA or a unit trip of either unit establishes that the diesel generators will not load and demonstrates the operability of the 230 kV system.

The analysis of the 230 kV system is performed with the nuclear qualified ETAP program to determine a time history of DCPP loads for a LOCA or a unit trip on the 230 kV system and the Western states grid. These DCPP loads are best estimate loads based on fluid system configurations anticipated during a LOCA or a unit trip. Loads are grouped together due to limitations of ETAP to provide a conservatism time loading. The time history loads from the ETAP model are used as an input to a model of the Western grid developed by the Western States Coordinating Council (WSCC). The WSCC model is a best estimate model that is periodically checked against actual system responses to disturbances. For the purposes of these studies the accuracy is taken as 1%. This accuracy was determined from engineering judgment of Transmission Planning personnel that regularly use the model and the fact that the specific interest is the response of the local 230 kV system with its ties to the 500 kV system at Midway and Gates substations.

Conservatism in the analysis is built into the 230 kV studies through the following:

- The 93% SLUR relay reset value is based on the worse case reset including allowance for drift of the relay. An analysis has been performed by Vectra Corporation that regarding the 93% setpoint. This analysis demonstrates that the setpoint can be considered as an analytical limit for reset of the SLUR relay in accordance with PG&E procedure ICE 10, Setpoint Analysis Methodology.

- The Los Padres load used in the analysis is the highest load anticipated for the period of the study. For the next few months that is 405 MW. Based on information from December of last year this maximum load was seen less than 1% of the time.

- The analysis is performed with a starting voltage 2 kV below that which System Operation will hold for that scenario or operating mode. This 2 kV is documented in System Operations procedure O-23. This margin is used to account for accuracy of metering at the DCPP switchyard and accuracy of the best estimate WSCC modeling. With respect to switchyard metering accuracy there is a high accuracy meter at Morro Bay and a less accurate meter at DCPP. DCPP will have a high accuracy within the next few weeks. In the past and for the immediate future System Operations personnel in the switchyards have been using and will use the Morro Bay meter to determine accurate voltage at DCPP until high accuracy metering is available at DCPP. Procedure O-23 also documents the voltage to hold at MBPP.

The purpose of this discussion is to document an uncertainty analysis performed to determine the distribution of the margin on the 4 kV buses to the Diesels do not load success criteria. The approach taken was to base this analysis on the existing WSCC/ETAP models. The particular case used was Case 2) with Unit 1 Operating and Unit 2 operations which resulted in a non-LOCA trip and a 4 kV bus voltage of 93.1% (tap 2.5%).

This case was modified to include the consideration of the following uncertainties:

- The Los Padres load variation was modeled to randomize the load linearly between 205 mw and 405 mw based on the load duration curve for 1/14/95 to 1/31/95. This load variation was introduced into the model by randomly selecting the load and taking credit for the load reduction from 405 mw at the 4 kV bus in the ratio of 1% per 30 mw load reduction.

- The PG&E practice of procedure O-23 of maintaining 2 kV higher than the 226 kV already analyzed was modeled as a 1% bias (up) at the 4 kV bus. The 230 kV meter inaccuracy was modeled as a +/- 1% error. This error was assumed to be normally distributed.

- The ETAP/WSCC modeling errors were considered by including a +/- 1% random error at the 4 kV bus. This error was assumed to be normally distributed.

- The SLUR relay behavior in pickup was modeled as a nominal 92.34% (the maximum allowed as-left drop-out corrected to manufacturers curve to pick-up) setpoint with a 95/95 uncertainty of 1.233% of 4 kV bus voltage.

- In the second Monte Carlo run discussed below the logic of the Diesel Start circuit was also modeled. The logic of the circuit is 2 out of 2 such that both undervoltage relays must not pick up for the diesel to start and load. If either undervoltage relay picks up prior to the 16 second time out the associated diesel will not start.

The first Monte Carlo run was done with 10,000 samples of the ETAP/WSCC modeling, 230 kV meter, the Los Padres load duration curve, and the SLUR relay pick-up uncertainties. The results were:

Mean margin: 5.1% 4 kV bus voltage
Std deviation: 2.14%
minimum margin: - 0.78%
Proportion of samples with margin below 0: 0.95% or 99% PASS (margin was defined as a bus voltage greater than the pick-up setpoint)

The second Monte Carlo run was done with 3,000 samples of the ETAP/WSCC modeling, 230 kV meter, the Los Padres load duration curve, and the SLUR relay pick-up uncertainties. In addition this run incorporated the 2-out-of-2 logic in the diesel start circuits. The results were:

Mean margin: 5.4% 4 kV bus voltage
Std deviation: 2.14%
minimum margin: + 0.38%
Proportion of samples with margin below 0: NONE ALL PASS

Of particular interest is that the addition of the diesel start logic raised the minimum margin from - 0.78% to + 0.38%. The shape of the distribution of the margin with the start logic became more normal while the shape of the distribution without the start logic was more uniform (flat). (Margin was again defined as a bus voltage greater than the pick-up setpoint).

An additional case was run (11/17/95) which includes the 2-out-of-2 logic but eliminated the 2 kV margin requirement on the 230 kV bus and reduced the 230 kV meter reading error to 1/2%. The run also was done with 10,000 samples. There was one further analysis change which was that the random Los Padres load benefit to the 4 kV bus was capped at 3% of 4 kV voltage. The results follow:

Mean of the margin distribution: 3.436% 4 kV bus voltage
Std deviation of the margin distribution: 1.234%
minimum margin: - 0.839%
Proportion of samples with margin below 0: 0.5%

Therefore, there is a 99.5% probability with 95% confidence that the Diesels will not load under all the conditions analyzed. This statement also applies to the condition where the 2 kV margin for the 230 kV system is not used. If the 2 kV margin were to be used the probability that the Diesels would not load would be about 99.99% (estimated on the basis that the minimum margin for the case without the 2 kV added was -0.839% which would be positive if 1% were added due to a 2 kV adder). The results also show that the minimum margin is relatively insensitive to the reduction in Los Padres load below 375 mw. The importance of this observation is that the success in the results of the model are relatively insensitive to the Los Padres load reduction beyond 30 mw. In actuality a Los Padres load below 375 mw would likely be of significant benefit to the system response to a disturbance.

B. Electrical Analysis and Equipment Capability

The input for the electrical analysis was obtained from Ref. 1 and various design documents. From an electrical design adequacy aspect, the use of Startup Transformer ST 1-1 as a substitute for AT 1-1 is a viable option. With the restrictions and design changes outlined below, ST 1-1 could be used to support the normal operation of Unit 1, even in the event of transients resulting from a Unit 2 trip.

Restrictions and Design Changes
• Block transfer of one Unit 2 12 kV bus (D or E) • Implement tap change of -2.5% on Unit 2 12 / 4 kV ST 2-2 • Implement tap change of -2.5% on Unit 1 12 / 4 kV ST 1-2 • 230 kV system voltage maintained at a minimum of 226 kV at DCPP (with a preload of 51 MVA) • Implement protective relaying design changes to accommodate removal of AT 1-1 • Implement change to feed 12 kV underground loop from the Unit 2 230 / 12 kV ST 2-1 only

1. Proposed System Lineup

With the AT 1-1 out of service, the Unit 1 12 kV Buses D and E will be lined up to receive power from the ST 1-1 through the startup bus. ST 1-1 receives power from the 230 kV line the secondary of the transformer is connected to the 12 kV startup bus (see Figure 1). The primary function of the startup transformer is to provide power to the plant auxiliary buses (12 kV and 4 kV) during plant startup and shutdown. Under normal operating conditions, the plant auxiliary buses receive power from the unit auxiliary transformers and the startup transformers are on standby.

2. Assumptions and Input Data

- Diablo Canyon 230 kV voltage at the DCPP switchyard is 226 kV with Morro Bay Unit 1 or 2 generator running, all 230 kV lines to DCPP are in service, and the initial load on the 230 kV system is limited to the 12 kV underground loop load, which was used to analyze the starting of all 12 kV and 4 kV loads.

- Diablo Canyon 230 kV voltage at the DCPP switchyard is 226 kV with Morro Bay Unit 1 or 2 generator running, all 230 kV lines to DCPP are in service, and the initial load on the 230 kV system is 51 MVA. These assumptions were used to analyze both units at 100% and a non-loca trip of one unit.

- The ETAP simulation of the 230 kV source voltage at the DCPP switchyard is based on a constant voltage behind an equivalent source impedance. The equivalent source impedance for the specific system configuration (i.e, all 230 kV lines in and Morro Bay Unit 1 or 2 in operation was provided by Transmission Planning (Ref. 43).

- The results of the ETAP simulation using the above model for the 230 kV source are in close agreement with the results obtained by a detailed simulation using WSCC model.

- All running load data per Calc. 96-DC, Rev. 3 (Ref. 44).

- The nominal loadings of 12 kV and 4 kV Buses used in the electrical analysis are estimated values based on the full load bhp of the motors. The actual loading for a specific scenario is calculated by the ETAP program and varies with the bus voltage.

- The nominal loading values are as follows:

Buses	Max. Startup	Full Power	Post Non-LOCA Trip
12 kV Buses D and E	43 MVA	43 MVA	31MVA
12 kV Bus D or E	21.5 MVA	21.5 MVA	21.5 MVA
4 kV Buses	24 MVA	24 MVA	24 MVA

- All starting load data per Calc. 96C-DC, Rev. 0 (Ref. 45).

- Time lines for the 12 kV bus transfer and 4 kV motor starting (Ref. 46)

- Acceptance criterion for vital 4 kV Buses to stay on the 230 kV system after bus transfer without "double sequencing" is to have a voltage recovery above 93% of 4.16 kV at the 4.16 kV Class 1E Buses within 16 seconds of the bus transfer. This is based on the reset value of the second level undervoltage relay (SLUR) per Calc. 174B-DC, Rev. 1 (Ref. 47). The recovery time of 16 seconds is based on the actual setting of the second level load shed relay . The Tech Spec acceptance criterion is not to exceed 20 seconds.

- Acceptance criterion for voltage dip of vital 4 kV Buses during motor starting is to have a voltage recovery above 70% within 4 seconds. This is based on first level undervoltage relay (FLUR) setting (Calc.114-DC, Ref. 48)

- Acceptance criterion for 12 kV RCP bus undervoltage during any transient disturbance is based on the Tech Spec limit of the UV relay setting of 8050 V. This is 67% of 12 kV.

- Minimum steady state voltage at the motor terminal is 90% of rated motor voltage. The rated motor voltages are 460 V, 4000 V, and 11,500 V. The SLUR reset value of 93% of 4160V ensures a minimum of 90% of 460 V at the 460 V vital motors.

- The criteria for motor starting is to have enough accelerating torque during starting. Typically, a starting voltage of 75% to 80% is enough to start any motor. For large motors, a dynamic ETAP simulation is performed to see how the motor is accelerating or stalling. Plots of voltage, current, power, and slip generated by ETAP are used to analyze motor starting capability. As the motor accelerates and approaches the rated speed, the terminal voltage reaches steady state value while the motor current approaches full load current. The ETAP load flow runs also show the power flow and voltage at selected intervals of the starting period. The motor starting current is compared with the overcurrent relay coordination curves in Calc. No. 161-DC and 170-DC (Refs. 49 and 50).

3. Equipment Rating Adequacy

With the proposed lineup, the ST 1-1 would be required to carry a continuous full load of 12 kV Buses D and E (~ 43 MVA). During startup, the loading of the 12 kV Buses will be less. However, if during the initial startup of the plant, Unit 1 AT 1-2 is not used, then there will be additional loading of the 4 kV Buses on the ST 1-1. In the worst case scenario, ST 1-1 would be carrying a full load of 12 kV Buses D and E (~ 43 MVA), the 12 kV underground loop load (~ 5 MVA), and a worst case shutdown load of 4 kV vital and non-vital buses (~ 24 MVA). The combined loading of 12 kV Buses and 4 kV Buses would be 72 MVA, which is below the transformer rating of 75 MVA (continuous rating at 65°C). Since the transformer ST 1-1 is only used during startup and plant shutdown, and the loading on the transformer during these operating conditions is substantially less than the transformer rating, there is no concern on the thermal degradation of the transformer. Hence the transformer is capable to carry its rated load of 75 MVA. (To add margin, the 5 MVA from the 12 kV underground loop will be aligned to Unit 2)

Plant startup will be performed using AT 1-2 and ST 1-1. During startup, the 4 kV Buses will be connected to the unit AT 1-2 backfeeding through the main bank, and the 12 kV Buses D and E will be energized from ST 1-1 using the 230 kV source. During the transition from plant startup to full power operation of Unit 1, the 12 kV Buses D and E will remain energized from the 230 kV power source. However, before synchronizing the generator to 500 kV, AT 1-2 will be energized from ST 1-1. For a limited duration, ST 1-1 will be carrying the total startup load of both 12 kV and 4 kV Buses. This loading is less restrictive than the worst case shutdown loading of 72 MVA.

Although it has been demonstrated that ST 1-1 is sized to carry the worst case plant loads including the total 12 kV underground load of 5 MVA, it is desirable that the 12 kV underground loop load is fed from the Unit 2 ST 2-1 during the period ST 1-1 is used to carry continuously the Unit 1 12 kV Buses D and E. With the 12 kV underground loop fed from Unit 1 ST 1-1, any ground fault at the Unit 1 12 kV feeder will result in excessive ground fault current because of the capacitive charging current of the 12 kV underground loop. By feeding the 12 kV loop from ST 2-1, the exposure of excessive ground fault current will be limited to a relatively short duration when ST 2-1 is used to provide startup or shutdown power for Unit 2.

The following evaluation addresses potential concerns with the proposed lineup:

12 kV bus voltage drop during starting of large 12 kV motors:

Two worst case scenarios were examined: (1) starting of the fourth RCP after the other 12 kV motors are running, and (2) starting of the second CWP motor after all other motors are running. In the above starting case scenarios, it is assumed that ST 1-1 is carrying all 12 kV and 4 kV loads, and that the 12 kV bus voltage would not drop below 80%. Therefore, the RCP bus undervoltage relay, which has an instantaneous undervoltage setting of 67%, would not be challenged. The RCP motor starting scenario uses the cold loop bhp of the motor which is higher than the hot loop bhp. The running voltage after the largest motor start would be close to 98% of motor rated voltage.

Starting current of the CWP motor:

A review of the project Calculation 160-DC (Ref. 2) indicates that good coordination exists between the existing relay setting protection of the CWP motor and the overcurrent protection of the startup transformer. Therefore, there will be no nuisance tripping of any breaker during starting of the CWP motor.

12 kV bus fault or feeder fault:

For a bus fault or feeder fault (three phase to ground), the protective relay for the startup transformer is designed to protect the transformer for an external fault by isolating the fault current before the short circuit withstand capability of the transformer is challenged. PG&E standard practice is to protect the transformer from an external fault within 1 seconds. This is based on the assumption that ST 1-1 was built with a minimum of a 1 second through fault capability. A review of project Calculation 154D-DC (Ref. 3) assures that the existing relay protection is adequate for 1 second through fault capability. Transformers built to the 1968 USAS C57.12.00 would meet a 5 second through fault capability. However, since there is no documentation available for the ST 1-1, the through fault capability is questionable and in the worst case scenario, the transformer ST 1-1 could be lost for an external short circuit. However, for an external single phase to ground fault at the 12 kV system (more likely to occur), the transformer through fault current will be limited by the grounding resistor which is sized to carry continuously a maximum ground fault without interruption of the power to the 12 kV loads.

Two-Unit operation - Unit 1 startup and Unit 2 normal operation:

Unit 2 is operating at full power with all auxiliary loads supplied by unit auxiliary transformers. The Unit 2 ST 2-1 is carrying the 12 kV underground loop load, which is about 5 MVA. The Unit 1 ST 1-1 is energized to carry the startup load of the 12 kV Buses D and E. Either AT 1-2 is energized from the 500 kV system or the 4 kV loads are from ST 1-2. In this scenario, ST 1-1 is fully capable of starting the largest motor (i.e., either RCP or CWP under the maximum loading on the transformer). The worst case starting voltage is well above 80% of bus voltage at the 12 kV Buses and we stay above the SLUR of 93%. With ST 1-1 carrying a full load of 12 kV buses

D & E, a unit trip on Unit 1 will require a 2.5% tap change on ST 1-2 to prevent double sequencing.

Two-unit operation - Unit 1 and Unit 2 normal operation:

In this scenario, the loading of ST 1-1 is about 45 MVA and is well within the rating of the transformer. Hence, there is no problem with continued operation of Unit 1. The loading on the ST 2-1 is about 5 MVA. The total loading on the 230 kV system is about 50 MVA, which is well within the capacity of the 230 kV line.

Two-unit operation - Unit 1 normal operation and Unit 2 generator trip:

In this scenario, prior to Unit 2 generator trip, the 230 kV system is supplying a load of approximately 48 MVA. Following the Unit 2 trip, the additional steady state loading on the 230 kV system would be 21.5 MVA due to the load from the Unit 2 12 kV bus transfer (one bus transfer) and 24 MVA load of 4 kV bus transfer. During the bus transfer of 4 kV loads, there will be motor starting inrush, and the transient inrush would be close to 50 MVA, which is more than the steady state load of 24 MVA. The momentary motor starting inrush causes the 4 kV bus voltages to dip below 90% of 4.16 kV .

With a design change implementing a -2.5% tap change on the ST 2-2 (a -2.5% tap change on 12 kV primary increases the 4 kV voltage by +2.5%), the transient voltage dip at the unit 2 4 kV Class 1E Buses is very close to 90% of 4.16 kV and recovers to 94% within 16 seconds thus preventing diesel loading. This assures no "double sequencing" **although the EDGs would be started through a SLUR actuation.** The acceptance criterion for no double sequencing is to have a voltage recovery above 93% of 4.16 kV at the 4 kV Class 1E Buses within 16 seconds.

Two-Unit operation - Unit 1 generator trip and Unit 2 normal operation:

In this scenario, the Unit 1 12 kV Buses will stay on the 230 kV system, being energized from the ST 1-1 transformer and carry a full load of 43 MVA. Unit 1 4 kV vital and non-vital loads would be transferred to the 230 kV system. The 4 kV bus transfer will impose an additional loading of 24 MVA on ST 1-1. The total load on the 230 kV system will remain within the 75 MVA rating of the transformer. The transient voltage dip at the Unit 1 Class 1E vital 4 kV Buses is more severe than the Unit 2 trip case discussed above.

With a design change implementing a -2.5% tap change on ST 1-2, the transient voltage dip at the Unit 1 4 kV Class 1E Buses is close to 89% and recovers to 93% in 16 seconds. **Therefore, EDGs start, but do not load.**

Two-Unit operation- Unit 1 at full power and Unit 2 startup

In this scenario, the Unit 1 is operating at full power while Unit 2 is being started up following a unit shutdown. Unit 1 transformer ST 1-1 is carrying the full load of 12 kV Buses D and E. Unit 2 startup transformer ST 2-1 is carrying a minimum shutdown load of Unit 2. The Unit 2

transition from shutdown to startup requires a heavy power demand on the ST 2-1. During initial heatup, the 12 kV and 4 kV loads are fed from the 500 kV system using unit auxiliary transformers. Just before synchronization of the Unit generator to the 500 kV source, all 4 kV and.12 kV loads will be transferred to 230 kV system. ST 2-1 will be carrying a maximum load of about 72 MVA. With ST 1-1 loaded to about 43 MVA and Unit 2 ST 2-1 loaded to about 72 MVA, the combined loading on the 230 kV system would be close to 115 MVA. The 230 kV system has enough capacity to carry 115 MVA and maintain acceptable voltages at the plant buses. However, starting of any 12 kV motor on Unit 2 ST 2-1 would require a special restriction of a tap on ST 2-2 be set at -2.5% before approaching Mode 4.

Cross-Tie from Unit 2 (12 kV) to Unit 1 (12 kV):

a. *Parallel Operation Using Cross Tie of 12 kV startup buses*:

Each section of the 12 kV startup bus (i.e., Unit 1 startup bus and Unit 2 startup bus) is designed to be cross-tied through a tie breaker. Each section is designed to carry 75 MVA, the full load rating of the startup transformer. The interrupting rating of the tie breaker is adequate to handle a maximum short circuit current with both ST 1-1 and ST 2-1 connected to the startup buses lineup. However, under this operating lineup with the tie breaker closed, the interrupting rating of the 12 kV Switchgear D or E would be exceeded significantly. The fault contribution from ST 1-1 and ST 2-1 is 23.kA. For a fault at the feeder breaker of 12 kV Bus D or E, the 230 kV system contribution would be 46 kA, and the motor contribution would be 12 kA. The two contributions together would require an interrupting duty of 58 kA compared to the maximum interrupting capability of 31 kA. Although by paralleling the two startup transformers, the bus voltage would improve appreciably during the starting of large motors, there is an inherent risk of exposing the 12 kV Buses D and E breakers significantly above their fault interrupting capability and is prohibited administratively.

b. *Non-Parallel Cross-Tie Operation:*

(i) Start one Unit 1 RCP from Unit 2 Aux Bus using cross-tie breaker:

In this scenario, it is assumed that Unit 1 has lost the 230 kV source. Consequently, the power to the Unit 1 12 kV Buses D and E is lost. It would be desirable to start one RCP from Unit 2 auxiliary bus by using the 12 kV cross-tie arrangement of the startup buses. Since the capacity of the unit auxiliary transformer is 56.25 MVA, and the normal demand of 12 kV Buses D and E is about 45 MVA, it would be possible to carry an additional running load of one RCP (6 MVA). It has also been verified that with the Unit 2 generator running at 1.0 pu voltage, AT 2-1 has adequate capacity to start one RCP while the transformer is carrying a full load of 12 kV Buses D and E. This cross-tie operation will require a special operating procedure.

(ii) Start one Unit 2 RCP from Unit 1 Startup Transformer using cross-tie breaker:

In this scenario, ST 1-1 is carrying Unit 1 12 kV Buses D and E loads, and ST 2-1 is not available. If it is desirable to continue Unit 2 operation, then it would be required to close the 12 kV cross-tie breaker to provide standby power to the Unit 2 vital buses. Using operating restrictions to block transfer of Unit 2 12 kV Buses D and E, it would be possible to shutdown the plant using ST 1-1. Upon Unit 2 trip, all 4 kV vital and non-vital buses will transfer to ST 1-1. The combined loading of Unit 1 Buses D and E, 12 kV underground loop, and post-transfer loading of Unit 2 4 kV Buses would be close to 72 MVA. Since the capacity of the ST 1-1 is 75 MVA, it would be possible to start one Unit 2 RCP motor without "double sequencing." It is, however, anticipated that the EDG would get a start signal during the initial voltage dip, and the bus voltage would recover above 93% of 4.16 kV within 16 seconds and would reset the SLUR. This cross-tie operation will require a special operating procedure.

(iii) Start Unit 1 RCPs from Unit 2 Startup Transformer using cross tie breaker:

In this scenario, ST 2-1 is available and Unit 2 in normal operation. Unit 1 12 kV Buses are fed from ST 1-1 and Unit 1 is operating at full power. In the event of a loss of ST 1-1, the Unit 1 will trip and the RCPs will be coasting down without power. The 4 kV vital buses will transfer to EDG. By cross tieing Unit 2 startup bus with Unit 1 startup bus , power from startup transformer ST 2-1 could be used to energize Unit 1 12 kV Buses D and E to power Unit 1 RCPs. The shut down of Unit 1 could continue using power from ST 2-1 as long as one of the two Unit 2 12 kV Buses D or E is blocked from automatic transfer. This will prevent "double sequencing " of Unit 2 vital buses in case of a Unit 2 trip.

4. Summary of Cases and Results:

- 12 kV motor starting with all Unit 1 12 kV Buses, 12 kV underground loop and 4 kV Buses on 230 kV source. Start second CWP with 4 RCPs and 1 CWP running.

  - Calc. No. 96C-DC, Rev. 1D, Case No. CS11B12L.
  - Results: Motor Starts successfully, 12 kV bus voltage does not dip below 80%. **EDG starts but does not load.**

- Two-unit operation, Unit 1 startup, Unit 2 non-LOCA trip: All Unit 1 loads fed from 230 kV source, reduced Unit 2 12 kV bus transfer, -2.5% tap on ST 2-2 and ST 1-2.

  - Calc. No 96C-DC, Rev. 1D, Case No. CS11B14T
  - Results: **Unit 2 EDG starts, but does not load.** 4.16 kV vital bus voltage recovers to 95% in 16 seconds. Unit 1 EDG does not start.

- Two-unit operation, Unit 1 full power, Unit 2 non LOCA trip: Unit 1 12 kV Buses fed from 230 kV source, reduced Unit 2 12 kV transfer, -2.5% tap on ST 2-2 and ST 1-2.

  - Calc. No. 96C-DC, Rev. 1D, Case No. CS 11B6L,T

- Results: **Unit 2 EDG starts, but does not load.** 4.16 kV bus voltage recovers to 95.7% in 16 seconds.

- Two-unit operation, Unit 1 LOCA, Unit 2 full power: Prior to Unit 1 LOCA, Unit 1 in startup, -2.5% tap on ST 2-2 and on ST 1-2.

  - Calc. No.96C-DC, Rev. 1D, Case No. CS11A5T
  - Results: **Unit 1 EDG starts, but does not load.** 4.16 kV bus voltage recovers to 94% in 16 seconds.

- Two-unit operation, Unit 1 full power, Unit 2 startup: Unit 1 12 kV loads and all Unit 2 loads fed from 230 kV system (8 RCPs, 3 CWPs and Underground loop) and start 1 CWP, - 2.5% tap on ST 1-2 and ST 2-2

  - Calc. No. 96C-DC, Rev. 1D, Case No.CS11B19M
  - **EDGs do not start.** 4.16 kV bus voltage recovers to 96% in less than 16 seconds.

- Two-unit operation, Unit 1 full power, Unit 2 Startup: Determine maximum Unit 2 startup load for Unit 1 trip without "double sequencing". Tap on ST 1-2 is -2.5%

  - Calc. No. 96C-DC, Rev. 1D, Case No. CS11B16T
  - Results: Maximum Unit 2 startup load is limited to <u>35 MVA</u>

C. Licensing and Design Bases

1. Licensing Bases

A search was performed to determine past discussions or commitments regarding starting up a unit without an operable 25 kV to 12 kV transformer. The following is a detailed summary of this review.

Technical Specifications

TS 3.8.1.1, "A.C. Sources - Operating"

This TS requires that two independent connections (one allowed to be delayed access) be available between the offsite network and the onsite Class 1E distribution system in Modes 1 through 4. The onsite Class.1E distribution system consists of the 4 kV system. Since AT 1-2 supplies the connection between one offsite power source and the onsite Class 1E distribution system, this TS is satisfied since AT 1-1 is operable.

TS 3.4.1.1, "Reactor Coolant Loops and Coolant Circulation - Startup and Power Operation"

This TS requires that all four RCPs be in service in Modes 1 and 2. This TS does not specify specific power requirements for the RCPs. If the RCPs are capable of being supplied with power from the 230 kV system and the pumps are running, this TS would be satisfied.

TS 3.4.1.2, "Reactor Coolant Loops and Coolant Circulation - Hot Standby"

This TS requires that at least two RCPs be in service in Mode 3. This TS does not specify specific power requirements for the RCPs. If the RCPs are capable of being supplied with power from the 230 kV system and the pumps are running, this TS would be satisfied.

TS 3.4.1.3, "Reactor Coolant Loops and Coolant Circulation - Hot Shutdown"

This TS requires that two RCPs and/or two RHR trains be operable and at least one in service in Mode 4. The RCPs are powered from the 12 kV bus. The TS does not specify the source of the power to the 12 kV bus. If the RCPs are operable from any power source, then the RCPs are capable of satisfying their portion of this TS requirement.

FSAR Update

The FSAR Update was reviewed to identify specific requirements associated with the operability of aux transformer 1-1 and the associated 12 kV Buses and components.

FSAR Update Chapter 8

FSAR Update Chapter 8 describes the onsite electrical power distribution system. The FSAR Update states that the capability exists to supply the unit auxiliaries from the 500 kV or the 230 kV systems via transformers. The FSAR Update also states that none of the loads supplied by 12 kV are ESF loads.

The FSAR Update also states that the 500 kV system is the delayed access source such that following a reactor trip, the unit auxiliaries can be supplied from 500 kV via backfeeding after 30 seconds plus operator action time. This statement will not be true of all the unit auxiliaries until a new transformer (AT 1-1) is installed.

FSAR Update Chapter 15

FSAR Update analyses generally do not credit offsite power being available. Offsite power is only assumed when a worst case condition results. Consequently, the assumption of offsite power being available is a conservative assumption that bounds operation with all 12 kV loads powered from 230 kV and the subsequent loss of the 230 kV system.

All accidents in Chapter 15 were reviewed. Results of the review are presented below in Section D.

Safety Evaluation Reports (SERs)

A review of all the SERs was performed. SER 0 describes AT 1-1. However, the SER does not credit the transformer for any accident mitigation function. The SER credits AT 1-2, since it supplies the vital 4 kV loads. The SER includes only one sentence on AT 1-1. No other SERs include information on the AT 1-1. Based on the review, the SERs do not credit AT 1-1 for any action.

Standard Review Plan (SRP)

Section 8 of the SRP (Ref. 11) only discusses the requirements for safety-related electrical power systems. No discussion or requirements of non-vital electrical power systems is included in the SRP. Since the safety-related (vital) power systems continue to meet its original design, the requirements of the SRP continue to be satisfied.

Section 15 of the SRP requires that worst case offsite power configurations be considered. Consequently, offsite power is only assumed to be available if the configuration results in a worse case accident.

Regulatory Guides (RGs)

All RGs were reviewed to identify potential guidance related to this issue. The following RGs were identified as potentially relevant: 1.6, 1.9, 1.22, 1.63, 1.93, and 1.118. Of these, only RG

1.93 (Ref. 12) included information on electric power system requirements. However, RG 1.93 only addressed the requirements associated with the operability of Class 1E equipment. It included no discussion of non-vital equipment. The other potentially relevant RGs provided no information on non-vital power equipment.

General Design Criteria (GDC)

A review was performed of GDC 17 and 18 (Ref. 13 and 14) to determine the requirements associated with electrical power systems. Per the SRP, GDC 17 encompasses GDCs 33, 34, 35, 38, 41, and 47 for power systems. GDCs 17 and 18 only provide guidance on the requirements associated with the design of Class 1E systems. These GDC do not address non-vital power systems such as AT 1-1 and the 12 kV Buses.

GDC 17 applies to those components important to safety. Therefore, it does not directly apply to the RCPs or CWPs.

GDC 17 requires two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable: The change does not alter the fact that DCPP has two physically independent circuits to its safety systems. In fact, DCPP has two physically independent circuits to each of its safety systems. DCPP does not utilize a common switchyard, which is allowed by GDC 17.

Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of or coincident with the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power systems. DCPP's compliance with 10 CFR 50.63 requirements and the fact that the proposed change has no impact on DCPP's compliance with the requirements of 10 CFR 50.63 demonstrate that the probability of losing the specified power sources will not be impacted by the proposed change.

Fire Protection/Appendix R Review

Operating the plant without an operable auxiliary transformer will not affect the results of the current Appendix R safe shutdown analysis or the proposed revision to the Appendix R analysis (Ref. 27). The start-up transformer would be a sufficient offsite power source for the vital 4 kV Buses, and will not affect the 10 CFR 50, Appendix R safe shutdown analysis.

Fire Areas 28 and 29 are the open yard areas for Unit 1 and Unit 2 and includes the transformer areas outside the containment and turbine buildings. Damage to either the main, auxiliary or startup transformers due to a fire in these fire areas will not affect the ability to achieve and maintain safe shutdown. The EDGs are credited for safe shutdown in these fire areas. The existing Appendix R analysis does not credit offsite power for safe shutdown. However, a proposed revision to the analysis will credit offsite power as a redundant source of energizing the

4 kV switchgears (F, G, and H buses). These offsite power sources will be from either the unit AT 1-2/2-2 or the stand-by ST 1-2/2-2. The availability of either offsite power source is acceptable.

Fire Hazards Analysis (Appendix 9.5.A of FSAR Update)

Fire Areas 28 and 29 are the open yard areas at Elevation 85-ft. The 4 main transformers, the two auxiliary transformers, and the three startup transformers are included in these areas. These transformers are separated from the containment building by 3-hour rated fire barriers, and from the turbine building by 2-hour rated fire barriers. The sloped grade of the pavement will divert spilled oil away from the containment and turbine buildings. The pipe chase outside containment is approximately 40 feet away from one of the nearest transformers. The only combustible material in the area is the oil in the transformers, which is equivalent to a fire duration of approximately 4 hours. The nine transformers in each area are provided with automatic water spray systems with remote annunciation. The yard hydrant with fully-equipped hose houses, the hose stations, and the portable fire extinguishers are available for manual fire fighting activities. The transformers are not credited for safe shutdown in these fire areas since the diesel generators are not affected by a fire in these fire areas. The current 10 CFR 50, Appendix R safe shutdown analysis assumes a loss of offsite power concurrent with a design basis fire.

Fire Protection Licensing Commitments

Actuation failure of the fire suppression system protecting the transformers is specifically discussed in response to Question 31 of the NRC request for additional information (Ref. 19) and in Amendment 51 of PG&E's application for an operating license (Ref. 20). The fire hazards analysis concluded that safe shutdown would not be affected by an unsuppressed transformer fire. The grade of the pavement will divert any oil spillage away from the safe shutdown equipment. Redundant safe shutdown equipment for reactor coolant system (RCS) Loops 3 and 4 are not located in the area, and the equipment will be available for safe shutdown. A fusible link was installed on the air lines for the main steam isolation valves (MSIVs) and bypass valves (FCV-24, FCV-25, FCV-41 and FCV-42) to vent the air and fail the valves closed when actuated. No other specific commitments are identified in the Operating License and SERs.

Evaluation of Proposed Configuration

The transformers in the year area are not credited for safe shutdown. The existing 10 CFR 50, Appendix R safe shutdown methodology assumes that offsite power is lost concurrent with a fire in any fire area. Onsite power sources (EDGs) are the only source of power credited for the 4 kV switchgear. Therefore, the transformers (auxiliary or start-up) are currently not required for safe shutdown.

A proposed revision to the existing methodology is currently being evaluated to resolve issues related with Pyrocrete fire barriers (Ref. 21). The proposed revision to the

Appendix R analysis will credit offsite power as a redundant source of energizing the 4 kV switchgears (F, G, and H busses). These offsite power sources are either the unit AT 1-2/2-2 or the stand-by ST 1-2/2-2. The assumption in the methodology will be revised to credit offsite power for safe shutdown, except for fire areas that utilize an alternative shutdown methodology and that are not adequately separated from onsite power sources (EDGs).

Operating the plant without an operable auxiliary transformer will not affect the results of the current Appendix R safe shutdown analysis or the proposed revision to the Appendix R analysis. The start-up transformer would be a sufficient offsite power source for the vital 4kV busses. A single failure is not postulated to occur during the design basis fire. Therefore, a source of offsite power will be available and the ability to achieve and maintain safe shutdown conditions will not be affected.

The combustible loading in these fire areas is comprised of the oil in the transformers. Therefore, the only credible fire in the area is at the transformers. Failure of the fire suppression system to actuate is already postulated in the original fire hazards analysis and the safe shutdown analysis. The effects of an unsuppressed fire in any of the transformers will not affect safe shutdown. Redundant circuits on RCS Loops 3 and 4 are not affected by a fire in this fire area and will be available for safe shutdown. The MSIVs and bypass valves are located in the pipe racks over 50 feet from the transformers. There are no combustible materials in the vicinity of the MSIVs and bypass valves. However, in the unlikely event a fire occurs, the fusible links installed on the air lines will melt and vent air to fail the valves closed should control of the MSIVs and bypass valves be lost.

Station Blackout (SBO) Analysis

DCPP's SBO analysis was submitted to the NRC in PG&E Letter No. DCL-92-084, dated April 13, 1992 and subsequently endorsed by the NRC in their letter of May 29, 1992, from Harry Rood to Gregory M. Rueger. This analysis was submitted in accordance with the requirements of 10 CFR 50.63 and followed the methodology contained in Regulatory Guide 1.155, dated August 1988 and NUMARC 87-00, Revision 1.

SBO at DCPP is defined as the complete loss of all offsite power (from the 500 kV and 230 kV switchyards and the Unit 1 and 2 main generators) with only one EDG operating. A LOOP is defined as the complete loss of all offsite power (same as above) with two or more EDGs operating.

The proposed change of operating Unit 1 without AT 1-1 has no impact on the above commitments or basis of analysis. Specifically, with reference to NUMARC 87-00, Revision 1, Step 1, AC Power Design Characteristic Group Determination:

Part 1.A Determine the site susceptibility to grid-related loss of offsite power events.

Based on the information provided in NUMARC 87-00, Section 3.2.1, Part 1A, plants should be classified as P3 sites if the expected frequency based on prior experience of grid-related events exceeds once per 20 years. This does not include events of less than 5 minutes duration. Events of longer duration may be excluded if the results of analysis conclude the event is not symptomatic of underlying or growing grid instability. According to NUREG-1032, the average occurrence for the majority of systems is about once per 100 site-years. NUREG-1032 notes sites having a frequency of grid-related events at the once per 20 site-year frequency are limited to St. Lucie, Turkey Point, and Indian Point. Therefore it was previously concluded, and this proposed change does not impact this conclusion, that the expected frequency of grid-related LOOP events for DCPP does not exceed once per 20 years. NUREG-1032 indicates that the once per 20 years is conservative for DCPP.

Part 1.B Estimate the frequency of LOOP due to Extremely Severe Weather (ESW).

The ESW factor considers storms with a wind speed greater than 125 MPH. From Table 3-2 in NUMARC 87-00, Section 3.2.1, Part 1A, the estimated frequency of LOOPs due to ESW places DCPP in ESW Group 1. It is noted that ESW Group 1 is the best group and that DCPP's ESW value could increase by three fold and it would still be in ESW Group 1. The proposed change has no impact on DCPP's ESW Group 1 rating, nor its frequency of LOOP due to ESW.

Part 1.C Determine the estimated frequency of LOOP due to Severe Weather (SW).

SW factors include snowfall, tornado, storms and salt spray. From NUMARC 87-00, Section 3.2.1, Part 1C, the estimated frequency of LOOP due to SW places DCPP in SW Group 1. The resulting estimated frequency of LOOP for DCPP is 0.0008525. The SW Group 1 category allows up to 0.0033, over three fold greater than that at DCPP. The proposed change has no impact on DCPP's SW Group 1 rating, nor its estimated frequency of LOOP due to SW.

Part 1D. Evaluate the independence of the offsite power system (I group).

Since safe shutdown buses at each unit at DCPP may be powered through either of two electrically isolated switchyards, the offsite power system is in the I 1/2 Group (NUMARC 87-00, Section 3.2.1, Part 1D). The proposed change has no impact on DCPP's capability of supplying power to the safe shutdown buses from two electrically isolated switchyards.

Part 1E: Determine the offsite AC Power design characteristic group (P group).

Using the Matrix shown on Table 3-5a of NUMARC 87-00, Section 3.2.1, Part 1.E, for a I 1/2 site with an ESW Group 1 and an SW Group 1, the resultant P group is P1. The proposed change has no impact on the resultant P1 group rating of DCPP.

The proposed change has no impact on DCPP's classification of a 4-hour coping time, nor the feasibility of utilizing the AAC (Alternate AC) option.

Review of Other Plant Experience

Licensing Information System (LIS) Survey

A survey was submitted through LIS, and the following question was asked:

"Do you run reactor coolant pumps off of normal off-site power?"

The responses received showed that a majority of plants operate their RCPs powered from normal offsite power.

Industry Precedent

A review of plants in the industry determined that there were 4 plants that have powered their RCPs from one offsite power source.

2. Licensing and Design Bases

Licensing Commitments

Based on the FSAR Update and the NRC Safety Evaluation Report (SER) and SER Supplements, DCPP is committed to meet the following for the 230 kV system:

1. IEEE 308-1971, "Class IE Electric Systems for Nuclear Power Generating Stations." [FSAR Update Section 8.1.4.4 (page 8.1-4)] [SER Section 8.2 (page 8-3)]
2. Atomic Energy Commission General Design Criteria (GDC) 17, "Electric Power Systems," and 18, "Inspection and Testing of Electric Power Systems." [FSAR Update 3.1 A, page 3.1A-3] [SER 3.1, 8.2, 8.3] [Chron 131464]
3. Regulatory Guide (RG) 1.32, "Criteria For Safety-Related Electric Power Systems For Nuclear Power Plants," August, 1972 [FSAR Update Section 8.1.4.3 (page 8.1-3)] [SER Section 8.2 (page 8-3)]
4. Safety Guide 1.6, "Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution System," Revision 0, March 10, 1971 [FSAR Update 8.1.4, page 8.1-3] [SER 8.3.3]

230 kV System Licensing Bases

1. *The offsite power system must be sufficient to operate the engineered safety features for a design basis accident (or unit trip) on one unit and those systems required for concurrent orderly safe shutdown on the remaining unit.*

[IEEE 308-1971, paragraph 8.1.1; follow-up letter to IE Information Notice No. 79-04 from NRC dated August 8, 1979] [RG 1.81, "Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants," Section B. "The Regulatory Staff has determined that, because of the low probability of a major reactor accident, a suitable design basis for multi-unit nuclear power plants is the assumption that an accident occurs in only one of the units at a time, with all remaining units proceeding to an orderly shutdown and a maintained cooldown condition."]

2. *The offsite power system shall be of sufficient capacity and capability to automatically start and operate all required safety loads within their required voltage ratings.*

   "Protection of safety loads from undervoltage conditions must be designed to provide the required protection without causing voltages in excess of maximum voltage ratings of safety loads and without causing spurious separations of safety buses from offsite power." [NRC Letter, follow-up to IE Information Notice No. 79-04, dated August 8, 1979]

3. *Concurrent safe shutdown of the other unit does not mandate an immediate shutdown.*

   [RG 1.93, "Availability of Power Sources," Section B, "Under certain conditions, it may be safer to continue operation at full or reduced power for a limited time than to effect an immediate shutdown on the loss of some of the required electric power sources."]

4. *Loss of the offsite power source should not challenge the availability of the remaining sources.*

   [GDC 17; IE Information Notice No. 79-04] The transmission system shall provide sufficient capacity and capability to assure that safety systems function during anticipated operational occurrences. This does not imply there are mechanistic events to cause this to occur.

IEEE 308-1971 states that "the type of accident and shutdown and the unit assumed to have the accident shall be those which give the largest total preferred capacity requirement." IEEE 308-1971 requires that a design basis accident and a safe shutdown of the other be postulated. This is interpreted as meaning that the units are independent and that a mechanistic failure is not required to be postulated in the other unit. It is, however, reasonable to examine the situation where a design basis accident occurs during a unit outage.
Also, the statement regarding the largest total preferred capacity based on the type of shutdown could be interpreted as requiring a design basis accident on one unit and a prompt shutdown on the other unit. This interpretation would require a mechanistic failure occurring in the other running unit concurrent with the accident. A mechanistic failure is not postulated. Therefore, DCPP does not address prompt shutdown on the other unit as a requirement.

In addition, the DCPP units are electrically independent and the offsite power system is stable. Therefore, an accident in one unit will not cause the shutdown of the other.

Other Transients Considered in the Licensing Basis

As noted in NRC Information Notice 79-04, there are other scenarios that could challenge the offsite power system. The DCPP licensing basis previously did not specifically consider these scenarios. It is prudent to assess the effect of these transients on the 230 kV System and to include this assessment into the next FSAR Update for completeness:

a. Both Units In Either Startup or Shutdown Mode
b. Trip of One Unit While the Other Unit Is in Either Startup or Shutdown
c. Simultaneous Trip of Both Units
d. Design Basis Accident on One Unit With the Other Unit in Startup or Shutdown

The underlying intent as described in IN 79-04 is that licensees should evaluate these other transients to ensure they are not safety significant, that is:

- A transient does not affect the availability of engineered safety feature equipment
- A transient does not overload one offsite power source such that the other source is lost.

Engineered safety feature equipment is available if it remains connected to a capable offsite power source or if it is subsequently loaded on the emergency diesel generator.

a. Both Units in Either Startup or Shutdown Mode

The DCPP units are normally operating and supplying power to the 500 kV grid. There is no planned scenario where both units would be in startup or shutdown at the same time. Startup and shutdown are controlled evolutions. There is no block-loading on the offsite power system during these evolutions. The loading is in controlled increments. The offsite power system voltage and capability is closely monitored. The 230 kV system is operated in a manner to assure it is fully capable. The duration of this evolution is relatively short. If any degradation were to occur due to the addition of a second unit, the evolutions can be terminated or alternative loadings, including starting the diesel generators, can be executed. During these brief periods of time, running loads should not be lost.

b. Trip of One Unit While the Other Unit is in Either Startup or Shutdown

To load the diesels, this scenario must occur in the brief time-frame when the startup/shutdown unit is heavily loaded on the 230 kV system and is not being backfed from the 500 kV source. Since 500 kV is the preferred source, this is normally a relatively brief period of time. Those brief periods while paralleling a unit or shutting down a unit with all loads on startup can only become risk significant if two additional conditions occur simultaneously. A non-loca trip must occur on the other operating unit and the 230 grid must be at its maximum load. The period of time Los Padres load might be high enough to be a concern during a non-loca trip is less than about 5%. The only reason to hold in this transient

configuration would be equipment problems which would have to be resolved long before this can became risk significant (on the order of several days).

c. Simultaneous Trip of Both Units

This scenario does not need to consider a simultaneous design basis accident on both units. Rather, it is a normal trip of both units, so the ESF loads are not required. Therefore, it is acceptable for the vital 4kV buses to be carried a brief period of time by the diesels, should they load.

Analysis has shown the 230kV system will remain stable during this event. The 12kV loads can transfer successfully. The 4kV loads can be transferred back to startup or the 500kV. Finally, this event has a low frequency of occurrence. This coupled with the fact that for the diesels to load, the Los Padres load would have to be greater than about 365MW (occurs less than 5% of the time), the total probability of these two events occurring is quite small, and the consequences are bounded by the diesels loading.

d. Design Basis Accident on One Unit with the Other Unit in Startup or Shutdown
The design and operation of the electric system transmission grid is based on Western Systems Coordinating Council standards requiring system frequency recovery within 10 minutes after a load or generation change. This requirement would apply to a Diablo Canyon design basis event. Recovery on the 230 kV supply would be demonstrated by recovery of system frequency to normal values. The system voltage would recover with frequency because dispatching instructions for system operation would require that the voltage of the 230 kV system be restored to normal values as soon as possible.

To load the diesels, this scenario must occur in the brief time-frame when the startup/shutdown unit is heavily loaded on the 230 kV system and is not being backfed from the 500 kV source. Since 500 kV is the preferred source, this is normally a relatively brief period of time. Those brief periods while paralleling a unit or shutting down a unit with all loads on startup can only become risk significant if three conditions occur simultaneously. A design bases accident (DBA) trip must occur on the other operating unit, the unit in startup must have its total auxiliary load on the 230 kV startup (not backfed from 500 kV) and the 230 grid must be at its maximum load. The 230 kV grid is at its maximum load for less than 1% of any year. The period of time Los Padres load might be high enough to be a concern during a DBA is less than about 5%. The only reason to hold in this transient configuration would be equipment problems which would have to be resolved long before this can became risk significant (on the order of several days).

D. Accident Analysis

The accident analysis was performed jointly by Regulatory Services, the System Transients Group, and Westinghouse. Input from Westinghouse was obtained for the 10 CFR 50.59 safety evaluation (Ref. 15). Chapter 15 analyses are divided into four conditions:

Condition 1: Normal Operations

Condition 2: Faults of moderate frequency (greater than or equal to 0.1 per year)

These faults result in, at worst, plant shutdown with the capability to restart. No full damage can occur.

Condition 3: Infrequent faults (0.1 to 0.01 per year)

These faults may result in fuel damage and considerable outage time, but no release of radioactivity sufficient to interrupt public use of areas beyond the exclusion zone.

Condition 4: Limiting faults.

These are required to meet 10 CFR 100 radioactive release limits, that are designed to prevent an undue risk to public health and safety.

With one exception, Condition 3 and 4 events are analyzed with simple conservative assumptions regarding offsite power. Where loss of offsite power is limiting due to loss of RCPs, condenser steam dump paths, etc., both 230 kV and 500 kV are assumed to fail. In addition to being conservative, this recognizes that unit trips may result in separation from the grid. Although mentioned in Chapter 15, no accident analysis credits DCPP's ability to backfeed 25 kV for 30 seconds after a turbine trip. Some accidents, in particular some main steam line breaks, are made more severe by assuming RCPs and feedwater pumps, etc., continue to operate. For these accidents, 500 kV and 230 kV are assumed to remain available. Hence, for all these Condition 3 and 4 accidents, 500 kV and 230 kV are treated as a single offsite power source and the proposed electrical alignment does not impact the analyses. The one exception is the Condition 3 Complete Loss of Forced Reactor Coolant Flow discussed below.

Condition 2 events often assume scenarios where 230 kV is available after the unit is separated from the 500 kV system. These scenarios are not affected by the proposed alignment if the 230 kV system functions. If the 230 kV system should fail, the scenario does not apply (a different accident scenario occurs).

Accident-by-Accident Review Summary

The auxiliary electrical buses supply non-vital power to the RCPs and other non-safety loads (i.e., CWPs). Normally, the auxiliary buses are supplied power through the unit auxiliary transformer from the bus between the main generator and the main power transformer. A majority of the non-LOCA safety analyses assume continued operation of the RCPs. A LOOP is also considered for the following events: (a) Loss of Normal Feedwater, (b) Feedline Break, (c) Steamline Break, and (d) as an initiating event for a Complete Loss of Flow. The consequences of a LOOP, as assumed in the non-LOCA analyses, is a coast down of all four RCPs. This remains a valid assumption with the proposed configuration.

Each accident that could potentially be impacted by the proposed configuration is evaluated below.

a. Condition 2 Events:

Loss of Normal Feedwater and Loss of Offsite Power to the Station Auxiliaries

Loss of Normal Feedwater is a Condition II event that is analyzed both with and without the availability of offsite power. The case without offsite power is referred to as the Loss of Offsite Power to the Station Auxiliaries. These cases are described in Sections 15.2.8 and 15.2.9 of the FSAR Update, respectively. As a bounding condition, the heatup caused by the loss of normal feedwater is assumed to progress until a reactor trip signal is generated on low-low steam generator level. The loss of offsite power, and subsequent RCP coast down, is delayed until after the time of reactor trip (i.e., rod motion). By delaying RCP coast down, this event is more limiting in terms of pressurizer filling than assuming a LOOP prior to reaching a reactor trip on low-low SG level. An early reactor trip due to the loss of offsite power would result in less heat generation, and subsequently less coolant expansion into the pressurizer.

The primary protection following reactor trip for the loss of normal feedwater accident is the Auxiliary Feedwater (AFW) system. The analysis must demonstrate that the AFW system is capable of removing stored and residual heat over the long-term transient, preventing water relief through the pressurizer. AFW flow is delayed 60 seconds after reactor trip for both the loss of normal feedwater cases with and without offsite power. Included in this delay is time for the diesel to start and load the pumps. Therefore, the AFW flow performance is modeled the same regardless of whether offsite power is available. In fact, since safety injection flow is not assumed, the only difference between the two cases is RCP coast down.

The loss of normal feedwater case that assumes a LOOP is bounded by the case that assumes continued availability of offsite power in terms of pressurizer filling. Also, this case is bounded by the Complete Loss of Reactor Coolant Flow analysis (discussed below) in terms of DNBR, since in the loss of flow analysis the reactor remains at power until reactor trip (i.e., rod motion) while the RCPs have begun to coast down. RCP coast down is assumed for the loss of normal feedwater without offsite power case until after rod motion. Powering the RCPs strictly from offsite power (230 kV source) would not invalidate the assumptions used in the loss of normal

feedwater analyses. Therefore, the conclusions of Sections 15.2.8 and 15.2.9 of the FSAR Update would remain valid under these conditions.

Partial Loss of Forced Reactor Coolant Flow (PLOF)

A partial loss of flow event can result from a mechanical or electrical failure in a RCP, or from a fault in the power supply to the pump. The analysis demonstrates that with a loss of two RCPs at event initiation, a reactor trip on low flow occurs in sufficient time to prevent the minimum DNBR from decreasing below the safety analysis limit. Powering the RCPs strictly from offsite power (230 kV source) would not invalidate the assumptions used in the partial loss of flow analysis. Should the 230 kV system fail, all four RCPs would coast down and the accident would be a Complete Loss of Forced Reactor Coolant Flow (see below). Therefore, the conclusions of Section 15.2.5 of the FSAR Update would remain valid under these conditions.

Loss of External Electrical Load/Turbine Trip (LOL)

A loss of load event can result from either a loss of external electrical load or from a turbine trip. For either scenario, offsite power is available for the continued operation of the RCPs. The case of a loss of offsite power is covered by the analysis performed in Section 15.2.9 of the FSAR Update. The case of a LOOP is covered by the analysis performed in FSAR Update Section 15.2.9. Powering the RCPs strictly from offsite power (230 kV source) would not invalidate the assumptions used in the loss of load analysis. Therefore, the conclusions of Section 15.2.9 of the FSAR Update would remain valid under these conditions.

Operation in the proposed configuration also eliminates the concern of having a failure in the transfer of the RCP power supply to offsite power following a turbine trip. This was a concern previously raised due to the possibility of losing the RCPs at a worse condition (e.g., higher temperature due to turbine trip and resultant steam flow reduction) than analyzed in the CLOF analysis. As a result of this concern, a generator trip is delayed 30 seconds, so that the RCPs continue to operate on a dependable power source before a fast bus transfer is initiated. These concerns are no longer applicable since no transfer of power would be necessary for the RCPs with the proposed configuration.

Complete Loss of All AC Power

The source of power supply for the auxiliary buses feeding the RCPs and other non-safety loads does not affect the availability of on-site emergency electrical power needed by vital safety equipment. Therefore, the potential for a complete loss of all AC power, both offsite and onsite, has not increased.

Turbine Generator Motoring

Under the current plant configuration, a generator trip is delayed for 30 seconds following a turbine trip that results from reactor trip, assuming there are no turbine or generator faults. During this delay, the electrical power flow through the main power transformer reverses and

power will come in from offsite through the switchyard to maintain generator terminal voltage and supply the auxiliary buses. The generator will motor and maintain synchronous speed, and power is maintained to the auxiliary buses feeding the RCPs. Following the 30-second delay, a fast bus transfer to the station startup transformer is made. This practice addresses the possibility of a single failure of the transfer initiating a complete loss of Forced Reactor Coolant flow following a turbine trip.

With the proposed plant change, no fast transfer of power would be available or necessary for the RCPs, and a 30-second period of continued operation of the RCPs using main generator power would no longer exist. The single failure concern mentioned above is no applicable, because the RCP power source would now be uninterrupted. Failure of the 230 kV system during the 30 seconds after a turbine trip would be a passive failure and therefore not a candidate for the single failure criteria. In addition, no accident analysis credits the 30 seconds of continued generator motoring.

b. <u>Condition 3 Events:</u>

Complete Loss of Forced Reactor Coolant Flow (CLOF)

At the initiation of this event, power is assumed to be lost to the RCPs resulting in a coast down of all four RCPs. This event is classified by ANS as a Condition III event. However, Westinghouse analyzes this event to Condition II criteria because a LOOP, which is classified as an ANS Condition II event, may produce a CLOF accident and a Condition II event must not precipitate a more severe event. Note that the NRC also reviews this event based on Condition II criteria as specified in the Standard Review Plan. It is true that loss of 230 kV power constitutes a higher frequency initiator for this event. However, powering the RCPs strictly from offsite power (230 kV source) would not invalidate the assumptions used in or the results of the CLOF analysis. The consequences of CLOF remain unchanged and acceptable. Therefore, the conclusion of Section 15.3.4 of the FSAR Update would remain valid under these conditions.

Because the CLOF event is increased in frequency, several other questions relating to CLOF were raised and addressed in preparing this report. One of these concerns the power at which CLOF is analyzed. Westinghouse determined that this accident scenario is most limiting at 100% power. At low powers (beneath the P-7 signal), the RCP loss trips-- undervoltage, underfrequency, breaker position, and low flow -- are all defeated because they are not necessary per DCM S-38A. Another question addressed the uniqueness of CLOF. CLOF is the only Condition III event that meets Condition II criteria. It was noted that other hybrid accidents do exist, specifically, Small Break LOCAs have a Condition III frequency but may result in Condition IV fuel failure fractions. It should also be noted that other Westinghouse plants -- McGuire, Catawba, and Robinson -- have chosen to classify CLOF as a Condition II event.

c. *Condition 4 Events:*

Feedline Break

The Feedline Break event is analyzed both with and without availability of offsite power. These cases are discussed in Section 15.4.2.2 of the FSAR Update. As a bounding condition, the latter case assumes that a LOOP occurs at reactor trip (i.e., rod motion) actuated by a low-low SG level. As a consequence, the RCPs coast down and safety injection delay are increased to allow for diesel start and loading delays. By delaying RCP coast down until after rod motion, this event is more limiting in terms of subcooling margin than otherwise would result from assuming a LOOP prior to reactor trip. An earlier reactor trip generated from a LOOP would increase the steam generator inventory that helps remove RCS heat over the long-term transient.

The Feedline Break case assuming a LOOP, as analyzed in the FSAR Update results in a less severe transient in terms of subcooling margin than the case assuming the availability of offsite power due to the reduction in total RCS heat generation caused by the absence of heat added by RCP operation. Powering the RCPs strictly from offsite power (230 kV source) would not invalidate the assumptions used in the feedline break analysis. Therefore, the conclusions of Section 15.4.2.2 of the FSAR Update would remain valid under these conditions.

Steamline Break

The steamline break core response event is analyzed both with and without availability of offsite power. As a bounding condition, the latter case assumes a LOOP occurs at the time of the safety injection signal (SIS). As a consequence, the RCP coast down and safety injection delay are increased to allow for diesel start and loading delays. By delaying RCP coast down, this event is more limiting in terms of minimum DNBR than assuming a LOOP prior to reaching the SIS. Assuming an earlier RCP coast down from a LOOP would result in a less severe cooldown, and a less severe subsequent power increase due to the loss of forced reactor coolant flow. For this same reason, the steamline break core response cases that assume availability of offsite power are more limiting in terms of minimum DNBR.

The inside and outside containment steamline break mass and energy release analyses conservatively assume offsite power is available since continued operation of the RCPs maximizes the steam generator blowdown rate.

Powering the RCPs strictly from offsite power (230 kV source) would not invalidate the assumptions used in the steamline break analyses. Therefore, the conclusions of Sections 15.4.2.1 and 6.2.1.3..8 of the FSAR Update would remain valid under these conditions.

LOCA and LOCA-related Accident Analysis

The following LOCA-related analyses are not adversely affected by the proposed modification: large- and small-break LOCA, reactor vessel and loop LOCA blowdown forces, post-LOCA long-term core cooling subcriticality, post-LOCA long-term core cooling minimum flow, and hot

leg switchover to prevent boron precipitation. The proposed configuration of powering the non-vital 12 kV Buses from the startup transformer does not affect the normal plant operating parameters, the safeguards systems actuation or accident mitigation capabilities important to a LOCA, the assumptions used in the LOCA-related accidents, or create conditions more limiting than those assumed in these analysis.

Steam Generator Tube Rupture (SGTR)

The proposed modification for the non-vital 12 kV power supply does not impact the SGTR event. In addition, there is no impact on the tube rupture event from the absence of the capability of the fast transfer to the 230 kV bus for the RCPs. The current SGTR analyses assume RCP coast down from a LOOP. Thus, the existing analyses required for radiological consequence and margin to overfill remain unaffected.

2. Design Transients

Both operation and component design transients were evaluated. For operational transients, the loss of AT 1-1 will not result in a transient response that is different from that presently analyzed. The response of the plant for normal operational transients, such as Loading/Unloading, Step Load Increase/Decrease, and Large Load Rejection, will not change as a result of the non-availability of the auxiliary transformer. The design transients are used as inputs in the component fatigue analyses. One of the design transients is called "Loss of Power." This transient is essentially a SBO, where power to the RCPs is lost immediately at the start of the transient. Therefore, the transient as analyzed covers the potential of losing power to the RCPs immediately on a reactor trip.

3. Impact on Electrical Systems

The proposed configuration has the RCPs and CWPs powered exclusively by the 230 kV transmission system. There is no option for switching one of the two load groups to a separate independent power source as was permitted in the original configuration. However, this does not result in an adverse impact to plant safety, nor would it result in an increase in accident event consequences. With this configuration, there is no redundant power source for the RCPs and CWPs. However, none is required. DCPP is one of a few domestic plants that have a redundant power source normally available for the RCPs and CWPs.

A loss of 230 kV transmission system (a Condition II event) immediately results in a loss of all four RCPs. The consequences of the loss of RCPs are within allowable limits for Condition II events. Other vital equipment that would normally be fed by the same transmission systems as Auxiliary Transformer 1-2 is unaffected under this scenario. These events are addressed in the accident analysis of record. Thus, there is no new accident created, nor are the consequences of any event increased beyond those already addressed in the FSAR Update.

4. Other Areas

Westinghouse has determined that the following safety analysis areas are not adversely affected by the proposed configuration. Most of these items are documented in Westinghouse Safety Evaluation Checklist (SECL) 95-160. The ATWS analysis was addressed by a faxed transmittal of the referenced letter.

Equipment Qualification

The proposed modification does not directly or indirectly involve equipment qualification or instrumentation considerations. Direct effects as well as indirect effects on equipment important to safety have been considered. Consideration has been given to seismic and environmental qualification.

Radiological Dose Evaluations

The proposed plant modification as evaluated would not affect radiological concerns or post-LOCA hydrogen production. Since none of the existing accident analyses, as performed, are adversely impacted by the proposed plant modification, there is no impact on the radiological consequences calculations.

Mechanical Equipment Performance Criteria

There is no impact in the mechanical equipment performance area. Operability and integrity of RCS components and functional capabilities of fluid systems would be unaffected. The proposed plant modification does not directly or indirectly involve mechanical component hardware considerations. Direct effects as well as indirect effects on equipment important to safety (ITS) have been considered. Indirect effects include activities which involve non-safety related equipment which may affect ITS equipment. Component hardware considerations may include overall component integrity, subcomponent integrity, and the adequacy of component supports during all plant conditions.

Containment Response

The proposed plant modification does not adversely affect the short- and long-term LOCA mass and energy releases and/or the main steamline break mass and energy release containment analyses. The condition does not affect the normal plant operating parameters, system actuations, accident mitigating capabilities, or assumptions important to the containment analyses, and does not create conditions more limiting than those assumed in these analyses. Therefore, the conclusions presented in the SAR remain valid with respect to the containment. There is no impact on the performance of the ECCS including safeguards equipment, ASW flow, CCW loads, etc.

Reactor Protection System (RPS)/ESFAS Setpoints

Reactor Protection System (RPS) and Engineered Safeguards Features Actuation System (ESFAS) setpoints are not impacted by the proposed plant modification. There are no changes to the RPS/ESFAS or EOP setpoint uncertainties as a result of using startup power to operate the Unit 1 reactor coolant pumps.

Emergency Operating Procedures

The Emergency Response Guidelines were reviewed and it was determined that there was no impact on generic EOPs. However, PG&E reviews their procedures, and has identified plant-specific procedure changes.

Anticipated Transient Without SCRAM (ATWS)

The ATWS Analysis was reviewed. Westinghouse Letter NS-TMA-2182 analyzed a response to LOOP without a SCRAM that is similar to 230 kV system failure without SCRAM. RCPs are assumed to coastdown at initiation and none of the relevant trip functions are credited. This is not the limiting ATWS scenario; loss of normal feed with offsite power is the limiting case. The coastdown of the RCPs may promote boiling, but the increased RCS heatup and voiding decrease the core power and is a net benefit. Aside: the ATWS acceptance criteria are based on core melt frequency, and fuel failure is acceptable. If the 230 kV system is available, other ATWS scenarios apply and are analyzed.

E. Probabilistic Risk Assessments (PRA)

A PRA evaluation was performed to assess the safety significance of having the DCPP Unit 1 12 kV non-vital buses aligned to the startup 12 kV bus 1-1 for a maximum of six months from November 1995 to May 1996 (Ref. 22). The RCPs and CWPs are normally aligned to AT 1-1 during power operations. Following a reactor trip which may occur as a result of any initiating event, these 12 kV non-vital loads would attempt to transfer to the ST 1-1. If there were insufficient voltage, the loads would trip. Also, during normal power operation, the 4 kV vital and non-vital loads would be powered by AT 1-2. Following a plant trip, the 4 kV loads would also attempt to transfer to the startup bus power via ST 1-2. If there were insufficient voltage on the startup bus, the vital 4 kV loads would transfer to the diesel generators. With insufficient voltage, the non-vital loads would trip.

To assess the PRA impact of the proposed configuration, the impact on initiating events (including new initiating events), and on the plant response models (system fault trees and event trees) was evaluated. The 4 kV vital and non-vital loads would remain on auxiliary power during power operation; and the loads would transfer to startup or the diesel generators following plant trips.

1. <u>Assumptions</u>

One of the assumptions made in this PRA study is that a Unit 2 transient with subsequent transfer of Unit 2 loads to startup buses will not cause Unit 1 to trip. A sensitivity study was performed to assess the significance of this assumption. The study showed that risk would be increased if Unit 2 transients affect Unit 1 operation in this configuration (Ref. 22). For example, if there was a 5 percent likelihood that a DCPP Unit 2 trip would cause DCPP Unit 1 to trip and load 4kV vital buses on the diesel generators, then the resulting increase in core damage frequency would be 4 percent (assuming operation in this configuration for six months).

Another assumption made in the PRA study is that the 230 kV system is expected to be reliable. That is, the information obtained from Transmission Planning, and any associated compensatory measures identified in OE 95-06 (Ref. 23) would ensure a reliable 230 kV system.

2. Impact on PRA Initiating Events

The impact on initiating events, including new initiating events was evaluated. The initiating events already considered in the PRA (reactor trips, LOCAs, seismic, fire, etc.) are not impacted by having the 12 kV non-vital loads on startup power. However, operating in this configuration does create an initiating event not currently assessed in the Diablo Canyon PRA. This new event is a Loss of 230 kV Initiating Event. With the 12 kV Buses D and E powered by startup power, any loss (or sustained undervoltage) of 230 kV will result in a reactor trip (due to RCP undervoltage) and transfer of vital 4 kV loads to the diesel generators, with 500 kV available for backfeed.

3. Likelihood of Loss of 230 kV Initiating Event

Plant-specific and generic data were compiled to determine the likelihood of a loss of 230 kV initiating event, assuming that DCPP Unit 1 only operates in this configuration during the wet months (November 1995 to May 1996), when loss of 230 kV power at DCPP due to offsite fires is unlikely. The likelihood of a loss of 230 kV initiating event during the wet months of the year is estimated to be 0.05 per year (probability of 0.025 in a six-month period), based on a Bayesian update of DCPP plant specific (1 event in 13 years) and generic industry data (0.05 events per year). It is a standard practice in PRAs to combine plant specific and industry data (generic data) in a "Bayesian" update, because of the limited amount of plant specific data typically available.

The Diablo Canyon specific experience of 6 events excluding maintenance activities (through 10/24/95) as well as the rationale for inclusion/exclusion is summarized in the table below :

LOSS OF 230 kV EVENTS AT DIABLO CANYON POWER PLANT			
DATE	SOURCE DOC	DESCRIPTION	INCLUDE/EXCLUDE RATIONALE
10/16/82	NSAC 176L .	Grass fire near 500 kV switchyard caused two 230kV lines to be deenergized. 14 hours later, the plant lost three 500 kV lines resulting in LOOP.	The California Department of Forestry requested that the two 230kV lines be deenergized. This was a planned shutdown of 230kV. The event was the subject of INPO Significant Event Report (SER) 5-83 and was referenced in NSAC 176L (Safety Assessment of PWR Risk During Shutdown Operations). This event was not included since there is no indication that the 230 kV system was ever in jeopardy.
1/27/83	NSAC 176L	Offsite fire caused onsite transient. LOOP.	The event was referenced in NSAC 176L but no additional information on this event is available in SER 5-83, although the SER is referenced in NSAC 176L. Existing DCPP data was reviewed, and no mention of this event was found. Conversations with the author of NSAC 176L determined that it is likely that there is an error in the report, and this event may not have occurred. Since no additional information is available, this event will not be included as a true loss of 230 kV event.
7/30/84	LER 1-84-023-00	230kV lost for 45 seconds due to staff technician inadvertently isolating 230kV. Unit 1 in Mode 3.	LER 1-84-023-00 describes the event. The error resulted from testing breaker action, in place, by use of the overcurrent relay (contrary to established procedures governing maintenance of 12 kV circuit breakers). In this case, the initiating relay not only caused breaker operation, but also separated the plant from the 230kV offsite power source. Procedural compliance regarding breakers related to 230kV is the issue and the 230kV source was still available. Tighter procedural controls

LOSS OF 230 kV EVENTS AT DIABLO CANYON POWER PLANT			
DATE	SOURCE DOC	DESCRIPTION	INCLUDE/EXCLUDE RATIONALE
			which would be expected after commercial operation would tend to preclude this event from happening again such that this event will not be included as a potential loss of 230 kV (during commercial operations).
7/17/88	LER 2-88-008-00	OCB 212 opened (causing a loss of the 230 kV system) due to a fire which resulted from a sheet of micarta type material inadvertently being left on the grounding resistor banks of the 230/12 kV S/U transformer.	The opening of OCB 212 (and thus the loss of the 230 kV offsite source) was as secondary event after an internal fire. Additionally, 11 corrective actions to prevent recurrence were identified in NCR DC2-88-EM-N082, some which directly address the placement (prohibition) of any material on top of the grounding resistor bank enclosures. This event will not be included as a true loss of 230 kV system since this event was, in fact, a secondary event, and that appropriate measures have been taken such that this sequence of events could not happen again.
5/31/89	Conversation with Demetrios Tziouvaras	Per Grid Maintenance and Construction, on May 31, 1989, flashover at Morro Bay switchyard caused OCB-212 at DCPP to open. 230kV offsite power was lost for 23 minutes, from 0604 to 0610 and 7:17 - 7:36.	This event should be included, although substantial corrective actions have been taken - most notably the application of silicon to the bus and replacing relays.
8/15/94	LER 1-94-016-00	Due to offsite wildfire, 230kV lost for 6 hrs, 46 minutes.	This event should be included as a true loss of the 230 kV offsite source, if evaluation is for all times of year. For operation during the wet months only this scenario can be excluded since this type of scenario in unlikely from November to May.

In addition to the information presented above, Reference 22 also reviewed a 230kV reliability study completed in 1980. Between January 1971 and April 1980, there were 3 lightning events and 1 flashover event that caused forced outages on both the Diablo-Mesa line and the Diablo-Morro Bay line. The flashover event was due to maintenance. Per PG&E Grid Maintenance and Construction with the RCP time delay set (a design change required prior to restart), the lightning events (which were only "momentary" in duration) would not result in a reactor trip and are excluded. The flashover event due to maintenance is unlikely due to the low probability of maintenance on the 230 kV lines (there is a compensatory measure to perform required 230kV maintenance prior to restart).

An additional calculation, Reference 52, was performed to determine the probability of a Loss of 230kV initiating event leading to Condition 3 accident consequences, i.e. Loss of 230kV in conjunction with failure of immediate reactor trip from a 12 kV undervoltage signal. The probability of failure of reactor trip is dominated by failures of the 12 kV undervoltage relays on both 12 kV buses, by failure of both SSPS trains, or by failure of the reactor trip/control rod system (or a combination of these events). It was determined that the probability of a Loss of 230kV initiating event, along with failure of the 12 kV undervoltage reactor trip signal was well below 0.001.

4. PRA Results/Conclusions

The PRA model was requantified with the new initiating event resulting in additional conditional core damage frequency for the loss of 230 kV of 3.37×10^{-5}/year. Using the initiating event frequency of 0.05 for a six month period, the increase in core damage probability is 8.5×10^{-7}. The resulting increase in annual average core damage frequency for all initiating events is estimated to be approximately 2%. According to EPRI guidelines (Ref. 51), temporary changes in core damage probability of less than 1E-6 are considered non-risk significant.

Other non-quantifiable factors can reduce the risk impact. Some of the non-quantifiable factors include plant performance (or reduced planned maintenance) on plant safety systems. Other factors also reduce risk, such as measures to justify why the 230 kV system should be expected to be reliable. For this study, the conservatisms in the analysis and possible compensatory measures to reduce the risks of the proposed configuration are discussed below.

5. Conservatisms in PRA Assessment

- The PRA only takes limited credit for recovery of diesel generators, should they fail.
- The PRA only takes limited credit for ASW flow via FCV-601, should ASW fail.
- The 230 kV system should be more reliable with the large 12 kV steady state loads aligned to startup. No credit is taken for the increased reliability.

6. Risk Management/Compensatory Measures

Compensatory measures should be considered to reduce the risks associated with aligning the 12 kV non-vital buses to startup power. The reduction in core damage frequency by implementing these compensatory measures which are also found in OE 95-12, is not easily quantified but will reduce risk.

- Have the operating crews review the loss of AC procedures, and practice scenarios on the simulator, including backfeeding vital buses via the 500 kV system.

- Take steps to maintain a reliable 230 kV system (two Morro Bay Units, no line outages without careful consideration, etc.)

- Perform appropriate 230 kV and MBPP preventative maintenance prior to starting DCPP up and during DCPP operation to assure reliable operation of the 230 kV system.

- If there is a fire in the vicinity of the 230 kV lines, evaluate if a Unit 1 controlled shutdown is warranted. After the unit is shutdown, the 4 kV vital buses could be aligned so they are backfeeding from 500 kV.

- If any other severe external event is threatening 230 kV lines or MBPP, evaluate if shutting the DCPP Unit 1 down and backfeeding 4 kV lines from 500 kV is warranted.

- Minimize the unavailability of other DCPP safety-related equipment, particularly the diesel generators, the auxiliary feedwater pumps, and the auxiliary saltwater pumps during operation in this configuration. Maintenance unavailability can be minimized by:

    1. Improved coordination between work groups
    2. Shorten time between hanging clearance and starting work
    3. Assuring work orders are completed prior to clearing equipment
    4. Assuring necessary equipment is staged prior to commencing work
    5. Performing post maintenance STP immediately upon completion of work

F. Impact on Operations

The proposed configuration will require revisions to numerous Operations procedures and additional operator training for both licensed and non-licensed personnel. The training will include simulator and classroom instruction.

1. Procedure Revisions

AR PK19-04	12 kV S/U Bus UV
OP AP-26	Loss of Offsite Power (Modes 1-4)
OP AP SD-1	Loss of AC Power (Modes 5,6)
OP J-2:V	Backfeeding the Unit from the 500 kV system
OP J-6A:I	4160 V System - Make Available
OP J-7A:IV	480 V Non-vital System - Re-energize After Loss of Power Cross-tieing & Ground Isolation
OP K-2B:I	Low Pressure CARDOX System - Make Available
OP L-1	Plant Heatup from Cold Shutdown to Hot Standby
OP L-3	Secondary Plant Startup
OP L-5	Plant Cooldown from Min Load to Hot Standby

Other procedure changes have been made, but are minor in nature, consisting of references affected by the proposed configuration.

Other secondary plant effects which are recognized as expected events if the 230kV system is lost while in the proposed configuration are:

a. The major effect is a loss of the CWPs and the main Condenser.

Response: The Operations secondary Foreman has reviewed the new AP-26 and provided comments for incorporation into the procedure. In the end, it was determined that the best guidance to give operating crews is to perform their immediate actions per OP O-19 (unchanged) and DO NOT start any condensate booster pumps until the hottest portion of the feedwater leads is less than saturation temperature.

Aside from the flashing that will occur due to depressurizing the secondary plant, damage will be limited as long as no uncontrolled repressurization occurs. This is dealt with clearly in OP AP-26.

b. The main generator will be pressurized with hydrogen, and the DC-powered Air Side Seal Oil Backup pump will start due to a loss of the normal Air Side Seal Oil pump, which is a non-vital load. This pump will maintain adequate pressure to keep the 75 psig hydrogen in the generator, but with no backup high pressure oil source available, the unit must be depressurized to 2 psig per Westinghouse recommendations.

Response: This is dealt with in OP AP-26, "Loss of Offsite Power", which instructs the operator to depressurize and purge the main generator per OP J-4C:III, so that the Air Side Seal Oil Backup pump may be secured to conserve batteries 15 and 16.

c. The main unit DC oil pump will be running due to an interruption of non-vital power. This will present a load on the 250V DC batteries 15 and 16.

Response: The AC bearing oil pump is vital powered, but must be manually started to allow shutting down the DC oil pump. Further, if the unit is no longer rotating (it shouldn't be, since condenser vacuum was broken), the oil pumps are not needed. Therefore, the operator is instructed to secure the DC oil pump if the unit is no longer rotating.

d. The Main Feed Pumps (MFPs) will be running due to an interruption of non-vital power. This will present a load on the 250V DC batteries 15 and 16.

Response: If the FWPs are not rotating, the oil pumps are not needed. Therefore, the operator is instructed to isolate the MFPs and secure the DC oil pumps to conserve battery power.

2. Lessons Learned

The following is a list of lessons learned (Ref. 40) from the October 21, 1995, auxiliary transformer 1-1 fire.

- The plant Personnel Announcement (PA) system did not work on Unit 1 because it is powered from non-vital power. The electrical circuits for the PA system have been reviewed to determine the power sources for the PA system in the turbine building, auxiliary building and intake structure. These power sources will be identified in OP AP-26 to give operators the option to align the applicable power sources in the event non-vital power is lost.

- The fire alarm sounded initially, but did not sound when attempted later. A review of the electrical circuits identified the power supplies for the Honeywell computer and PFAC data gathering panels. These power supplies are identified in OP AP-26 to give operators the option to re-energize the panels with any available power source.

- Because the event occurred during Mode 5, operators manually restarted Residual Heat Removal (RHR) Pump 1-1 in approximately 2 minutes after the occurrence of a LOOP. This pump does not start on transfer to the EDGs. OP AP SD-1 was revised to add a caution statement that the RHR pumps and spent fuel pool (SFP) pumps may be tripped on a transfer-to-diesel signal, and may need to be manually restarted. OP AP-26 currently includes a step to restart the pumps, if necessary.

- Operators manually restarted SFP 1-1 approximately 8 hours after the event. The pump trips on a bus transfer, and does not auto-restart. The SFP 1-1 trip is identified in response procedures, but not in abnormal operating procedures (AOPs). No alarm was received, as the SFP 1-1 high temperature setpoint of 130°F was not reached. The temperature of SFP 1-1 before the event was 92°F, and the temperature at the time of restart was 112°F. The round sheet limit is 125°F. OP AP SD-1 has been revised to add a caution statement that the RHR and SFP pump(s) may be tripped on a transfer-to-diesel signal, and may need to be restarted.

OP AP-26 currently contains a step to restart the pumps, if necessary. Operations has also requested an alarm on low pressure discharge for the SFPs.

- One long-term effect was loss of control power to the 230/500 kV switchyards, which is normally supplied by 4 kV D/E. When this power is lost, the switchyards transfer to a battery back-up for instrumentation control. The main batteries are new, and showed only a one volt degradation (out of 120), in the 15-hour period. This was not a cause for concern. The communication room batteries degraded further, from 48 V to 46 V. If voltage had reached 42 V, the microwave links would have been lost, which would have disabled one set of protective relays. A second set is on power line carrier, which would have been available. A third set could have also been placed in service. Remote monitoring and control of the 230 kV switchyard (SCADA) was lost for approximately 2.5 hours into the event; this was not a loss of protection. The switchyard operator requested a longer-rated UPS for this equipment. In OP AP-26, operations has captured the information, as well as the expected time that the batteries will last. The switchyard controls are listed in the foldout page of OP AP-26 as loads which will remain on batteries until power can be restored.

- The procedures associated with returning the 480 non-vital buses to service will be revised to state that a 480 V bus does not need to be stripped if maintenance has not been performed on the bus. To safely do this action, the current requirements to strip the bus will need to be evaluated. Operations reviewed this action and found the normal operating procedures overly restrictive, reflecting a conservative approach to General Operating Order 12.110. This operating order requires that the loads which could cause an excessive inrush current be stripped from the bus before it is energized. OP J-7A:I will be revised to remove the pre-requisite to strip the bus prior to re-energizing after power has been interrupted.

- OP AP SD-1, Appendix N needs to be revised for cross-tieing a diesel generator to a non-vital bus. This appendix lists non-vital loads that are of concern. Based on this event, this appendix will be updated. OP AP SD-1 was revised to include enhancements identified by the operating crew from the October 21, 1995, event. References have been placed appropriately in OP AP SD-1 to refer the user to OP AP-26 to identify other non-vital loads which may be desirable to re-energize.

- The security diesel generator started, and loaded during the event. The fuel oil level will need to be monitored periodically while the diesel is operating. OP AP-26 was revised to add the action to check the diesel fuel oil level every 12 hours. This action was acceptable to the Security group.

- The plant phone system began to act erratically following the incident. It is suspected that overheating of the communications room (adjoining the Cable Spreading Room) was partially the reason. The non-vital power supplies to the Cable Spreading Room and Communication room air conditioning units have been added to OP AP-26 as desirable loads to be reenergized following restoration of power.

- Some time after the event, it was recognized that chlorine monitoring had been lost after the loss of offsite power. This required suspension of chlorine injection per PG&E's NPDES permit. Chlorine injection had not been secured at the appropriate time. An action was added to OP AP-26 to attempt to restore power to the chlorine monitoring equipment.

- During the event, CARDOX tank alarms activated, indicating that tank pressure control had failed (this is non-vital power). Subsequently, an operator was dispatched to control the tank pressure manually. No procedure existed to perform this evolution. OP K-2B:I was revised to incorporate the information obtained from the operator who manually controlled the tank pressure.

3. Training

A training plan has been implemented to train Operations prior to startup and heat up of the plant. The training primarily involves a validation of OP AP-26. Learning Services ran a series of simulator exercises in order to test the effectiveness of OP AP-26 (Ref. 41). The exercises consisted of four separate scenarios, each using a five-person Operations crew, and each lasting from 20 to 45 minutes in length. A discussion was held after each scenario in order to capture any thoughts concerning the implementation of OP AP-26. Comments concerning the procedure were collected by the Operations Procedures Group representative on a red line copy of the draft procedure for incorporation into the final draft of OP AP-26. The following scenarios were used to evaluate OP AP-26 (with conclusions):

- Mode 4, 210°F, RHR in service, LOOP: Due to the nature of the loss, Unit 1 must implement Appendix N, " "

- 2% power, all buses (except 12 kV) on auxiliary power, LOOP (startup power was lost first), Unit 1 must cross-tie to Unit 2 startup power

- 100% power, LOOP, Unit 1 re-energizes startup power

- 50% power, loss of startup transformer 1-2 and load rejection

The results of the simulator training were successful. Even with basic overview type training on the procedure, the crew had little difficulty in interpreting the procedure flowpaths. Every flowpath in OP AP-26 was tested and no significant problems were noted.

The first 3 scenarios will be used to train the Operations crew. The first scenario will be modified so that the RCS will be at 250°F, and the plant will be off of RHR to be more challenging to the crews.

For licensed operators, the simulator training will last approximately 3 hours. Following the simulator training, a critique lasting one hour will be done. In addition, classroom training lasting two hours will also be performed. This training will consist of industry event training on the AT

1-1 event (one hour), and also on procedure changes associated with starting the plant on startup power (one hour).

For non-licensed operators, the training will consist of classroom training on the AT 1-1 event (one hour), and on procedure changes which impact watchstanders (one hour). This will be followed by In-Plant task walkdowns of new/infrequently performed tasks. These tasks include emergency purge of the main generator, transferring PY-17 onto back-up power, and manually controlling pressure of the cardox tank. These In-Plant tasks walkdown will last one to two hours.

IV. Recommendations

As a result of the analyses that addressed the 230 kV system, the electrical design basis for the 12 kV system, the accident analysis, and the PRA, several recommendations were identified:

1) Implement 2.5% tap change on Unit 1 12/4 kV Startup Transformer 1-2 [DCP E-49237] and Unit 2 12/4 kV Startup Transformer 2-2 [DCP E-50237]

2) Block auto transfer of one Unit 2 12 kV bus, D or E.

3) DCPP 230 kV voltage maintained at a minimum of 226 kV [O-23, Attachment I]

4) Reschedule DFO tank replacement and ASW bypass work to less risk sensitive time. [AR A0385949, AE 05]

5) Create an "operational" safety plan patterned after the outage safety plan. [AR A0385949, AE 06]

6) Complete deferred maintenance on 230 kV circuits prior to startup. [Chron 228362, Ref. 39]

7) Review outstanding work on 230 kV system for "critical" reliability problems and get them resolved. [Chron 228362, Ref. 39]

8) Perform "walkdown" or "flyover" of the 230 kV system to establish system capability. [Chron 228362, Ref. 39]

9) Examine 230 kV system vulnerability to external events such as fire, earthquake, flood or other grid disturbance. Take steps to minimize vulnerability or include response to event in "operational" safety plan. [Chron 228362, Ref. 39] [AR A0385949, AE 02]

10) Issue procedure establishing and limiting access control to the 230 kV and 500 kV switchyards prior to Unit startup. [AR A0385949, AE 03]

11) Implement policy and subsequently issue procedure delineating interface between Transmission Planning, System Operations and DCPP. The policy/procedure would include

defining how organizations notify each other of circumstances that impact the 230 kV system. [O-23, Attachment I][AR A0385949, AE 01]

12) Establish reactor coolant pump anticipatory trip time delay settings of 0.5 seconds. [DCP E-49200]

13) Revise operating procedures for operation on startup power prior to restart. [Chron 228365, Ref. 40]

14) Train operators on procedure revisions, including time in the simulator if deemed appropriate. [Chron 228364, Ref. 41]

15) Review ongoing plant maintenance of safety-related equipment from a risk perspective. Defer maintenance activities if increase in risk is determined to be substantial as defined by PRA review. [AR A0385949, AE 06]

16) Operate 12 kV Site Underground loads on Unit 2 230/12 kV Startup Transformer 2-1 [AR A0385949, AE 08]

V. Critical Assessment of Proposed Configuration

Operation with Unit 1 supplied from Startup Power resolves the dilemma of how to bring Unit 1 back on line with Auxiliary Transformer (AT) 1-1 unavailable. However, the final decision must be predicated on providing a safe and reliable means for operation of both DCPP Units. Inherent with this choice are a number of factors which either support or detract from the viability of this option. The following summarizes some of the stronger points that support operation in this mode. Following this list is a list of factors which highlight weaknesses in operating from Startup Power. The intent of these two lists is to help put the decision into a better perspective by weighing both positive and negative aspects of the issue.

Factors Supporting Operation In This Configuration:

1. Startup Power (230 kV System) is normally used to supplied the 12-k V loads during unit startup, shutdown or in response to unit trip or design basis accident.

2. Extensive Transmission Planning studies have demonstrated that the 230 kV System has the required robustness to handle Unit 1 and 2 operation, and survive system transients.

3. Electrical analysis has shown that all equipment electrical ratings are met, and that the Startup Transformer has the required capacity.

4. Licensing review found no restrictions preventing the unit from operating in this configuration in any licensing document.

5. Industry research found past and current precedence for plants operating under similar conditions.

6. Operating Unit 1 from Startup Power does not challenge the licensing design basis for the 230 kV System.

7. No new accident is introduced than those previously credited and analyzed for in Chapter 15 of the FSAR

Factors Challenging Operation In This Configuration

1. In normal operation, Unit 1 has two independent sources of power to the RCPs and CWPs. Now there is only one.

2. Plant operators are not familiar with operating a unit with non-vital loads continuously powered from Startup Power.

3. Loss of 230 kV introduces a new initiating event for complete loss of forced coolant flow which potentially increases the probability for this event.

4. Transfer of one 12 kV bus from Unit 2 must be blocked which limits operator flexibility in responding to an accident.

5. Unit 1 becomes more susceptible to external events on the 230 kV System which can result in a unit trip.

6. There is a small increase (2%) in the risk to core damage associated with operation in this configuration.

VI. Conclusion

This report analyzes the option of operating Unit 1 with the 12 kV non-vital buses D and E continuously energized from Startup Power. The report studied this option by examining a number of parameters. The parameters included an evaluation of the overall robustness of the offsite 230 kV System, and the ability of onsite electrical equipment to function. In addition, detailed reviews were completed in licensing and design bases, accident analysis, and probabilistic risk assessment. Operating procedures were reviewed and revised and training was conducted on the new procedures. The summation of all these reviews is that the plant can operate safely and reliably while in this configuration. The underlying recommendation of the Transformer Recovery Options Team is that Plant Management support operation of Unit 1 12 kV Buses D and E from Startup Power.

VII. References

1. E-mail dated 10/31/95 (11:23:44 am PST) from Anil Kar (AKK2@IE@NTS) to Dan Brosnan (DFB4@BASES@NTS); Chron. 228311; Subject: Electrical Evaluation of 230 kV LineUp for SU/POWER operation

2. Electrical Calculation 160-DC, "Overcurrent Relay Setting for Non-1E 12 kV & 4 kV Motors"

3. Electrical Calculation 154D-DC, "12 kV System Protection for Units 1 and 2"

4. E-mail dated 10/31/95 (11:42:27 am PST) from Pat Nugent (PXN2@RS@NTS) to Dan Brosnan (DFB4@BASES@NTS); Chron. 228312; Subject: Licensing Review Summary

5. Technical Specification 3.8.1.1, "A.C. Sources - Operating"

6. Technical Specification 3.4.1.1, "Reactor Coolant Loops and Coolant Circulation - Startup and Power Operation"

7. Technical Specification 3.4.1.2, "Reactor Coolant Loops and Coolant Circulation - Hot Standby"

8. Technical Specification 3.4.1.3, "Reactor Coolant Loops and Coolant Circulation - Hot Shutdown"

9. FSAR Update Chapter 8, "Electrical Power"

10. FSAR Update Chapter 15, "Accident Analysis"

11. NUREG-0800, Standard Review Plan

12. Regulatory Guide 1.93, "Availability of Electric Power Sources"

13. 10 CFR 50, Appendix A, General Design Criterion 17, "Electric Power Systems"

14. 10 CFR 50, Appendix A, General Design Criterion 18, "Inspection and Testing of Electric Power Systems"

15. Westinghouse Letter PGE-95-592, dated 10/31/95, Chron. 228313, Subject: Operation Without Auxiliary Transformer 1-1 Safety Evaluation, SECL-95-160.

16. Operability Evaluation 95-12, "Acceptability of Operation of Unit 1 With No Auxiliary Transformer 1-1 and 12 kV Busses Paralleled to the 230 kV System"

17. E-mail dated 10/28/95 (12:01:14 PM) from Rich Fields (RLF8@TP@PS) to Dan Brosnan (DFB4@BASES@NTS), Chron. 228314, Subject: Unit 1 Startup and Unit 2 Non-LOCA Transfer

18. PG&E Memorandum dated 11/3/95, Chron 228292, from Richard L. Fields (Transmission Planning) to Klemme Herman et al

19. PG&E to NRC Letter dated 8/3/78, Response to Question 31 of NRC's Request for Additional Information on Fire Protection

20. Amendment 51 to Application for Operating License, Fire Protection Review dated 7/27/77

21. Non-conformance Report N0001887, "Testing Discrepancies Identified with Fire Barrier Material"

22. PG&E Calculation File No. PRA95-012, Rev. 3, "PRA Evaluation of Aligning 12 kV Non-vital Buses to Startup,", dated 11/16/95

23. Operability Evaluation 95-06, "Operability of the 230 kV Startup Power System"

24. E-mail dated 11/6/95 (11:38:10 AM) from Robert Jenkins (RTJ1@TP@PS) to Dan Brosnan (DFB4@BASES@NTS), Chron. 228363, Subject: Response to Questions

25. Design Change Package E-49228, Unit 1, "Change UV Relay Time Delay for Condensate/Condensate Booster Pump"

26. Design Change Package E-50228, Unit 2, "Change UV Relay Time Delay for Condensate/Condensate Booster Pump"

27. E-mail dated 10/26/95 from Fleur de Peralta (FAD3@BASES@NTS) to Dan Brosnan (DFB4@BASES@NTS), Chron. 228315, Subject: Fire Protection Review of Transformer Issues

28. IEEE 308-1971, "Class 1E Electric Systems for Nuclear Power Generating Stations"

29. Regulatory Guide 1.32, "Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants," August 1972

30. Safety Guide 1.6, "Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution System," Revision 0, dated March 10, 1971

31. Regulatory Guide 1.81, "Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants"

32. Information Notice 79-04, "Degradation of Engineered Safety Features"

33. NRC letter dated 8/8/79, "Adequacy of Station Electric Distribution Systems Voltages," (Follow-up to IE Information Notice 79-04)

34. NRC Inspection Report 91-07 of Diablo Canyon Power, dated 7/18/91

35. PG&E Letter DCL-92-084, dated 4/13/92, Subject: Revised Response to Station Blackout"

36. Regulatory Guide 1.155, "Station Blackout

37. NUMARC 87-00, Revision 1, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors"

38. NUREG-1032, "Evaluation of Station Blackout Accidents at Nuclear Power Plants"

39. E-mail dated 11/5/95 (@ 6:43:33 AM) from Jerry Timiraos (JMT3@TS@MLPP) to Dan Brosnan (DFB4@BASES@ NTS) and Joe Goryance (JXG3@ElecEngr@DCPP); Chron. 228362; Subject: GM&C Commitment for DCPP 230 kV Reliability

40. E-mail dated 11/8/95 (@ 12:07:58 PM) from Dennis Peterson (DBP1@OPS@DCPP) to Fleur de Peralta (FAD3@BASES@NTS); Chron. 228365; Subject: Lessons Learned and List of Operating Procedures Needing Revision

41. E-mail dated 11/7/95 (@ 4:38:00 PM) from Jeff Davis (JOD1@LRN@NTS) to Fleur de Peralta (FAD3@BASES@NTS); Chron. 228364; Subject: Operations Training Plan and Simulator Exercises

42. Memo from Richard L. Fields (Transmission Planning) to Klemme Herman et al., dated 11/6/95, Chron. 228359, Subject: Effects on Unit 1 12 kV RCPs and CWPs due to a Three-Phase Fault at the DCPP 230 kV switchyard

43. E-mail dated 11/3/95 (@ 9:51:05 AM) from Richard L. Fields (RLF@TP@PS) to Anil Kar (AKK2@IE@NTS), Subject: Short Circuit Impedance

44. Calculation 96-DC, Rev. 3, "Load Flow Study (Unit 1)"

45. Calculation 96C-DC, Rev. 0, "Bus Transfer Calculation"

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47. Calculation 174B-DC, Rev. 1, "Second Level Undervoltage Setting (SLURs) 4.16 kV"

48. Calculation 114-DC, "Protection Relay Setting for Bus and Feeders (Class 1E 4.16 kV Switchgear)"

49. Calculation 161-DC, "11.5 kV and 4 kV Non-Class 1E Motors (Systems 7, 17 & 64)"

50. Calculation 170-DC, "Overcurrent Relay Settings for Class 1E 4 kV Motors"

51. EPRI TR-105396, "PSA Applications Guide", EPRI, prepared by ERIN Engineering, August 1995.

52. PG&E Calculation File No. PRA95-014, Rev. 0, "PRA Evaluation of Condition 3 Event for Proposed 230kV alignment," dated 11/16/95

Figure 1

Electrical Distribution Overview