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James D. Shiffer
Senior Vice President and
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February 16, 1990

PG&E Letter No. DCL-90-046

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

Re: Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Long Term Seismic Program Probabilistic Risk Assessment

Gentlemen:

On January 19, 1990, the NRC Staff issued a letter transmitting several documents related to the Staff's review of the Long Term Seismic Program (LTSP). Enclosure 3 of that letter identified several questions regarding the LTSP probabilistic risk assessment (PRA) of electric power systems. PG&E's responses to these questions are provided in Enclosure 1 of this letter, with the exception of questions related to instrument AC analysis, which will be submitted in the near future. In addition, pursuant to discussions with the Staff, Enclosure 2 provides clarifying information regarding development of the PRA dominant sequence models. Enclosure 3 of this letter provides Table F.3-4 of the PRA documentation, which updates the data reflected in Table 6-47 of the LTSP Final Report.

Kindly acknowledge receipt of this material on the enclosed copy of this letter and return it in the enclosed addressed envelope.

Sincerely,

J. D. Shiffer

cc: M. Bohn, Sandia
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Diablo Distribution (w/o Enc.)

Enclosures

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ENCLOSURE 1

PACIFIC GAS AND ELECTRIC COMPANY

RESPONSE TO BROOKHAVEN NATIONAL LABORATORY LETTER REPORT-08

"A REVIEW OF SYSTEMS ANALYSIS IN THE DCPRA -
ELECTRIC POWER SYSTEMS
(Except Diesel Generator and Diesel Fuel Transfer System)"

FEBRUARY 1990

## 1.0 GENERAL DISCUSSION

This discussion provides PG&E's responses to Brookhaven National Laboratory (BNL) Letter Report-08, which documented several questions on the electric power systems modeled in the Diablo Canyon PRA. Section 2.0 is structured as follows:

2.1 Comments on the Nonvital Electric Power Systems
2.2 Comments on the Vital 125V DC System
2.3 Comments on the Vital AC System - Unit 1
2.4 Comments on the Vital AC/DC System - Unit 2
2.5 Comments on the Instrument AC System
2.6 Comments on the Loop Initiator

Section 2.5 will be provided at a later date under separate cover.

## 2.0 RESPONSES TO COMMENTS

### 2.1 COMMENTS ON THE NONVITAL ELECTRIC POWER SYSTEM

BNL COMMENT 1:

> The startup transformers (SU-11 and SU-12) are depicted in the nonvital electric power system description (Figure D.2.1-1, Sheet 4) as somewhat complex systems, e.g., transformer SU-11 has two cooling oil pumps and 25 cooling fans (powered via breaker 52-11D-23 from bus 11D 480V) as well as radiators. They can carry only up to 60-70% of the load without cooling. The analysis apparently neglected the unavailabilities due to failure and maintenance of these subcomponents and the unavailability of the bus. As a result, split fraction OG1 seems to be somewhat underestimated.

RESPONSE TO COMMENT:

The value for split fraction OG1 is not underestimated. The statement that the transformer can only carry 60 - 70% of the load without cooling is based on overall transformer aging concerns. The startup transformers can carry

100% load without the transformer cooling system for at least 2 hours pursuant to ANSI standard C57.92-1981, Section 3.6. After the initial transfer to startup, the load requirement is reduced to the transformer OA rating as the plant goes to shutdown.

BNL COMMENT 2:

> It is not clear if the switch yard/plant breakers (542 and 632) have already been replaced by "seismic resistant" Hitachi breakers or not. If not, their seismic contribution might be relevant.

RESPONSE TO COMMENT:

The DCPRA documentation (Table D.2.1-1 Sheet 1 and Figure D.2.1-1 Sheet 3) refer to breakers 532, 632, 542, and 642. Of these breakers, the ones normally used for connection to offsite power are 632 and 642. These two breakers have been replaced with Hitachi dead tank breakers. Dead tank breakers are lower to the ground and have been proven to be much more resistant to seismic events.

In the seismic analysis, no credit was given for the 500kV offsite power source (i.e., it was assumed to have failed due to the seismic event); however, a fragility was developed for the 230kV standby power source. Therefore, the type of 500kV breakers installed at DCPP does not have any effect on the results of the seismic analysis.

BNL COMMENT 3:

> Assumption 2 for quantifying Top Event OG states that failure events to accomplish load rejection to house loads are included in the loss of power initiator. How big is this contribution and how was it estimated?

RESPONSE TO COMMENT:

The loss of offsite power (LOOP) initiating event frequency is based on generic industry data and Diablo Canyon plant specific experience; the generic industry data includes plants which have load rejection capability and plants

which do not. Therefore, the generic prior distribution is composed of both types of events. Although Diablo Canyon does have load rejection capability, no credit was given for this feature in the DCPRA. Effectively then, the generic prior distribution for the LOOP initiating event frequency has a 100% contribution from failure of load rejection (i.e., all events are assumed to have failed load rejection). In actuality, some percentage of the total LOOP frequency involves failure of load rejection. This percentage, however, cannot be determined easily from the DCPRA results.

BNL COMMENT 4:

> Block 3 shown in Figures 2.2 and 2.3 was not developed at the equation level. It is said that it might be modelled as a recovery action if it is needed. Please identify which power recovery action(s) includes it, if any.

RESPONSE TO COMMENT:

Backfeeding AC power from the 500kV grid through the main transformer (Block 3) was not modeled in any power recovery actions in DCPRA.

## 2.2 COMMENTS ON THE VITAL 125V DC SYSTEM

BNL COMMENT 1:

> The DCPRA does not mention ground fault testing of the batteries. This is performed at some nuclear plants as often as once per shift. Is there a potential failure of loss of a vital dc bus due to operator error associated with this test (e.g., push a dc bus trip breaker switch instead of the ground fault test switch)? Is there any potential to lose a vital dc bus due to operator error during the operability tests of the batteries required at each seven days?

RESPONSE TO COMMENT:

During power operation, battery ground faults are monitored by a continuously indicating milliamp meter. The operators do not need to perform separate testing to demonstrate the battery operability regarding ground faults. A

review of the surveillance test procedures, the electrical systems rounds sheets, and discussions with plant operations personnel determined that loss of a vital DC bus due to operator error is extremely unlikely. If such an event were to occur, it would be included in the loss of DC bus initiating event frequency. It is, therefore, inappropriate to model these events in the system model.

BNL COMMENT 2:

> Figure 2.1 as well as Figures 2.4.1 and 2.4.2 indicate a bus tie between dc buses 11 and 12 (which might be in use during maintenance). The system analysis does not consider common cause failures between dc trains. It is known, however, that a bus tie has the potential to compromise the independence of the dc trains. Please explain the reason for the omission of the bus tie from the unavailability model of the dc system.

RESPONSE TO COMMENT:

The referenced bus tie between DC buses 11 and 12 cannot be used to physically connect buses 11 and 12 together. The two breakers on this "tie" (72-1200 and 72-1101) are key interlocked so that only one breaker can be closed at a time. The purpose of this tie is to allow the backup battery charger 121 to service either bus 11 or 12 but not both. The presence of this "tie" does not compromise the independence of DC trains 11 and 12.

BNL COMMENT 3A:

> It is not clear which are the values of the split fractions for top events DF, DG, and DH for station brownout (unit blackout) and blackout initiators. After battery depletion (assumed in the dc power analysis to be two hours), their values are 1, or is recovery assumed?

RESPONSE TO COMMENT:

Because of the dependency between DC power and AC power, the approach adopted in the DCPRA event tree analysis is to question the DC power top events first. After the DC power status is determined, AC power top events are asked. In quantifying the frequency of a sequence in the event tree, the

split fraction values used for DC power top events can only be conditioned on the status (i.e., success, failure, or bypass) of the preceding top events. Since the status of AC power is not known when DC power top events are asked, the DC power top event split fractions that correspond to the boundary condition of successful AC power were used in the event tree quantification. Given DC power top events are successful, control power for breaker operations and emergency AC power generation is available and the unavailability of AC power can be evaluated under this boundary condition.

The unavailability of DC power after battery depletion in the blackout scenarios is accounted for by the impact mapping technique in the event tree quantification. For example, if DC power top events are successful and AC power top events have failed, the impact of this sequence is modeled as AC power failure and long-term failure of DC power. Guaranteed failure split fractions were used in the event tree quantification for all of the AC loads, including frontline and other support system equipment. For DC loads, such as controls for the turbine driven auxiliary feedwater pump, the unavailability was conservatively evaluated for a mission time of 24 hours under a boundary condition of DC power available. Success of the AFW top event is, however, interpreted as the successful operation of AFW only for a duration equal to the battery lifetime.

No DC power recovery was assumed in the electric power analysis of DCPRA. Therefore, the long-term DC power failure due to battery depletion was included by mapping the affected sequences to core damage if AC power was not recovered prior to battery depletion or prior to the onset of core damage. The system modeling of the DC power unavailability was conservative because a bounding model was used (discussed in the Response to Comment 3B).

<u>BNL COMMENT 3B</u>:

> In modelling of the electrical recovery actions, the DCPRA states (p.3-5-18), "Based on the actual plant operation data, PG&E electrical design personnel estimated an extended battery availability of more than 12 hours with no reduction in dc loads during a station blackout." In

the unavailability analysis of the diesel generator, it was assumed that they are unrecoverable after depletion of the dc batteries. Depletion time was taken to be 12 hours. Please clarify the consistency of the assumptions used for battery depletion time in the DCPRA (2 hours or 12 hours) and its impact on accident sequences where battery depletion is important (operation of turbine driven AFW pump, etc.).

RESPONSE TO COMMENT:

The analysis of DC power unavailability includes two possible boundary conditions: AC power unavailable and AC power available. For the case of AC power unavailable, the realistic success criteria for DC power top events should be the successful operation of a battery to provide DC power for the battery lifetime. When AC power is available, either the battery charger or the battery can supply DC power for the battery lifetime. Since the mission time (i.e., 24 hours) established for the DCPRA study is longer than the battery lifetime, the battery charger must also be available for a period of time equal to the difference between the mission time and battery lifetime. In addition, during the time that operations of most DC transient loads are taking place, the battery is assumed necessary to provide sufficient DC power capacity to accommodate the transient current. Therefore, the unavailability of DC power can be approximately expressed for these two cases as follows:

I. AC power unavailable:

$$U_I = Q_{Bat} + X_{Bat} * T_{BL}$$

where:

$Q_{Bat}$ is the battery demand failure rate

$X_{Bat}$ is the battery operation failure rate

$T_{BL}$ is the battery lifetime

II. AC power available:

$$U_{II} = Q_{Bat} + X_{Bat} * T_{TR} + (X_{Bat} * T_{BL}) * (X_{Chg} * T_{BL}) + X_{Chg} * (T_{24} - T_{BL})$$

where:

$X_{Chg}$ is the battery charger operation failure rate

$T_{TR}$ is the assumed duration of transient DC load operation

$T_{24}$ is mission time (24 hours)

For the convenience of the analysis, it was decided to use a bounding expression to envelope the top event unavailability for both cases. Because the battery charger failure rate is almost an order of magnitude higher than the battery failure rate, the bounding equation was chosen to be:

$$U = Q_{Bat} + X_{Bat} * T_{TR} + X_{Chg} * T_{24}$$

Finally, a conservative value of 2 hours was used for $T_{TR}$ in the unavailability modeling of the DC power top events. This equation was conservatively used to represent the DC power unavailability for all cases.

For scenarios in which DC power is successful but AC power is lost, credit is only given for electric power recovery within the 12-hour battery depletion time. This treatment of the DC power unavailability is conservative in the estimate of core damage frequency, especially when battery depletion is important.

<u>BNL COMMENT 4</u>:

> The unavailability model does not reflect the following potential operator failure that may occur when given a LOOP; the battery chargers are automatically tripped and procedure requires that the battery chargers be manually restored.

RESPONSE TO COMMENT:

The battery chargers 11, 12, 121, 131, and 132 at Diablo Canyon do not automatically trip on loss of offsite power. Therefore, there is no potential for the operator error discussed above.

BNL COMMENT 5:

> The analysis is tacit about a potential loss of air to the drawout breakers on distribution panels 11 and 12.

RESPONSE TO COMMENT:

Success of the DC power top events (DF, DG, and DH) requires the respective DC buses and the associated distribution panels to remain energized for 24 hours. For DC distribution panels 11 and 12 to remain energized, drawout breakers 72-1102 and 72-1202 must remain in the closed position. These breakers are normally aligned in the closed position. They are electro-mechanical devices which do not require compressed air for operation (e.g., opening, closing, or arc suppression). As such, loss of air is not applicable to the unavailability modeling of the DC power top events.

## 2.3 COMMENTS ON THE VITAL AC SYSTEM - UNIT 1

BNL COMMENT 1:

> The system analysis stated that the 4.16kV switchgear room needs cooling (heavy equipment being used during normal operation) via cooling fans. The unavailability modelling of the system assumes that the 4.16kV switchgear room does not require ventilation. The analysis seems to be contradictory.

RESPONSE TO COMMENT:

Each 4kV switchgear room is equipped with a cooling supply fan. No exhaust fan is provided. However, the floor/ceiling opening provides very good

cooling air flow. The equipment in the 4kV switchgear rooms generate little heat (the largest heat load would be the 4.16kV/480 V transformer which is located in the 480 V switchgear rooms); therefore, 4.16kV switchgear ventilation is not necessary and in practice, the room temperature without ventilation has been observed to be 72$^{o}$ F, which is well below the switchgear thermal fragility limit. Therefore, ventilation for these rooms was assumed to be not required.

BNL COMMENT 2:

> The 480V switchgear room ventilation was considered so important that a top event was dedicated to it (Top Event SV; not reviewed). Why then was the "failure of fire damper" in the 480V switchgear room (a fairly infrequent event) included in the top event analysis of the vital AC system and not in that of the switchgear room?

RESPONSE TO COMMENT:

The 480V switchgear ventilation system provides cooling air flow for all three 480V switchgear rooms. Failure of this system was assumed to incapacitate the equipment contained in all three 480V switchgear rooms. Spurious closure of a switchgear room fire damper does not disable equipment in all three rooms. It only affects ventilation to one switchgear room. Since three top events (one for each train) were modeled for the vital AC system, these fire dampers were included in these top events to correctly reflect that failure of a fire damper will only impact a single AC train.

BNL COMMENT 3:

> Manual operation of malfunctioning 4.16kV feeder breakers was considered as an acceptable recovery action for top events AF, AG, AH, as well as SF, SG, and SH, in the case of all initiators except large and medium LOCAs. Why was it not applied for the 12kV breakers, i.e., for top event NV?

RESPONSE TO COMMENT:

Top event NV was established to track the status of power supply to the reactor coolant pumps. Failure of this top event only affects the reactor coolant pumps which are not required to continue to operate in response to an initiating event. Failure of top event NV has insignificant impact on the mitigation of initiating events occurrence. Therefore, recovery of breaker failures included in top event NV was not considered to be important and thus was not modeled in DCPRA.

BNL COMMENT 4:

> The failures of the hardware (relays, electronics) associated with the permissives (allowing/disallowing power source transfer) were not modelled. Why?

RESPONSE TO COMMENT:

The control circuits and devices associated with the permissives for power source transfer were included in the boundary for those circuit breakers that must operate (open or close) to achieve bus transfer. Malfunctioning of these devices resulting in failures of breaker operation for power source transfer was included in the breaker failures in the DCPRA data analysis task. As such, vital AC power top events do not model the permissive devices as separate components.

## 2.4 COMMENTS ON THE VITAL AC/DC SYSTEM - UNIT 2

> The Unit 2 AC/DC system unavailability is modelled in the DCPRA as a combination of the vital AC and DC systems of Unit 1 with the only difference that Unit 2 components are substituted for the Unit 1 components. This approach compels BNL:
>
> 1. To reiterate all the observations made in the previous two sections (Sections 3.2.2 and 3.2.3) also with respect to the Unit 2 vital ac/dc system, and

2. To disagree on the assumptions made in the analysis about maintenance, tests, and human failure contributions to the total unavailability. This latter item is detailed below.

The DCPRA apparently overlooked the fact that, throughout a time period while Unit 1 is in operation, Unit 2 will have one refueling (and/or several cold shutdowns). During a refueling (or cold shutdowns), the components of the Unit 2 vital ac/dc system will be subjected to longer lasting scheduled maintenance tests required by Technical Specifications, etc., which can render the various trains of the vital ac/dc system unavailable for protracted periods of time. The contributions due to these scheduled maintenance/test activities to the total unavailability of the vital ac/dc systems is believed to be not negligible. BNL assumes that each Unit 2 ac/dc train will be unavailable at least for ten days as a minimum between consecutive refuelings of Unit 1 (1.5 years); therefore, the lower limit of the unavailability of the top events BF, BG, and BH would be:

$$\frac{10}{1.5 \times 365} = 1.862\text{-}2$$

This value alone is an order of magnitude higher than the majority of conditional split fractions (BF1 through BH2) listed in Table 2.3d.

According to BNL, the conditional split fractions associated with the top events BF, BG, and BH should be requantified and their impact to the total core damage frequency should be reevaluated before the truncation of the non-leading sequences (i.e., for the non-reduced unavailability model of the unit).

It is not clear to the reviewers why the seismic contributions were neglected from the Unit 2 vital ac/dc systems unavailability analysis, while they were considered rather important for the vital ac/dc systems of Unit 1. The subject of the unavailability analysis of Unit 2 ac/dc system was not to provide power recovery to Unit 1 by crosstying buses but, given a loss of outside power, to provide power to the Unit 2 vital loads, particularly to the auxiliary saltwater system. Seismic events can potentially disrupt the power supplies to this system.

Assuming longer equipment outages and seismic contributions to BF, BG, and BH, it seems that new sequences (due to a coupling of seismic and non-seismic failures at Unit 1 and Unit 2) will appear and contribute to the total core damage frequency. This expectation is based on the similar conditions that arise when the swing diesel is in overhaul or the train associated with BF is unavailable. These types of new sequences were neatly calculated in the PG&E's diesel generator allowed outage time study. A similar calculation here would also be beneficial.

RESPONSE TO COMMENTS:

The responses to comments in Sections 2.2 and 2.3 are equally applicable to the models developed for the vital AC/DC system for Unit 2.

The effect of Unit 2 scheduled maintenance activities for the diesel generators (during refueling outage) was evaluated and discussed in the Response to BNL Letter Report-07/Rev.1: Diesel Generator and Diesel Fuel Transfer Systems, January 1990, submitted in PG&E Letter DCL-90-021.

The unavailability due to scheduled maintenance of the Unit 2 vital buses is of minor importance. These maintenance activities are scheduled to correspond with other required maintenance activities; for example, if maintenance is performed on one train of the auxiliary saltwater system, the maintenance of the Unit 2 vital bus which powers that ASW train would be performed at the same time; in this way, system clearances may be coordinated and overall outage duration minimized. Since the Unit 2 vital buses are primarily modeled to determine the availability of power to the Unit 2 ASW system, and since scheduled maintenance activities are done on a train wise basis, the effect of Unit 2 vital bus unavailability is captured in the scheduled maintenance unavailability of the Unit 2 ASW system; the effect of this added unavailability was evaluated in the Response to BNL Letter Report-04/Rev.1: Auxiliary Saltwater System, June 1989, submitted in PG&E Letter DCL-89-160.

Seismic failures of the Unit 2 vital AC/DC systems analysis was not neglected. Seismic failures of like equipment pertaining to redundant AC or

DC power trains were treated with complete dependence in the quantification of plant model for seismic initiating events. If the first Unit 1 AC power top event fails due to seismic failures, all of the subsequent Unit 1 AC power top events were assumed to be guaranteed failure. Furthermore, core damage was assumed to occur due to the complete loss of AC on Unit 1; the Unit 2 AC/DC power top events were therefore not questioned. This is equivalent to an analysis in which seismic failures are also included in top events BF, BG, and BH and these top events are assumed to fail when Unit 1 AC power fails seismically (because of complete dependence). Therefore, seismic failures of Unit 2 vital AC/DC systems were effectively accounted for in the DCPRA.

## 2.5 COMMENTS ON THE INSTRUMENT AC SYSTEM

To be addressed in a later report.

## 2.6 COMMENTS ON THE LOOP INITIATOR

> In a very recent article in the EPRI Journal, there is a discussion concerning solar magnetic storms. This subject would not normally be a concern in a PRA; however, the article includes a map which shows all of California within a "high-potential" zone and includes a discussion with specific examples that demonstrates a real threat to power grid integrity. Based upon this article, BNL believes that PG&E should evaluate whether or not this phenomenon would have an impact on the derivation of their LOOP initiator frequency.

RESPONSE TO COMMENT:

The frequency of LOOP initiating event was calculated in DCPRA using the two-stage Bayesian update approach. Loss of offsite power event data from most nuclear plant sites (except those that have been decommissioned) were collected to perform the first stage Bayesian analysis. This LOOP event data base covers a period starting from October 1959 (i.e., the commercial operation of Dresden) through the end of 1983. This is over a span of approximately two solar magnetic disturbance (SMD) cycles. Furthermore, many nuclear plants were already in commercial operation by the time SMD peaked

around 1980. As such, ample data regarding SMD related LOOP events should be included in the experience data. However, in this industry-wide database, no loss of offsite power event was caused by SMD. This may be an indication that SMD effects on the transmission network connecting to the U. S. nuclear plants are less severe than that in certain Canadian areas. In addition, the latitude of Diablo Canyon is lower than many other U. S. nuclear plants; this should make the transmission network around Diablo Canyon less susceptible to solar magnetic storms.

In any event, the Bayesian data analysis approach, in principle, accounts for all factors that may affect the frequency of LOOP initiating event. If the effect is sufficiently strong, it would have exhibited itself as one or more actual events in the database. As a result, the calculated frequency would be higher to reflect this. If the effect is insignificant, it is usually indicated by low frequency or no occurrence of the event. Consequently, the Bayesian updated frequency would be lower. Since the generic data used in the DCPRA covers about two cycles of SMD, the frequency of LOOP initiating events calculated for Diablo Canyon accounts for the possibility of transmission network failure caused by SMD.

# ENCLOSURE 2

## CLARIFYING INFORMATION REGARDING DEVELOPEMENT OF THE DIABLO CANYON PRA

REGARDING DEVELOPMENT OF

ENCLOSURE 2
CLARIFYING INFORMATION ~~ON~~ THE DIABLO CANYON PRA

The following information is being provided to clarify information submitted previously to the NRC:

1. Clarification of the Development of the Non-Seismic Dominant Sequence Model.

2. Clarification of the Development of the Seismic Model

3. Derivation of Table 6-59 of the Long Term Seismic Program Final Report.

4. Clarification and Corrections to Table 6-47 of the Long Term Seismic Program Final Report.

Non-Seismic Dominant Sequence Model Development

The dominant sequence model is a compilation of the highest frequency sequences which lead to core damage. These sequences were compiled by the computer code SQLINK. SQLINK was used to link the support model sequences with the frontline model sequences and generate a listing of core damage sequences. A cutoff of 1.0E-6 was used in SQLINK; this cutoff operates as follows: sequences with frequency greater than 1.0E-6 times the total core damage frequency (prior to recovery) were retained by SQLINK for inclusion in the dominant sequence model. The highest frequency sequence excluded by SQLINK due to this cutoff would be approximately 6.0E-10.

Additionally, the maximum number of sequences which can be processed by SQLINK is 1999. The DCPRA quantification reached this limit; due to reaching this limit the highest frequency sequence excluded from the SQLINK output was approximately 8.0E-8.

Neither the cutoff nor the storage limitation affected the composition of the dominant sequence model. The dominant sequence model contains the first 420 sequences contained in the SQLINK output. These 420 sequences total 88.1% of the total non-seismic core damage frequency. The largest sequence excluded from the dominant sequence model, but contained in the SQLINK output, had a frequency of 1.1E-7 (i.e., sequence 421).

The dominant sequence model was developed by writing the sequences in the form of equations; each sequence is written as the product of an initiating event and the failed split fractions. This process was automated by using the computer code RMODEL; however, split fractions for successful top events were not automatically included in these equations. The most important success terms were manually added to the dominant sequence model where the rare event approximation was not appropriate. The dominant sequence model was then requantified using point estimates for initiating events and split fractions. The resulting value, from the 420 sequences, did not equal the total core damage frequency before any truncation. The 420 sequence total was actually higher. The result from the 420 sequences differed because of the missing success terms (those not included in the sequences) and because of the limited number of sequences included in the

model; this indicated that the absence of success terms in the dominant sequence model out weighed the total frequency of the sequences below the 420th. Therefore, to make the total frequency from the dominant sequence model match the total frequency from the SQLINK output, a ratio was applied to the dominant sequence model total.

Finally, selected sequences in the dominant sequence model were multiplied by recovery factors; the recovery factors were described previously in PG&E letter number DCL-89-283 dated November 13, 1989.

In summary, the most important cutoff or limitation with respect to the development of the non-seismic dominant sequence model is the limit of 420 sequences. Sequences with frequency as high as 1.0E-7 are not explicitly included in the dominant sequence model. In principle, however, the frequency of these sequences is included because the total core damage frequency from the dominant sequence model prior to recovery was adjusted to match the total core damage frequency without any truncation.

## Seismic Model Development

The risk due to seismic events at Diablo Canyon was quantified using the same linked event tree approach as was used for the internal events. The range of possible earthquakes, in terms of peak ground acceleration, was discretized and modeled as six separate initiating events. The six seismic initiating event categories were quantified using point estimates, and the dominant seismic sequences were generated by SQLINK.

To quantify the uncertainty for the total seismic core damage contribution the computer code SEIS4 was used. The dominant seismic core damage sequences were translated into core damage boolean equations (submitted in PG&E Letter No. DCL-89-283 dated November 13, 1989). This boolean, which is a function of component fragilities, non-seismic failures and the seismic hazard curve, was then quantified using the computer code SEIS4. SEIS4 uses discrete probability arithmetic to propagate the uncertainty in the hazard curves and the equipment fragilities.

is anything missing here? or adjectival use??

The seismic boolean logic model was developed based on inspection of the 150 highest frequency seismic core damage sequences. In addition to the top 150 sequences, many other lower frequency sequences are also included in the boolean; this is because each sequence in SQLINK represents core damage caused by a seismic event of a particular magnitude, and corresponds to one of the six seismic initiating event categories. When this sequence is added to the SEIS4 boolean, it represents the same core damage sequence for all six seismic initiating events. Therefore, explicitly modeling the top 150 sequences in the SEIS4 boolean, implicitly includes many more sequences of lower frequency.

The result of the SEIS4 quantification is a distribution representing the uncertainty in the seismic core damage frequency. This distribution was then added to the non-seismic dominant sequence model.

## Development of Table 6-59 of the Long Term Seismic Program Final Report

The core damage frequencies and percent contribution for the internal initiating event categories listed in Table 6-59 were calculated using the DCPRA non-seismic dominant sequence model. The core damage contribution for each initiator was calculated as the difference between the total core damage frequency and the core damage frequency calculated with the initiating event of interest set equal to zero. All calculations used to generate the core damage frequencies in Table 6-59 were point estimate quantifications.

For three of the initiating events in Table 6-59, the core damage frequency was calculated using a different method; for the initiating events Closure of all MSIV's, Main steam relief valve opening, and Core power excursion, there were no core damage sequences included in the dominant sequence model due to the low frequency of sequences involving these events. Therefore, the dominant sequence model could not be used directly to calculate the values in Table 6-59.

The conditional core damage frequency for these three initiators was assumed to be equal to the conditional core damage frequency for reactor trip initiating event after recovery; this assumption was based on the fact that the quantification of the event tree models for these initiating events are similar. The conditional core damage frequency for the reactor trip event was calculated by dividing the core damage frequency for reactor trip initiating event, in Table 6-59, by the reactor trip initiating event frequency. This conditional core damage frequency was then multiplied by the initiating event frequencies for Closure of all MSIV's, Main steam relief valve opening, and Core power excursion to calculate the corresponding core damage frequencies in Table 6-59.

## Clarification of Table 6-47 of the Long Term Seismic Program Final Report

Table 6-47 of the Long Term Seismic Program Final Report presents the fire scenarios evaluated for risk quantification. The values in this table differ from those used in the quantification of the dominant sequence model and the data reflected in PG&E Letter No. DCL-88-238 dated October 10, 1988. There are two reasons for the differences: the first is that the values in Table 6-47 are point estimates while those used in the dominant sequence model are the mean values from the results of Monte Carlo simulations; the second is that the values listed for the scenarios in category FS1 are incorrect; these values are the screening values before incorporation of the fire geometry and severity factors. The final point estimate results from the fire analysis section of the DCPRA are presented in Table F.3-4 which is Enclosure 3 of this submittal. The results in Table F.3-4 supersede the values presented in Table 6-47.

# ENCLOSURE 3

## PRA, TABLE F.3-4

## FIRE SCENARIOS FOR RISK QUANTIFICATION

TABLE F.3-4 FIRE SCENARIOS FOR RISK QUANTIFICATION



| Scenario Designation | Scenario Impact on Plant Equipment | Estimate Frequency | Designator for Support Model Event Tree |
|---|---|---|---|
| 3-Q-2-FS-1 | Loss of Both Motor-Driven Auxiliary Feedwater Pumps | 1.2-4 | FS1 |
| 14-A-FS-1 | Loss of Both Motor-Driven Auxiliary Feedwater Pumps | 2.0-5 | FS1 |
| 14-A-104-FS-1 | Loss of Both Motor-Driven Auxiliary Feedwater Pumps | 3.0-5 | FS1 |
| 3-BB-100-FS-1 | Loss of Both Motor-Driven Auxiliary Feedwater Pumps | 2.1-6 | FS1 |
| 6-A-5-FS-1 | Loss of Both Motor-Driven Auxiliary Feedwater Pumps | 8.7-6 | FS1 |
| 5-A-4-FS-1A | Loss of Both Motor-Driven Auxiliary Feedwater Pumps | 4.0-6 | FS1 |
| 5-3-FS-1 | Loss of Both Motor-Driven Auxiliary Feedwater Pumps | 3.5-5 | FS1 |
| 12-A-FS-1 | Failure to Start Both Motor-Driven Auxiliary Feedwater Pumps | 1.7-5 | |
| 5-A-4-FS-1B | Loss of Both Motor-Driven Auxiliary Feedwater Pumps Plus All 10% Dump Valves | 2.0-6 | FS1 |
| | Total Frequency of FS1 | 2.39-4 | |
| 3-H-1-FS-1 | Loss of All Three Charging Pumps | 2.0-3 | FS2 |
| 3-C-FS-5 | Loss of All Charging Pumps | 4.0-4 | FS2 |
| 3-AA-FS-1 | Loss of All Charging Pumps and Loss of Two MSIVs | 3.8-5 | FS2 |
| 3-J-2-FS-1A | Loss of All Charging Pumps | 4.5-4 | FS2 |
| | Total Frequency of FS2 | 2.89-3 | |
| 3-J-2-FS-1B | Loss of All CCW Pumps | 3.05-6 | FS3 |
| 8-B-3-FS-1 | Loss of Control Room Venting Failing All Three Fans | 2.0-3 | FS4 |
| 4-A-FS-1B | Loss of Both ASW Pumps | 3.0-5 | FS5 |
| 4-B-FS-1 | Loss of Both ASW Pumps | 2.82-6 | FS5 |
| 14-E-FS-1 | Loss of All ASW and CCW | 1.0-5 | FS5 |
| | Total Frequency of FS5 | 4.28-5 | |

NOTE: Exponential notation is indicated in abbreviated form; i.e., 4.0-4 = $4.0 \times 10^{-4}$.

1579P062788:2

TABLE F.3-4 (continued)



| Scenario Designation | Scenario Description | Estimate Frequency | Designator for Support Model Event Tree |
|---|---|---|---|
| 4-A-FS-1A | Loss of Buses F and G | 7.5-6 | FS6 |
| 5-A-1-FS-3 | Loss of Buses F and G | 1.0-6 | FS6 |
| 5-A-2-FS-3 | Loss of Buses F and G | 1.0-6 | FS6 |
| 12-A-FS-2 | Loss of Buses F and G | 1.3-7 | FS6 |
| 12-B-FS-2 | Loss of Buses F and G | 1.3-7 | FS6 |
| 13-A-FS-3 | Loss of Two Buses (F and G) | 6.0-6 | FS6 |
| 13-B-FS-2 | Loss of Two Buses (F and G) | 6.0-6 | FS6 |
| | Total Frequency of FS6 | 2.18-5 | |
| 5-A-2-FS-4 | Loss of Buses G and H | 1.0-6 | FS7 |
| 5-A-3-FS-3 | Loss of Buses G and H | 1.0-6 | FS7 |
| 13-C-FS-2 | Loss of Two Buses (G and H) | 6.0-6 | FS7 |
| 13-B-FS-3 | Loss of Two Buses (G and H) | 6.0-6 | FS7 |
| | Total Frequency of FS7 | 1.4-5 | |
| 14-D-FS-3 | Delayed Failure of All Three Buses F, G, and H | 5.0-6 | FS8 |

NOTE: Exponential notation is indicated in abbreviated form; i.e., 7.5-6 = $7.5 \times 10^{-6}$.