BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Implementing Senate Bill 846	)	
Concerning Potential Extension of	)	
Diablo Canyon Power Plant	)	Rulemaking 23-01-007
Operations.	)	
______________________________________	)	

**ALLIANCE FOR NUCLEAR RESPONSIBILITY'S
OPENING COMMENTS STRUCTURED AS TESTIMONY
ON STATUTORY INTERPRETATION, ISSUES OF POLICY, AND
CERTAIN REPORTS IN THE RECORD OF THIS PROCEEDING**

ATTACHMENTS VOLUME 2: EXHIBITS K THRU Z3

PUBLIC VERSION

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EXHIBIT K

Application: 10-01-022
(U 39 E)
Exhibit No.: ____________________
Date: April 12, 2010
Witness: Various

PACIFIC GAS AND ELECTRIC COMPANY

DIABLO CANYON POWER PLANT LICENSE RENEWAL

SUPPLEMENTAL REPORTS RECOMMENDED BY THE CALIFORNIA ENERGY COMMISSION

SEISMIC ASSESSMENT OF DIABLO CANYON POWER PLANT NON-SAFETY RELATED STRUCTURES, SYSTEMS, AND COMPONENTS

March 2010

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EXECUTIVE SUMMARY

California State Assembly Bill AB 1632 addresses the potential vulnerability of power plant buildings and structures at Diablo Canyon Power Plant (DCPP) due to a seismic event. AB 1632 requires the California Energy Commission (CEC) to assess key policy and planning issues affecting the future role of nuclear power plants in the State. The CEC issued "An Assessment of California's Nuclear Power Plants: AB 1632 Report" in November 2008. The report noted the following: "The non-safety related systems, structures, and components (SSCs) of the plants are most vulnerable to damage from earthquakes. The seismic-related reliability risk of non-safety-related SSCs is not well understood in large part because the nuclear industry and the NRC historically have focused on safety-related SSCs. The electrical switchyards of the plants could be particularly vulnerable to earthquake damage because the equipment configuration and the dispersed and interconnected nature of the switchyard facilities make them vulnerable to ground motion and subsidence. For Diablo Canyon, the switchyard through which the plant's energy is transmitted (500 kV) and the alternate AC source switchyard (230 kV) are located on deep fill and therefore are particularly vulnerable to damage. The 500 kV switchyard has had some seismic upgrades to improve its robustness."

The California Energy Commission recommended PG&E to evaluate whether there are any additional preplanning or mitigation steps that the utility could take for the power plant that could minimize plant outage times following a major seismic event. The Report recommended the following:

- Investigate and report their findings on the extent to which their respective plants' non-safety-related systems, structures, and components (SSCs) comply with current building codes and seismic design standards for non-nuclear power plants.

- Evaluate the seismic vulnerability and reliability implications for the nuclear plants' non-safety-related SSCs from changes to seismic design standards that have occurred since the plants were designed and built. Such an analysis should consider the IAEA (International Atomic Energy Agency) Standards and Safety Reports and any retrofits that the plant owners may have undertaken and should focus on those plant systems or components whose failure could lead to extended outages.

- Describe plant component repair/replacement plans including initial estimates of time needed to repair or replace key plant systems or components that could cause a prolonged plant outage as a result of earthquake damage. This should consider the fragility of components both in their operating positions and when relocated for refueling or plant maintenance.

- As part of their license renewal feasibility analyses for the CPUC, PG&E and SCE should summarize the lessons learned from the KKNPP plant experience in response to the 2007 earthquake and any implications for Diablo Canyon and SONGS, including whether any additional pre-planning or mitigation could minimize plant outage times following a major seismic event .

This report provides an assessment of the probability of a prolonged post-earthquake outage at DCPP due to damage to non-safety related structures, systems, and components (SSCs) and evaluates additional preplanning or mitigation steps to minimize a prolonged outage following a major seismic event.

All of the SSCs at DCPP are designed to the appropriate seismic criteria. All SSCs that are required for mitigation of an accident or for safe shutdown of the plant are designed to the Design Earthquake (DE), and Double Design Earthquake (DDE) criteria, and are evaluated to withstand a M7.5 earthquake on the Hosgri fault. These SSCs are categorized as safety related and meet the Seismic Category I criteria. The SSCs that are required to support operation of the plant, mostly balance of plant SSCs, are designed to less stringent seismic performance criteria. The balance of plant SSCs are categorized as non-safety related Design Class II components. Operating performance of these Design Class II SSCs may be compromised due to a significant earthquake and result in a prolonged shutdown of the plant for over 120 days. Nuclear power plants have periodic major outages to replace components. One hundred twenty days was chosen as the time limit for an extended major outage following a seismic event since this period was longer than the routine refueling and component replacement outages and outages longer than 120 days may adversely affect the power grid.

Several standards are used in the design of Design Class II SSCs, including the Uniform Building Code (UBC) and the California Building Code (CBC) for equipment anchorage, equipment support structures, and building structures not required for safe shutdown of DCPP. The use of building codes is generally not relevant to assess the function and operation of equipment after an earthquake. The codes are intended primarily to safeguard against major failures and loss of life.

Essentially the only effect that the evolution of building design codes over the years has had on the seismic durability of equipment is through upgrades in the loads for which equipment anchorage would be designed. While anchorage of equipment is one factor in seismic durability, there are other factors that would not be affected by changes in the building codes over a 40 year period. As a general observation from the EPRI database of historical equipment earthquake performance, perhaps 20% of the instances of equipment damage in past earthquakes could be attributed to lack of anchorage or inadequate anchorage. Remaining causes of damage would usually not have been affected by building code changes. Thus improvements in building design codes would have only marginal effect on improvement in the seismic durability of equipment.

Design Class II SSCs are generally not mathematically computer modeled or shaker table tested to determine the effects of earthquakes because of the high cost of the analysis and testing. Instead, estimating the effects of earthquake ground shaking relies primarily on the historical record for the particular equipment in past earthquakes. The primary source of this historical information is the database of earthquake experience compiled from 1971 to present for the Electric Power Research Institute (EPRI). Nonsafety-related buildings that are essential for continued operations at DCPP were assessed using building type specific fragility curves from the program HAZUS.

For qualification of Design Class 1 equipment, DCPP employs seismic qualification methods that conform to Regulatory Guide 1.100, Revision 1, "Seismic Qualification of Electrical Equipment for Nuclear Power Plants", August 1977, and IEEE Standard 344-1975, "IEEE Recommended Practice for Seismic Qualification of Class IE Equipment for Nuclear Power Generating Stations". Since the safety related SSCs are designed to the NRC accepted seismic design criteria; they will not need to be evaluated any further. Similarly, the power block buildings with the exception of some interior walls, are also designed to the NRC accepted seismic design criteria, they will not need to be evaluated any further.

This report provides an assessment of the probabilities of damage to the Design Class II SSCs and provides recommendations to minimize the outage time.

Using the EPRI Earthquake Database as a basis to determine the probability of damage to power plant SSCs, and based on observations through walk down of DCPP SSCs, the conclusions are summarized as follow:

- As a general rule power plants survive earthquakes with minor damage, typically including only a few items that require repair. Restoration of operation can usually be accomplished within hours or days. The EPRI Database includes post-earthquake investigations of 39 power plant sites, experiencing peak ground acceleration from 0.15g to 0.50g. Of these 39 power plants, all but five were back in operation within two or three days of their earthquake. Only two power plants remained off line for periods of months, both cases due to serious damage from soil liquefaction, a risk not applicable to the DCPP site. See Attachment C for the summary of the earthquake performance of steam power plants investigated for the Electric Power Research Institute.
- The primary causes of serious damage to power plants can be generally summarized as follows:
  1. Ground settlement resulting in damage to buried utility lines, offsets in foundations and misalignment in rotating machinery.
  2. Damage to high voltage switchyards primarily due to collapse of brittle ceramic insulators or failure of anchorage in large-mass equipment such as circuit breakers or transformers.
  3. Damage to large steel storage tanks, either by failure of seams at the tank-base interface or failure of piping attachments due to tank rocking or shifting.
  4. Differential displacement between adjoining structures or equipment supported on independent foundations.
  5. Impact damage due to sway of suspended structures such as tower-supported steam boilers.
  6. Damage to bearings in large rotating equipment due to loss of lube oil pressure.
- Most common causes of serious damage to power plants in past earthquakes, such as soil liquefaction or collapse of live tank high voltage circuit breakers would not apply to the DCPP site. Backfill operations were carefully controlled to ensure stability and safety and conformed to the standards of ASTM D1557. Earthquake loading following periods of prolonged precipitation will not produce any significant slope failure that can impact Design Class I structures and equipment. Potential slope failures under such conditions will not adversely impact other important facilities, including the raw water reservoirs, the 230 kV and 500 kV switchyards, and the intake and discharge structures.
- The eight categories of balance-of-plant equipment with potential long replacement times (defined as greater than 120 days) have probabilities of serious damage due to earthquake on the order of 1 x 10EE-4 per item per year (about one chance in 10,000 per year). In the rare instances where equipment damage has occurred, it is almost always to single equipment items. Equipment

redundancy, where there are two or more items sufficient to perform the design function, would therefore make the probability of loss-of-the-required-service much lower than the probability of individual equipment damage.

- The Class II buildings and structures were evaluated for probability of reaching the complete damage state. The annualized probability of structural damage that will cause unacceptable outages is predicted to be 1.25 x 10EE-3 or less for each of the buildings. For newer construction designed to criteria for structures of standard importance using the current building code, it is generally less likely to experience an unacceptable outage, but the difference in probability of reaching the complete damage state between the DCPP Class II buildings and the newer construction is not significant.
- Shop buildings are determined as not required to support plant operation. Any repair work that requires machining or welding to support returning the plant to operable status can be done offsite.
- For an earthquake with a peak ground acceleration value higher than 0.2 g at the site, the seismic load may exceed the allowable load of the main turbine thrust bearings. The turbine thrust bearings may not be able to prevent damage to the turbine under a severe earthquake. The recommendation is to pursue a thrust bearing capacity evaluation.
- There may be minor issues to supply replacement parts to support plant restart, but not to the extent of preventing a 120-day restart schedule.

STUDY APPROACH

A Team was assembled to assess the probability of a prolonged post-earthquake outage at DCPP. The team consisted of Enercon Services, Inc., PG&E, Simpson Gumpertz & Heger (SGH), and consultants Sam Swan and Dave Miklush.

Enercon Services, Inc., founded in 1983, is an engineering, environmental, technical and management services firm with a wealth of engineering design and project management experience in the nuclear power industry, including extensive design change experience at Diablo Canyon.

Simpson Gumpertz & Heger (SGH) is an engineering firm that designs, investigates, and rehabilitates structures and building enclosures. Their work encompasses building, transportation engineering, water-wastewater, and nuclear power plants throughout the U.S. and over twenty foreign countries.

Sam Swan (Risk Assessment, LLC) is a consultant in earthquake risk assessment & mitigation, fault-tree modeling, seismic fragility assessment and seismic qualification.

Dave Miklush was the former Director of DCPP Engineering and now a consultant on systems and components with extensive knowledge on the history and design of DCPP.

As an initial step to the study, the Team defined the term "prolonged post-earthquake outage" as 120 days. Nuclear power plants have periodic major outages to replace components. One hundred and twenty days was chosen as the time limit for an extended major outage following a seismic event since this period was longer than the routine refueling and component replacement outages and outages longer than 120 days may adversely affect the power grid.

The Team developed a seismic hazard curve for the DCPP site, i.e., the decreasing probability of exceedance per year for increasing intensity of ground shaking. Then a comparison was made of the seismic design criteria based on the original Uniform Building Code (UBC) when the plant was built (1968), and the current California Building Code (CBC) criteria (2007). These criteria were used to assess the improvement, if any, of the seismic durability for the Design Class II SSCs, if they were designed to the 2007 CBC.

To further evaluate the seismic impact, the inventory of the Design Class II SSCs (excluding the assessed Class II buildings) was assembled in a spread sheet format as presented in Appendix 2. This inventory was screened to identify items that meet the following criteria: a) items not seismically designed to nuclear safety were excluded, b) items not required to support plant operation were excluded, and c) if the item were damaged by an earthquake, and can be repaired or replaced within 120 days, it is excluded. The above screening was done without consideration of whether or not the item would actually be damaged by an earthquake. In assessing if the item could be repaired or replaced within 120 days category, some items were conservatively screened in with a “Yes/No” answer with a note “Depending on the extent of the damage”. This generally means that if there were only a few of the items damaged the repair/replacement time frame would be less than 120 days; but if the majority of the items were damaged, then the repair/replacement time frame could be more than 120 days, due to unavailability of the components or shortage of man power.

The screened items were then categorized into generic types of similar components. This screening process reduced the list to a manageable number of generic types that could credibly result in a prolonged post-earthquake outage. A site walk down was performed to further assess the robustness of the installed conditions of these items.

The generic types are assessed through past earthquake experience with similar equipment based on estimates of seismic fragility (damage probability) of the generic type. The seismic fragility determination is based on statistics collected from post-earthquake investigations sponsored by Electric Power Research Institute (EPRI). The results are presented in Appendix 3. Using the EPRI database of historical performance of comparable earthquakes was a much better assessment methodology than code comparison as the UBC and CBC do not directly assess function and operability during and after an earthquake. Furthermore, the historical data from 1971 to present allows performance assessment of SSCs that were designed to older codes.

Various Class II buildings and structures are evaluated separately based on convolving HAZUS fragility curves, modified to the appropriate Class II building types at DCPP, with the seismic hazard curves provided by PG&E. This results in the probability on an annual basis of the six Class II buildings being in the complete damage state, which will cause unacceptable outages. The results are presented in Appendix 4.

The main turbine generator thrust bearings were also evaluated separately since they potentially are a major contributor to the risk of a prolonged post-earthquake outage.

SEISMIC DESIGN BASES

At DCPP, All SSCs that are required for mitigation of an accident or for safe shutdown of the plant are designed to the Design Earthquake (DE), and Double Design Earthquake (DDE) criteria, and are evaluated to withstand the HOSGRI earthquake criteria. The Peak Ground Acceleration values for these earthquakes are defined as 0.2 g, 0.4 g and 0.75 g, respectively. [SSER 7, Section 2.5; SSER 4, Section 3.7]

Seismic Qualification for Design Class 1 equipment is based on IEEE Standard 344 and Regulatory Guide 1.100. DCPP employs seismic qualification methods that conform to Regulatory Guide 1.100, Revision 1, "Seismic Qualification of Electrical Equipment for Nuclear Power Plants", August 1977, and IEEE Standard 344-1975, "IEEE Recommended Practice for Seismic Qualification of Class IE Equipment for Nuclear Power Generating Stations" [SSER-7, Section 3.10.2].

For those SSCs that are already qualified to the NRC accepted standards, they will not need further assessment for the purpose of this report.

Several standards are used in the design of Design Class II SSCs, including the Uniform Building Code (UBC) and the California Building Code (CBC) for equipment anchorages, equipment support structures, and building structures not required for safe shutdown of DCPP. The use of building codes is generally not relevant to assess the function and operation of equipment after an earthquake. The codes are intended primarily to safeguard against major failures and loss of life.

Design Class II SSCs are in general too complicated to be mathematically modeled in an accurate manner for the effect of earthquake forces. Instead, estimating the effects of earthquake ground shaking relies primarily on the historical record for the particular equipment in past earthquakes. The primary source of this historical information is the database of earthquake experience compiled from 1971 to present for the Electric Power Research Institute (EPRI). Non-safety-related buildings, that are essential for continued operations at DCPP, were assessed using building type specific fragility curves from the program HAZUS.

Peak ground acceleration (PGA) seismic hazard curves for two soil conditions, Vs30 values of 760 m/s and 250 m/s (500 kV and 230kV switchyards) were used to convolve with the EPRI database fragility curves of the equipment categories.

To assess the operability of the turbine thrust bearings, a 500-year return period ground motion parameter (i.e., peak ground acceleration - PGA) was selected from the seismic hazard curve, representative of the site conditions at the turbine building. This PGA value is 0.28g. The 500-year return period (also known as the 1/500 annual probability of being exceeded) was selected as it correlates with California building codes.

BUILDING CODE COMPARISON

Essentially the only effect that the evolution of building design codes over the years has had on the seismic durability of equipment is through upgrades in the loads for which equipment anchorage would be designed. While anchorage of equipment is one factor in seismic durability, there are other factors that would not be affected by changes in the building codes over a 40 year period. As a general observation from the EPRI database of historical equipment earthquake performance, damage to equipment is usually not due to equipment anchorage design. Perhaps 20% of the instances of equipment damage in past earthquakes could be attributed to lack of anchorage or inadequate anchorage. Remaining causes of damage would usually not have been affected by building code changes. Thus improvements in building design codes would have only marginal effect on improvement in the seismic durability of equipment. This marginal effect on seismic durability for equipment resulting from changes in anchorage design is discussed in the sections that follow.

Typical DCPP Equipment Anchorage System Lateral Seismic Forces Through Time

<u>Overview of Prescriptive Lateral Seismic Force Associated with Equipment Anchorage System Qualifications</u>

The prescriptive lateral seismic force (typically designated F_p in various industry codes) applicable for design of equipment anchorage systems is applied at the equipment's center of gravity and is specified in terms of various variables (e.g., V_1, V_2, and V_3) that are multiplied with the equipment's inertial operating weight (typically designated as W_p in various codes). Upon development of values for these various variables for site-specific applications, the prescriptive lateral seismic force becomes a defined function (factor) of its inertial operating weight (i.e., $F_p = [V_1\ V_2\ V_3]\ W_p$).

<u>Original Qualification Era of DCPP Equipment Anchorage Systems</u>

For the original design of DCPP non-safety-related equipment (i.e., Design Class II or III) anchorage systems in 1970s and 1980s, PG&E typically used two approaches for lateral demand loading on anchorage systems as follows:

- Specified that lateral demand loading be in accordance with UBC seismic loading provisions. For example, per Section 2312 (g) of 1976 UBC, the prescriptive formula for F_p is as follows:

  $$F_{p\ 1976\ UBC} = Z\ I\ C_p\ S\ W_p$$

  where

  Z = Numerical coefficient dependent upon the seismic zone for DCPP per UBC Figure No. 1 - Based on UBC Figure No. 1, DCPP is within Seismic Zone 3. Per UBC Section 2312 (a), Z = 0.75 for Seismic Zone 3.

  I = Occupancy Importance Factor as specified in UBC Table No. 23-K - For typical Design Class II and III equipment, I = 1.0.

C_p = Numerical coefficient as specified in UBC Table No. 23-J - Considering DCPP Design Class II and III equipment, Item 4c (equipment not required for life safety systems or for continued operations of essential facilities) of UBC Table No. 23-J is germane and associated $C_p = 0.20$.

S = Numerical coefficient for site-structure resonance - Per UBC Section 2312 (a), a minimum default value, S = 1.0 is specified and S = 1.5 is permitted when characteristic site periods are not available.

A typical value of F_p for DCPP Design Class II or III rigid equipment at grade per 1976 UBC, based on above defined variables and S = 1.0, is as follows:

$$F_{p\ 1976\ UBC} = (0.75)\ (1.0)\ (0.20)\ (1.0)\ W_p = 0.15\ W_p$$

- PG&E specified the design requirement that lateral demand loading be equal to 20 percent of equipment's inertial operating weight, i.e., $F_{P\ PG\&E} = 0.2\ W_p$, for Design Class II and III equipment. (Note that generally PG&E also required that a vertical seismic load component of 13 percent of W_P be simultaneous considered.)

1997 to 2006 Equipment Era Qualification of Anchorage Systems

As reflected in 1997 UBC and 2001 California Building Code (CBC) that is based on 1997 UBC, the prescriptive lateral seismic force requirements for equipment anchorage systems have become more complicated to quantify and more stringent for site locations in classified high seismic zones per these codes. The 1997 UBC requires many more variables to be considered for determination of F_p, including consideration of near-source zones for California, soil profile types, in-structure component amplification and response modification factors and elevation effects of equipment located inside structures. Upon review of *Maps of Known Active Fault Near-Source Zones in California and Adjacent Portions of Nevada*, the Hosgri and Los Osos Faults are germane to the DCPP site.

An example of determination of an F_P value for the anchorage design for a relocated specific Stator Coil Cooling Water (SCCW) pump at DCPP inside the Turbine Building may best demonstrate the more stringent requirements. See Attachment A for details.

As shown on Sheet No. A-4 for a rigid pump, controlling $F_{p\ 1997\ UBC/2001\ CBC} = 0.37\ W_p$ for SCCW pump anchorage system per CBC Equation 32-3. This F_p value is higher than original era values of 0.15 W_p and 0.2 W_p that would be applicable for this SCCW pump.

2007 to Present Equipment Era Anchorage Design

2007 CBC [based on 2006 International Building Code (IBC), with applicable California amendments] is now code of record at DCPP for Design Class II and III equipment anchorage design. This current code has completely revised its nomenclature for seismic variables and requirements. For example, near-source fault zones and related factors are gone and are replaced by seismic acceleration contour maps for short and 1-second periods. The 2007 CBC also references sections to ASCE 7-05 as applicable.

An example of determination of an F_P value for the anchorage design for a relocated specific SCCW pump at DCPP inside the Turbine Building based on 2007 CBC is shown in Attachment B. Attachment B is a mark-up of an existing calculation to cover the SCCW pump inside Turbine Building.

As shown on Sheet Nos. B-2 and B-3 for a rigid pump, controlling $F_{p\ 2007\ CBC} = 0.33\ W_p$ for SCCW pump anchorage system per ASCE Equation 13.3-3. The 2007 CBC F_p value is higher than original era values of $0.15\ W_p$ and $0.2\ W_p$ that would be applicable for this SCCW pump.

Although the design values are higher, it is difficult to make a direct comparison to the earlier codes as the 1997 UBC and the 2007 CBC are based on strength design (i.e., 1.4 factor higher with associated higher acceptance criteria). If the 1997 UBC and the 2007 CBC results were divided by the 1.4 factor for the rigid pump example that does not include elevation effects for its location within building, the results are comparable to the original code, e.g. $0.33W_p / 1.4 = 0.24W_p$. If elevation effects within building and flexible equipment are included, results based on 1997 UBC and 2007 CBC will be significantly higher.

WALKDOWN AND OBSERVATION

A walk down at DCPP was performed on November 16, 2009 to assess the as-installed conditions of the screened items. The following are the participants in the walk down:

Sam Swan – Consultant with Acceptable Risk, LLC responsible for seismic damage assessment of equipment with extensive experience on seismic fragility assessment

Dave Miklush – Former Director of DCPP Engineering, now a consultant on systems and components with extensive knowledge on history and required state of plant SSCs. Dave has 30 years experience at DCPP and has held a Senior Reactor Operators License (retired) with management assignments in Engineering, Maintenance and Operations.

Rich Clark – Consultant with Enercon Services, Inc. responsible for preparing the report. Rich has over 30 years of experience in power plant design and construction, 20 of which were directly related to DCPP.

Francis Ling – Consultant with Enercon Services, Inc. responsible for preparing the report. Francis has over 38 years of Nuclear power plant experience, 20 of which were at DCPP working on Mechanical systems and plant modification.

The following areas in the plant were walked down:

- 230 kV and 500 kV Switchyards
- Raw Water Reservoir area
- Makeup Water and Reverse Osmosis Processing Plant Area and piping
- Large oil-filled transformers
- Administration Building and Plant Support Computers housed in the building
- Simulator and Training Buildings
- Security Building
- Main Warehouse and Storage Racks
- Turbine Building and all major Balance of Plant (BOP) Equipment housed in the building, including Main Turbine and Generators, Feedwater Heaters, Moisture Separator Reheaters, large tanks in the building, Condensate Demineralizers, Main Feedwater Pumps, Condensate Pumps, Condensate Booster Pumps, Service Cooling Water Pumps and Heat Exchangers, Battery Racks and Switchgear, Instrument Air Compressors, Piping and hangers, Electrical Conduits and Cable Trays, Switchgear and Instrument Panels, etc.
- Intake Structure including Traveling Water Screens, Circulating Water Pumps and Screen Wash Pumps.

The following conditions were observed:

- Large tanks and vessels (Feedwater Heaters, Moisture Separator Reheaters, and Main Lube Oil Tanks, etc.) have lateral bracing on the support pedestals
- 120VDC and 250 VDC batteries are installed in racks with cross bracings. The racks are bolted or welded to the floor
- The 480V, 4 kV and 12 kV switchgear and bus cabinets are welded to floor embedment
- Large outside oil-filled transformers (500/25 kV, 230/12 kV, 25/12 kV, 25/4 kV, and 12/4 kV) are welded to the foundation embedment
- In the 500 and 230 kV switchyards, the breakers are all low profile style and the 500 kV breakers have epoxy impregnated bushings rather than porcelain bushings to improve seismic durability
- All piping, conduit, and cable trays are well supported, equivalent to typical power plant practice. This allows an appropriate comparison to the power plants in the EPRI data base.
- Instrument panels are bolted or welded to floor embedment or building structural steel

EARTHQUAKE DAMAGE ASSESSMENT

BOP SSCs

The balance-of-plant equipment in a large steam plant includes hundreds of equipment items, comprising the electrical, mechanical and control systems. A major factor in the post-earthquake restoration time for a large plant like DCPP is the prevalence of damage throughout the inventory of equipment required to operate the plant. In other words, recovery of operation within a reasonable time frame (days or weeks rather than months) might allow repair of a few items, but not hundreds of items. Past earthquake experience with steam plants provides the best indication that earthquake damage is limited and manageable.

The EPRI database includes 114 fossil-fueled steam generating units and 27 gas-to-steam-turbines cogeneration units. The sites investigated following earthquakes represent a broad spectrum in vintage of power plants, ranging in age from the 1930s to plants new at the time of the earthquake, and in size from 10 to 750 megawatts per unit. The investigated plant sites generally experienced ground shaking in the range of 0.20g to 0.60g peak ground acceleration (PGA), from earthquakes ranging from magnitude 5.5 to 8.1.

The time to recover operation of the generating units that were on line at the time of the earthquake is perhaps the best gauge of the level of damage. Generating plants that suffer serious damage would not be able to restart without extensive repairs. As indicated in the EPRI data base, most generating plants recovered from their earthquake within 24 hours. This does not mean that the plant site did not suffer damage; only that damage was sufficiently minor that repairs could be completed in less than a day or deferred until a scheduled maintenance. The one notable exception to this is the KKNPP plant in Japan which experienced a M6.8 earthquake in 2007 with peak ground accelerations exceeding 0.6 g. The station consists of seven 1200 MW Boiling Water Reactor plants and was shutdown for more than a year after the 2007 earthquake. The plant site experienced significant ground subsidence and ground settlement; however, the power block buildings and equipment were relatively undamaged because of adequate foundation designs under the power block buildings. The extended shutdown was due to regulatory issues and public concerns of earthquake design adequacy, not for plant damage.

The most useful information comes from steam plants that suffered the most damage and were delayed the longest in restoration of operations. In the EPRI database, there are six plants that suffered serious damage that required extensive repair and prolonged outages. The primary causes of serious damage to the six power plants can be generally summarized as follows.

1. Ground settlement resulting in damage to buried utility lines, offsets in foundations and misalignment in rotating machinery.

2. Damage to high voltage switchyards primarily due to collapse of brittle ceramic insulators or failure of anchorage in large-mass equipment such as circuit breakers or transformers.

3. Damage to large steel storage tanks, either by failure of seams at the tank-base interface or failure of piping attachments due to tank rocking or shifting.

4. Differential displacement between adjoining structures or equipment supported on independent foundations.

5. Impact damage due to sway of suspended structures such as tower-supported steam boilers.

6. Damage to bearings in large rotating equipment due to loss of lube oil pressure.

The general causes of serious damage listed above do not include all things that may go wrong in a power plant due to earthquake. The list does however indicate the more common causes of prolonged outage that have appeared more than once in the past. From the walk down observations and review of the DCPP installations indicates that only Items 1, 2 and possibly Item 6 would apply to the site.

For Item 1: Soil condition due to ground settlement is not an issue. The DCPP backfill operations were carefully controlled to ensure stability and safety. All engineered backfill was placed in lifts not exceeding 8 inches in loose depth. Yard areas and roads were compacted to 95 percent relative compaction as determined by the method specified in ASM D1557. Rock larger than 8 inches in its largest dimension that would not break down under the compactors was not permitted. This evaluation is documented in FSAR Section 2.5.1.2.6.4. Yard slope stability was evaluated separately (See evaluation under the heading "Yard Slope Stability" below.) The evaluation included slope stability of the Design Class I structures and equipment, raw water reservoirs, the 500 and 230 kV switchyards, and the intake and discharge structures. The conclusion was that soil stability is not an issue.

For Item 2: In the DCPP 500 and 230 kV switchyards, the breakers are all low profile style and the 500 kV breakers have epoxy-impregnated bushings rather than porcelain bushings to improve seismic durability. Although some damage is expected in the porcelain bushings, repairs should be accomplished in a few weeks. This is based on PG&E's experience in the 1989 Loma Prieta earthquake at its Moss Landing Power Plant switchyard. Also, the large oil-filled transformers are all located on solid foundations next to the power block buildings (none are located in the switchyards). The large transformers are welded to foundation embedment, which precludes toppling over.

For Item 6: Plants in the data base that experienced turbine bearing damage appear to have lost bearing oil pressure during or after the earthquake due to a loss of power to their bearing oil supply systems. At DCPP the backup bearing oil supply system has three stages. First the main turbine shaft driven oil pump provides bearing oil pressure while the shaft is spinning above 1200 rpm (normal speed is 1800 rpm). This supply lasts long enough to allow the emergency oil pumps to begin supplying oil pressure to allow turbine rotor coast down. The next two stages are electric driven pumps (one AC pump powered by the plants seismically qualified emergency Diesel Generators and one DC pump). These pumps come up to speed on their emergency power supplies to supply oil pressure following a loss of offsite AC power or low lube oil pressure indication. Either electric pump is sufficient to supply adequate lube oil to the turbine bearings. The DC pump's batteries are rack mounted and bolted to the floor. With all the redundancy and robust installation, damage to the turbine due to loss of lubrication is not likely at DCPP.

The total inventory of Class II SSCs at DCPP was screened to identify items for which repair or replacement, if damaged during a seismic event, could exceed the threshold of unacceptable delay of 120 days. These SSCs were grouped into 8 generic categories:

Generic Category	**Specific Items from SSC List**
Vertical Pumps	Condensate Pumps, Circulating Water Screen Wash Pumps
Hydro-Turbine Generators	Circulating Water Pumps
Horizontal Pumps	Condensate Booster Pumps, Main Feedwater Pumps, Heater Drain Tank Pumps, Service Cooling Water Pumps
Steel Tanks	Lo-Conductivity Waste Tanks, Hi-Conductivity Waste Tanks, Resin Mixing & Holding Tanks, Anion and Cation Regeneration Tanks, Resin Separation Tanks, Condensate Demineralizers
Large Transformers	25/12 kV Aux Transformers, 12 kV Grounding Transformers, 25/4 kV Aux Transformers, 12/4 kV Standby & Startup Transformers, 230/12 kV Startup Transformers, 500/25 kV Main Transformers
High Voltage Switchyards	230 kV Circuit Breakers, 230 kV Air Switches, 500 kV Circuit Breakers, 500 kV Air Switches
Steam Turbine and Support Equipment	Main Condenser, Gland Steam Condenser, Steam Jet Air Ejector, Lube Oil Tank, Pumps & Filter Skid, Feedwater Heaters, HP & LP Turbine Generator
Control & Instrumentation System	Control & Instrument Panels & Cabinets containing components no longer commercially available as replacement

These SSC categories were assessed against the EPRI database for earthquake damage to estimate the seismic fragility of the equipment category. The conclusions and observations are summarized as follows:

- As a general rule power plants survive earthquakes with minor damage, typically including only a few items that require repair. Restoration of operation can usually be accomplished within hours or days. The EPRI Database includes post-earthquake investigations of 39 power plant sites, experiencing peak ground acceleration from 0.15g to 0.50g. Of these 39 power plants, all but five were back in operation within two or three days of their earthquake. Only two power plants remained off line for periods of months, both cases due to serious damage from soil liquefaction, a risk not applicable to the DCPP site. See Attachment C for the summary of the earthquake performance of steam power plants investigated for the Electric Power Research Institute.

- Most common causes of serious damage to power plants in past earthquakes, such as soil liquefaction or collapse of live tank high voltage circuit breakers would not apply to the DCPP site. Backfill operations were carefully controlled to ensure stability and safety and conformed to the standards of ASTM D1557. Earthquake loading following periods of prolonged precipitation will not produce any significant slope failure that can impact Design Class I structures and equipment. Potential slope failures under such conditions will not adversely impact other important facilities, including the raw water reservoirs, the 230 kV and 500 kV switchyards, and the intake and discharge structures.
- The eight categories of balance-of-plant equipment with potential long replacement times have probabilities of serious damage due to earthquake on the order of 10^{-4} per item per year (about one chance in 10,000 per year). In the rare instances where equipment damage has occurred, it is almost always to single equipment items. Equipment redundancy, where there are two or more items sufficient to perform the design function, would therefore make the probability of loss-of-the-required-service much lower than the probability of individual equipment damage.

Acceptable Risk's detailed report titled "Estimate of the Annual Probability of Earthquake Damage to Balance-0f Plant Structures, Systems, & Components Resulting in a Prolonged Outage of the Diablo Canyon Power Plant" describing the approach and conclusions is included as Appendix 3.

<u>Class II Buildings</u>

In addition, Simpson, Gumpertz & Heger (SGH) prepared a separate report on Class II buildings and structures, including the Administration Building, Warehouse, Simulator and Training Building, 500 kV and 230 kV Switchyard Buildings, and Security Building.

The following table lists the acceptable building outage times determined by PG&E. These outages were developed by taking into consideration the importance of the building to post-earthquake recovery of the DCPP. Note that outage durations are the time required to allow for critical functions in a building.

Building	Building Outage Duration
Main Warehouse.	Two weeks – need to retrieve parts for repair efforts for rest of the Plant.
Administration Building.	There are no functions in the Administration Building that could not be relocated or are not backed up elsewhere. Required performance is to protect occupants and not to endanger adjacent Turbine or Security Buildings.
Simulator Building.	1 month to allow for training for operations.

Security Building.	Two weeks – manual security checks and backup facilities at other locations in the plant could be used in short term.
500 kV Switchyard Building.	Two weeks – restoration to coincide with expected switchyard repair time desirable.
230 kV Switchyard Building.	Two weeks – restoration to coincide with expected switchyard repair time desirable.

The above outage durations will be met if the buildings are in the extensive damage state or better using HAZUS terminology. Extensive damage is associated with a yellow placard using the Cal EMA Safety Assessment Program post-earthquake placarding system.

For each of the six buildings, SGH conservatively assumed the use of Moderate-Code design using HAZUS terminology. This corresponds to buildings constructed between 1976 and 1994 in seismic zone 2B. This determined the probability of reaching the complete damage state, as listed below:

Probability of Experiencing Damage That Will Cause Unacceptable Outage Duration on an Annualized Basis

Building	**Moderate- Code**
Main Warehouse	7.1 x 10EE-4
Administration Building	3.1 x 10EE-4
Simulator Building	7.2 x 10EE-4
Security Building	5.3 x 10EE-4
500 kV Switchyard Building	1.25 x 10EE-3
230 kV Switchyard Building	9.8 x 10EE-4

Although the buildings evaluated as part of this project were constructed in the 1970s and 1980s, the annualized probability of structural damage that will cause unacceptable outages is predicted to be 1.25 x 10EE-3 or less for each of the buildings. These relatively low probabilities are due to:

- The use of seismic design criteria in excess of that required by the building codes current during the time of construction.
- The relatively small size of some of the buildings.
- The use of structural steel as opposed to concrete or concrete block for most of the structures.
- The relatively low hazard for a California site.

For comparison purposes, the same values were derived for typical new, code-compliant buildings of the same construction. These values are listed below:

Annualized Basis

Building	**Moderate Code**
Main Warehouse	3.3 x 10EE-4
Administration Building	3.1 x 10EE-4
Simulator Building	3.3 x 10EE-4
Security Building	3.9 x 10EE-4
500 kV Switchyard Building	1.1 x 10EE-3
230 kV Switchyard Building	1.1 x 10EE-3

By comparing the values of the two tables, they show that the newer construction designed to criteria for structures of standard importance using the current building code is generally less likely to experience an unacceptable outage, but the difference between the values in the two tables is not significant.

The SGH detailed report describing the approach and conclusions is included as Appendix 4.

Yard Slope Stability

Slope stability at the site has been evaluated by DCPP as noted in the Facility Safety Analysis Report (FSAR) Section 2.5.5. The following is an excerpt from the DCPP FSAR Section 2.5.5:

2.5.5 SLOPE STABILITY

2.5.5.1 Slope Characteristics

The only slope whose failure during a DDE could adversely affect the nuclear power plant is the slope east of the building complex (see Figures 2.5-17, 2.5-18, and 2.5-22). To evaluate the stability of this slope, the soil and rock conditions were investigated by exploratory borings, test pits, and a thorough geological reconnaissance by the soil consultant, Harding-Lawson Associates, and was in addition to the overall geologic investigation performed by other consultants.

The slope configuration and representative locations of the subsurface conditions determined from the exploration are shown on Plates 2, 3, and 4 of Appendix 2.5C of Reference 27 of Section 2.3. Reference 44 provides further information compiled in 1997 in response to NRC questions on landslide potential.

Bedrock is exposed along the lower portions of the cut slope up to about the lower bench at elevation 115 feet. It consists of tuffaceous siltstone and fine-grained sandstone of the Monterey Formation. Terrace gravel overlies bedrock and extends to an approximate elevation of 145 feet. Stiff clays and silty soils with gravel and rock fragments constitute the upper material on the site. The upper few feet of fine-grained soils are dark brown and expansive.

No free groundwater was observed in any of the borings which were drilled in April 1971, nor was any evidence of groundwater observed in this slope during the previous years of investigation and construction of the project.

2.5.5.2 Design Criteria and Analyses

Undisturbed samples of the materials encountered in pits and borings were examined by the soil consultant in the laboratory and were subsequently tested to determine the shear strength, moisture content, and dry density. Strain controlled, unconsolidated, undrained triaxial tests at field moisture were performed on the clay to evaluate the shear strength of the materials penetrated. (The samples were maintained at field moisture since adverse moisture or seepage conditions were not encountered during this investigation nor previous investigations.) The confining stress was varied in relation to depth at which the undisturbed sample was taken. The test results are presented on the boring logs and are explained by the Key to Test Data, Figure 2.5-28.

The results of strength tests were correlated with the results developed during earlier investigations of DCPP site. Mohr circles of stresses at failure (6 to 7 percent strain) were drawn for each strength test result, and failure lines were developed through points representing one-half the deviator stresses. An average C-θ strength equal to a cohesion (C) value of 1000 psf and an angle of internal friction (θ) of 29° was selected for the slope stability analysis. The analysis was checked by maintaining the angle of internal friction (θ) constant at 19° and varying the cohesion (C) from 950 psf (weakest layer) to 3400 psf (deepest and strongest layer).

Because of the presence of large gravel sizes, it was not possible to accurately determine the strength of the sand and gravel lense. However, based on tests on sand samples from other parts of the site, an angle of internal friction of 35° was selected as being the minimum available. An assumed rock strength of 5000 psf was used. This value is consistent with strength tests performed on remold rock samples from other areas of the site.

The stability of the slope was analyzed for the forces of gravity using a static method that is, the conventional method of slices. This analysis was checked using Bishop's modified method. The static method of analysis was chosen because, for the soil conditions at the site, it was judged to be more conservative than a dynamic analysis.

Because the overall strength of the rock would preclude a stability failure except along a plane of weakness which was not encountered in the borings or during the many geologic mappings of the slope, only the stability of the soil over the rock was analyzed. The strength parameters were varied as previously discussed to determine the minimum factor of safety under the most critical strength condition. For the static analysis excluding horizontal forces, the factor of safety was computed to be 3. When the additional unbalanced horizontal force of 0.4 times the weight of the soil within the critical surface combined with a vertical force of 0.26 times the weight was included, the minimum computed factor of safety was 1.1.

On the basis of the investigation and analysis, it was concluded that the slope adjacent to DCPP site would not experience instability of sufficient magnitude to damage adjacent safety-related structures.

The above conclusion is substantiated by additional field exploration, laboratory tests, and dynamic analyses using finite element techniques. See Appendix 2.5C of Reference 27 in Section 2.3, Harding-Lawson Associates' report on this work.

In response to an NRC request in early 1997, PG&E conducted further investigations of slope stability at the site. The results of the investigations showed that earthquake loading following periods of prolonged precipitation will not produce any significant slope failure that can impact Design Class I structures and equipment. In addition, potential slope failures under such conditions will not adversely impact other important facilities, including the raw water reservoirs, the 230 kV and 500 kV switchyards, and the intake and discharge structures. Potential landslides may temporarily block the access road at several locations. However, there is considerable room adjacent to and north of the road to reroute emergency traffic.

Breakwater and Discharge Structure

The breakwater is an interlocking tribar design with a concrete cap. Should significant breakwater damage occur during a seismic event, spare tribars are available and repair activities could be completed within 120 days.

The discharge structure is a concrete box structure founded on bedrock. Because of its foundation design, it is not expected to experience significant lateral loading from seismic activity. If seismic damage were to occur, it would only be to the roof of the box structure. The resulting debris could be removed and temporary lateral bracing could be installed to replace the damaged sections of the roof within 120 days. This is practical because the discharge structure is an open channel design and does not need an enclosed roof to operate.

Main Turbine Thrust Bearings

A separate assessment is performed on the main turbine thrust bearings since they appear to be a major factor in the risk of prolonged post-earthquake plant outage. The main turbine thrust bearings were evaluated by Alstom, the turbine retrofit vendor (Alstom Calc No. STD0002038, PG&E Document No. 6020487-44-1). The evaluation was based on a horizontal acceleration value of 0.2 g with no amplification factor due to mounting on the turbine pedestal. The results indicate that for this seismic loading, the utilization factor (the percentage of loading based on allowable) is approximately 80% for Unit 1 and 70% for Unit 2.

For an earthquake with an acceleration value higher than 0.2 g, the seismic load may exceed the allowable load of the thrust bearings. The turbine thrust bearings may not be able to prevent damage to the turbine under a severe earthquake. The earthquake would cause high axial motion of the turbine shaft, as was seen in the 2003 San Simeon earthquake at DCPP. The turbines have balanced steam flows which lead to reduced shaft thrust loads and a subsequently smaller thrust bearing than would be designed into an unbalanced steam flow machine. Thrust bearing failure could result in rotating-to-stationary blade contact and extensive turbine damage, taking one to two years to repair.

It is likely that turbines would see contact axially on their interstage steam seals prior to blade contact. This may be the reason operating steam turbines did not see serious thrust bearing problems or blade failures in past earthquakes (although there was reported thrust bearing damage at KKNPS in 2007 Niigata Earthquake). The steam seal impacts helped cushion the axial loading. Although there would be steam seal damage, that damage would not require immediate extensive repairs and turbines could run (as long as there are no vibration issues) with damaged seals. As this may or not be the case at DCPP, the recommendation is to pursue a thrust bearing capacity check.

Warehouse Racks and Cabinets

The Main Warehouse was walked down to assess the conditions of the storage racks and cabinets. An interview with the Procurement Manager was conducted to help determine the warehouse's capability to provide parts after a seismic event. The following conditions were noted:

- In the mid 1980's the warehouse racks were seismically upgraded to include bolting all racks to the floor and adding cross bracing.
- The Vidmar cabinets (high cabinets with drawers) that house most of the small electrical/ I&C components have locking bars on the drawers to prevent them from sliding out and overturning the cabinet.
- The warehouse maintains a critical components list and make sure that these components are all sitting on the first shelf or no higher than the second shelf. The goal is to minimize damage if they slide off the shelf in a seismic event.

Based on the walk down observations, there may be minor issues to supply replacement parts to support plant restart, but not to the extent of preventing a 120-day restart schedule.

KKNPP LESSONS-LEARNED

Lessons learned from the KKNPP seismic event has been evaluated and are summarized in a separate report by PG&E.

CONCLUSION AND RECOMMENDATIONS

Conclusion

Based on the observations from the walk down performed onsite, the probability of the items included in the generic list of SSCs to be out of service for more than 120 days is acceptably low.

The eight categories of balance-of-plant equipment with potential long replacement times (defined as greater than 120 days) have probabilities of serious damage due to earthquake on the order of 1 x 10EE-4 per item per year (about one chance in 10,000 per year). In the rare instances where equipment damage has occurred, it is almost always to single equipment items. Equipment redundancy, where there are two or more items sufficient to perform the design function, would therefore make the probability of loss-of-the-required-service much lower than the probability of individual equipment damage.

The six Class II buildings and structures were evaluated for probability of reaching the complete damage state. The annualized probability of structural damage that will cause unacceptable outages is predicted to be 1.25 x 10EE-3 or less for each of the buildings. For newer construction designed to criteria for structures of standard importance using the current building code, it is generally less likely to experience an unacceptable outage, but the difference in probability of reaching the complete damage state between the DCPP Class II buildings and the newer construction is not significant.

Backfill operations were carefully controlled to ensure stability and safety and conformed to the standards of ASTM D1557. Earthquake loading following periods of prolonged precipitation will not produce any significant slope failure that can impact Design Class I structures and equipment. In addition, stability of the slopes around the Raw Water Reservoirs, 230 kV and 500 kV switchyards, Intake and Discharge Structures will not be impacted by the considered earthquake shaking levels generated by DDE or Hosgri.

For an earthquake with a PGA of higher than 0.2 g at the site, the seismic load may exceed the allowable load of the main turbine thrust bearings. The turbine thrust bearings may not be able to prevent damage to the turbine under a severe earthquake. Thrust bearing failure could result in rotating-to-stationary blade contact and extensive turbine damage, taking one to two years to repair. Although no plants in the EPRI data base experienced catastrophic turbine thrust bearing failure, the potential damage to the turbine rotors from such a failure would exceed the four month repair criteria and a special evaluation of the main turbine thrust bearing seismic capacity is warranted.

There may be minor issues to supply replacement parts to support plant restart, but not to the extent of preventing a 120-day restart schedule.

Recommendations

1. Review and revise as necessary plant seismic response procedures to be consistent with Regulatory Guides 1.166, 1.167 and EPRI NP-6695. This is consistent with the recommendations in the KKNPP Lessons Learned Report. These standards would help DCPP personnel to make timely assessments of plant condition to support restart activities and meet NRC post earthquake assessment requirements.

2. Evaluate the main turbine thrust bearings seismic capacity and upgrade the bearings, if necessary.

ACRONYMS AND ABBREVIATIONS

AB	Assembly Bill
AC	Alternating Current
ASCE	American Society of Civil Engineers
BOP	Balance of Plant (Not Nuclear Safety Related)
CAL EMA	California Emergency Management Agency
CBC	California Building Code
CEC	California Energy Commission
CPUC	California Public Utilities Commission
DCPP	Diablo Canyon Power Plant
DDE	Double Design Earthquake
DE	Design Earthquake
ECG	Equipment Control Guide
EPRI	Electric Power Research Institute
F_p	Prescriptive Lateral Seismic Force
FSAR	Final Safety Analysis Report
HAZUS	An Earthquake Damage Model
HOSGRI	Hosgri Earthquake Fault
I&C	Instrumentation and Controls
IAEA	International Atomic Energy Agency
IEEE	The Institute of Electrical and Electronic Engineers
KKNPP	Kashiwazaki-Kariwa Nuclear Power Plant
kV	Thousand Volts
M6.8	Earthquake Magnitude 6.8 Richter Scale
MLLW	Mean Lower Low Water Level
m/s	meters per second
NRC	Nuclear Regulatory Commission
PG&E	Pacific Gas a & Electric Company
PGA	Peak Ground Acceleration
SCCW	Stator Coil Cooling Water
SCE	Southern California Edison
SGH	Simpson, Gumpertz & Heger
SSC	Systems, Structures and Components
SSER	Supplemental Safety Evaluation Report
UBC	Uniform Building Code
Vs30	Average Shear-Wave Velocity in the First 30 Meters of Subsoil
VDC	Volts Direct Current
W_p	Inertial Operating Weight

ATTACHMENTS

Attachment A – Determination of F_p for Relocated SCCW Pump Inside DCPP Turbine Building Based on 2001 CBC

Attachment B - Determination of Fp for Relocated SCCW Pump Inside DCPP Turbine Building Based on 2007 CBC

Attachment C - Summary of the Earthquake Performance of Steam Power Plants Investigated for the Electric Power Research Institute

Attachment A
Determination of F_p for Relocated SCCW Pump Inside DCPP Turbine Building
Based on 2001 CBC

1.0 OBJECTIVE

The existing pump/motor assemblies associated with the Stator Coil Cooling Water (SCCW) System that are located on the Westinghouse skid inside the Unit 1 Turbine Building will be removed from the Westinghouse skid. New pump/motor units will be installed on the foundation mat at Elevation 85', nearby, but separate, from the existing Westinghouse skid. The purpose of this calculation is to provide the following designs for the new pump/motor assemblies associated with the SCCW System:

- Design the hold-down bolts and mounting skid for the new SCCW pump/motor assemblies.
- Design the foundation pads and associated anchorage system for the new mounting skids that support the new SCCW pump and motor assemblies.

2.0 DETERMINATION OF VARIOUS SEISMIC-RELATED VARIABLES, DESIGN SEISMIC FORCES, AND APPLICABLE LOAD COMBINATIONS

Both pumps and motors associated with the SCCW System are Seismic Design Class II (Ref: Sections III.L.6.2 and IV.A.1 of Q-List). Therefore, the 2001 California Building Code (CBC) will be used for the design code of record for anchorage designs of this non-safety related equipment. See Section 1632 of CBC-2001 for determination of lateral forces on elements of structures, nonstructural components and equipment supported by structures.

2.1 DETERMINATION OF VARIABLES

A. Seismic Zone Factor (Z) for DCPP Site

Based on CBC Figure 16-2, DCPP Site is located within Seismic Zone 4. Per CBC Table 16-I for Seismic Zone 4, Z = 0.40.

B. Seismic Source Types Impacting DCPP Site

Upon review of "Maps of Known Active Fault Near-Source Zones in California and Adjacent Portions of Nevada", the Hosgri and Los Osos Faults are germane for the DCPP site.

1. Seismic Source Type Associated with Hosgri Fault
   a. Per Table 1 (Page xiv) of "Maps of Known Active Fault Near-Source Zones in California and Adjacent Portions of Nevada", the Hosgri Fault is classified as Seismic Source Type B.
   b. Seismic Source Type for Hosgri Fault Based on PG&E's Long Term Seismic Program Characterization
      - Per Page 10 of PG&E's "Final Report of the Diablo Canyon Long Term Seismic Program," dated July 1988, the Hosgri fault zone is the controlling seismic source for the DCPP site and has an associated maximum magnitude potential of 7.2 M_w.

- Per Pages 2-120 through 2-123 and Page 3-24 of PG&E's "Final Report of the Diablo Canyon Long Term Seismic Program," dated July 1988, typical Hosgri slip rates are postulated at between 1 to 3 millimeters per year. However, the Hosgri slip rate may be as high as 6 millimeters per year per this report.

- Conservatively considering the Hosgri slip rate to be in excess of 5 mm/year in conjunction with CBC Table 16-U, use Seismic Source Type A as the classification for the Hosgri Fault.

c. Conservatively, consider the Hosgri Fault to be a Seismic Source Type A since it is more severe than Seismic Source Type B.

2. Seismic Source Type Associated with Los Osos Fault

Per Table 1 (Page xv) of "Maps of Known Active Fault Near-Source Zones in California and Adjacent Portions of Nevada", the Los Osos Fault is classified as a Seismic Source Type B.

C. Near Source Factor, N_a

1. Near Source Factor Associated with Hosgri Fault

a. Per Page 10 of PG&E's "Final Report of the Diablo Canyon Long Term Seismic Program," dated July 1988, the Hosgri fault zone is located 4.5 kilometers from the DCPP site.

b. Considering Seismic Source Type A and seismic source distance of 4.5 km to DCPP site, the prorated value of N_a per CBC Table 16-S is as follows:

$$N_a = 1.5 - [(4.5\text{ km} - 2\text{ km})/(5\text{ km} - 2\text{ km})]\,(1.5 - 1.2) = 1.25$$

2. Near Source Factor Associated with Los Osos Fault

a. Per Pages H-28 and H-29 of "Maps of Known Active Fault Near-Source Zones in California and Adjacent Portions of Nevada", the Los Osos Fault is located within 2 kilometers from the DCPP site.

b. Considering Seismic Source Type B and seismic source distance of ≤ 2.0 km to DCPP site, value of N_a per CBC Table 16-S is 1.3.

D. Soil Profile Type for Turbine Building

1. The foundation mat for the Turbine Building either rests on base rock or on lean concrete fill, which is placed between the base rock and bottom of foundation mat (Ref: Section 4.3.1.1 of DCM No. T-4, Rev. 6). Per Table 4.1-1 of Appendix C to DCM No. T-6, Rev. 7, the shear wave velocity for the supporting rock profile of the Turbine Building is greater than 3,600 feet per second.

2. Per CBC Table 16-J, Soil Profile Type S_B is applicable for a rock profile that is characterized by shear wave velocity values that are between 2,500 to 5,000 feet per second.

3. Based on the above information, use Soil Profile Type S_B as the appropriate classification for the soil profile supporting the Turbine Building.

E. Seismic Coefficient, C_a

1. Seismic C_a coefficients are specified in CBC Table 16-Q.

2. Considering Seismic Zone Factor of Z = 0.4 and Soil Profile Type S_B, $C_a = 0.40N_a$.

3. Using the higher N_a factor that is associated with the Los Osos Fault (i.e., 1.3), then the critical C_a value is as follows:

$C_a = (0.4)(1.3) = 0.52$

F. Importance Factor, I_p

Considering the non-safety function of the SCCW pump/motor assemblies (i.e., not required for continued operation or support of standby power-generating equipment), the appropriate Occupancy Category for this equipment per CBC Table 16-K is Standard Occupancy Structures. The corresponding seismic importance factor, I_p, for Standard Occupancy Structures per CBC Table 16-K is 1.00.

G. In-Structure Component Amplification (a_p) and Component Response Modification (R_p) Factors

The horizontal force factors, a_p and R_p, are specified in CBC Table 16-O. For mechanical equipment, use the horizontal force factors consistent with Item 3B of CBC Table 16-O for guidance as follows:

$a_p = 1.0$ and $R_p = 3.0$

To maintain the validity of the above R_p value (i.e., 3), any proposed expansion anchors will be required to have an embedment length-to-diameter ratio equal to, or greater than 8. (Ref: CBC Section 1632.2).

H. Component Attachment Elevation (h_x)

Considering that the new SCCW pump/motor assemblies will be located on foundation mat at Elevation 85' (i.e., grade level), let $h_x = 0$.

I. Structure Roof Elevation (h_r)

Considering the concrete slab at Elevation 140' as the roof elevation with respect to grade (i.e., Elevation 85'), then

h_r = Elev. 140' - Elev. 85' = 55 feet

2.2 TOTAL LATERAL SEISMIC COEFFICIENT APPLICABLE IN ANY HORIZONTAL DIRECTION AND VERTICAL SEISMIC COEFFICIENT

A. Total Lateral Seismic Coefficient Applicable in Any Horizontal Direction

Based on CBC Section 1632.2, the total lateral seismic force F_p shall be calculated based on CBC Equations 32-1 through 32-3, except that F_p shall not be less than 0.7 $C_a I_p W_p$ and need not be more than 4 $C_a I_p W_p$. Based on these equations, determine an appropriate total lateral seismic coefficent that will be multiplied by the component weight, W_p, to establish the total design lateral seismic force.

1. Maximum Value Per CBC Equation 32-1

$$F_{p\,(max)} = 4\, C_a\, I_p\, W_p$$

$$F_{p\,(max)} = (4)\,(0.52)\,(1.0)\, W_p = 2.1\, W_p$$

2. Explicit Value Per CBC Equation 32-2

$$F_p = \frac{a_p\, C_a\, I_p}{R_p} \left[1 + \frac{3\, h_x}{h_r}\right] W_p$$

$$F_p = \frac{(1.0)\,(0.52)\,(1.0)}{3} \left[1 + \frac{(3)\,(0)}{55}\right] W_p = 0.173\, W_p$$

3. Minimum Value Per CBC Equation 32-3

$$F_{p\,(min)} = 0.7\, C_a\, I_p\, W_p$$

$$F_{p\,(min)} = (0.7)\,(0.52)\,(1.0)\, W_p \approx 0.37\, W_p$$

B. Since the explicit value of F_p is less than the minimum value, the minimum value of $0.37W_p$ shall be used for this rigid pump located at ground level.

Attachment B
Determination of F_p for Relocated SCCW Pump Inside DCPP Turbine Building
Based on 2007 CBC

1.0 Development of DCPP-Specific Values and Classifications for Various CBC/ASCE Parameters Applicable for SCCW Pump Inside Turbine Building

1.1 Latitude and Longitude Values for DCPP Site

Based on FSARU Section 2.1.1 for Unit 1 reactor, let the latitude and longitude values for DCPP site be as follows:

- Latitude = 35°12’44” N
- Longitude = 120°51’14” W

1.2 Occupancy Category Associated with Turbine Building

Per CBC definitions in CBC Table 1604.5, Turbine building shall be considered as an Occupancy Category III structure.

1.3 Seismic-Related CBC/ASCE Parameters Applicable for Turbine Building and Supported Equipment

1.3.1 Site Class Associated with Turbine Building

Site Class B shall be applicable for the Turbine Building.

1.3.2 Mapped Spectral Response Accelerations (S_S and S_1)

1.3.2.1 Mapped Spectral Acceleration for Short Period (i.e., 0.2 seconds), S_S

Based on location of DCPP Site per Section 1.1 and consideration of Figure 1613.5(1) for 0.2 second periods per CBC Section 1613.5.1, the corresponding mapped spectral acceleration for short periods, based on 5% critical damping and Site Class B, is as follows:

$S_S = 1.636$ g

1.3.2.2 Mapped Spectral Acceleration for 1-Second Period, S_1

Based on location of DCPP Site per Section 1.1 and consideration of Figure 1613.5(2) for 1-second periods per CBC Section 1613.5.1, the corresponding mapped spectral acceleration for 1-second periods, based on 5% critical damping and Site Class B, is as follows:

$S_1 = 0.634$ g

1.3.3 Site Coefficients (F_a and F_v)

1.3.3.1 Site Coefficient F_a

Based on CBC Section 1613.5.3 and CBC Table 1613.5.3(1), considering Site Class B per Section 1.3.1 and S_S = 1.636 g per Section 1.3.2.1, the applicable Site Coefficient F_a is as follows:

$F_a = 1.0$

1.3.3.2 Site Coefficient F_v

Based on CBC Section 1613.5.3 and CBC Table 1613.5.3(2), considering Site Class B per Section 1.3.1 of this calculation and S_1 = 0.634 g per Section 1.3.2.2 of this calculation, the applicable Site Coefficient F_v is as follows:

$F_v = 1.0$

1.3.4 Maximum Considered Earthquake Spectral Response Accelerations (S_{MS} and S_{M1})

1.3.4.1 Maximum Considered Earthquake Spectral Response Acceleration, S_{MS}

Based on CBC Section 1613.5.3 and CBC Equation 16-37, the maximum considered earthquake spectral response acceleration for short periods, S_{MS}, is determined as follows:

$S_{MS} = F_a S_S = (1.0)(1.636 \text{ g}) = 1.636 \text{ g}$

1.3.4.2 Maximum Considered Earthquake Spectral Response Acceleration, S_{M1}

Based on CBC Section 1613.5.3 and CBC Equation 16-38, the maximum considered earthquake spectral response acceleration for 1-second periods, S_{M1}, is determined as follows:

$S_{M1} = F_v S_1 = (1.0)(0.634 \text{ g}) = 0.634 \text{ g}$

1.3.5 Design Spectral Response Accelerations (S_{DS} and S_{D1})

1.3.5.1 Design Spectral Response Acceleration, S_{DS}

Based on CBC Section 1613.5.4 and CBC Equation 16-39, the design spectral response acceleration for short periods, S_{DS}, is determined as follows:

$S_{DS} = 2/3\ S_{MS} = (2/3)(1.636 \text{ g}) = 1.09 \text{ g}$

1.3.5.2 Design Spectral Response Acceleration, S_{D1}

Based on CBC Section 1613.5.4 and CBC Equation 16-40, the design spectral response acceleration for 1-second periods, S_{D1}, is determined as follows:

$S_{D1} = 2/3\ S_{M1} = (2/3)(0.634 \text{ g}) = 0.42 \text{ g}$

2.0 Governing ASD Demand Loads Associated with Seismic Event for Anchorage System Configuration

2.1 Horizontal Strength-Level Seismic Design Force Component in Any Direction (F_p)

2.1.1 Based on ASCE Sections 13.4.1 and 13.3.1 and ASCE Equations 13.3-1 through 13.3-3, F_p shall be at least equal to minimum specified value per ASCE Equation 13.3-3 and or less than or equal to maximum value per ASCE Equation 13.3-2.

2.1.2 Minimum Value per ASCE Equation 13.3-3

$F_{p\,(min)} = 0.3\, S_{DS}\, I_p\, W_{d\,pump}$

where

S_{DS} = design spectral response for short periods; equals 1.09 g per Section 1.3.5.1
$W_{d\,pump}$ = total dead weight of skid-mounted booster pump; equals 1.13 kips
I_p = importance factor determined in accordance with ASCE Section 13.1.3; equals 1.0 per cited ASCE section.

$F_{p\,(min)} = (0.3)\,(1.09\text{ g})\,(1.0)\, W_{d\,pump} = 0.33\, W_{d\,pump}$

2.1.3 Maximum Value per ASCE Equation 13.3-2

$F_{p\,(max)} = 1.6\, S_{DS}\, I_p\, W_{d\,pump}$

$F_{p\,(max)} = (1.6)\,(1.09\text{ g})\,(1.0)\, W_{d\,pump} = 1.74\, W_{d\,pump}$

2.1.4 Explicit Value per ASCE Equation 13.3-1

Since height effects (i.e., z) are not applicable, associated modified ASCE Equation 13.3-1 is as follows:

$$F_{p\,exp} = \frac{0.4\, a_p\, S_{DS}\, W_{d\,pump}}{(R_p/I_p)}\left(1 + \frac{2z}{h}\right)$$

where

a_p = component amplification factor per ASCE 7-05 Table 13.6-1; use 1.0 for rigid pump
R_p = component response modification factor per ASCE 7-05 Table 13.6-1; use 1.5 for other mechanical components
Z = height of component in structure; use 0 since the pump is located at ground level
h = height of structure, use 55 feet for turbine building

$$F_{p\,exp} = \frac{(0.4)\,(1.0)\,(1.09\text{ g})\, W_{d\,pump}}{(1.5/1.0)}[1 + (2)(0)/55] = 0.29\, W_{d\,pump}$$

2.1.5 Based on review of the above values for a rigid pump at ground level, use $F_p = F_{p\,min} = 0.33\, W_{d\,pump}$ since $F_{p\,exp}$ is less than the minimum values.

ATTACHMENT C

Summary of the Earthquake Performance of Steam Power Plants Investigated for the Electric Power Research Institute

San Fernando Earthquake, 1971, Magnitude 6.7		
Site	Peak Ground Acceleration	Recovery Time
Valley Steam Plant: Four gas-fired steam units, 1950s vintage, 500 MW	0.30g	Hours
Burbank Power Plant: Six gas-fired steam units, two gas turbine peakers, 1950s, 200 MW	0.30g	Hours
Glendale Power Plant, Five gas-fired steam units, 1950s – 60s, 150 MW	0.25g	Continued operating
Pasadena Power Plant, Five gas-fired steam units, 1950s vintage, 200 MW	0.20g	Continued operating
Point Mugu Earthquake, 1973, Magnitude 5.7		
Ormond Beach, Two gas-fired steam units, 1970, 1500 MW	0.20g	Hours
Ferndale Earthquake, 1975, Magnitude 5.5		
Humboldt Bay, Two gas-fired steam units, 1950s, One nuclear unit, 1961, 160 MW	0.30g	Hours
Imperial Valley Earthquake, 1979, Magnitude 6.6		
El Centro Steam Plant, Four gas-fired steam units, 1950s – 60s, 100 MW	0.42g	Hours
Humboldt Earthquake, 1980, Magnitude 7.0		
Humboldt Bay, Two gas-fired steam units, 1950s, 100 MW	0.25g	Hours
Chile Earthquake, 1985, Magnitude 7.5		
Renca, Two coal-fired steam units, 1960s, 100 MW	030g	Hours
Laguna Verde, 1930s- 40s, 50 MW	0.25g	Hours

Las Ventanas, Two coal-fired steam units, 1960s – 70s, 340 MW	0.25g	Two days
Mexico Earthquake, 1985, Magnitude 8.1		
Sicartsa, Two gas-fired steam units, 1970s, 22 MW	0.25g	Hours
Whittier Earthquake, 1987, Magnitude 5.9		
Commerce, Trash-fired steam unit, 1985, 12 MW	0.30g	Continued operating
Puente Hills, Methane-fired steam unit, 1986, 40 MW	0.20g	Hours
Superstition Hills Earthquake, 1987, Magnitude 6.3		
Mesquite Lake, Manure-fired steam unit, 1987, 16 MW	0.20g	Plant undergoing initial start-up
El Centro Steam Plant, Four gas-fired steam units, 1950s – 60s, 100 MW	0.26g	Hours
Loma Prieta Earthquake, 1989, Magnitude 6.9		
Moss Landing, Four gas-fired units, 1950s – 60s, 1900 MW	0.30g	One month
Gilroy Cogeneration, 1988, 120 MW	0.32g	Hours
Stanford Cogen, 1985, 50 MW	0.25g	Down for maintenance
Hunters Point, Three gas-fired units, 1950s, 330 MW	0.15g	Hours
Portrero, Five gas-fired steam units, three gas turbine peakers, 1960s, 360 MW	0.15g	Two days
Sierra Madre Earthquake, 1991, Magnitude 5.8		
Pasadena, Five gas-fired steam units, two gas turbine peakers, 1950s, 200 MW	0.20g	Continued operating
CapeMendocino Earthquake Sequence, 1992, Magnitude 7.0		
Pacific Lumber Cogen, Two wood-waste-fired units, 1989, 30 MW	0.47g	Two weeks
Humboldt Bay, Two gas-fired steam units,	0.24g	Hours

1950s, 100 MW		
Landers Earthquake, 1992, Magnitude 7.5		
Cool Water, Two gas-fired steam units, two cogen units, 196s – 70s, 1300 MW	0.35g	Two weeks
Guam Earthquake, 1993, Magnitude 8.0		
US Navy Power Plant, Four oil-fired steam units, 1960s, 76 MW	0.25g,	Three months
Cabras, Two oil-fired steam units, 1970s vintage, 130 MW	0.25g	Three days
Tanguisson, Two oil-fired steam units, 1970s, 50 MW	0.25g	Two days
Yigo gas turbine generator, 1993, 22 MW	0.25g	Hours
Dededo gas turbine generator, 1993, 32 MW	0.25g	Hours
Northridge Earthquake, 1994, Magnitude 6.7		
AES Placerita cogeneration unit, 1980s, 110 MW	0.50g	Three weeks
ARCO Placerita cogeneration unit, 1980s, 40 MW	0.50g	Two days
Pitchess cogeneration unit, 1980s, 28 MW	0.50g	One day
Valley Steam Plant: Four gas-fired steam units, 1950s vintage, 500 MW	0.30g	Hours
Burbank Power Plant: Six gas-fired steam units, two gas turbine peakers, 1950s, 200 MW	0.25g	Hours
Glendale Power Plant, Five gas-fired steam units, 1950s – 60s, 150 MW	0.25g	Hours
Pasadena Power Plant, Five gas-fired steam units, 1950s vintage, 200 MW	0.20g	Down for maintenance
Colima Earthquake, 1995, Magnitude 7.6		
Manzanillo, Six Oil-fired steam units,	0.40g	Five months

1980s – 90s, 2100 MW		
Michoacan Earthquake, 1997, Magnitude 7.3		
Petacalco, Four oil-fired steam units, 1990s, 2100 MW	0.28g	Two days

APPENDICES

1. Diablo Canyon Power Plant Site Aerial Views

2. AB 1632 SSC List

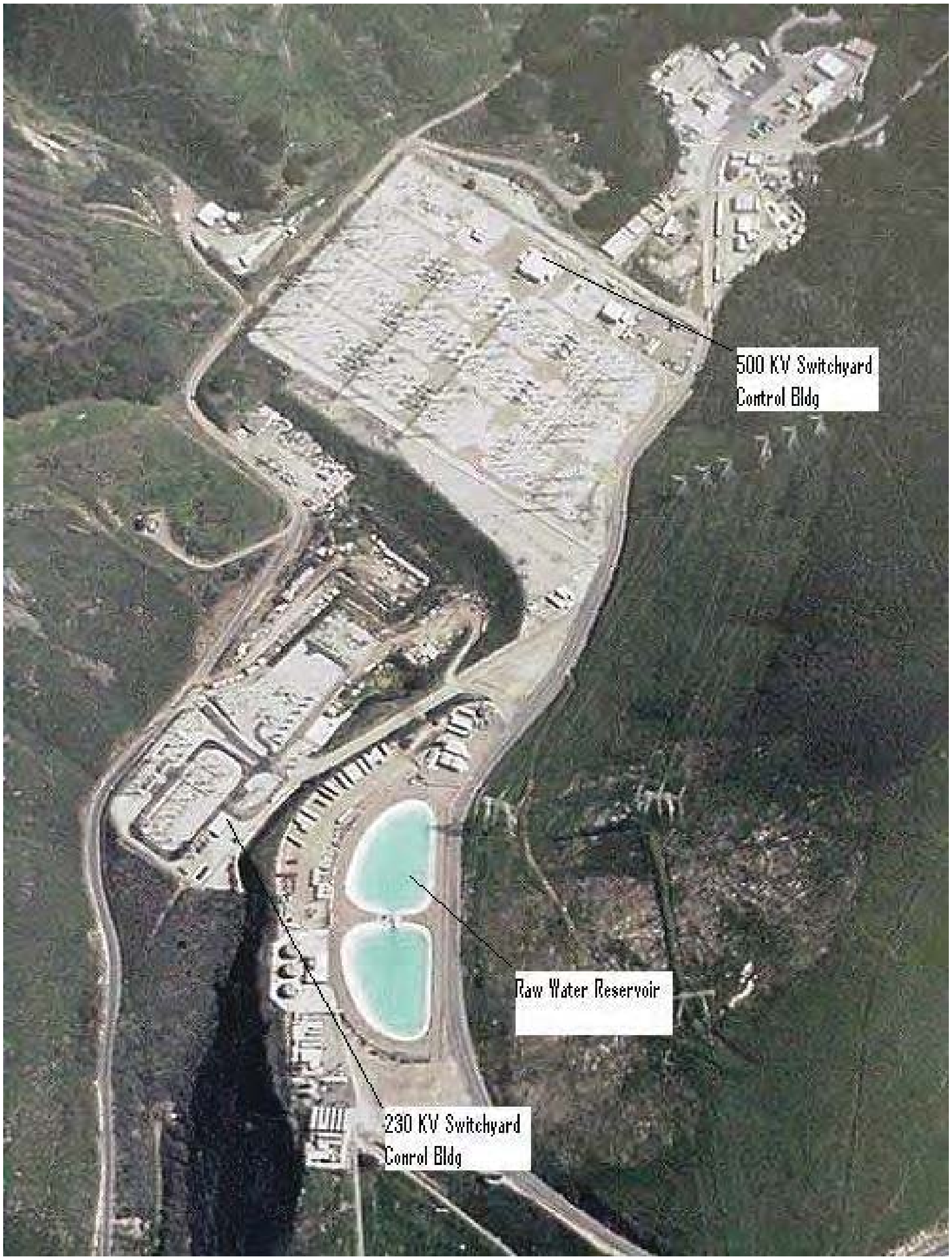
3. Report - Estimate of the Annual Probability of Earthquake Damage to Balance-0f Plant Structures, Systems, & Components Resulting in a Prolonged Outage of the Diablo Canyon Power Plant

4. Report - Summary of Assessment of Diablo Canyon Power Plant Non-Safety Related Structures to a Severe Seismic Event

Appendix 1

Topographic Aerial View of DCPP

Aerial View of Power Block Showing Various Buildings



Aerial View of 230/500 KV Switchyards and Raw Water Reservoirs

APPENDIX 2

This inventory was screened to identify items that meet the following criteria: a) items not seismically designed to nuclear safety were excluded, b) items not required to support plant operation were excluded, and c) if the item were damaged by an earthquake, and can be repaired or replaced within 120 days, it is excluded. The above screening was done without consideration of whether or not the item would actually be damaged by an earthquake. In assessing if the item could be repaired or replaced within 120 days category, some items were conservatively screened in with a “Yes/No” answer with a note “Depending on the extent of the damage”. This generally means that if there were only a few of the items damaged the repair/replacement time frame would be less than 120 days; but if the majority of the items were damaged, then the repair/replacement time frame could be more than 120 days, due to unavailability of the components or shortage of man power.

CIVIL STRUCTURAL

SSCs	Seismic Classification	In AB1632 Seismic Scope? (yes/no)	Required for Plant Operation? (yes/no)	Repair/replace within 120 days? (yes/no)	Comments/Justifica
	Design Class II	Yes	Yes	No	Depends on extent o required if damage is ECG 17.3).

re not required for plant operation and/or whose function could be replaced with temporary facilities to facilitate DCPP return to power in 120 days are not listed (i.e., Administration E Security Building, Training Building, and Warehouse.)

NSSS

	SSCs	Seismic Classification	In AB1632 Seismic Scope? (yes/no)	Required for Plant Operation? (yes/no)	Repair/replace within 120 days? (yes/no)	Comments/Justificatio
n	Pressurizer Relief Tank	Design Class II	Yes	Yes	No	
n	Remainder of System Piping that connects other systems to the Pressurizer Relief Tank	Design Class II	Yes	Yes	Yes/No	Depending on extent of damage
n	Valves for the above portion of System	Design Class II	Yes	Yes	Yes/No	Depending on extent of damage
	Portion of system piping that handles letdown from LCV 112A to the Liquid Holdup Tanks, from the LHUTs through the Evaporator Feed Ion Exchangers, and through the Boric Acid Evaporator; concentrates through the Concentrates Holding Tank up to the Boric Acid Tanks, and condensates through the Boric Acid Evaporator Condensates Demineralizers up to the Boric Acid Reserve Tanks; Boric Acid Reserve Tank recirculation and transfer piping up to the Batch Tank and the Boric Acid Tanks	Design Class II	Yes	Yes	Yes/No	Depending on extent of damage
	Valves for the above portion of system	Design Class II	Yes	Yes	Yes/No	Depending on extent of damage
	Portion of System Piping that pumps condensate from the monitor tanks to the liquid holdup tanks, or back to the evaporator package feed line, the makeup water system (primary water storage tank), or the liquid radwaste system (processed waste receivers)	Design Class II	Yes	Yes	Yes/No	Depending on extent of damage
	Valves for the above portion of system	Design Class II	Yes	Yes	Yes/No	Depending on extent of damage
g	Remainder of System Piping	Design Class II	Yes	Yes	Yes/No	Depending on extent of damage
g	Remainder of System Valves	Design Class II	Yes	Yes	Yes/No	Depending on extent of damage

BOP

	SSCs	Seismic Classification	In AB1632 Seismic Scope? (yes/no)	Required for Plant Operation? (yes/no)	Repair/replace within 120 days? (yes/no)	Comments/Justificatio
	Condensate Pump	Design Class II	Yes	Yes	No	
	Condensate Booster Pump	Design Class II	Yes	Yes	No	
	Main Condenser	Design Class II	Yes	Yes	No	
	Condenser Tubes	Design Class II	Yes	Yes	No	
	Feedwater Heaters (No. 2-6)	Design Class II	Yes	Yes	No	
	Condensate Cooler	Design Class II	Yes	Yes	No	
	Heaters for 1 - 6 Drain Cooler	Design Class II	Yes	Yes	No	
	Gland Steam Condenser	Design Class II	Yes	Yes	No	
	Air Ejector Condenser	Design Class II	Yes	Yes	No	
	Hydrogen Coolers	Design Class II	Yes	Yes	No	
	Stator Coil Coolers	Design Class II	Yes	Yes	No	
	Condensate Piping	Design Class II	Yes	Yes	Yes/No	Depending on extent of d
	Condensate Valves	Design Class II	Yes	Yes	Yes/No	Depending on extent of d
	Lo-Conductivity Waste Tank	Design Class II	Yes	Yes	No	
	Hi-Conductivity Waste Tank	Design Class II	Yes	Yes	No	
	Resin Mixing & Holding Tank	Design Class II	Yes	Yes	No	
	Anion Regen Tank	Design Class II	Yes	Yes	No	
	Resin Sep. & Cation Regen Tank	Design Class II	Yes	Yes	No	
	Condensate Demin. Ion Exchangers	Design Class II	Yes	Yes	No	
	Caustic Dilution Heat Exchanger	Design Class II	Yes	Yes	No	
	Condensate Polishing System Piping	Design Class II	Yes	Yes	Yes/No	Depending on extent of d
	Condensate Polishing System Valves	Design Class II	Yes	Yes	Yes/No	Depending on extent of d
	Condensate Polishing System Sump Centrifugal Separator	Design Class II	Yes	Yes	No	
	Steam Generator Feedwater Pumps	Design Class II	Yes	Yes	No	
	Feedwater Heaters (No. 1)	Design Class II	Yes	Yes	No	
	Remainder of Feedwater System Piping	Design Class II	Yes	Yes	Yes/No	Depending on extent of c
	Remainder of Feedwater System Valves	Design Class II	Yes	Yes	Yes/No	Depending on extent of c
System	Main Turbine - HP Elements	Design Class II	Yes	Yes	No	
System	Main Turbine - LP Elements	Design Class II	Yes	Yes	No	
System	Steam Generator Feed Pump Turbines	Design Class II	Yes	Yes	No	
System	Moisture Separator Reheater	Design Class II	Yes	Yes	No	
System	Remainder of Turbine Steam Supply System Piping	Design Class II	Yes	Yes	Yes/No	Depending on extent of c
System	Remainder of Turbine Steam Supply System Valves	Design Class II	Yes	Yes	Yes/No	Depending on extent of c
Heater	Heater No. 2 Drain Tank Pump	Design Class II	Yes	Yes	No	
Heater	Heater No. 2 Drain Tank	Design Class II	Yes	Yes	No	
Heater	Heater No. 6 Drain Tank	Design Class II	Yes	Yes	No	
Heater	Extraction Steam Downstream Drip Pot	Design Class II	Yes	Yes	No	

BOP

	SSCs	Seismic Classification	In AB1632 Seismic Scope? (yes/no)	Required for Plant Operation? (yes/no)	Repair/replace within 120 days? (yes/no)	Comments/Justificatio
leater	Feedwater Heaters	Design Class II	Yes	Yes	No	
leater	Heater No. 6 Drain Cooler	Design Class II	Yes	Yes	No	
leater	All System Piping	Design Class II	Yes	Yes	Yes/No	Depending on extent of da
leater	All System Valves	Design Class II	Yes	Yes	Yes/No	Depending on extent of da
leater	Flow Nozzle FE-122	Design Class II	Yes	Yes	No	
n	Auxiliary Steam System Piping from package boiler (0-1) to first isolation valve	Design Class II	Yes	Yes	Yes/No	Depending on extent of d
n	Valves for above portion of system	Design Class II	Yes	Yes	Yes/No	Depending on extent of d
n	All Other Auxiliary Steam Piping	Design Class II	Yes	Yes	Yes/No	Depending on extent of d
n	All Other Auxiliary Steam Valves	Design Class II	Yes	Yes	Yes/No	Depending on extent of d
n	Auxiliary Steam System Piping from Auxiliary Boiler (0-2) to First Isolation Valve	Design Class II	Yes	Yes	Yes/No	Depending on extent of d
n	Valves for above portion of system	Design Class II	Yes	Yes	Yes/No	Depending on extent of d
System	Service Cooling Water Pump	Design Class II	Yes	Yes	No	
System	Service Cooling Water Booster Pump	Design Class II	Yes	Yes	No	
System	Service Cooling Water Heat Exchanger	Design Class II	Yes	Yes	No	
System	Service Cooling Water System Piping	Design Class II	Yes	Yes	Yes/No	Depending on extent of c
System	Service Cooling Water Valves	Design Class II	Yes	Yes	Yes/No	Depending on extent of c
System	Main Turbine Reservoir Lube Oil Coolers	Design Class II	Yes	Yes	No	
	Primary Water Makeup Pump	Design Class II	Yes	Yes	No	
	5000-gallon Hypochlorite Storage Tank	Design Class II	Yes	Yes	No	
	Circulating Water Pump	Design Class II	Yes	Yes	No	
	Screen Wash Pump	Design Class II	Yes	Yes	No	
	Screen Refuse Pump	Design Class II	Yes	Yes	No	
	Service Cooling Water	Design Class II	Yes	Yes	No	
	Intake Cooler	Design Class II	Yes	Yes	No	
	Main Condenser (listed under Section III.A.3)	Design Class II	Yes	Yes	No	
	Wave Protection Measures	Design Class II	Yes	Yes	Yes/No	See Civil Item I.D.1.5 (B
	Circulating Water Gate Operators	Design Class II	Yes	Yes	No	
	Circulating Water System Piping	Design Class II	Yes	Yes	No	
	Valves for The Above Portion of Piping	Design Class II	Yes	Yes	No	
	Manually Adjusted Circulating Water Discharge Weir	Design Class II	Yes	Yes	No	
	Biolab Saltwater Supply System Piping	Design Class II	Yes	Yes	Yes/No	Depending on extent of
	Valves for Biolab Supply Piping	Design Class II	Yes	Yes	Yes/No	Depending on extent of
	Screen Wash and Refuse System Piping	Design Class II	Yes	Yes	Yes/No	Depending on extent of
	Valves for the above portion of piping	Design Class II	Yes	Yes	Yes/No	Depending on extent of
	Intake Cooling Water System Piping	Design Class II	Yes	Yes	Yes/No	Depending on extent of

BOP

	SSCs	Seismic Classification	In AB1632 Seismic Scope? (yes/no)	Required for Plant Operation? (yes/no)	Repair/replace within 120 days? (yes/no)	Comments/Justificatio
	Valves for the above portion of piping	Design Class II	Yes	Yes	Yes/No	Depending on extent of da
	Condenser Transition Spool	Design Class II	Yes	Yes	No	
	Circulating Water Traveling Screens	Design Class II	Yes	Yes	No	
	Auxiliary Saltwater Traveling Screen	Design Class II	Yes	Yes	No	
nd	Lube Oil Transfer Pump	Design Class II	Yes	Yes	No	
nd	Dirty and Clean Lube Oil Storage Tanks	Design Class II	Yes	Yes	No	
nd	Main Turbine Lube Oil Reservoir	Design Class II	Yes	Yes	No	
nd	Feedwater Pump Turbine Lube Oil Reservoir	Design Class II	Yes	Yes	No	
nd	Main Turbine Lube Oil Coolers	Design Class II	Yes	Yes	No	
nd	Main Turbine Oil Vapor Extractor	Design Class II	Yes	Yes	No	
nd	Main Turbine Oil Reservoir Demister	Design Class II	Yes	Yes	No	
nd	Bearing Oil Pump (ac)	Design Class II	Yes	Yes	No	
nd	Emergency Lube Oil Pump (dc)	Design Class II	Yes	Yes	No	
nd	Shaft-driven Oil Pump	Design Class II	Yes	Yes	No	
nd	Bearing Lift Pump (bearings 3-7)	Design Class II	Yes	Yes	No	
nd	Feedwater Pump Lube Oil Coolers	Design Class II	Yes	Yes	No	
nd	Feedwater Pump Oil Vapor Extractor	Design Class II	Yes	Yes	No	
nd	Feedwater Pump Oil Reserv. Demister	Design Class II	Yes	Yes	No	
nd	Main Oil Pumps (ac)	Design Class II	Yes	Yes	No	
nd	Emergency Oil Pump (dc)	Design Class II	Yes	Yes	No	
nd	High Pressure Oil Accumulator	Design Class II	Yes	Yes	No	
nd	Electrohydraulic (E-H) Control Unit	Design Class II	Yes	Yes	No	
nd	Lube Oil Distribution and Purification Piping and Valves	Design Class II	Yes	Yes	Yes/No	Depending on extent of c
ine	Air Compressors	Design Class II	Yes	Yes	No	

BOP

	SSCs	Seismic Classification	In AB1632 Seismic Scope? (yes/no)	Required for Plant Operation? (yes/no)	Repair/replace within 120 days? (yes/no)	Comments/Justificati
or-	**Turbine-generator Unit**	Design Class II	Yes	Yes	No	
r-	Generator Hydrogen Coolers	Design Class II	Yes	Yes	No	
r-	Turbine and Generator-associated Systems Piping	Design Class II	Yes	Yes	Yes/No	Depending on extent of d
r-	Turbine and Generator-associated Systems Valves	Design Class II	Yes	Yes	Yes/No	Depending on extent of d
r-	Gland Steam Condenser (shell side)	Design Class II	Yes	Yes	No	
and System	All System Piping	Design Class II	Yes	Yes	Yes/No	Depending on extent of d
and System	All System Valves	Design Class II	Yes	Yes	Yes/No	Depending on extent of d

ELECTRICAL EQUIPMENT

	SSCs	Seismic Classification/IEEE 308 Class	In AB1632 Seismic Scope? (yes/no)	Required for Plant Operation? (yes/no)	Repair/replace within 120 days? (yes/no)	Comments/
t	Main Generator (includes all auxiliary systems such as excitation, seal oil, H2, stator cooling, etc.)	Design Class II/Non- 1E	Yes	Yes	No	
t	Isolated Phase Bus	Design Class II/Non- 1E	Yes	Yes	No	
t	Generator Neutral Transformer and Resistor	Design Class II/Non- 1E	Yes	Yes	No	
t	Generator Relay Boards	Design Class II/Non- 1E	Yes	Yes	No	
	12-kV System	Design Class II/Non- 1E	Yes	Yes	No	
	25/12-kV Auxiliary Transformers	Design Class II/Non- 1E	Yes	Yes	No	
	12-kV Grounding Transformers	Design Class II/Non- 1E	Yes	Yes	No	
	12-kV Fuse Cabinets	Design Class II/Non- 1E	Yes	Yes	No	
	12-kV Grounding Resistors	Design Class II/Non- 1E	Yes	Yes	No	
	Startup Relay Board	Design Class II/Non- 1E	Yes	Yes	No	
	4-kV System - Nonvital	Design Class II/Non- 1E	Yes	Yes	No	
	25/4-kV Auxiliary Transformers	Design Class II/Non- 1E	Yes	Yes	No	
	12/4-kV Standby/Startup Transformers	Design Class II/Non- 1E	Yes	Yes	No	
	4-kV Grounding Resistors	Design Class II/Non- 1E	Yes	Yes	No	
	4-kV Metalclad Switchgear - Nonvital (D & E)	Design Class II	Yes	Yes	No	
	4-kV Metalclad Bus Ducts	Design Class II	Yes	Yes	No	
	Contactor Panels and panel loads	Design Class II/Non- 1E	Yes	Yes	No	
	Diesel Start Timing Panels, HMI Displays and Static Inverters	Design Class II/Non- 1E	Yes	Yes	No	
	480-V Load Centers - Nonvital (Fed from buses D and E)	Design Class II/Non- 1E	Yes	Yes	No	
	480-V Motor Control Centers-Nonvital (Fed from Buses 2 & E)	Design Class II/Non- 1E	Yes	Yes	No	
	480-V Circuit Breaker Panel Boards	Design Class II/Non- 1E	Yes	Yes	No	
nt	Distribution Panels and internal components	Design Class II/Non- 1E	Yes	Yes	No	

ELECTRICAL EQUIPMENT

	SSCs	Seismic Classification/IEEE 308 Class	In AB1632 Seismic Scope? (yes/no)	Required for Plant Operation? (yes/no)	Repair/replace within 120 days? (yes/no)	Comments/J
ems	dc Ground Detection System	Design Class II/Non- 1E	Yes	Yes	No	
ems	Station Storage Batteries and Battery Racks	Design Class II/Non- 1E	Yes	Yes	No	
ems	Distribution Panels	Design Class II/Non- 1E	Yes	Yes	No	
ems	250-V Motor Control Center	Design Class II/Non- 1E	Yes	Yes	No	
ems	dc Ground Detection System	Design Class II/Non- 1E	Yes	Yes	No	
ems	Battery Chargers	Design Class II/Non- 1E	Yes	Yes	No	
ways	Insulated Electrical Conductors - Nonvital Systems	Design Class II/Non- 1E	Yes	Yes	Yes/No	Depending on Extent
ways	Electrical Raceway - Vital and Nonvital	Design Class II/Non- 1E	Yes	Yes	Yes/No	Depending on Extent
ways	Raceway Supports (For raceway containing nonvital circuits)	Design Class II/Non- 1E	Yes	Yes	Yes/No	Depending on Extent
	230/12-kV Standby Startup Transformer	Design Class II/Non- 1E	Yes	Yes	No	
	230-kV Circuit Breakers	Design Class II/Non- 1E	Yes	Yes	No	
	230-kV Air Switches	Design Class II/Non- 1E	Yes	Yes	No	
	230-kV Carrier Relays	Design Class II/Non- 1E	Yes	Yes	No	
	230-kV Line Carrier Coupling Equipment	Design Class II/Non- 1E	Yes	Yes	No	
	125-V dc Batteries for 230-kV Switchyard	Design Class II/Non- 1E	Yes	Yes	No	
	125-V dc Battery Chargers for 230-kV Switchyard	Design Class II/Non- 1E	Yes	Yes	No	
	500-kV System	Design Class II/Non- 1E	Yes	Yes	No	
	Main Transformers (25/500-kV)	Design Class II/Non- 1E	Yes	Yes	No	
	500-kV Circuit Breakers	Design Class II/Non- 1E	Yes	Yes	No	
	500-kV Air Switches	Design Class II/Non- 1E	Yes	Yes	No	
	500-kV Carrier Relays	Design Class II/Non- 1E	Yes	Yes	No	
	125-V dc Batteries for 500 kV Switchyard	Design Class II/Non- 1E	Yes	Yes	No	
	125-V dc Battery Chargers for 500-kV Switchyard	Design Class II/Non- 1E	Yes	Yes	No	

I&C

	SSCs	Seismic Classification	In AB1632 Seismic Scope? (yes/no)	Required for Plant Operation? (yes/no)	Repair/replace within 120 days? (yes/no)	Comments/Justific
	Source Range Audio Count Rate Drawer	Design Class II	Yes	Yes	Yes/No	Depending on extent of damag
	Scaler-Timer Module	Design Class II	Yes	Yes	Yes/No	Depending on extent of damag
	Comparator and Rate Assembly	Design Class II	Yes	Yes	Yes/No	Depending on extent of damag
	Miscellaneous Control and Indication Panel	Design Class II	Yes	Yes	Yes/No	Depending on extent of damag
	Flux Mapping System	Design Class II	Yes	Yes	Yes/No	Depending on extent of damag
	Incore Instrumentation Control Console	Design Class II	Yes	Yes	Yes/No	Depending on extent of damag
	Full-Length CRDM Operating Coil Stack Assembly	**Design Class II**	**Yes**	**Yes**	Yes/No	Depending on extent of damag
	Power Cabinets	**Design Class II**	**Yes**	**Yes**	Yes/No	Depending on extent of damag
	Logic Cabinet	**Design Class II**	**Yes**	**Yes**	Yes/No	Depending on extent of damag
	dc Hold Supply Cabinet	**Design Class II**	**Yes**	**Yes**	Yes/No	Depending on extent of damag
	Pulse-to-Analog Converter	**Design Class II**	**Yes**	**Yes**	Yes/No	Depending on extent of damag
	Operator Controls and Indicators	**Design Class II**	**Yes**	**Yes**	Yes/No	Depending on extent of damag
	Rod Disconnect Switch Panel (Life Coil Disconnects)	**Design Class II**	**Yes**	**Yes**	Yes/No	Depending on extent of damag
	Rod Control Cable Connector Assembly	**Design Class II**	**Yes**	**Yes**	Yes/No	Depending on extent of damag
	Motor Generator Sets	**Design Class II**	**Yes**	**Yes**	**No**	
	Generator Output Breakers	**Design Class II**	**Yes**	**Yes**	Yes/No	Depending on extent of damag
	Control Board Demultiplexer Cabinet	Design Class II	Yes	Yes	Yes/No	Depending on extent of damag
	Computer Demultiplexer	Design Class II	Yes	Yes	Yes/No	Depending on extent of damag
	Analysis Instrument System, Dwgs 102031/108031	Design Class II	Yes	Yes	Yes/No	Depending on extent of damag
	Flow Instrument Systems, Dwgs 102032/108032	Design Class II	Yes	Yes	Yes/No	Depending on extent of damag
	Level Instrument Systems, Dwgs 102033/108033	Design Class II	Yes	Yes	Yes/No	Depending on extent of dama
	Pressure Instrument Systems, Dwgs 102034/108034	Design Class II	Yes	Yes	Yes/No	Depending on extent of dama
	Temperature Instrument Systems, Dwgs	Design Class II	Yes	Yes	Yes/No	Depending on extent of dama

I&C

SSCs	Seismic Classification	In AB1632 Seismic Scope? (yes/no)	Required for Plant Operation? (yes/no)	Repair/replace within 120 days? (yes/no)	Comments/Justific
Multivariable Instrument Systems, Dwgs 102036/108036	Design Class II	Yes	Yes	Yes/No	Depending on extent of damag
Front Panel Controls and Indicators	Design Class II	Yes	Yes	Yes/No	Depending on extent of dama
Signal Conditioning and Test Panel	Design Class II	Yes	Yes	Yes/No	Depending on extent of dama
Analog Multiplier/Divider	Design Class II	Yes	Yes	Yes/No	Depending on extent of dama
Power Supply	Design Class II	Yes	Yes	Yes/No	Depending on extent of dama
Digital Panel Meter	Design Class II	Yes	Yes	Yes/No	Depending on extent of dama
Auxiliary Building Control Board	Design Class II	Yes	Yes	Yes/No	Depending on extent of dama
Computer Digital System	Design Class II	Yes	Yes	Yes/No	Depending on extent of dama
DEH Operator's Panels @ CC3	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
Governor Valves, Servoactuator Control System	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
Control room main annunciator display windows (lamp boxes PK01 through PK20 on vertical boards)	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
Remote annunciator cabinet PK011 at elevation 85' Turbine Building	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
Remote Main Annunciator Display Windows (lamp box PK21 on panel PGA)	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
Auxiliary Annunciator System	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
Fire Alarm System	QA G, Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
Radiation Access Alarm System	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
Main Generator Seal Oil, Stator Cooling and Hydrogen System Annunciator	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
Main Turbine Lube Oil Purifier System Local Annunciator	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
Makeup Water Demineralizers System Local Annunciator	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
Site Emergency and Containment Evacuation Alarm System	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
Station Power Transformers Local Annunciator	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
Data Communication/Ethernet Network (Excludes PDN Section V.BB)	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam

I&C

	SSCs	Seismic Classification	In AB1632 Seismic Scope? (yes/no)	Required for Plant Operation? (yes/no)	Repair/replace within 120 days? (yes/no)	Comments/Justifi
	Central Processor Unit (CPU)	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
	Input/Output System (I/O), Data Acquisition and Remote Multiplexers	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
	PPC Room Console (CC5)	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
	Smoke and Flame Detectors	QA G, Design Class II	Yes	Yes	Yes/No	
	Fire Detection Control Cabinet	QA G, Design Class II	Yes	Yes	Yes/No	
	CARDOX System Controls	QA G, Design Class II	Yes	Yes	Yes/No	
	Fire Alarm Control Panel	QA G, Design Class II	Yes	Yes	Yes/No	
	Containment Leak Rate Test Facilities	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
	Central Alarm System	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
	Secondary Alarm System	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
	Door and Gate Intrusion Alarm	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
	Lock and Key Control System	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
	Security System Perimeter Lighting	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
y S)	Signal Cables and Terminations to Interconnect Signals and RRM	Design Class II	Yes	Yes	Yes/No	Depending on extent of damag
y S)	Transient Recording System	Design Class II	Yes	Yes	Yes/No	Depending on extent of damag
lay S)	SPDS Computer and Communication Cabinet	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
lay S)	Data Acquisition Cabinet	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
trol	Computer Digital System (Automatic Control)	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
	Turbine Supervisory Instrumentation (TSI)	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
	Barometric Pressure Instrument	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
	Data Storage Equipment	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
	Network Hardware	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam
	PDMS Hardware	Design Class II	Yes	Yes	Yes/No	Depending on extent of dam

HVAC

	SSCs	Seismic Classification	In AB1632 Seismic Scope? (yes/no)	Required for Plant Operation? (yes/no)	Repair/replace within 120 days? (yes/no)	Comments/J
m Air	Air Handling Units	Design Class II	Yes	Yes	No	
m Air	Chilled Water Sub-system (Chillers, Piping, Valves, Fittings, Pipe Mounted Instruments, Expansion Tank and Pumps)	Design Class II	Yes	Yes	No	

Estimate of the Annual Probability of Earthquake Damage to Balance-of-Plant Structures, Systems & Components Resulting in a Prolonged Outage of the Diablo Canyon Nuclear Plant

California State Assembly Bill AB-1632 addresses the possibility of a prolonged outage of the Diablo Canyon Power Plant (DCPP) due to damage in non-safety-related structures, systems or components (SSC) following a severe earthquake. This report is intended to estimate the probability of a prolonged post-earthquake outage of the DCPP due to damage to balance-of-plant (non-nuclear-safety-related) SSC requiring repair or replacement times of months.

1.0 Identification of SSC Incurring Prolonged Restoration Time

As an initial step the inventory of structures, systems and components (SSC) required for operation of the plant was screened to identify items for which repair or replacement could exceed the threshold of unacceptable delay of 120 days. The initial list of items necessary for plant operation that might incur a prolonged repair or replacement time is included in Appendix A. This initial list has some 300 entries (some entries actually representing multiple equipment items). A prolonged repair or replacement time might be caused by one or a combination of the following factors.

1. Large equipment in the plant could require periods of months for replacement if damaged beyond repair. Examples include large motors (several hundred horsepower), large transformers or large tanks. Such items are not off-the-shelf components, but must be fabricated-following-order, a process that may require months including specification, procurement, manufacture, factory testing, shipment, installation, and post-installation testing. Some equipment could be replaced by surplus items found somewhere in the world. Still, locating the items, followed by the remaining steps of assurance of fit, form and function, procurement, shipping, installation and post-installation testing, could still take weeks or months.

2. Large equipment might be replaceable within a matter of weeks if damaged beyond repair. However the location of the equipment within the interior of the plant, surrounded by adjacent or peripheral fixtures, may complicate replacement. Problems develop if there is insufficient clearance around installations blocking the egress and re-entry path

for moving the equipment out of and back into place. Other problems could be insufficiently-sized door penetrations, lack of overhead cranes or hoists, or impediments for mobile cranes to lift and move the equipment.

3. Obsolescence may be a problem, not just with large equipment, but even with small items that simply are no longer commercially available as replacement parts. Most original equipment in the Diablo Canyon plant dates from the late 1960s or early 1970s. This is before digital-electronics became the norm for control and instrumentation systems. The site warehouse stocks much of the inventory of replacement parts that would not otherwise be available. However, no on-site inventory can be fully redundant to all critical components required to operate the plant. Furthermore an earthquake incurs the risk that items in storage in the warehouse could be themselves damaged, most likely by toppling from shelves.

A process of further screening the inventory of balance-of-plant SSC necessary for operation of the DCPP reduced the list to some three dozen items where it appeared that one of the three conditions outlined above could preclude replacement of the equipment within a 120-day period. This short list of SSC that could credibly result in a prolonged post-earthquake outage becomes the focus for detailed study. The short list of possible long-replacement-time SSC is presented as Table 1-1.

The short list in Table 1-1 groups equipment into generic categories as outlined below.

- The larger pumps required for plant operation are grouped as vertical or horizontal pumps.
- Several entries are grouped as standard components of steam generating units. For example every steam unit normally includes a condenser, a steam jet air ejector, a gland seal condenser, a lube oil system (consisting of tank, pump & filtration skid), etc.
- One item of equipment, the circulating saltwater intake pumps located in the concrete intake structure, are actually structurally similar to small hydroelectric generating units.
- The generic category of large transformers is assumed to include all large units necessary for operation of the DCPP, from the 12/4.16 kilovolt power supply transformers to the 500-kV step-up transformers. Any of these transformers could require replacement times longer than 120 days if a suitable unit could not be found somewhere in the world.

- The generic category of “high voltage switchyards” is intended to include a range of common fixtures in 220- and 500-kV yards, including circuit breakers, overhead bus, disconnect switches, current and potential transformers, capacitors, reactors, etc. While individually switchyard equipment will vary in its susceptibility to seismic damage, the prevalence of tall brittle ceramic insulators almost always results in some level of switchyard damage when subjected to moderate or strong shaking.
- A generic category simply called “control and instrumentation systems” is intended to cover control panels and instrument racks within the plant where components may be irreplaceable due to obsolescence.

The purpose of this study is to estimate the probability of damage due to earthquake for any of the equipment listed in Table 1-1, where replacement of the equipment could incur a prolonged delay in restart of one or both units of the DCPP. The probability of earthquake damage has two components:

- The probability of earthquake occurrence, usually expressed as a probability of exceedence of a certain intensity of ground shaking per year (the ground motion exceedence function)
- The probability, given the event of ground shaking of a certain intensity, that a specific item of equipment would be seriously damaged, possibly requiring replacement with a possible prolonged delay in restart of one or both DCPP units.

The ground shaking exceedence probability for the DCPP site has been provided by the PG&E geotechnical department (refer to ground shaking exceedence functions graphed in the figures of Section 4). The probability of serious damage to equipment is estimated through past experience in earthquake effects to power and large industrial facilities. Specifically this information is collected from the Electric Power Research Institute’s (EPRI) earthquake experience database.

Table 1-1: Short List of Equipment for Which Serious Damage Could Result in a Prolonged Outage of One or Both Diablo Canyon Generating Units

Generic Category	Specific Items from SSC List	Comment
Vertical Pumps	Condensate Pump	Relevant examples from the EPRI database of earthquake experience should be limited to large pumps operating at the time of their earthquake.
	Circ. Water Screen Wash Pumps	
Hydro-Turbine Generators	Circulating Saltwater Pumps	The large circ. water pumps are best represented by small hydro plants in their construction & operation.
Horizontal Pumps	Condensate Booster Pump	Relevant examples from the EPRI database of earthquake experience should be limited to large pumps operating at the time of their earthquake.
	Steam Generator Feedwater Pumps	
	Heater Drain Tank Pump	
	Service Cooling Water Pumps	
Steel Tanks	Lo-Conductivity Waste Tank	Relevant examples from the EPRI database include a range of welded steel tanks, both pad-mounted & supported on steel posts. Instances of serious damage would be limited to tanks that may have required replacement.
	Hi-Conductivity Waste Tank	
	Resin Mixing & Holding Tank	
	Anion Regeneration Tank	
	Resin Separation & Cation Regeneration Tank	
	Condensate Demineralizer Ion Exchangers	
Large Trans-formers	25/12-kV Auxiliary Transformers	Instances of serious damage would be limited to transformers requiring rebuild or replacement.
	12-kV Grounding Transformers	
	25/4-kV Auxiliary Transformers	
	12/4-kV Standby/Startup Transformers	
	230/12-kV Standby Startup Transformer	
	Main Transformers (25/500-kV)	
High Voltage Switch-yards	230-kV Circuit Breakers	Because of the number & complexity of interconnected equipment, switchyards are addressed as an "item".
	230-kV Air Switches	
	500-kV Circuit Breakers	
	500-kV Air Switches	
Control & Instru-mentation Systems	Control & Instrument Panels & Cabinets Containing Component No Longer Commercially Available as Replacements	Examples from the EPRI database would cover a 40-year range of control systems.
Steam generating units include at least one of these items	Main Condenser	Relevant examples from the EPRI database of earthquake experience should be limited to large steam units (>100 MW) operating at the time of their earthquake.
	Gland Steam Condenser	
	Steam Jet Air Ejector	
	Lube Oil Tank, Pumps & Filtration Skid	
	Feedwater Heaters	
	High-Pressure & Low--Pressure Turbine-Generators	

2.0 Summary of EPRI Database

The tendency for serious earthquake damage to equipment requiring a long repair or replacement time is assessed through past earthquake experience with similar equipment. Estimates of seismic fragility (damage probability) for selected types of standard industrial equipment are based on statistics collected from post-earthquake investigations sponsored by EPRI.

The EPRI database details effects to several thousand items of equipment investigated at some 170 sites in the regions of strong shaking from 30 earthquakes occurring throughout the world from 1971 to 2001. A list of all earthquakes and sites that comprise the EPRI database is presented in Appendix B. The list includes a brief description of each site and the more serious effects from the earthquake.

Peak ground acceleration at the various power plant and industrial sites that make up the database ranged from about 0.20g to 0.80g based on the nearest strong motion recorders. The severity of ground shaking in this report is characterized interchangeably by peak ground acceleration (PGA) and by Modified Mercalli Intensity (MMI). Modified Mercalli Intensity (MMI) ratings were assigned to the database sites according to the MMI maps presented in various post-earthquake publications. The correlation between peak ground acceleration (PGA) and shaking intensity (MMI) is illustrated in the spreadsheet of Appendix C, where the average PGA is listed for database sites in each shaking intensity interval. Sites within the database rated at Intensity Seven (MMI VII) shaking averaged about 0.26g peak ground acceleration. Sites rated at MMI VIII (Intensity Eight) averaged about 0.42g PGA, and the few sites rated above Intensity Eight shaking (MMI VIII+) averaged about 0.59g. The use of Mercalli Intensity in addition to peak ground acceleration allows rough estimates of the PGA experienced at sites where no ground motion recordings were available.

3.0 Application of Earthquake Data to Estimate Seismic Fragility

The EPRI database consists of some two dozen generic categories of equipment common to power plants and industrial facilities. Each equipment category includes an inventory of specific items investigated following earthquakes. For each equipment item the corresponding data set notes details such as the size, capacity, make-and-model, location within a building, and of course whether the earthquake incurred any noticeable effects. The inventory of data sets for each generic equipment category allows a statistical analysis to estimate the seismic fragility of the equipment type, i.e., the probability of equipment failure as a function of shaking intensity.

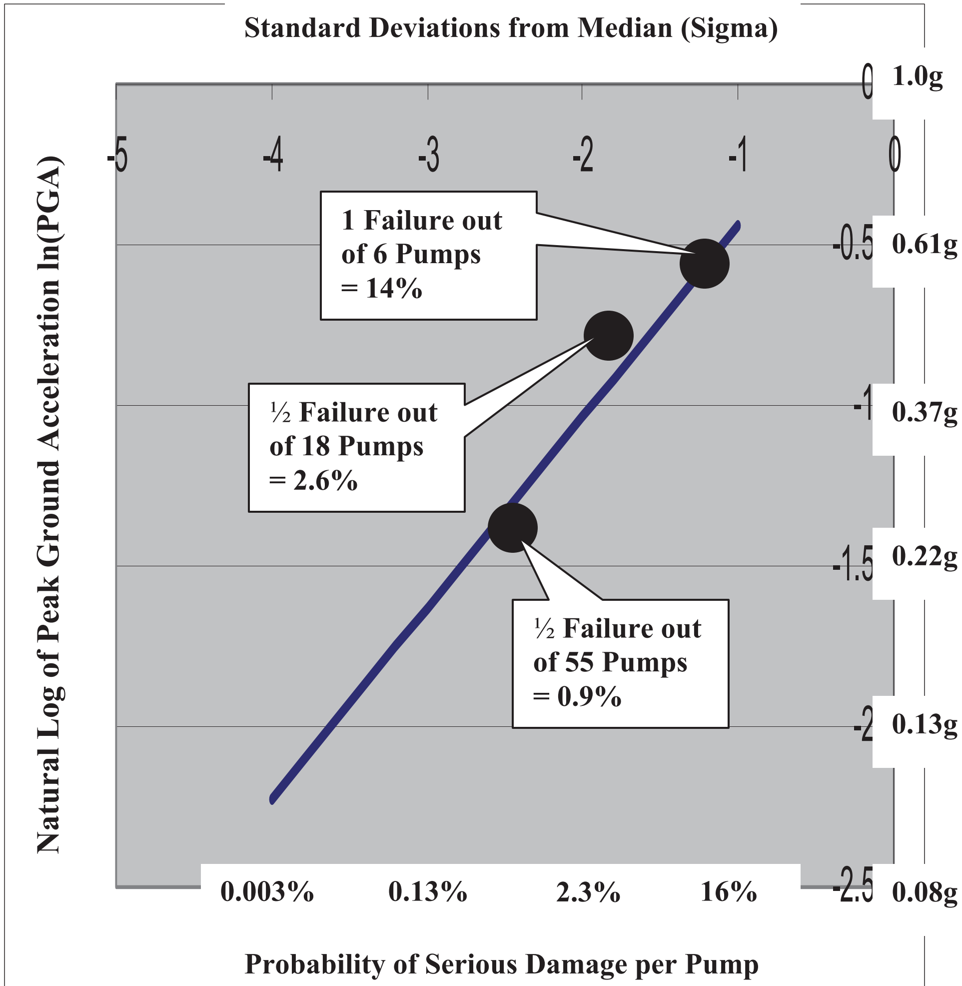
Failure probabilities for equipment under stress are conventionally assumed to follow a log-normal distribution. The measurement of uncertainty in the estimate of the median (50% probability of failure) is the standard deviation (beta) of the natural logs of the independent variable. If earthquake shaking is the cause of equipment stress, the independent variable is peak ground acceleration (PGA). The easiest way to estimate both the median and the beta for a distribution of data points is by plotting the points on a probability graph. The X-axis of a probability graph is scaled in equal increments of standard deviation (sigma). The Y-axis for a log-normal distribution is scaled in even increments of the natural log of the independent variable, peak ground acceleration (PGA). A cumulative probability distribution that forms an S-shaped curve when plotted on a linear graph becomes a straight line when plotted on a probability graph. A straight line is easier to fit to data points than an S-shape. On a probability graph the beta is simply the slope of the line, the change in the independent variable (in this case the natural log of PGA) per unit sigma.

Statistics derived from the EPRI database would be described as a “multi-censored sample”. The sample is multi-censored in that all equipment is not shaken to failure, and the sample size of equipment shrinks with increasing shaking level. The procedure for estimating failure probability at any shaking intensity is: $P = N_f / (N_s + 1)$, where N_f is the number of failures at the shaking intensity level, and N_s is the sample size. The sample size is the number of items of equipment subjected to shaking equal to or higher than an interval of shaking intensity. For example if 20 items of equipment were subjected to MMI VIII or greater ground shaking (corresponding to an average PGA of 0.42g), and three items failed at sites subjected to MMI VIII, the fragility for that shaking intensity would be 3/ (20+1) = 14% probability of failure per item of equipment.

An example of this procedure for estimating a seismic fragility function using a probability graph is illustrated in Figure 3-1 for the generic equipment category of large vertical pumps, the first entry in Table 1-1. The graph features a table listing the raw data sample for large vertical pumps from the EPRI database. The table includes an abbreviated name of the plant site, the peak ground acceleration measured or estimated for the site, the number of pumps exposed to shaking at the site, and the number failed if any. For the purpose of this study, “failure” of a pump would be limited to serious earthquake damage, where the pump required disassembly and replacement of a major component such as the motor, drive shaft, impeller, bearings, suction casing, etc. For large pumps (several hundred horsepower) this process could require weeks or even months depending on the availability of replacement components and impediments to disassembling the pump and moving replacement components in and out of its plant location.

Data points are plotted on the probability graph in Figure 3-1 for three shaking intensity levels, MMI VII (0.26g), MMI VIII (0.42g), and MMI VIII+ (0.59g). If there are no instances of failure at any site within a shaking intensity level, a conservative assumption of ½ failure is made in order to avoid data points of zero value.

A best-fit straight line for the three data points is drawn using the regression algorithm in the program Excel. The best-fit line on the probability graph correlates failure probability with peak ground acceleration by correlating standard deviations from the median (sigma) as the X-axis versus natural logs of PGA as the Y-axis.



Site	PGA	Number of Pumps	Number Damaged
Manzanillo	0.42g	4	1
Getty Oil Plant	0.51g	2	0
Coalinga Water	0.53g	3	0
San Luis Canal	0.30g	7	0
Piti Steam Plant	0.26g	2	0
Moss Landing	0.30g	1	0
Gilroy Cogen	0.32g	2	0
Coolwater Cogen	0.35g	2	0
Burbank 1971	0.30g	2	0
Burbank 1994	0.30g	2	0
Glendale 1971	0.25g	3	0
Glendale 1994	0.25g	2	0
Pasadena 1971	0.20g	3	0
Pasadena 1987	0.20g	3	0
Pasadena 1991	0.20g	3	0
Ormond Beach 1973	0.10g	2	0
Ormond Beach 1994	0.10g	2	0
Humboldt Bay 1975	0.31g	2	0
Humboldt Bay 1980	0.30g	2	0
Humboldt Bay 1991	0.38g	2	0
Hunters Point	0.15g	2	0
Petacalco	0.27g	2	0

Figure 3-1: The data sample of large vertical pumps from the EPRI database includes 55 items subjected to ground shaking intensity of MMI VII to MMI VIII+ or PGA averaging 0.26g to 0.59g. There is one instance of serious damage at a site experiencing MMI VIII+, as noted in the data summary table at right. Incremental failure rates (black dots) are plotted on the probability graph as the number of pump failures out of the number of pumps subjected to the shaking intensity interval or higher, for sites subjected to MMI VII, MMI VIII and MMI VIII+ shaking intensity.

4.0 Combination of Fragility with Shaking Exceedence

The ultimate purpose of estimating seismic fragility functions is to develop estimates of the probability of damage to the few critical items that could result in a prolonged post-earthquake outage of the Diablo Canyon plant. In general the probability of serious earthquake damage to an item of equipment would be the probability of occurrence of a specific ground shaking intensity (0.30g PGA for example) multiplied by the equipment seismic fragility at that shaking intensity. The occurrence probability for ground shaking intensity is normally given as an exceedence function for peak ground acceleration (PGA). For example the probability of the site experiencing 0.20g PGA or higher is about 0.003 (0.3%) per year for the firm soil beneath the main plant, and about 0.006 (0.6%) per year the fill beneath the 220- and 500-kV switchyards uphill.

An estimate of the overall probability of earthquake damage for an item of equipment of a specific type would involve a summation of fragility-times-occurrence-probabilities over the range of credible ground shaking for the site. Each increment in the summation would be the probability of damage to the specific equipment type at a specific shaking intensity, times the occurrence probability of that shaking intensity. The summation of fragility-times-occurrence probabilities could be accomplished by a graphic integration, as illustrated by the hypothetical example in Figure 4-1.

The X-axis of the graph in Figure 4-1 is a mapping of the ground shaking intensity exceedence function for the specific site. The Y-axis is a mapping of the seismic fragility (probability of damage) for the specific equipment type over the range of credible ground shaking intensity. The annual probability of serious earthquake damage per item of equipment would be a summation of the products of seismic fragility at specific PGA levels times the corresponding probability of occurrence for the PGA, added over the range of credible ground shaking.

The graph of the hypothetical example in Figure 4-1 illustrates the summation. The increments in area beneath the curve are represented by the steps shaded in blue. Each area increment is the fragility (damage probability) of the equipment at the specific peak ground acceleration, F(pga), times the width of the area increment. The width of the area increment is the differential in ground shaking exceedence function dE. For example the differential dE could be the annual probability of exceeding a PGA of 0.30g at the Diablo Canyon site minus the probability of exceeding 0.29g. But of course this dE is simply the annual occurrence probability for the PGA interval 0.29 – 0.30g, i.e., the probability per year of peak ground acceleration at the site greater than 0.29g but less than 0.30g.

The graphic integration illustrated in Figure 4-1 is simply the summation over the range of credible PGA of the increments of equipment fragility times the annual probability of occurrence of that PGA level. The result of the graphic integration is the probability per year that the item of equipment would be seriously damaged by an earthquake.

Estimates of the annual probability of serious earthquake damage for the eight categories of equipment listed in Table 1-1 are illustrated in the graphs of Figures 4-2 through 4-9. In each figure the upper graph is the PGA exceedence probability for the DCPP site. (The PGA exceedence probabilities are slightly different for the firm soil beneath the plant versus the filled soil beneath the high voltage switchyards.) At lower left of each figure is the best-fit fragility function for the equipment type, based on a log-normal probability distribution (refer to the example in Figure 3-1). The lower right graph correlates the fragility function with the PGA exceedence probability. The correlation curve is plotted on a linear-linear scale to facilitate graphic integration. The area beneath the curve is the estimate of the annual probability of serious earthquake damage per item for each equipment type.

The eight graphs result in estimates for the annual probability of earthquake damage ranging from 6.3E-5 (steel tanks) to 2.2E-04 (steam-plant-specific-equipment). The probability of serious earthquake damage averages around 1.E-04 (one chance in 10,000 per item per year). As an order-of-magnitude check, it might be noted that the seismic fragility for most categories of equipment is less than 10% at 0.35g, which corresponds roughly to the 1,000-year earthquake the Diablo Canyon site. The product of these two factors results in an annual probability of earthquake damage on the order of 10^{-4} per-equipment-item-per-year.

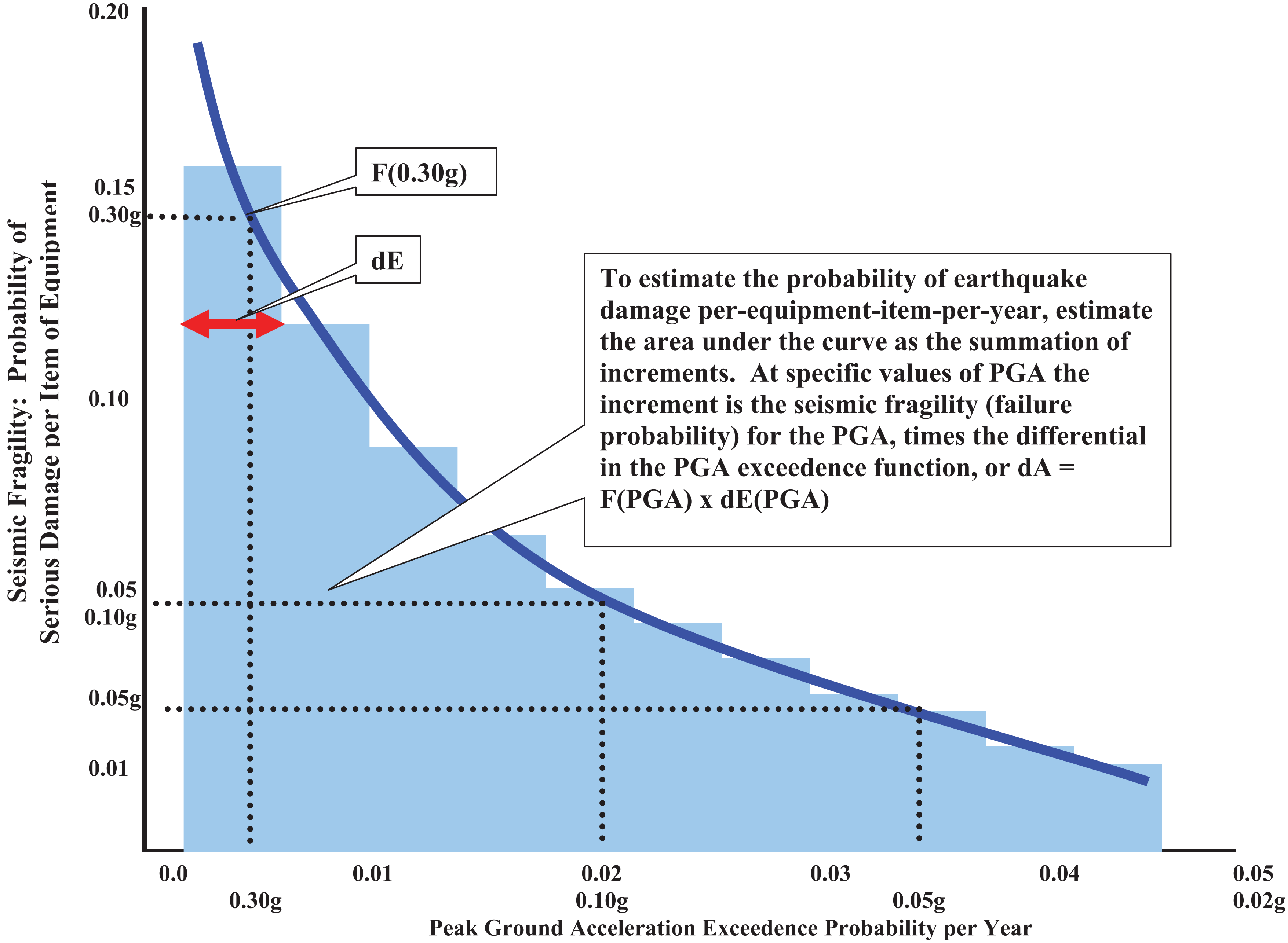


Figure 4-1: Illustration of seismic fragility integrated over PGA exceedence for the range of credible ground motion to estimate the annual probability of earthquake damage per item of equipment

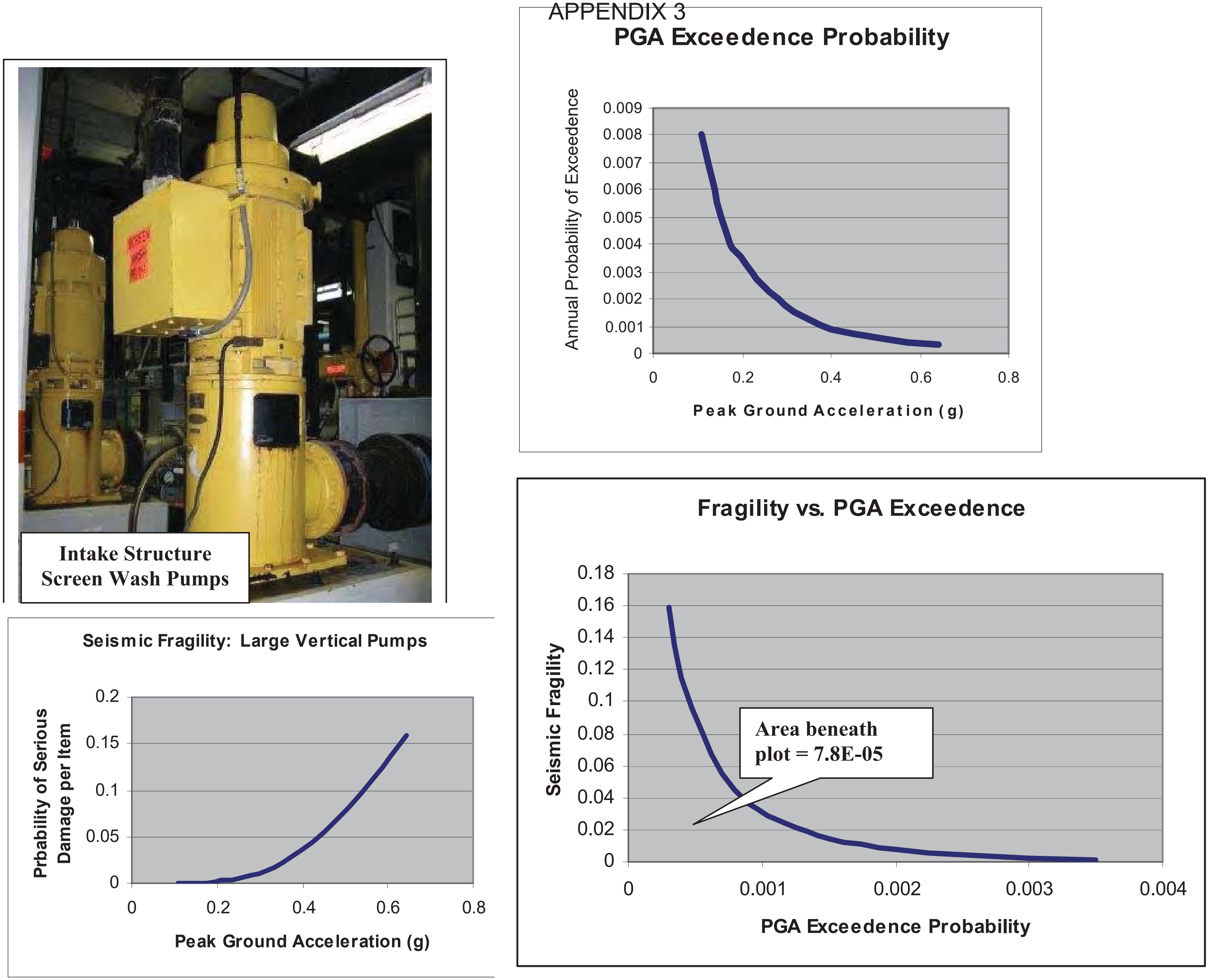


Figure 4-2: The exceedence function for peak ground acceleration (PGA) for the DCPP site (upper right) is graphed against the seismic fragility function for large vertical pumps (lower left). Integrating the area beneath the plot at lower right results in an estimate of the annual probability of serious earthquake damage of 7.8E-05 per pump per year.

APPENDIX 3

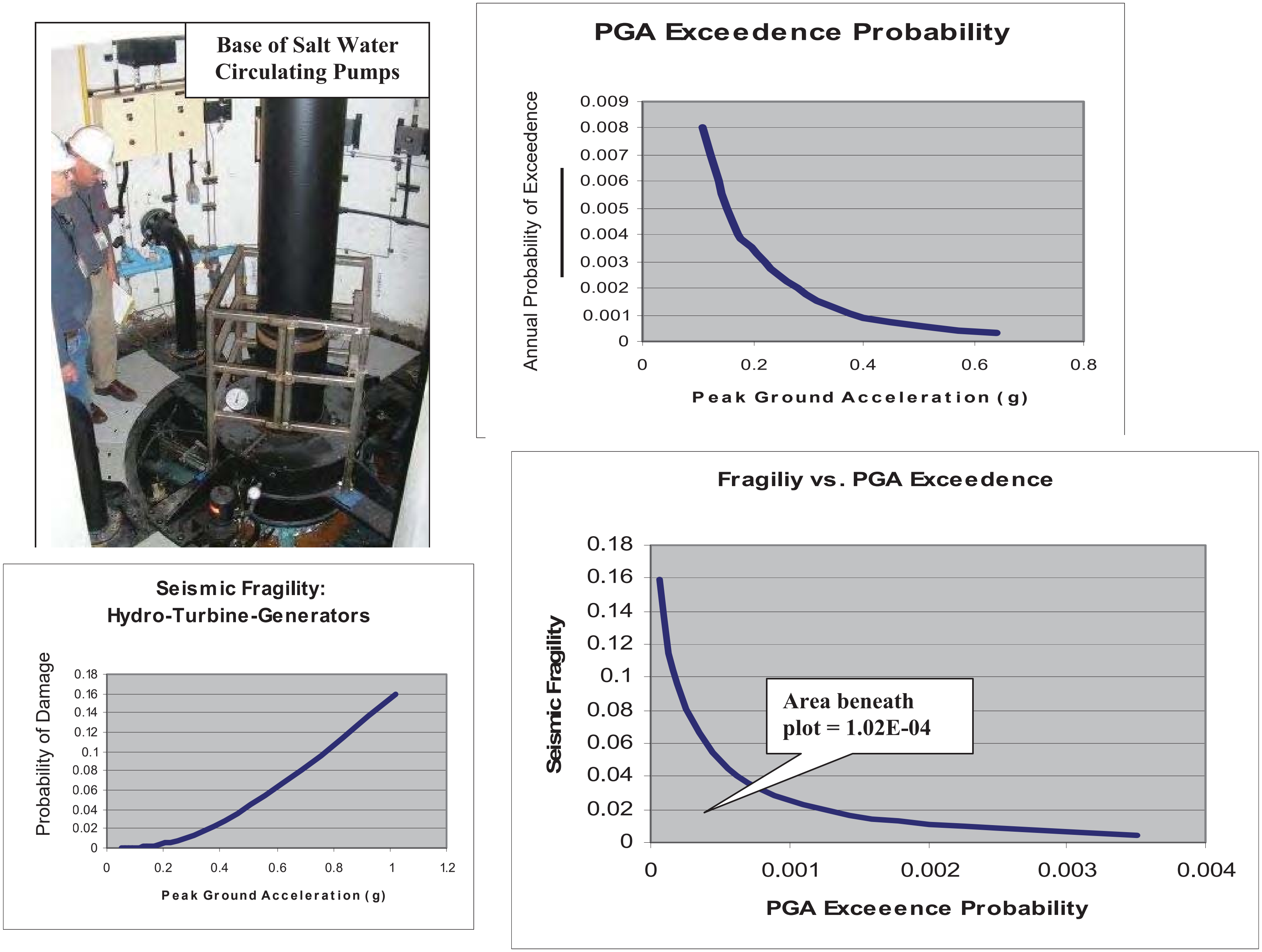
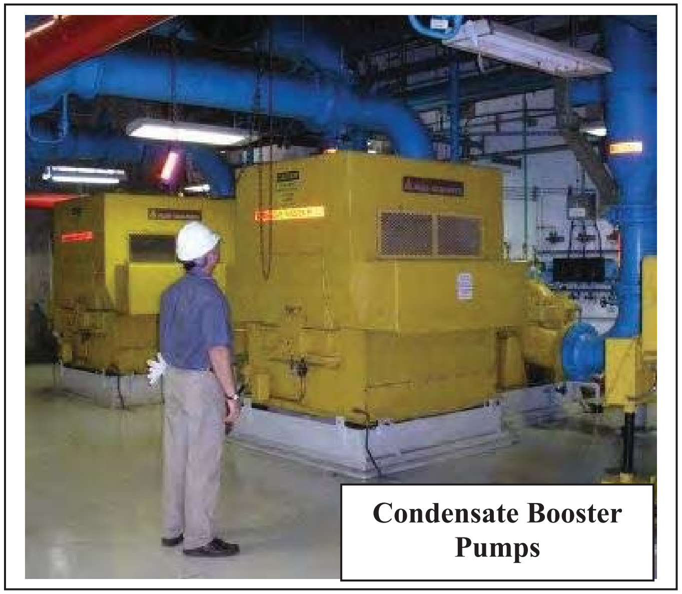
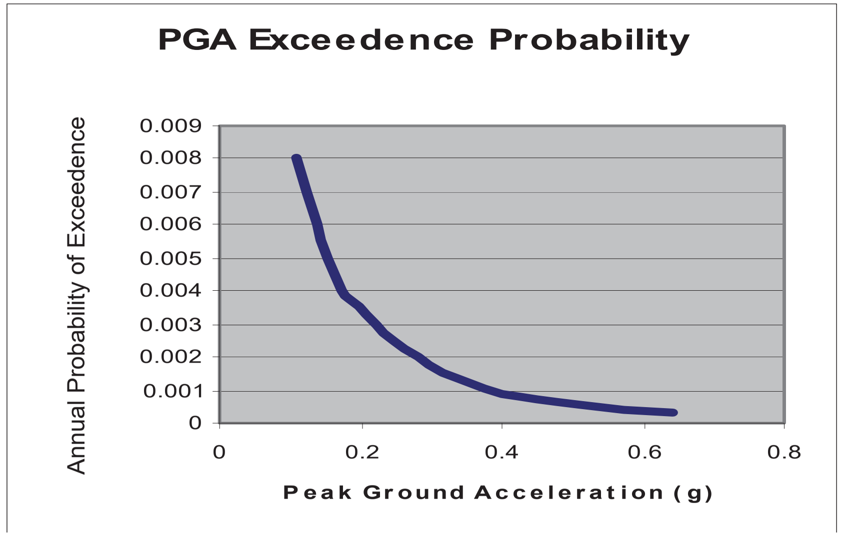
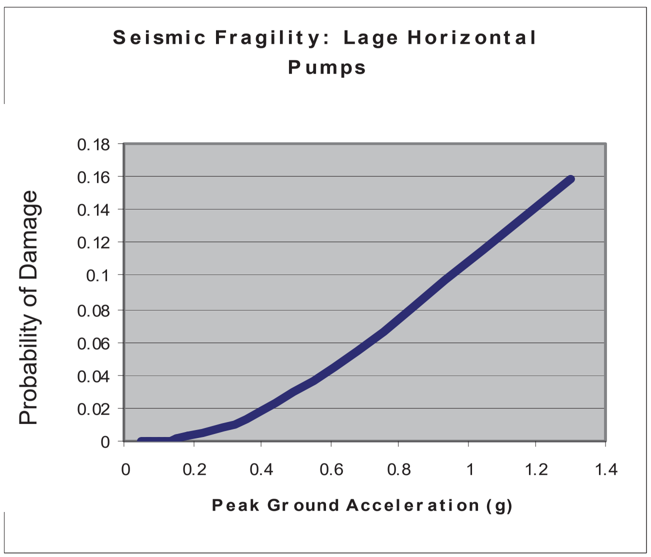


Figure 4-3: The exceedence function for peak ground acceleration (PGA) for the DCPP site (upper right) is graphed against the seismic fragility function for hydro-turbine-generators (lower left), Hydro turbines are considered most representative of the large salt water circulating pumps for the DCNPP. Integrating the area beneath the plot at lower right results in an estimate of the annual probability of serious earthquake damage of 1.02E-04 per circulating water pump.







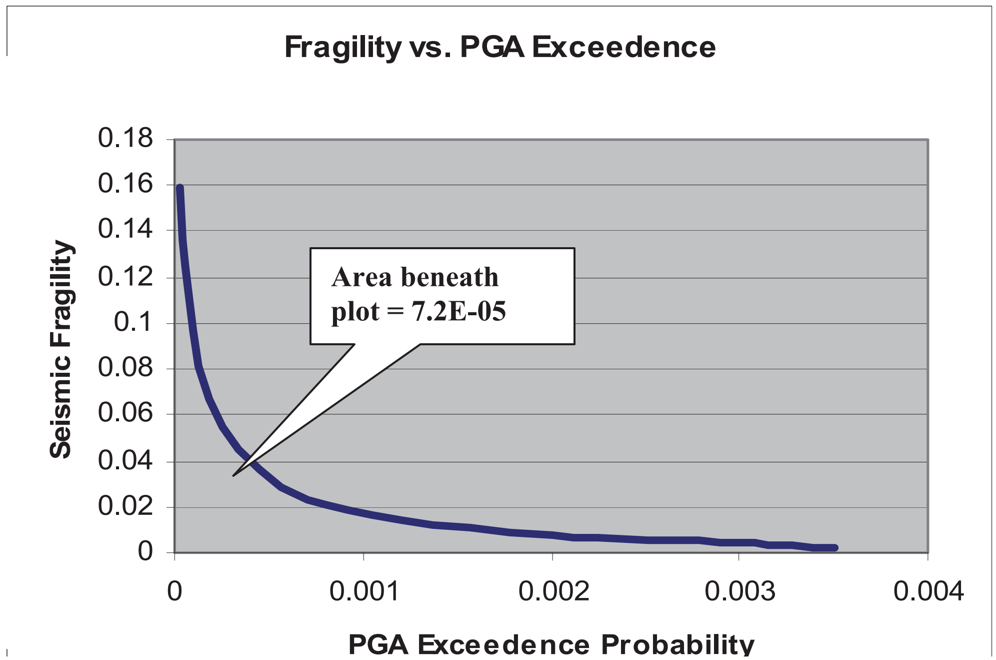


Figure 4-4: The exceedence function for peak ground acceleration (PGA) for the DCPP site (upper right) is graphed against the seismic fragility function for large horizontal pumps (lower left), Integrating the area beneath the plot at lower right results in an estimate of the annual probability of serious earthquake damage of 7.2E-05 per pump.

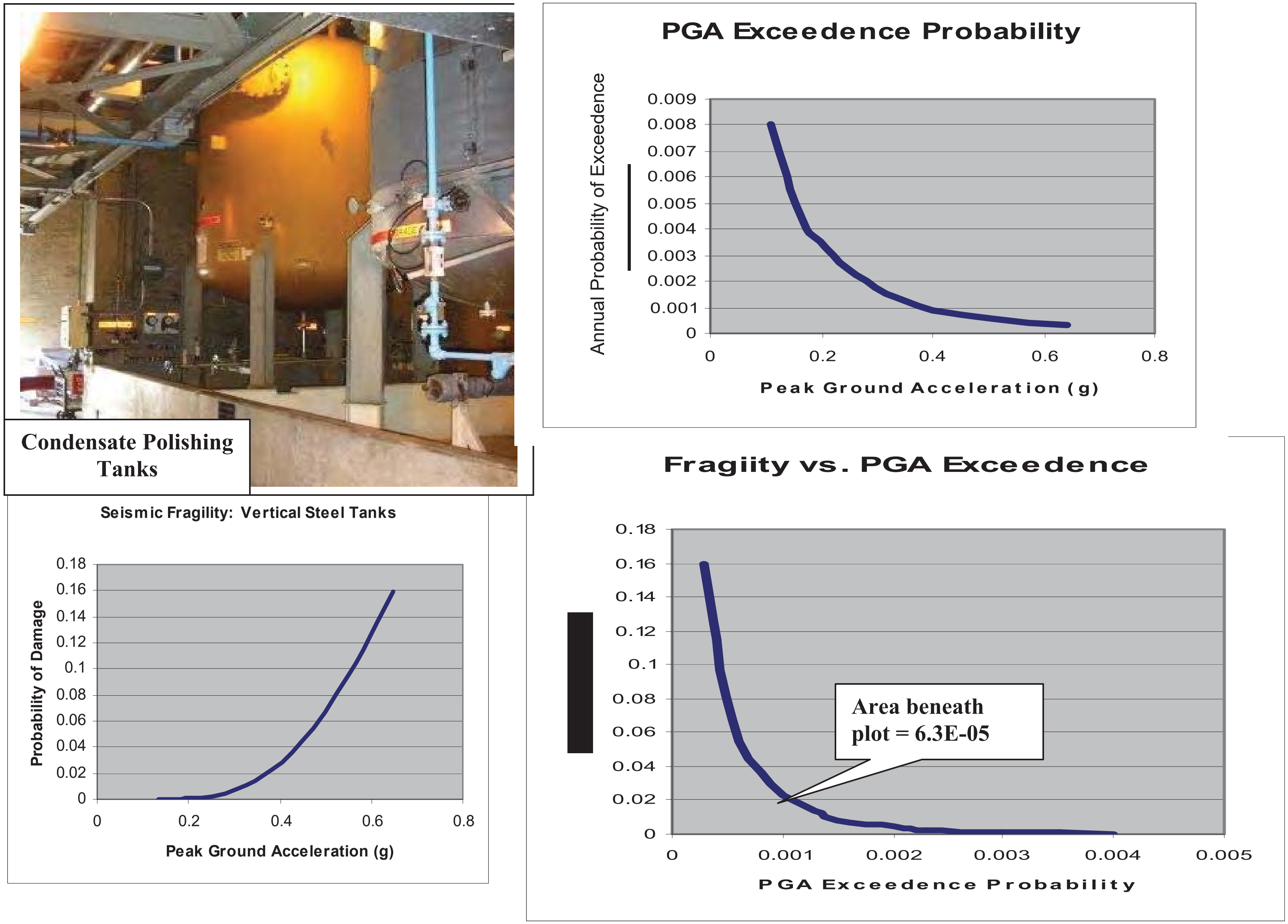


Figure 4-5: The exceedence function for peak ground acceleration (PGA) for the DCPP site (upper right) is graphed against the seismic fragility function for vertical steel tanks (lower left), Integrating the area beneath the plot at lower right results in an estimate of the annual probability of serious earthquake damage of 6.3E-05 per vessel.

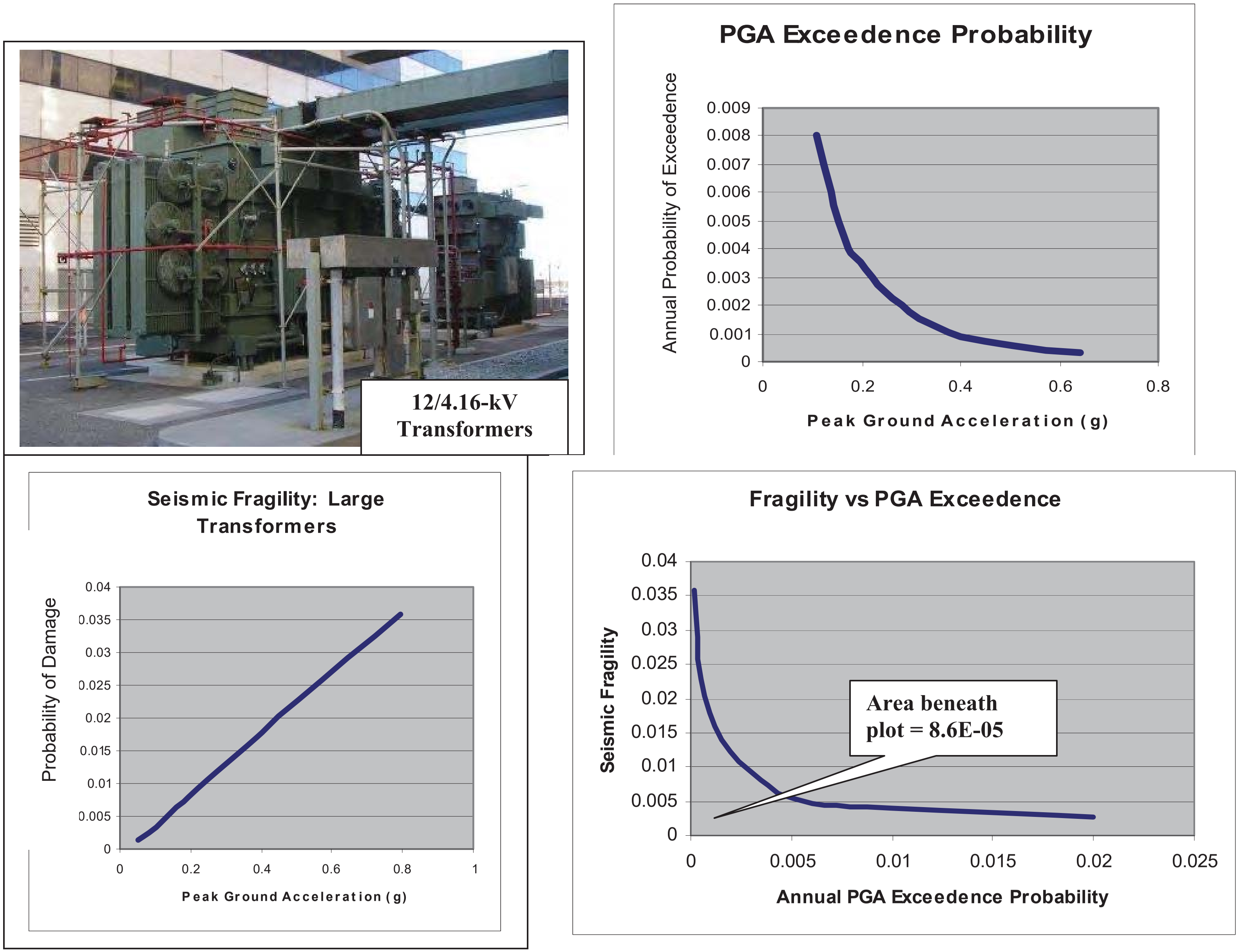


Figure 4-6: The exceedence function for peak ground acceleration (PGA) for the DCPP site (upper right) is graphed against the seismic fragility function for large transformers (lower left), Integrating the area beneath the plot at lower right results in an estimate of the annual probability of serious earthquake damage of 8.6E-05 per transformer.

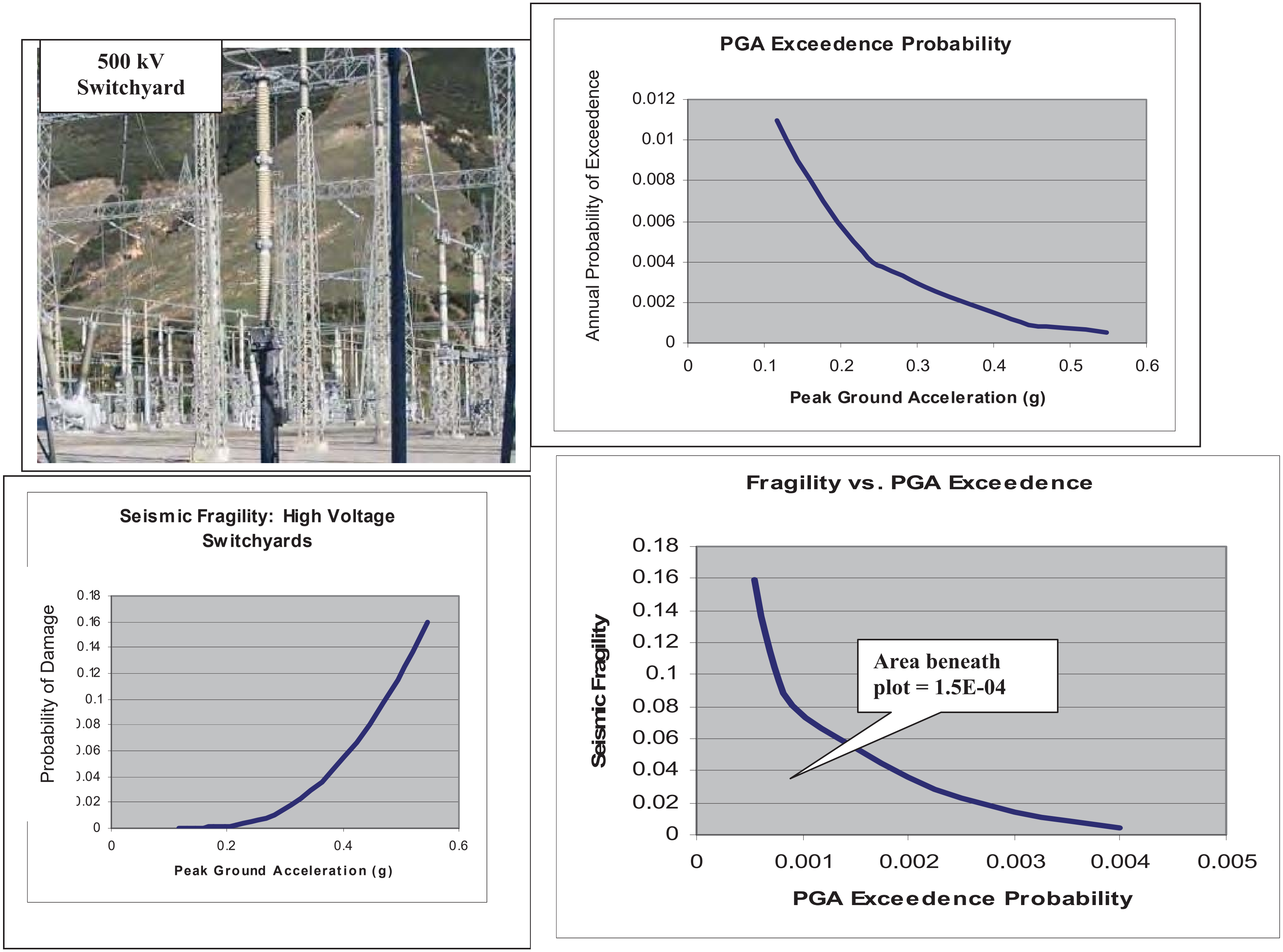


Figure 4-7: The exceedence function for peak ground acceleration (PGA) for the DCPP site (upper right) is graphed against the seismic fragility function for high voltage switchyards (lower left), Integrating the area beneath the plot at lower right results in an estimate of the annual probability of 1.5E-04 for switchyard repair time exceeding 4 months.

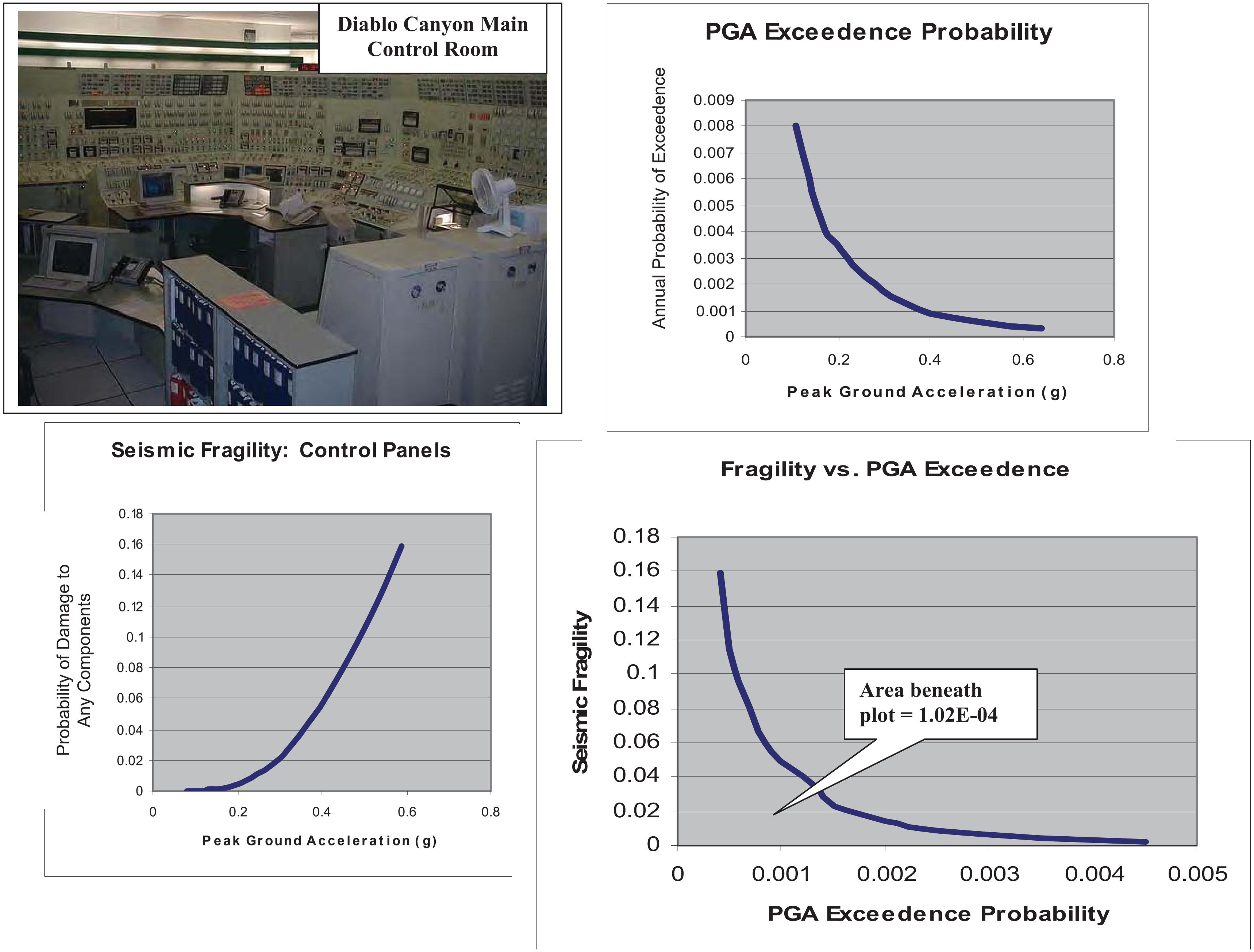


Figure 4-8: The exceedence function for peak ground acceleration (PGA) for the DCPP site (upper right) is graphed against the seismic fragility function for components of control panels (lower left), Integrating the area beneath the plot at lower right results in an estimate of the annual probability of 1.02E-04for damage to any control panel component.

APPENDIX 3

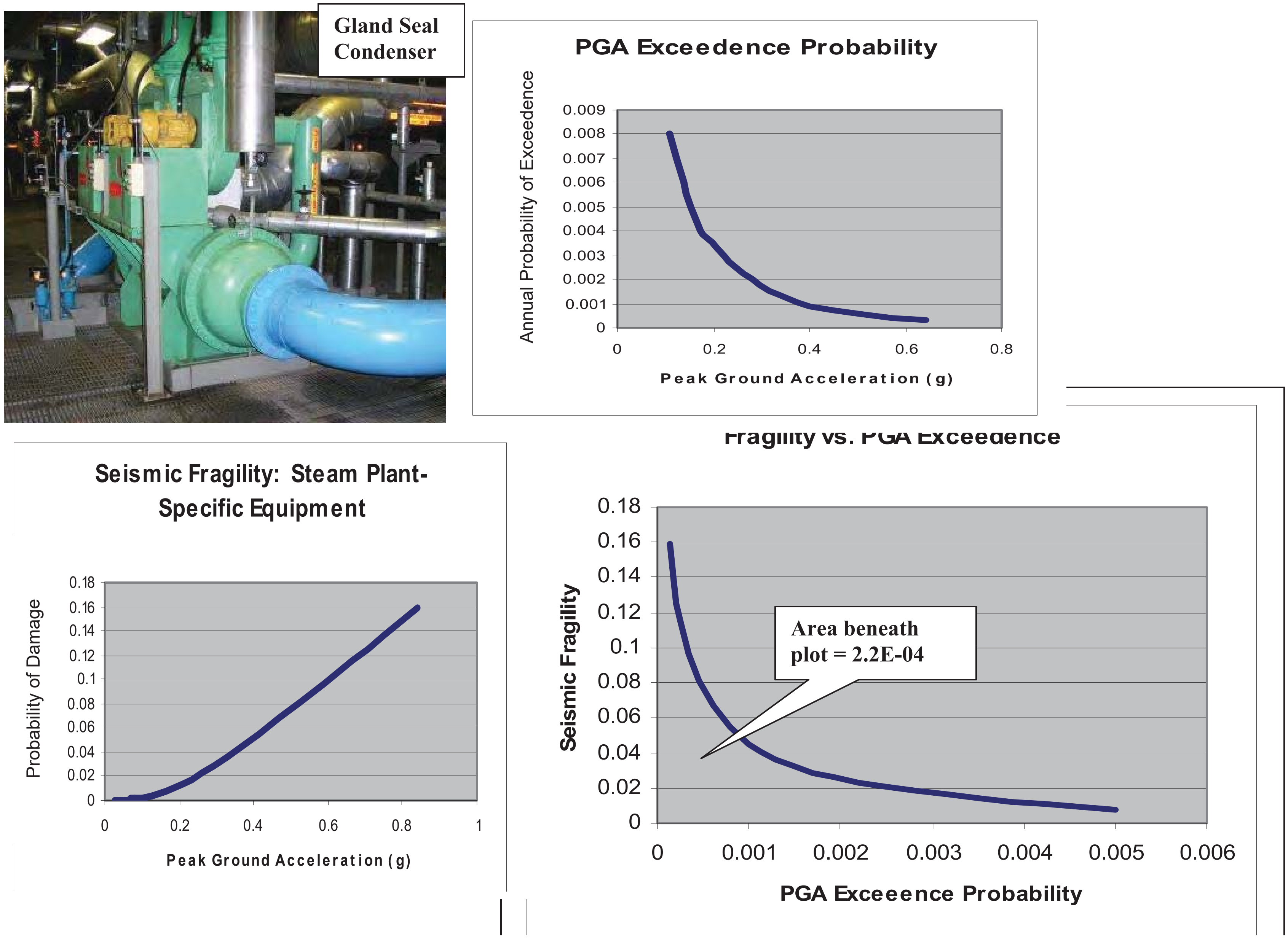


Figure 4-9: The exceedence function for peak ground acceleration (PGA) for the DCPP site (upper right) is graphed against the seismic fragility function for equipment specific to steam generating units (lower left), Integrating the area beneath the plot at lower right results in an estimate of the annual probability of 2.2E-04 for serious damage per equipment item per year.

5.0 Equipment Categories with Long Replacement Times

The sections below discuss the eight generic categories of equipment listed in Table 1-1, for which annual earthquake damage probabilities are computed in Figures 4-2 to 4-9. The inventory of examples of equipment from the EPRI database that would be representative of equipment in the DCPP is listed in Appendix C, reproduced from an Excel spreadsheet. The spreadsheet includes all database sites that would have at least one item of equipment within the eight generic categories listed in Table 1-1.

The inventory of earthquake-affected equipment represents a range of installations, applications and vintages (year of equipment manufacture). The database should therefore provide some indication of significant variations in the tendency for earthquake damage with vintage of the equipment and with age of the equipment at the time of the earthquake. Any decrease in the tendency for damage in newer equipment would tend to illustrate the effect of improvements in design codes over the years. The question of improved seismic performance in newer equipment is particularly relevant to the DCPP equipment. Equipment in the DCPP was for the most part purchased in the late 1960s or early 1970s. This makes most components of the plant about 40 years old at the present time. Any improvement in the seismic durability of equipment with the evolution of design codes over 40 years would presumably show up in the record of actual earthquake performance.

5.1 Large Vertical Pumps

Large vertical pumps at the DCPP that could require long replacement times include the condensate and the intake structure screen wash pumps, as listed in Table 1-1. Figure 5-1 includes photos of example large vertical pumps from the EPRI database. Only large pumps would present a likely long replacement time if seriously damaged. A large pump would generally be one powered by a drive motor of several hundred horsepower. Motors tend to be the most often replaced component in the rare event of pump failure. Large motors are not off-the-shelf items from manufacturers, but have to be made-to-order. It may be possible to find a large motor somewhere in the world (either new or used) that would work as a replacement, although this would require finding a motor that specifically fit the frame and pump drive, or could be modified to fit.

The spreadsheet in Appendix C lists 55 examples of large vertical pumps. The database sample is limited to pumps of several hundred horsepower, which were operating at the time of their earthquake according to the best available information from site investigations. Of the 55 pumps there are 12 instances of damage where disassembly and rebuilding or complete replacement of the pump may have been required. Each instance of damage is briefly summarized below.

At the LLolleo pump station and water treatment plant near Santiago, Chile, a deep well pump suffered a cracked well casing in the 1985 earthquake. The repair required removing the pump motor and well casing including the drive shaft and pump impeller, re-welding the casing and re-installing all components. The time period for completing these repairs was not reported, but such a repair procedure could stretch to weeks or even months depending on the size of the pump, the availability of replacement parts and access difficulties in the pump location.

One of condensate pumps in the Manzanillo Steam Plant was found to be damaged following MMI VIII ground shaking in the earthquake of 1995. Bearings supporting the 20-foot drive shaft of the pump were found to be damaged, presumably due to the earthquake. The pump motor was lifted from its base pad and the drive shaft and impeller removed. Following replacement of the bearings within the sub-floor well casing, the impeller, shaft and motor were replaced. Here again, while the replacement time for the Manzanillo pump did not stretch to months, this type of damage could require a prolonged replacement period depending on the size of the pump and accessibility problems with the pump location.

A deep well pump motor burned out and required replacement at the Rio Acelhuate pump station serving the City of San Salvador in the earthquake of 1986. The cause of motor burnout was not clear, although settlement around the deep well casing may have imposed a binding moment on the impeller drive shaft, subsequently overloading the motor. Replacement of a pump motor in a large vertical pump could require a prolonged period depending on motor size and availability, and accessibility of the pump location.

A total of nine vertical pumps were damaged at several water and wastewater pumping stations serving the US Navy facilities on the Island of Guam in the 1993 earthquake. Serious damage included motor burnout and replacement of drive shaft bearings. Damage to pumps appeared to result from a water hammer effect. The sanitary water pumps discharged into a distribution system of many miles of piping, while the wastewater pumps drew from miles of sewage intake line. Pressure surges during the earthquake in these long runs of piping appear to have caused extreme overload of the pumps and their drive motors are several station locations.

The procedure for estimating seismic fragility discussed in Section 3 allows estimates of the probability of serious damage to large vertical pumps as the number of failures divided by the total sample size for different intensities of ground shaking. Large vertical pumps would appear to have a failure probability of about 1% for sites subjected to ground shaking intensity of MMI VII (0.27g average PGA), and a failure probability of about 20% for sites subjected to ground shaking of MMI VIII or higher (0.42g or higher). The abrupt increase in seismic fragility results from the relatively large number of failures at sites experiencing MMI VIII shaking intensity.

The fragility estimates above may be excessively conservative for vertical pumps in the DCPP. Most of the instances of serious damage appear due to pressure surges in long runs of piping upstream or downstream of the pumps serving water and wastewater systems on the Island of Guam. The systems containing large vertical pumps at the Diablo Canyon site do not draw from or discharge into long runs of piping, making the earthquake-induced water hammer risk unlikely. Similarly, the instance of a motor burnout at the Rio Acelhuate pump station in San Salvador appears due to settlement in the soft soil surrounding the deep well casing. Finally the instance of cracking in the well casing at the Llolleo pump station in Chile was reported to have occurred in a prior weld repair of a corrosion-induced crack. If apparent water hammer, soil settlement and corrosion causes were eliminated from the data sample, there is only one instance of serious vertical pump damage, the condensate pump at the Manzanillo Plant. The resulting estimates of seismic fragility would be about 1% for MMI VII ground shaking, 3% for MMI VIII shaking, and 14% for MMI VIII+ shaking (the large figure for MMI VIII+ is due to a very limited sample size). These estimates would appear more appropriate for the DCNPP vertical pumps.

5.2 Circulating Salt Water Pumps

Large vertical pumps would also include the circulating salt water pumps that provide the heat removal source for the steam turbine condensers. The circulating water pumps consist of a large drive motor mounted on the upper level of the intake structure, with the pump impellers mounted at the base of the structure below. Because of their size and embedment in the concrete enclosure, the circulating water pumps are structurally similar to small hydroelectric generating units. The circulating water pumps are therefore discussed as a separate category of equipment. Photos of installations similar to the circulating water pumps from the EPRI database are presented in Figure 5-2.

The spreadsheet in Appendix C lists 33 examples of hydroelectric generating units of various sizes in the database. The database sample is limited to hydro units operating at the time of their earthquake according to the best available information from site investigations. Operating hydro-turbine-generators were therefore subject to their normal rotational and hydraulic pressure loads as well as seismic loads. There are no instances of serious damage to hydro-turbine-generators for the 14 dam sites where generating units were operating at the time of their earthquake. As zero is not an acceptable estimate for pump fragility, the sample size of hydro units results in a conservative estimate of about 1.5% failure probability for sites subjected to ground shaking intensity of MMI VII and a failure probability of 3% at MMI VIII. As there are no hydro plants in the database subjected to shaking in excess of MMI VIII, a fragility estimate is not available for MMI VIII+ ground shaking.

Because hydroelectric plants, like the DCPP circulating water pumps, are built into heavy concrete concrete enclosures, it would appear that upgrades in building codes over the years would affect seismic performance. However the design of concrete enclosures for hydro plants tends to far exceed the requirements of conventional buildings codes, as most hydro plants are built into dams and must resist massive hydraulic pressure. The evolution of building codes for conventional structures therefore has probably had little effect on the design of hydroelectric plants

5.3 Horizontal Pumps

Horizontal pumps at the DCPP that could require long replacement times include the condensate booster, feedwater, heater drain and service water pumps, as listed in Table 1-1. Photos illustrating similar equipment from the EPRI database are presented in Figure 5-3. As with vertical pumps discussed above, the sample in the spreadsheet of Appendix C is limited to horizontal pumps of several hundred horsepower, which were likely operating at the time of their earthquake.

Out of a data sample of 116 large pumps, there are two instances of serious damage where replacement of the pump might have been required. In the 1987 earthquake, at the Sanwa data center near Whittier, California, a chilled water pump suffered a fractured impeller casing. The fracture was apparently due to excessive loads on the impeller nozzles from the long runs of rod-hung overhead piping. One horizontal pump at a water pumping station serving the US Navy facilities on the Island of Guam suffered a motor burn-out in the 1993 earthquake. As with the damage to vertical pumps on the island discussed in Section 5.1, the cause of motor burnout appears to have been pressure surges (water hammer) in the long runs of piping in the downstream water distribution system. Here again the instance of water hammer damage would not appear applicable to the DCNPP pumps. The instance of impeller casing damage due to loads from the flexure of attached piping might be credible for the DCPP pumps. This single instance of failure is therefore retained for estimating the seismic fragility of large horizontal pumps. The sample size of 116 large horizontal pumps, with one failure, results in estimates of about 0.8% failure probability for sites subjected to MMI VII, 1.4% for MMI VIII, and 4.5% for MMI VIII+.

For both vertical and horizontal pumps, age of the pumps at the time of their earthquake, or the vintage of the pumps (year of manufacture), does not seem to correlate with seismic damage. The only instance of serious damage to a large vertical pump occurred at a plant that was only a few years old at the time of its earthquake in 1995. The pump would have dated from around 1990 and thus would be more representative of current product lines than equipment dating from the 1960s or early 1970s. Most instances of pump damage actually resulted from causes external to the pump itself, specifically pressure surges in long runs of attached piping. There are no instances of damage to pumps due to failure of anchorage, perhaps the only factor that might be affected by improvements in building codes over the years. Pump anchorage requirements are normally determined by operating loads, not by seismic requirements. The anchorage capacity for pumps and pump skids is therefore usually well above the minimum requirements for earthquake.

5.4 Steel Vessels

Large storage tanks that are part of Design Class I safety systems of the DCPP are specifically designed for the safe shutdown earthquake (SSE). These tanks would presumably survive any credible level of ground shaking. Smaller Design Class II balance-of-plant vessels that could be damaged by earthquake and incur long replacement times are listed in Table 1-1. These vessels include waste collection tanks, demineralizers and demineralizer regeneration tanks for the condensate polishing system located in an annex of the turbine building. Possible long replacement times for these vessels could result from the time required to build a replacement tank, and the difficulty in removing the damaged tank and installing the replacement in the congested area.

The condensate polishing system vessels are represented by the equipment category of small-to-medium-sized welded steel vertical tanks, pressure vessels and demineralizers in the EPRI database. The database includes pad-mounted-flat-bottom, steel-skirt-mounted and steel-post-mounted vessels. The data sample in the spreadsheet of Appendix C is an even number of 300 tanks. There are 11 instances of serious damage where the tank required either extensive repair or replacement. Almost half the tank failures occurred at a single site, a distillery on the northern island of New Zealand in the earthquake of 1987. There were no ground motion records near the distillery site, although the immediate area was rated at MMI IX (Intensity Nine) from observed effects. About one-fifth of the stainless steel and carbon steel tanks on the site required replacement. The most apparent causes of damage was failure of light anchorage resulting in lift-up and slam-down of the tanks, buckling the wall at the base and rupturing the welded seam between wall and tank bottom. If all dozen instances of serious tank failure are included in the data sample, the resulting estimates for tank failure probabilities are about 0.3% for MMI VII sites, 3% for MMI VIII sites, and 12% for MMI VIII+.

Of the dozen instances of serious tank damage in the data sample, only three tanks were unanchored. One failure involved overturning of a tall liquid oxygen pressure vessel mounted on unanchored steel legs. The second and third failures occurred at steam power plants where unanchored pad-mounted tanks ruptured their welded base-wall seam, apparently due to lift-up and slam-down. The remaining nine instances of serious damage all occurred to tanks equipped with some amount of anchorage to their concrete pads or floors. It is unclear whether sufficient anchorage of these tanks to preclude pull-out of their bolts would have prevented damage. The vessels listed in Table 1-1 for the DCPP waste treatment area all appear adequately anchored to resist credible ground shaking for the site. Therefore the estimates of seismic fragility derived by including failures of unanchored and under-anchored tanks would appear conservative. However, there is no way to determine which of the dozen instances of serious tank damage would not have occurred if the vessels had been adequately anchored. The seismic fragility derived from a dozen failures out of 300 tanks is therefore retained as a conservative estimate.

The design of steel tanks has evolved over the years, both in anchorage requirements and in the vessel shell itself, as determined by standards such as the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API) or the American Water Works Association (AWWA). It would appear that improvements in tank design codes have improved the durability against earthquake damage. However the performance of tanks in the EPRI database leads to no clear indication that older tanks are more subject to seismic damage. The concentration of tank failures at the site in New Zealand was due to a combination of intense ground shaking, inadequate tank anchorage and the thin-walled design of stainless steel tanks. The facility was in fact relatively new at the time of its earthquake. Perhaps the only clear indication of age-related degradation as a factor in tank failure occurred at the Moss Landing Plant in the 1989 earthquake, where rupture of the unanchored tank appeared to be exacerbated by corrosion in the welded seam of the tank wall and bottom.

5.5 Large Transformers

Large transformers required for operation of the DCPP include units ranging from 12 kilovolts primary power to the 25/500-kilovolt step-up transformers. Photos of large transformers from the database are presented in Figure 5-5. The sample from the database listed in the Appendix C spreadsheet is drawn primarily from high voltage substations and large power plants. The sample is limited to transformers of primary voltage 220-kV and higher, as the higher voltage units have a tendency for seismic damage due to their mass and tall ceramic bushings. Damage to high voltage transformers is very common at sites experiencing more than MMI VII ground shaking intensity. However in nearly all instances transformer damage is repairable. The most common damage is to ceramic bushings atop the transformer tanks. Mild effects include leaking of insulating oil from seals at the bushing attachment, with fracture or disconnection of the bushing occurring at higher ground shaking. Also common are oil leaks at the junction of the transformer tank and the attached coil cooling radiators. The cantilevered mass of the radiators typically overstresses the flanged connections to the tank.

Many transformers are mounted on wheeled undercarriages atop rails, especially in older facilities. Wheels are often inadequately anchored to their rails, resulting in shifting of the transformers or derailing under strong ground shaking. Derailing of transformers often results in serious damage including rupture of the transformer tank. As the DCPP transformers are pad-mounted, damage to rail-mounted transformers are excluded from the data sample in the Appendix C spreadsheet.

While transformer damage is common at facilities experiencing ground shaking above MMI VII, damage is almost always repairable, usually within a few days. The sample of some 180 high voltage transformers listed in Appendix C includes three instances of damage where the transformer apparently required replacement. In two of the three instances of complete transformer failure the interior coil was reported as burned out, most likely due a sudden current surge from grounding of live conductor external to the transformer. The third instance reported an "exploded transformer and circuit breaker", apparently the step-up unit, at the Kukuan Hydroelectric plant in Taiwan. Presumably this also resulted from a current surge through the coil, as in the other two instances. The data sample for high voltage transformers results in an estimated failure probability of about 1% for MMI VII sites and 2% for MMI VIII sites. (Because two out of three transformer failures occurred at MMI VII sites, and no failures at MMI VIII+ sites, only two points are used to estimate a fragility function.)

The large mass of high voltage transformers makes it a category of equipment where improvements in building codes over the years may have some influence on seismic durability. Anchorage failures on large transformers are relatively common at high ground motion sites. While none of the three instances of transformer failure requiring replacement can be directly attributed to anchor failure, restraining the massive tank from shifting on its pad reduces the chance of conductor toppling and subsequent grounding of live conductor on adjacent steel. Inspection of the large transformers at the DCPP during the recent plant walk-down indicates that they are adequately anchored for any probable level of ground shaking. Thus increases over the years in the seismic loads for which equipment anchorage is designed would not appear relevant to the seismic fragility of the DCPP transformers.

5.6 High Voltage Switchyards

Construction of the 220- and 500-kV switchyards serving the DCNPP are generally similar to high voltage switchyards at some 34 sites in the EPRI database. One exception is the use of "dead tank" circuit breakers at DCPP, where the breaker is housed in an insulated tank near the ground. Dead tank breakers have a much better seismic performance record compared to "live tank" circuit breakers, where the breaker is mounted atop tall ceramic columns. This difference would tend to favor the seismic durability of the DCNPP switchyards compared to the majority of switchyards in the database.

Other than the circuit breakers, the DCPP switchyards have the typical components of column-mounted disconnect switches, current and potential transformers, surge arrestors and overhead rigid bus conductor. Photos of high voltage switchyards from database sites are presented in Figure 5-6.

Most switchyards of 220-kV or higher experience some degree of damage, usually concentrated in ceramic columns, at sites experiencing MMI VII or greater ground shaking. Switchyard damage can usually be repaired within days as long as the utility has access to replacement parts. Restoration time for switchyards increases to weeks or months if large equipment, specifically circuit breakers or transformers require replacement. The equipment category of high voltage transformers is discussed separately in the proceeding section. The balance of high voltage switchyard equipment is represented by the data sample listed in the Appendix C spreadsheet. Out of some 34 high voltage substation switchyards, the time period for restoration of service following the earthquake stretched to several months at two substations subjected to MMI VIII+ ground shaking. From this sample it would appear that the probability of multi-month repair times would be about 1.4% for sites subjected to MMI VII, 3 % for MMI VIII sites, and 22% for MMI VIII+ sites.

As with high voltage transformers, the large mass and high centers-of-gravity for most switchyard equipment would make anchorage to concrete pads an important factor in the seismic fragility of the equipment. Increases in design loads for anchorage with improvements in building codes could therefore influence failure tendency. However most substations in the PG&E and SCE systems have been upgraded over the years, to ensure adequate anchorage for credible levels of ground shaking. Improvements in building codes should therefore not be a significant factor in the durability of the DCNPP switchyards, as periodic upgrades have been implemented.

5.7 Control Panels

The original list of balance-of-plant SSC required for operation of the DCPP listed over 100 components of control and instrumentation systems. Most of these components are mounted in perhaps a dozen control panels, steel-framed-sheet-metal cabinets of various sizes located either in the main control room area or at remote points within the plant. As listed in the spreadsheet of Appendix C, the equipment category of control and instrumentation panels from the EPRI database includes some 340 separate cabinets, housing components that would total in the thousands. Examples of control panels from database sites are illustrated in Figure 5-7.

Control panel "failures" rarely involve all components in a cabinet, but are usually limited to one or two components. A "failure" in the database therefore is defined as any cabinet where at least one component was found to be inoperable after the earthquake. Failed components would generally not present a repair problem as long as replacements were available. Control panels are included as a generic category in Table 1-1 because of the possible problem of obsolescence in the older control systems of the DCPP. In the event that a replacement for a failed component could not be found in the warehouse, weeks or even months might be required to obtain or fabricate a replacement for product lines no longer supported by the original manufacturers or their successors.

Most of the database sites listed in the Appendix C spreadsheet include at least one control panel in some form or another This data sample for the equipment category ranges from combined electronic & pneumatic control systems dating from the 1950s, to analog systems of the 1960s & 1970s, through the conversion to digital systems in the 1980s and 90s. From the data sample of some 360 control panels, there are 25 instances where at least one component in the cabinet was found to be inoperable following the earthquake. The most common damage is failure of one or two components due to electrical burnout or an internal disconnection (loss of conduction within a component). Current surge is the likely cause of burnout in control components, due perhaps to grounding of power supply conductor during the earthquake, possibly external to the control cabinet. After burnout or internal disconnection, common causes of damage include failure of light anchors and overturning of the cabinets, or impact from falling ceiling fixtures. Cabinet anchorage and securing of ceiling fixtures would be affected by improvements in building codes over the years. However, all control and instrumentation cabinets reviewed at the DCPP were anchored sufficiently to withstand probable levels of shaking for the site. While other common causes of earthquake damage appeared possible, it appears unlikely that the DCNPP cabinets would fail their anchorage and overturn.

If the data sample of control and instrumentation panels included anchorage failure, then the probabilities for failure of at least one component in a panel would be about 1.5% for MMI VII sites, 6% for MMI VIII sites, and 17% for MMI VIII+ sites. If instances of anchorage failure and overturning were excluded from the data sample, the fragility estimates would be about 1% for MMI VII, 3% for MMI VIII and 11% for MMI VIII+. These estimates would appear more appropriate for the well-restrained cabinets found at the DCNPP.

5.8 Equipment Common to all Steam Generating Units

Some types of long-replacement-time equipment for the DCPP listed in Table 1-1 is found in essentially every steam turbine generating unit. The spreadsheet in Appendix C therefore correlates the inventory of steam condensers, steam jet air ejectors, gland seal condensers, lube oil system, and feedwater heaters, with the larger steam generating plants in the EPRI database that were operating at the time of their earthquake. The sample is limited to steam generating units of at least 100 megawatts capacity in order to ensure that the equipment is more-or-less representative of installations in the 1100-MW units of the DCNPP. Furthermore the sample is limited to units that were in operation, either generating power or at least on hot standby, to ensure that equipment was subjected to the combination of seismic and operating loads such as steam pressure or vacuum. The process of estimating seismic fragilities is simplified in that there are no instances of serious damage to any of the types of equipment listed in Table 1-1 as common to all steam units.

The EPRI database includes 20 steam units of at least 100 MW capacity in operation at the time of their earthquake. This sample size that includes no instances of serious damage results in a conservative estimate for failure of any steam-plant-specific-equipment of about 2% for MMI VII sites, 5% for MMI VIII sites, and 10% for MMI VIII+ sites. These estimates would apply to the condensers, air ejectors, gland seal condensers and components of the lube oil system for the DCNPP. A seismic fragility estimate for feedwater heaters is based on an assumed average of four feedwater heat stages per steam unit. The absence of damage to feedwater heaters results in an estimate of about 1/2% failure probability for MMI VII sites, 1% for MMI VIII sites, and 2% for MMI VIII+ sites.

Even if the data sample were expanded to include all steam generating units, regardless of size or operating state at the time of the earthquake, there are still no instances of serious damage to steam-plant-specific equipment. The only exception are a few leaking tubes in condensers reported at two sites following their earthquake. The increase in tube leak however did not prevent the steam units from operating, and the damaged tubes were quickly repaired. Increasing the sample size to some 90 steam units in the EPRI database of all sizes would result in estimates of about 1/2% failure probability for sites subjected to MMI VII, about 2% for MMI VIII, and about 8% for MMI VIII+.

5.9 Steam Turbine Generators

The large turbine generators of the DCNPP are considered an exception for the application of past earthquake experience in estimating seismic fragility. Steam turbine generators are of course present in every steam unit. Out of the data sample of some 20 larger steam generating units that were in operation at the time of their earthquake, there are two instances of serious damage to turbine generators. A low-pressure turbine at the Piti Steam Plant on the Island of Guam suffered bearing damage during the 1993 earthquake due to loss of lube oil pressure to the turbine bearings. Loss of oil pressure was due to loss of emergency DC power supply to the oil pumps, caused by toppled batteries that lacked restraint against overturning. A similar incident occurred in the single operating unit at the Moss Landing Steam Plant in the 1989 earthquake. Here again bearings on the low pressure turbine were found to be damaged following the earthquake. The exact cause of the bearing damage was not completely clear. Loss of the normal AC supply during the earthquake appears to have caused a drop in lube oil pressure to the turbine bearings before the DC-powered pumps reached full speed.

The two instances of bearing damage to spinning turbines, out of the limited data sample of steam units operating at the time of their earthquake, would appear to indicate a tendency for damage in operating turbine generators. A third instance of turbine damage at a site outside the EPRI database is of even greater interest. Damage to turbine bearings was reported by engineers at Tokyo Electric for operating units at the Kashiwazaki-Kariwa Nuclear Power Plant (KKNPP) in the magnitude 6.8 earthquake in Japan in 2007. The KKNPP steam units are essentially the same size as Diablo Canyon's, and would therefore be considered the most representative data point. Ground motion at the KKNPP site was measured at about 0.60g, indicating an apparent shaking intensity of MMI VIII+. While this intensity of shaking is very unlikely for the DCPP site, the instance of turbine bearing damage at KKNPP raises a particular concern. It would appear that the small size of the EPRI data sample for large turbine generators, and the occurrence of multiple instances of damage to bearings, would warrant special consideration. The potential for damage to the DCPP low pressure turbine bearings is addressed in a separate section of this report.

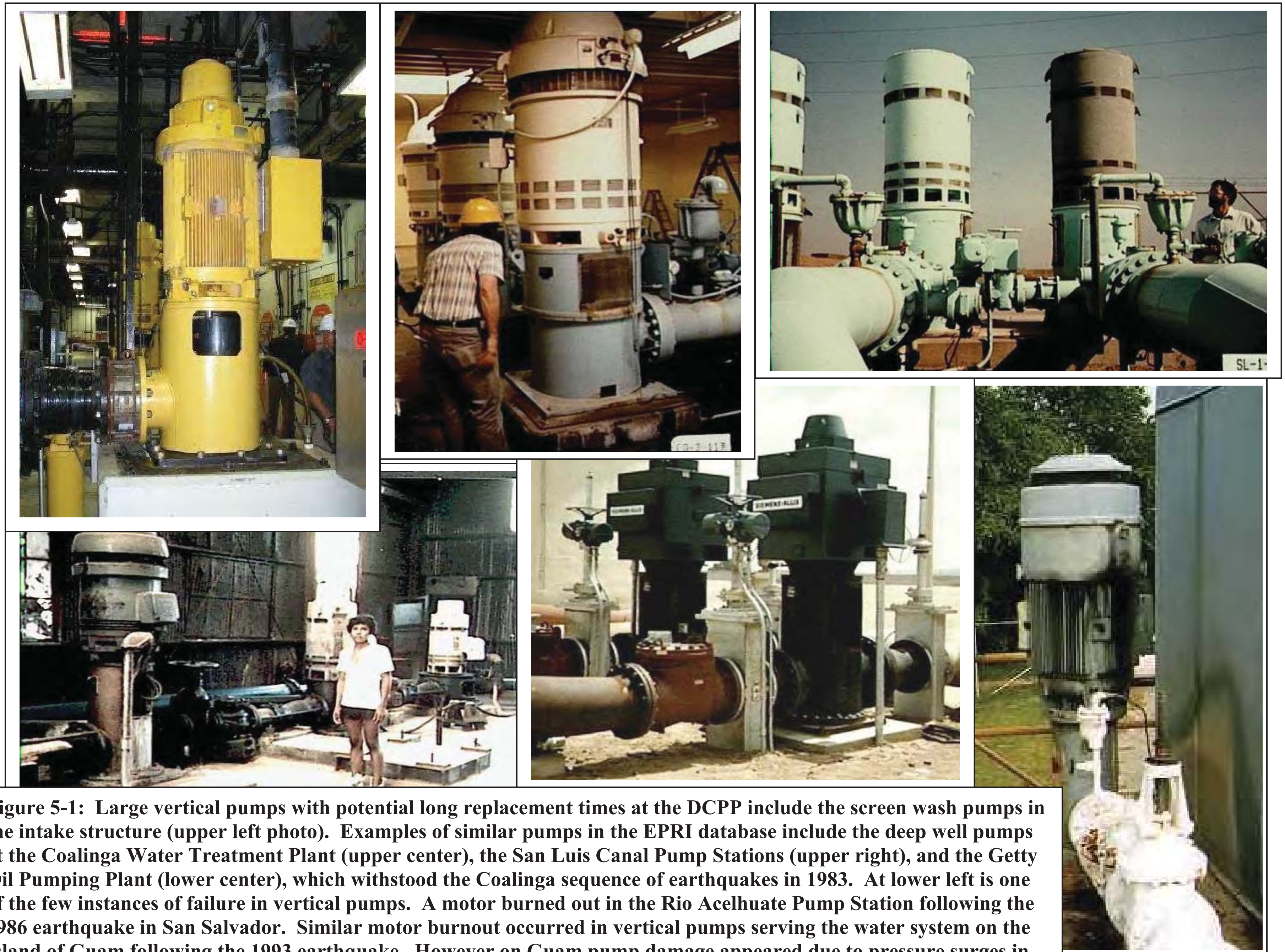


Figure 5-1: Large vertical pumps with potential long replacement times at the DCPP include the screen wash pumps in the intake structure (upper left photo). Examples of similar pumps in the EPRI database include the deep well pumps at the Coalinga Water Treatment Plant (upper center), the San Luis Canal Pump Stations (upper right), and the Getty Oil Pumping Plant (lower center), which withstood the Coalinga sequence of earthquakes in 1983. At lower left is one of the few instances of failure in vertical pumps. A motor burned out in the Rio Acelhuate Pump Station following the 1986 earthquake in San Salvador. Similar motor burnout occurred in vertical pumps serving the water system on the Island of Guam following the 1993 earthquake. However on Guam pump damage appeared due to pressure surges in the long runs of downstream distribution piping, and unlikely cause of damage for the DCPP.

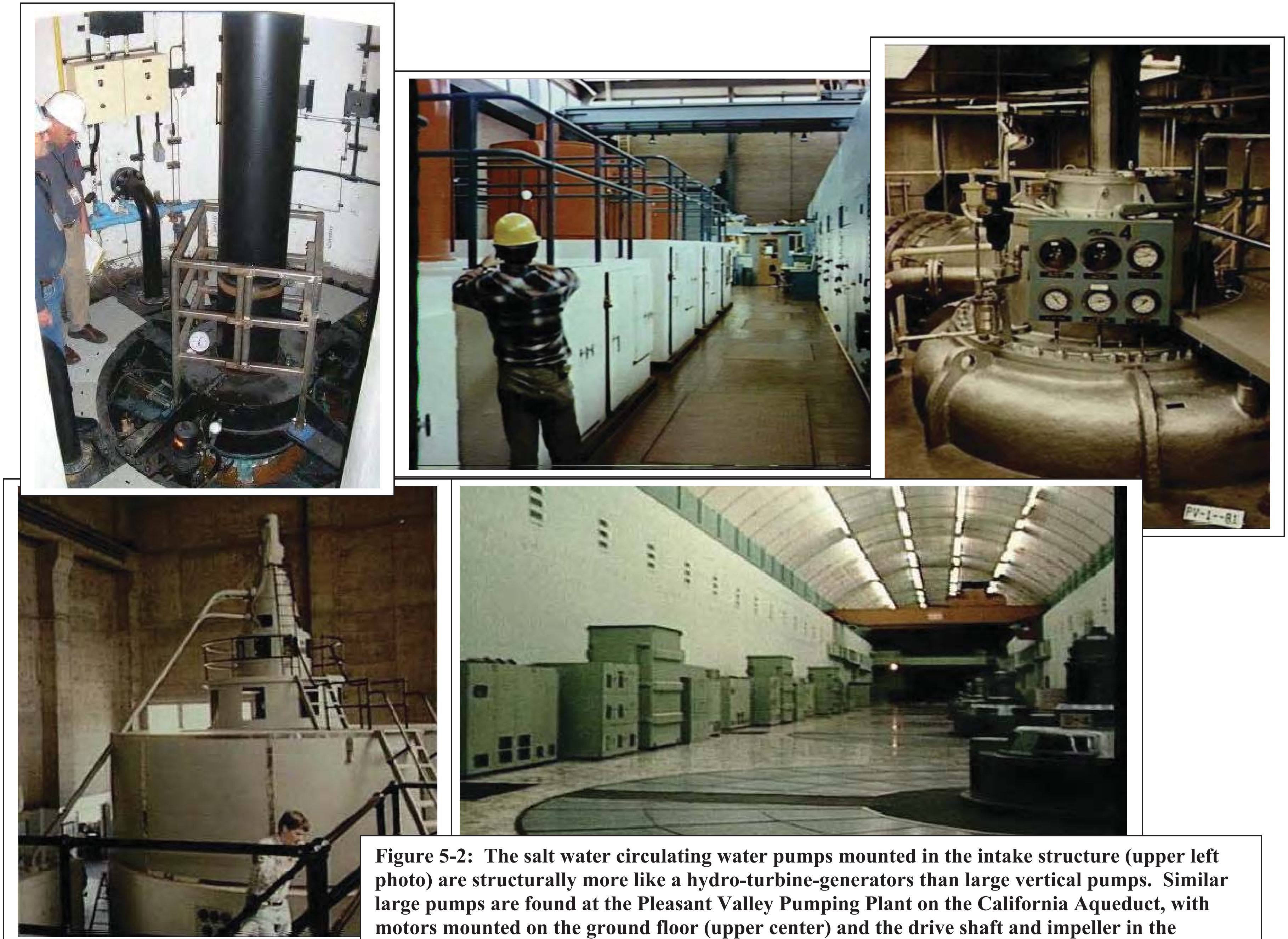
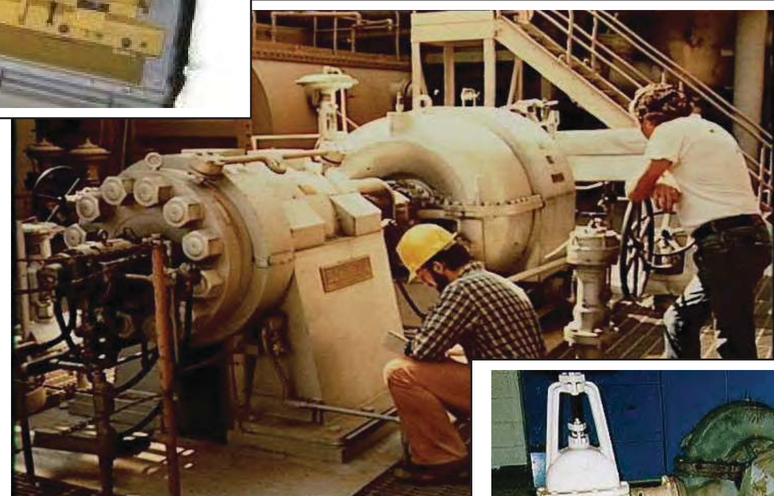


Figure 5-2: The salt water circulating water pumps mounted in the intake structure (upper left photo) are structurally more like a hydro-turbine-generators than large vertical pumps. Similar large pumps are found at the Pleasant Valley Pumping Plant on the California Aqueduct, with motors mounted on the ground floor (upper center) and the drive shaft and impeller in the subgrade level of the concrete enclosure below (upper right). The EPRI database includes many examples of hydroelectric units, such as the 1940s-vintage Drop IV Hydro Plant (generator at lower left) or the large six-unit Infiernillo Hydro Plant in Mexico (operating floor at lower right).



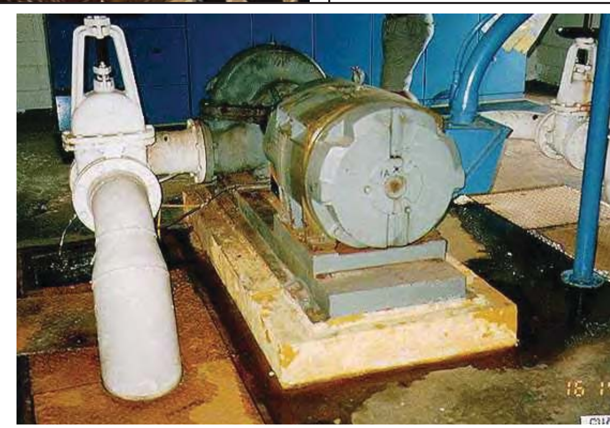


Figure 5-3: Large horizontal pumps like the DCPP heater drain pump (upper left) are present in many forms at sites investigated for the EPRI database. Examples include circulating water pumps, such as the unit at the Valley Steam Plant at upper right, and feedwater pumps such as the units serving the Manzanillo Steam Plant at lower left. Variations on large feedwater pumps include steam-turbine-powered units, such as at the Pasadena Power plant at lower center. Serious earthquake damage to horizontal pumps is rare. One of the few instances occurred in the Island of Guam water system, where motors required replacement on two pumps (lower right) due to apparent pressure surges in the downstream pipelines.

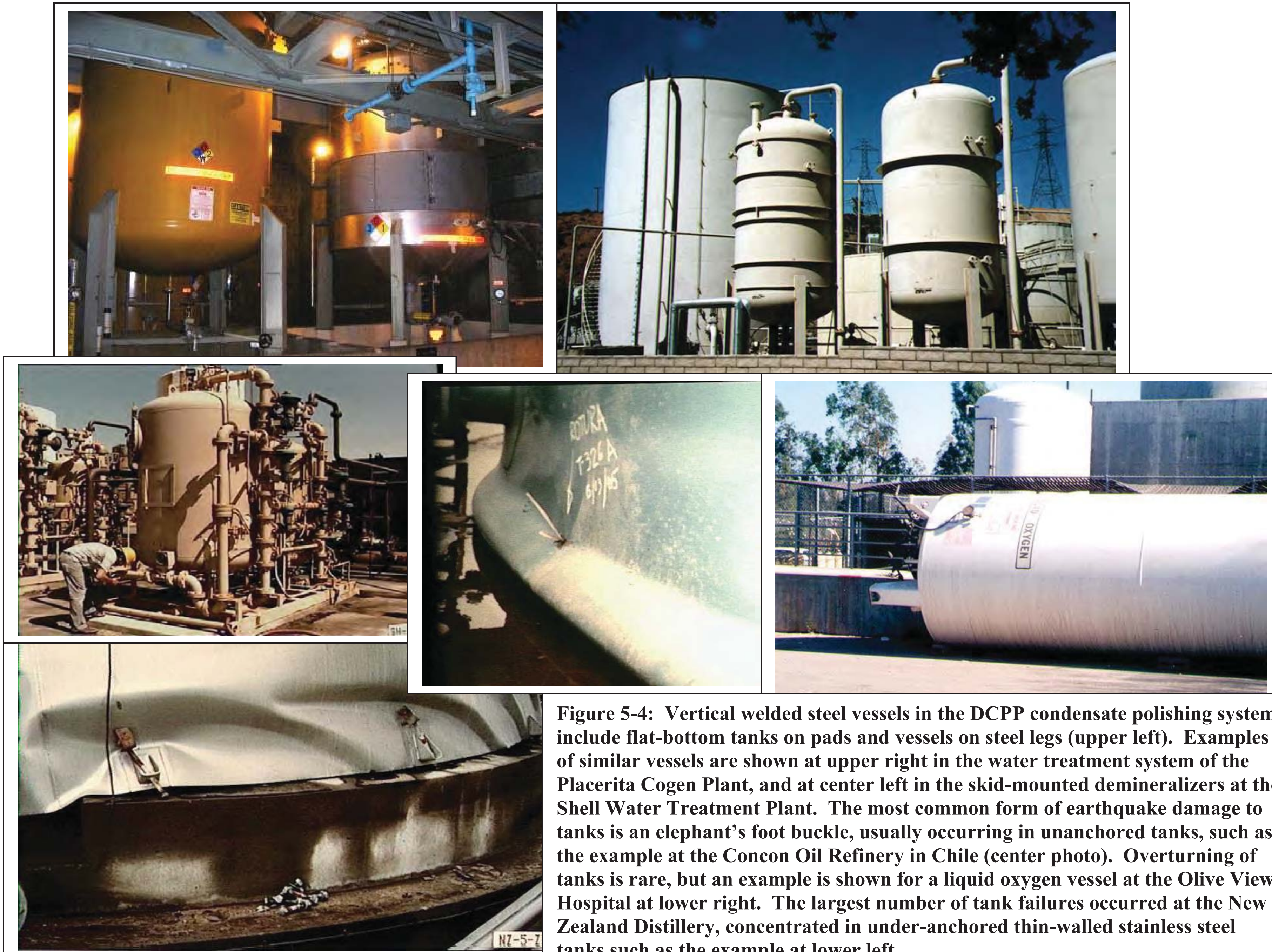


Figure 5-4: Vertical welded steel vessels in the DCPP condensate polishing system include flat-bottom tanks on pads and vessels on steel legs (upper left). Examples of similar vessels are shown at upper right in the water treatment system of the Placerita Cogen Plant, and at center left in the skid-mounted demineralizers at the Shell Water Treatment Plant. The most common form of earthquake damage to tanks is an elephant's foot buckle, usually occurring in unanchored tanks, such as the example at the Concon Oil Refinery in Chile (center photo). Overturning of tanks is rare, but an example is shown for a liquid oxygen vessel at the Olive View Hospital at lower right. The largest number of tank failures occurred at the New Zealand Distillery, concentrated in under-anchored thin-walled stainless steel tanks such as the example at lower left.

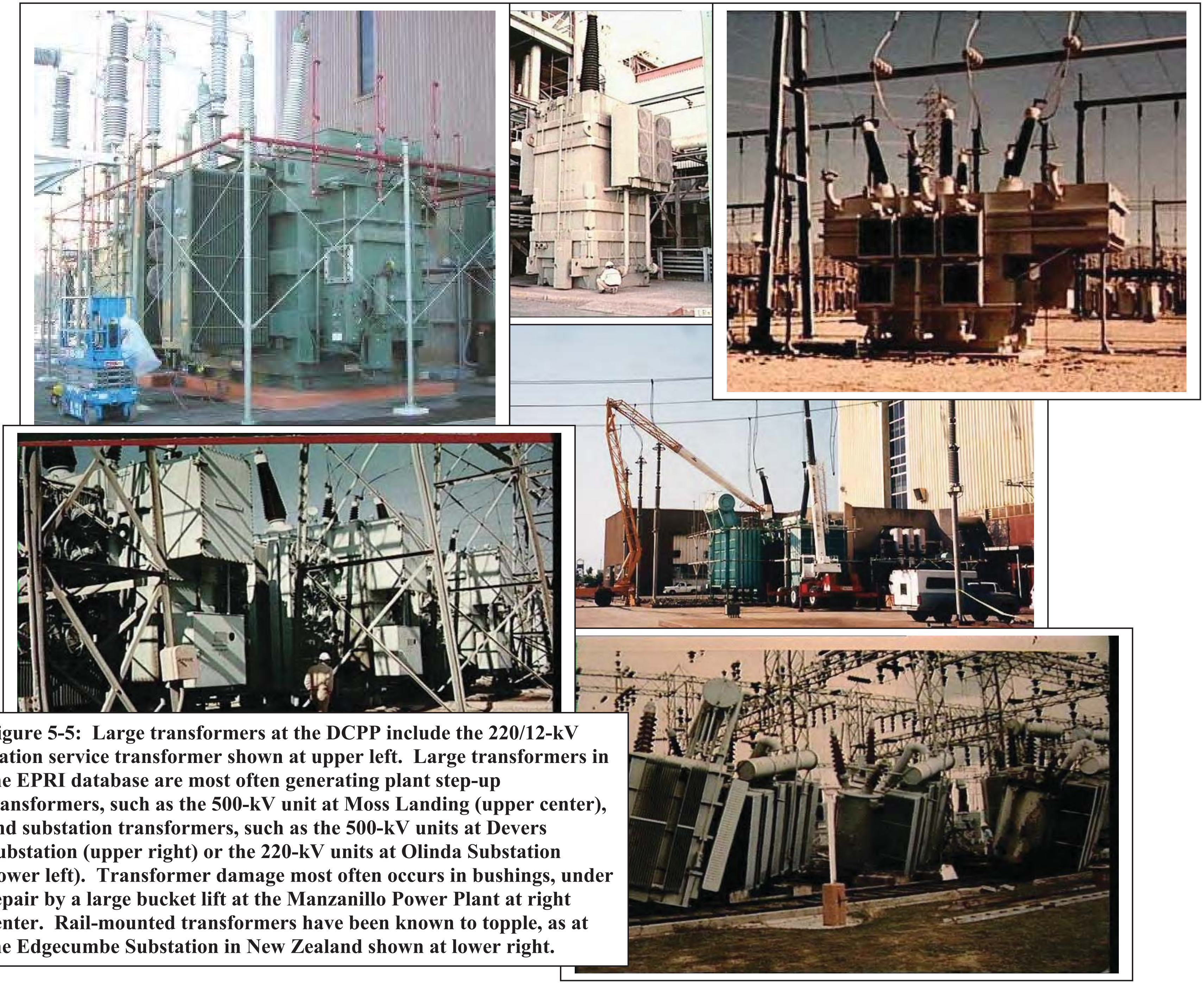


Figure 5-5: Large transformers at the DCPP include the 220/12-kV station service transformer shown at upper left. Large transformers in the EPRI database are most often generating plant step-up transformers, such as the 500-kV unit at Moss Landing (upper center), and substation transformers, such as the 500-kV units at Devers Substation (upper right) or the 220-kV units at Olinda Substation (lower left). Transformer damage most often occurs in bushings, under repair by a large bucket lift at the Manzanillo Power Plant at right center. Rail-mounted transformers have been known to topple, as at the Edgecumbe Substation in New Zealand shown at lower right.

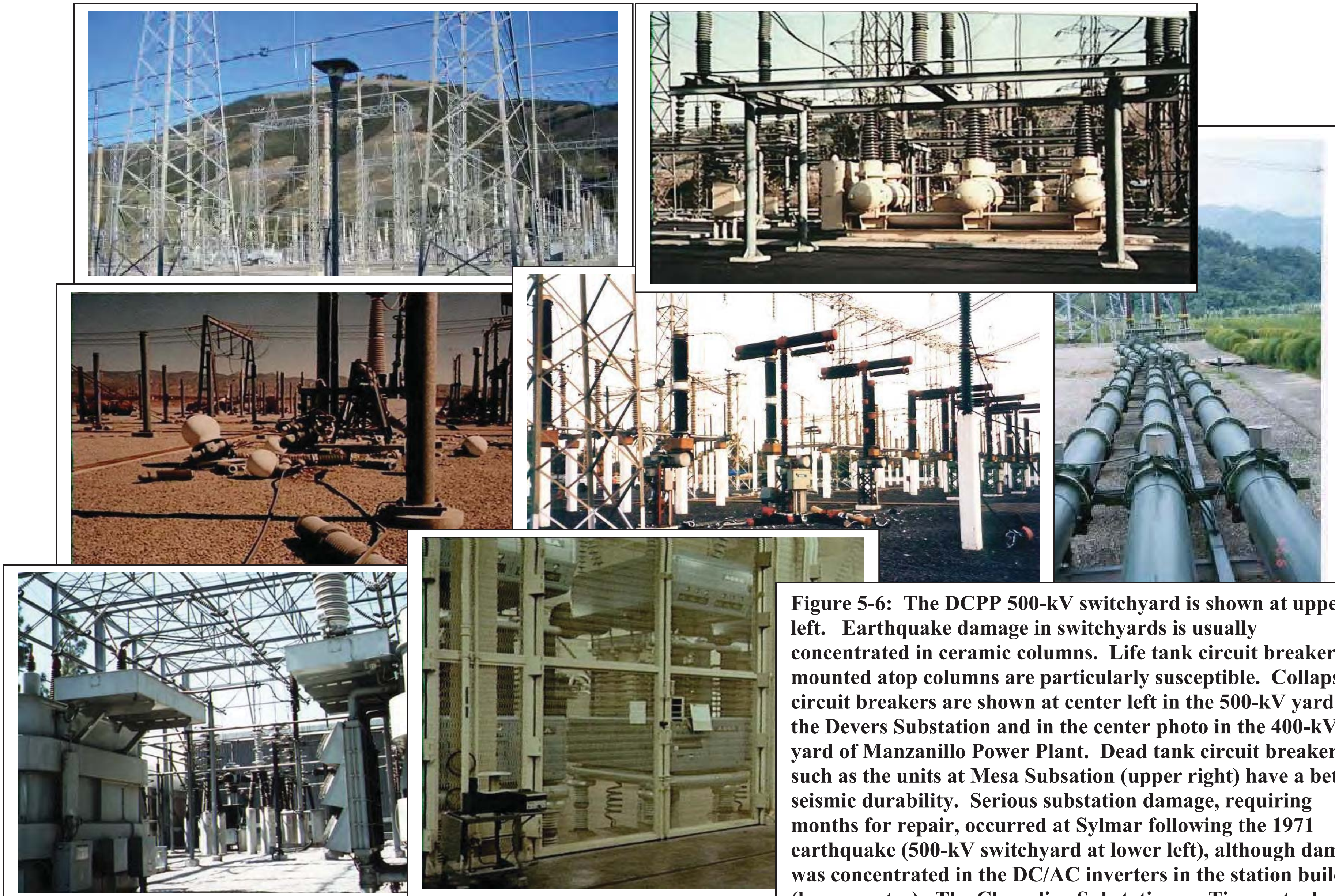
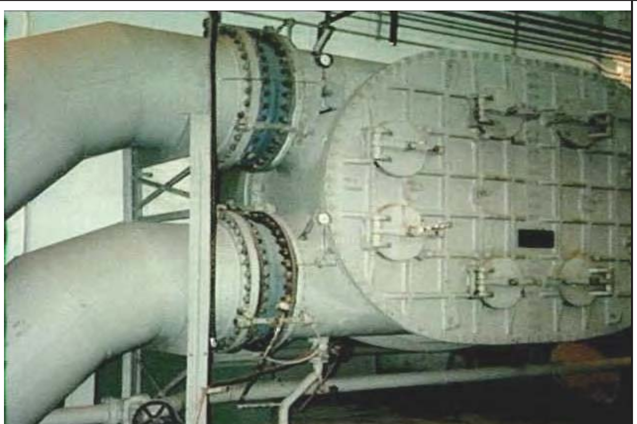


Figure 5-6: The DCPP 500-kV switchyard is shown at upper left. Earthquake damage in switchyards is usually concentrated in ceramic columns. Life tank circuit breakers mounted atop columns are particularly susceptible. Collapsed circuit breakers are shown at center left in the 500-kV yard of the Devers Substation and in the center photo in the 400-kV yard of Manzanillo Power Plant. Dead tank circuit breakers, such as the units at Mesa Subsation (upper right) have a better seismic durability. Serious substation damage, requiring months for repair, occurred at Sylmar following the 1971 earthquake (500-kV switchyard at lower left), although damage was concentrated in the DC/AC inverters in the station building (lower center). The Chungliao Substation on Tiawan took months to repair, largely due to ground failure which fractured the long runs of gas-insulated conduit pipe (lower right).



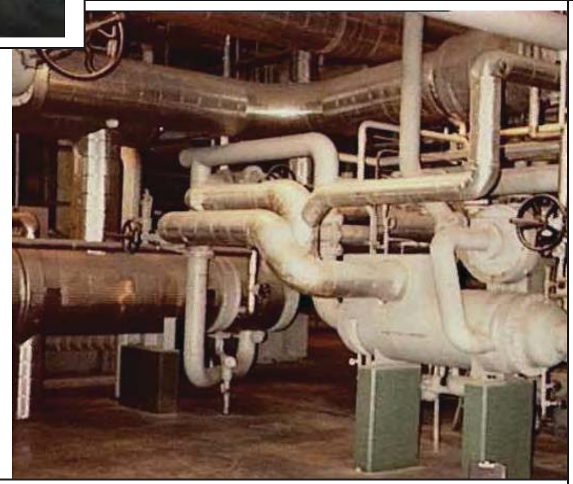


Figure 5-7: Essentially all steam generating units include one item of steam-plant-specific equipment. An example is the lube oil tank and pumps for the DCPP at upper left. The lube oil tank at one of the Burbank steam units is shown at upper right. The main steam condenser and the gland steam condenser for one of the units at El Centro are shown at lower left and lower center. At lower right is the lube oil conditioner for one of the steam units at Humboldt Bay. Within the data sample of some 20 of the larger steam generating units operating at the time of their earthquake, there are no instances of serious damage to steam-plant-specific equipment.

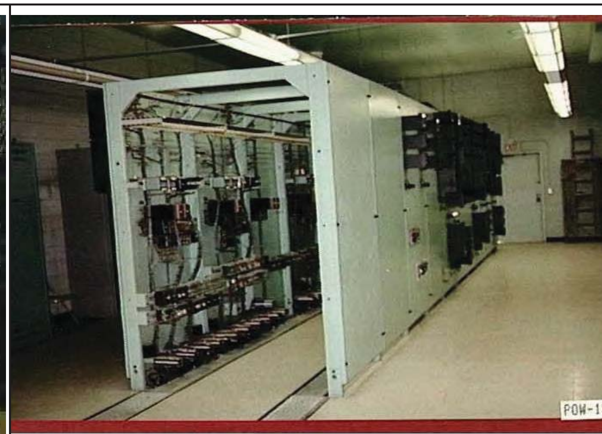






Figure 5-8: Examples of control panels necessary for operation of the DCPP include the generator relay board shown at upper left. A similar relay board is shown at upper center, mounting relays for the switchyard of Olinda Substation. Control systems dating from the 1970s are concentrated in large walk-in cabinet-consoles as in the main control room for the Manzanillo Steam Plant No. 1 (upper right). Manzanillo Plant No. 2, dating from about 1990 has a digital control system consisting of a small console (center photo) and data processing cabinets in a separate room (center right). The most common damage in control panel components consists of internal disconnections or burnout in small electronic components. An example is a circuit board found to be non-functional in auxiliary panels for the Fertimex Steam Plant following the 1985 Mexico earthquake (panels & bad board at lower left).

6.0 Performance of Steam Power Plants in Earthquakes

The earthquake performance of steam generating units was discussed briefly in Sections 5.8 and 5.9 above, focusing on the primary components of steam turbine generators, steam condensers and the peripheral equipment common to all steam units. However the balance-of-plant equipment in a large steam plant includes hundreds of equipment items, comprising the electrical, mechanical and control systems. A major factor in the post-earthquake restoration time for a large plant like DCPP is the prevalence of damage throughout the inventory of equipment required to operate the plant. In other words, recovery of operation within a reasonable time frame (days or weeks rather than months) might allow repair of a few items, but not hundreds of items. Past earthquake experience with steam plants provides the best indication that earthquake damage is limited and manageable.

6.1 General Performance of Steam and Cogeneration Plants

The EPRI database includes 114 fossil-fueled steam generating units and 27 gas-to-steam-turbine cogeneration units. The sites investigated following earthquakes represent a broad spectrum in vintage of power plants, ranging in age from the 1930s to plants new at the time of the earthquake, and in size from 10 to 750 megawatts per unit. The investigated plant sites generally experienced ground shaking in the range of 0.20g to 0.60g peak ground acceleration (PGA), from earthquakes ranging from magnitude 5.5 to 8.1.

A summary of EPRI-investigated power plants is presented in Table 6-1. The table includes a brief description of each plant, the level of ground shaking (PGA) either measured or estimated at the site, and the time for operation to be restored following the earthquake. It should be noted that several power plants experienced multiple earthquakes during the ~30-year period of the investigations.

The time to recover operation of the generating units that were on line at the time of the earthquake is perhaps the best gauge of the level of damage. Generating plants that suffer serious damage would not be able to restart without extensive repairs. As indicated in Table 6-1, most generating plants recovered from their earthquake within 24 hours. This does not mean that the plant site did not suffer damage; only that damage was sufficiently minor that repairs could be completed in less than a day or deferred until a scheduled maintenance. A delay of a day or two in restarting a power plant is often irrelevant. Experience indicates that the regional power system is typically blacked out following a strong earthquake for a day or two due to damage in substations. If the regional network is de-energized, power plants are not able to come back on line even if they are operable.

Table 6-1: Summary of the Earthquake Performance of Steam and Cogeneration Power Plants Investigated for the Electric Power Research Institute

San Fernando Earthquake, 1971, Magnitude 6.7		
Site	**Peak Ground Acceleration**	**Recovery Time**
Valley Steam Plant: Four gas-fired steam units, 1950s vintage, 500 MW	0.30g	Hours
Burbank Power Plant: Six gas-fired steam units, two gas turbine peakers, 1950s, 200 MW	0.30g	Hours
Glendale Power Plant, Five gas-fired steam units, 1950s – 60s, 150 MW	0.25g	Continued operating
Pasadena Power Plant, Five gas-fired steam units, 1950s vintage, 200 MW	0.20g	Continued operating
Point Mugu Earthquake, 1973, Magnitude 5.7		
Ormond Beach, Two gas-fired steam units, 1970, 1500 MW	0.20g	Hours
Ferndale Earthquake, 1975, Magnitude 5.5		
Humboldt Bay, Two gas-fired steam units, 1950s, One nuclear unit, 1961, 160 MW	0.30g	Hours
Imperial Valley Earthquake, 1979, Magnitude 6.6		
El Centro Steam Plant, Four gas-fired steam units, 1950s – 60s, 100 MW	0.42g	Hours
Humboldt Earthquake, 1980, Magnitude 7.0		
Humboldt Bay, Two gas-fired steam units, 1950s, 100 MW	0.25g	Hours
Chile Earthquake, 1985, Magnitude 7.5		
Renca, Two coal-fired steam units, 1960s, 100 MW	030g	Hours
Laguna Verde, 1930s- 40s, 50 MW	0.25g	Hours
Las Ventanas, Two coal-fired steam units, 1960s – 70s, 340 MW	0.25g	Two days
Mexico Earthquake, 1985, Magnitude 8.1		
Sicartsa, Two gas-fired steam units, 1970s, 22 MW	0.25g	Hours
Whittier Earthquake, 1987, Magnitude 5.9		
Commerce, Trash-fired steam unit, 1985, 12 MW	0.30g	Continued operating
Puente Hills, Methane-fired steam unit, 1986, 40 MW	0.20g	Hours
Superstition Hills Earthquake, 1987, Magnitude 6.3		
Mesquite Lake, Manure-fired steam unit, 1987, 16 MW	0.20g	Plant undergoing initial start-up
El Centro Steam Plant, Four gas-fired steam units, 1950s – 60s, 100 MW	0.26g	Hours

Table 6-1: Summary of the Earthquake Performance of Steam and Cogeneration Power Plants Investigated for the Electric Power Research Institute (Continued)

Site	Peak Ground Acceleration	Recovery Time
Loma Prieta Earthquake, 1989, Magnitude 6.9		
Moss Landing, Four gas-fired units, 1950s – 60s, 1900 MW	0.30g	One month
Gilroy Cogeneration, 1988, 120 MW	0.32g	Hours
Stanford Cogen, 1985, 50 MW	0.25g	Down for maintenance
Hunters Point, Three gas-fired units, 1950s, 330 MW	0.15g	Hours
Portrero, Five gas-fired steam units, three gas turbine peakers, 1960s, 360 MW	0.15g	Two days
Sierra Madre Earthquake, 1991, Magnitude 5.8		
Pasadena, Five gas-fired steam units, two gas turbine peakers, 1950s, 200 MW	0.20g	Continued operating
CapeMendocino Earthquake Sequence, 1992, Magnitude 7.0		
Pacific Lumber Cogen, Two wood-waste-fired units, 1989, 30 MW	0.47g	Two weeks
Humboldt Bay, Two gas-fired steam units, 1950s, 100 MW	0.24g	Hours
Landers Earthquake, 1992, Magnitude 7.5		
Cool Water, Two gas-fired steam units, two cogen units, 196s – 70s, 1300 MW	0.35g	Two weeks
Guam Earthquake, 1993, Magnitude 8.0		
US Navy Power Plant, Four oil-fired steam units, 1960s, 76 MW	0.25g,	Three months
Cabras, Two oil-fired steam units, 1970s vintage, 130 MW	0.25g	Three days
Tanguisson, Two oil-fired steam units, 1970s, 50 MW	0.25g	Two days
Yigo gas turbine generator, 1993, 22 MW	0.25g	Hours
Dededo gas turbine generator, 1993, 32 MW	0.25g	Hours
Northridge Earthquake, 1994, Magnitude 6.7		
AES Placerita cogeneration unit, 1980s, 110 MW	0.50g	Three weeks
ARCO Placerita cogeneration unit, 1980s, 40 MW	0.50g	Two days
Pitchess cogeneration unit, 1980s, 28 MW	0.50g	One day
Valley Steam Plant: Four gas-fired steam units, 1950s vintage, 500 MW	0.30g	Hours
Burbank Power Plant: Six gas-fired steam units, two gas turbine peakers, 1950s, 200 MW	0.25g	Hours
Glendale Power Plant, Five gas-fired steam units, 1950s – 60s, 150 MW	0.25g	Hours
Pasadena Power Plant, Five gas-fired steam units, 1950s vintage, 200 MW	0.20g	Down for maintenance

Table 6-1: Summary of the Earthquake Performance of Steam and Cogeneration Power Plants Investigated for the Electric Power Research Institute (Continued)

Site	Peak Ground Acceleration	Recovery Time
Colima Earthquake, 1995, Magnitude 7.6		
Manzanillo, Six Oil-fired steam units, 1980s – 90s, 2100 MW	0.40g	Five months
Michoacan Earthquake, 1997, Magnitude 7.3		
Petacalco, Four oil-fired steam units, 1990s, 2100 MW	0.28g	Two days

6.2 Most Seriously Damaged Power Plants

The most useful information comes from steam plants that suffered the most damage and were delayed the longest in restoration of operations. A summary of effects and recovery efforts for the six most seriously damaged steam plants in the EPRI database is presented in Appendix D.

The primary causes of serous damage to the six power plants can be generally summarized as follows.

1. Ground settlement resulting in damage to buried utility lines, offsets in foundations and misalignment in rotating machinery.

2. Damage to high voltage switchyards primarily due to collapse of brittle ceramic insulators or failure of anchorage in large-mass equipment such as circuit breakers or transformers.

3. Damage to large steel storage tanks, either by failure of seams at the tank-base interface or failure of piping attachments due to tank rocking or shifting.

4. Differential displacement between adjoining structures or equipment supported on independent foundations.

5. Impact damage due to sway of suspended structures such as tower-supported steam boilers.

6. Damage to bearings in large rotating equipment due to loss of lube oil pressure.

The general causes of serious damage listed above do not include all things that may go wrong in a power plant due to earthquake. The list does however indicate the more common causes of prolonged outage that have appeared more than once in the past. Review of the DCPP indicates that only Item 2 and possibly Item 6 would present would apply to the site. Soil conditions beneath the main plant are considered sufficiently firm to preclude serious settlement. The two high voltage switchyards are founded on engineered fill, and could possibly suffer settlement damage. The switchyards also include the normal installations of tall ceramic insulators. Possible damage to bearings in the low pressure turbines are addressed in a separate section of this report.

7.0 Summary

The general conclusions and observations from the preceding sections could be summarized as follows.

- As a general rule power plants survive earthquakes with minor damage, typically including only a few items that require repair. Restoration of operation can usually be accomplished within hours or days.
- Most common causes of serious damage to power plants in past earthquakes, such as soil liquefaction or collapse of live tank high voltage circuit breakers would not apply to the DCPP site.
- Balance-of-plant equipment necessary for operation of DCPP has a good performance record in past earthquake. Seismic fragility does not reach significant levels (e.g., 10% probability of damage) unless peak ground acceleration exceeds about 0.50g. The annual recurrence rate for this level of shaking at the DCPP site is about 0.05% per year (about once chance in 2,000).
- The eight categories of balance-of-plant equipment with potential long replacement times have probabilities of serious damage due to earthquake on the order of 10^{-4} per item per year (about one chance in 10,000 per year).

The list of potential-long-replacement-time equipment in Table 1-1 includes some 27 entries representing perhaps about 50 individual items of equipment. Some entries on the list represent duplicate items such as pumps, circuit breakers, disconnect switches and control panels. Perhaps half of this equipment has N+1 redundancy, meaning that if one item is damaged a second unit is available. Redundancy does not mean that the unit is free of earthquake risk, as equipment damage is sometime caused by common mode causes. However redundancy should at least reduce the probability of failure in earthquake by half. It would appear that there are two to three dozen items of equipment in the plant lacking redundant back-up, necessary for operation of the DCNPP, and requiring a possible prolonged replacement time. As an order-of-magnitude estimate, the cumulative probability of a prolonged post-earthquake outage of DCPP due to damage to at least one of these items, over the remaining plant life, would be a figure less than 0.1 (10%).

Appendix A: Initial List of Structures, Systems & Component Necessary for Operation of the DCNPP for Which Repair or Replacement May Incur a Prolonged Delay

Balance of Plant Components

Item No.	System	SSCs
III.A.1.1	Condensate System	Condensate Pump
III.A.1.2	Condensate System	Condensate Booster Pump
III.A.3.1.1	Condensate System	Main Condenser
III.A.3.1.2	Condensate System	Condenser Tubes
III.A.3.2	Condensate System	Feedwater Heaters (No. 2-6)
III.A.3.3	Condensate System	Condensate Cooler
III.A.3.4	Condensate System	Heaters for 1 - 6 Drain Cooler
III.A.3.5	Condensate System	Gland Steam Condenser
III.A.3.6	Condensate System	Air Ejector Condenser
III.A.3.8	Condensate System	Hydrogen Coolers
III.A.3.9	Condensate System	Stator Coil Coolers
III.A.4.1	Condensate System	Condensate Piping
III.A.4.2	Condensate System	Condensate Valves
III.A.6.2.6	Condensate System	Lo-Conductivity Waste Tank
III.A.6.2.7	Condensate System	Hi-Conductivity Waste Tank
III.A.6.2.8	Condensate System	Resin Mixing & Holding Tank
III.A.6.2.9	Condensate System	Anion Regen Tank
III.A.6.2.10	Condensate System	Resin Sep. & Cation Regen Tank
III.A.6.2.11	Condensate System	Condensate Demin. Ion Exchangers
III.A.6.3.1	Condensate System	Caustic Dilution Heat Exchanger
III.A.6.4.1	Condensate System	Condensate Polishing System Piping
III.A.6.4.2	Condensate System	Condensate Polishing System Valves
III.A.6.5.1	Condensate System	Condensate Polishing System Sump Centrifugal Separator
III.B.1.1	Feedwater System	Steam Generator Feedwater Pumps
III.B.3.1	Feedwater System	Feedwater Heaters (No. 1)
III.B.4.5	Feedwater System	Remainder of Feedwater System Piping
III.B.4.5.1	Feedwater System	Remainder of Feedwater System Valves
III.C.1.1	Turbine Steam Supply System	Main Turbine - HP Elements
III.C.1.2	Turbine Steam Supply System	Main Turbine - LP Elements
III.C.1.3	Turbine Steam Supply System	Steam Generator Feed Pump Turbines
III.C.3.1	Turbine Steam Supply System	Moisture Separator Reheater
III.C.4.6	Turbine Steam Supply System	Remainder of Turbine Steam Supply System Piping
III.C.4.6.1	Turbine Steam Supply System	Remainder of Turbine Steam Supply System Valves

Balance of Plant Components (Continued)

III.D.1.1	Extraction Steam and Heater Drip System	Heater No. 2 Drain Tank Pump
III.D.2.1	Extraction Steam and Heater Drip System	Heater No. 2 Drain Tank
III.D.2.2	Extraction Steam and Heater Drip System	Heater No. 6 Drain Tank
III.D.2.3	Extraction Steam and Heater Drip System	Extraction Steam Downstream Drip Pot
III.D.3.1	Extraction Steam and Heater Drip System	Feedwater Heaters
III.D.3.2	Extraction Steam and Heater Drip System	Heater No. 6 Drain Cooler
III.D.4.1	Extraction Steam and Heater Drip System	All System Piping
III.D.4.2	Extraction Steam and Heater Drip System	All System Valves
III.D.5.1	Extraction Steam and Heater Drip System	Flow Nozzle FE-122
III.E.4.1	Auxiliary Steam System	Auxiliary Steam System Piping from package boiler (0-1) to first isolation valve
III.E.4.1.1	Auxiliary Steam System	Valves for above portion of system
III.E.4.2	Auxiliary Steam System	All Other Auxiliary Steam Piping
III.E.4.3	Auxiliary Steam System	All Other Auxiliary Steam Valves
III.E.4.4	Auxiliary Steam System	Auxiliary Steam System Piping from Auxiliary Boiler (0-2) to First Isolation Valve
III.E.4.4.1	Auxiliary Steam System	Valves for above portion of system
III.F.1.1	Service Cooling Water System	Service Cooling Water Pump
III.F.1.2	Service Cooling Water System	Service Cooling Water Booster Pump
III.F.3.1	Service Cooling Water System	Service Cooling Water Heat Exchanger
III.F.4.1	Service Cooling Water System	Service Cooling Water System Piping
III.F.4.2	Service Cooling Water System	Service Cooling Water Valves
III.F.5.4	Service Cooling Water System	Main Turbine Reservoir Lube Oil Coolers
III.G.1.5	Makeup Water System	Primary Water Makeup Pump
III.G.2.9	Makeup Water System	5000-gallon Hypochlorite Storage Tank
III.H.1.1	Saltwater System	Circulating Water Pump
III.H.1.3	Saltwater System	Screen Wash Pump
III.H.1.4	Saltwater System	Screen Refuse Pump
III.H.3.1	Saltwater System	Service Cooling Water
III.H.3.2	Saltwater System	Intake Cooler
III.H.3.4	Saltwater System	Main Condenser (listed under Section III.A.3)
(e)	Saltwater System	Wave Protection Measures
III.H.4.3	Saltwater System	Circulating Water Gate Operators

Balance of Plant Components (Continued)

III.H.4.4	Saltwater System	Circulating Water System Piping
III.H.4.4.1	Saltwater System	Valves for The Above Portion of Piping
III.H.4.5	Saltwater System	Manually Adjusted Circulating Water Discharge Weir
III.H.4.6	Saltwater System	Biolab Saltwater Supply System Piping
III.H.4.6.1	Saltwater System	Valves for Biolab Supply Piping
III.H.4.7	Saltwater System	Screen Wash and Refuse System Piping
III.H.4.7.1	Saltwater System	Valves for the above portion of piping
III.H.4.8	Saltwater System	Intake Cooling Water System Piping
III.H.4.8.1	Saltwater System	Valves for the above portion of piping
III.H.5.1	Saltwater System	Condenser Transition Spool
III.H.5.2	Saltwater System	Circulating Water Traveling Screens
III.H.5.4	Saltwater System	Auxiliary Saltwater Traveling Screen
III.J.1.1	Lube Oil Distribution and Purification System	Lube Oil Transfer Pump
III.J.1.2	Lube Oil Distribution and Purification System	Dirty and Clean Lube Oil Storage Tanks
III.J.1.3	Lube Oil Distribution and Purification System	Main Turbine Lube Oil Reservoir
III.J.1.4	Lube Oil Distribution and Purification System	Feedwater Pump Turbine Lube Oil Reservoir
III.J.3.1	Lube Oil Distribution and Purification System	Main Turbine Lube Oil Coolers
III.J.3.2	Lube Oil Distribution and Purification System	Main Turbine Oil Vapor Extractor
III.J.3.3	Lube Oil Distribution and Purification System	Main Turbine Oil Reservoir Demister
III.J.3.4	Lube Oil Distribution and Purification System	Bearing Oil Pump (ac)
III.J.3.5	Lube Oil Distribution and Purification System	Emergency Lube Oil Pump (dc)
III.J.3.6	Lube Oil Distribution and Purification System	Shaft-driven Oil Pump
III.J.3.7	Lube Oil Distribution and Purification System	Bearing Lift Pump (bearings 3-7)
III.J.4.1	Lube Oil Distribution and Purification System	Feedwater Pump Lube Oil Coolers
III.J.4.2	Lube Oil Distribution and Purification System	Feedwater Pump Oil Vapor Extractor
III.J.4.3	Lube Oil Distribution and Purification System	Feedwater Pump Oil Reserv. Demister
III.J.4.4	Lube Oil Distribution and Purification System	Main Oil Pumps (ac)
III.J.4.5	Lube Oil Distribution and Purification System	Emergency Oil Pump (dc)
III.J.4.7	Lube Oil Distribution and Purification System	High Pressure Oil Accumulator
III.J.6	Lube Oil Distribution and Purification System	Electrohydraulic (E-H) Control Unit

Balance of Plant Components (Continued)

III.J.7	Lube Oil Distribution and Purification System	Lube Oil Distribution and Purification Piping and Valves
III.K.2.3.1	Emergency Diesel Engine Generating System	Air Compressors
III.L.1	**Turbine and Generator-Associated System**	**Turbine-generator Unit**
III.L.2.1	Turbine and Generator-Associated System	Generator Hydrogen Coolers
III.L.3.1	Turbine and Generator-Associated System	Turbine and Generator-associated Systems Piping
III.L.3.2	Turbine and Generator-Associated System	Turbine and Generator-associated Systems Valves
III.L.4.1	Turbine and Generator-Associated System	Gland Steam Condenser (shell side)
III.O.3.1	Oily Water Separator and Turbine Building Sump System	All System Piping
III.O.3.2	Oily Water Separator and Turbine Building Sump System	All System Valves

Structures

Item No.	SSCs
I.D.1.2	Discharge Structure
I.D.1.5	Breakwaters
I.L.1	Security Building
I.M.2	Administration Building
I.M.4	Permanent Warehouse
I.M.8	Raw Water Reservoir
I.M.9	Training and Simulator Building

Electrical Components

Item No.	System	SSCs
IV.A.1	**Main Generator and Associated Equipment**	**Main Generator (includes all auxiliary systems such as excitation, seal oil, H2, stator cooling, etc.)**
IV.A.2	**Main Generator and Associated Equipment**	**Isolated Phase Bus**
IV.A.3	**Main Generator and Associated Equipment**	**Generator Neutral Transformer and Resistor**
IV.A.4	**Main Generator and Associated Equipment**	**Generator Relay Boards**
IV.B.1	**12-kV System and Equipment**	**12-kV System**
IV.B.2	**12-kV System and Equipment**	**25/12-kV Auxiliary Transformers**
IV.B.3	**12-kV System and Equipment**	**12-kV Grounding Transformers**
IV.B.4	**12-kV System and Equipment**	**12-kV Fuse Cabinets**
IV.B.5	**12-kV System and Equipment**	**12-kV Grounding Resistors**
IV.B.7	**12-kV System and Equipment**	**Startup Relay Board**
IV.C.2	**4-kV Systems and Equipment**	**4-kV System - Nonvital**
IV.C.3	**4-kV Systems and Equipment**	**25/4-kV Auxiliary Transformers**
IV.C.4	**4-kV Systems and Equipment**	**12/4-kV Standby/Startup Transformers**
IV.C.5	**4-kV Systems and Equipment**	**4-kV Grounding Resistors**
IV.C.8	**4-kV Systems and Equipment**	**4-kV Metalclad Switchgear - Nonvital (D & E)**
IV.C.9	**4-kV Systems and Equipment**	**4-kV Metalclad Bus Ducts**
IV.C.10.1.1	4-kV Systems and Equipment	Contactor Panels and panel loads
IV.C.10.4	4-kV Systems and Equipment	Diesel Start Timing Panels, HMI Displays and Static Inverters
IV.D.2.1	480-V Systems and Equipment	480-V Load Centers - Nonvital (Fed from buses D and E)
IV.D.2.2	480-V Systems and Equipment	480-V Motor Control Centers-Nonvital (Fed from Buses 2 & E)
IV.D.2.3	480-V Systems and Equipment	480-V Circuit Breaker Panel Boards
IV.E.2.1	120-V Instrument ac Systems and Equipment	Distribution Panels and internal components
IV.G.1.4	125 and 250-V dc Systems and Equipment	dc Ground Detection System

Electrical Components (Continued)

IV.G.2.1	125 and 250-V dc Systems and Equipment	Station Storage Batteries and Battery Racks
IV.G.2.2	125 and 250-V dc Systems and Equipment	Distribution Panels
IV.G.2.3	125 and 250-V dc Systems and Equipment	250-V Motor Control Center
IV.G.2.4	125 and 250-V dc Systems and Equipment	dc Ground Detection System
IV.G.2.5	125 and 250-V dc Systems and Equipment	Battery Chargers
IV.I.2	**Wire, Cable, and Raceways**	**Insulated Electrical Conductors – Nonvital Systems**
IV.I.5	**Wire, Cable, and Raceways**	**Electrical Raceway – Vital and Nonvital**
IV.I.6	**Wire, Cable, and Raceways**	**Raceway Supports (For raceway containing nonvital circuits)**
IV.J.2	**230-kV System and Equipment**	**230/12-kV Standby Startup Transformer**
IV.J.3	**230-kV System and Equipment**	**230-kV Circuit Breakers**
IV.J.4	**230-kV System and Equipment**	**230-kV Air Switches**
IV.J.5	**230-kV System and Equipment**	**230-kV Carrier Relays**
IV.J.6	**230-kV System and Equipment**	**230-kV Line Carrier Coupling Equipment**
IV.J.12	**230-kV System and Equipment**	**125-V dc Batteries for 230-kV Switchyard**
IV.J.13	**230-kV System and Equipment**	**125-V dc Battery Chargers for 230-kV Switchyard**
IV.K.1	**500-kV System and Equipment**	**500-kV System**
IV.K.2	**500-kV System and Equipment**	**Main Transformers (25/500-kV)**
IV.K.3	**500-kV System and Equipment**	**500-kV Circuit Breakers**
IV.K.4	**500-kV System and Equipment**	**500-kV Air Switches**
IV.K.5	**500-kV System and Equipment**	**500-kV Carrier Relays**
IV.K.13	**500-kV System and Equipment**	**125-V dc Batteries for 500 kV Switchyard**
IV.K.14	**500-kV System and Equipment**	**125-V dc Battery Chargers for 500-kV Switchyard**

Instrumentation & Controls

Item No.	System	SSCs
V.A.1.3	Excore Nuclear Instrumentation System	Source Range Audio Count Rate Drawer
V.A.1.4	Excore Nuclear Instrumentation System	Scaler-Timer Module
V.A.1.6	Excore Nuclear Instrumentation System	Comparator and Rate Assembly
V.A.1.7	Excore Nuclear Instrumentation System	Miscellaneous Control and Indication Panel
V.B.2.1	Incore Instrumentation System	Movable Neutron Flux Detectors and Drive Cable Assemblies
V.B.2.2	Incore Instrumentation System	Drive Unit Assembles
V.B.2.3	Incore Instrumentation System	Transfer Device Assemblies, Isolation Valves, and Limit Switch Assemblies
V.B.2.4	Incore Instrumentation System	Interconnecting Tubing Runs
V.B.2.5	Incore Instrumentation System	Gas Purge System
V.B.2.6	Incore Instrumentation System	Leak Detection System
V.B.3.1	Incore Instrumentation System	Position Indication and Control
V.B.3.2	Incore Instrumentation System	Detector Drive Path Selection
V.B.3.3	Incore Instrumentation System	Detector Position Control
V.B.3.4	Incore Instrumentation System	Drive Motor Control
V.B.3.5	Incore Instrumentation System	Distribution Panel
V.B.3.6	Incore Instrumentation System	Detector Power Supplies
V.B.3.7	Incore Instrumentation System	Detector Current Readout
V.B.3.8	Incore Instrumentation System	Detector Signal Recorders
V.B.3.9	Incore Instrumentation System	Special Low Level Equipment (Picoammeter)
V.C.1	**Rod Control System**	**Full-Length CRDM Operating Coil Stack Assembly**
V.C.2	**Rod Control System**	**Power Cabinets**
V.C.2.1	Rod Control System	Half-Wave Thyristor Bridge Control
V.C.2.2	Rod Control System	Multiplex Thyristor Control

Instrumentation & Controls (Continued)

V.C.2.3	Rod Control System	Regulation and Phase Control – Thyristor Firing Control, Signal Processing, Failure Detector, Multiplex Error Detector, and Alarm Control
V.C.2.4	Rod Control System	dc Power Supplies
V.C.2.5	Rod Control System	Phase Sensing Transformers
V.C.2.6	Rod Control System	Monitor Test Panel Assembly
V.C.3.1	Rod Control System	Input/Output Section Pulse Shaper; Relays and Relay Drivers; and Amplifier, Receiver, and Failure Detector
V.C.3.2	Rod Control System	Supervisory Section – Supervisory Logic, Buffer Memory, and Data Logging; Pulsing and Master Cycler; and Shutdown Control Drive Logic
V.C.3.3	Rod Control System	Slave Cycler – Slave Cycler Logic and Counter, Stationary/Movable/Lift Coil Decoders
V.C.3.4	Rod Control System	Bank Overlap Unit
V.C.3.5	Rod Control System	Shutdown Bank Card D Control – Pulser Unit, Slave Cycler Unit, and Logic Unit
V.C.4.1	Rod Control System	70-V dc Section – 260/95-V Wye-Delta Transformer Full Wave Rectifier and Surge Suppressor
V.C.4.2	Rod Control System	125-V dc Section – 260/95-V Wye-Delta Transformer, Full Wave Rectifier, and Surge Suppressor
V.C.4.3	Rod Control System	Relays
V.C.5	**Rod Control System**	**Pulse-to-Analog Converter**
V.C.6	**Rod Control System**	**Operator Controls and Indicators**
V.C.7	**Rod Control System**	**Rod Disconnect Switch Panel (Life Coil Disconnects)**
V.C.8	**Rod Control System**	**Rod Withdrawal Interlocks**
V.C.9	**Rod Control System**	**Rod Control Cable Connector Assembly**
V.C.10	**Rod Control System**	**Motor Generator Sets**
V.C.11	**Rod Control System**	**Generator Output Breakers**
V.D.1.4	Solid-state Protection System	Control Board Demultiplexer Cabinet
V.D.1.5	Solid-state Protection System	Computer Demultiplexer
V.F.2.1	Instrumentation and Controls for various systems	Analysis Instrument System, Dwgs 102031/108031
V.F.2.2	Instrumentation and Controls for various systems	Flow Instrument Systems, Dwgs 102032/108032
V.F.2.3	Instrumentation and Controls for various systems	Level Instrument Systems, Dwgs 102033/108033

Instrumentation & Controls (Continued)

V.F.2.4	Instrumentation and Controls for various systems	Pressure Instrument Systems, Dwgs 102034/108034
V.F.2.5	Instrumentation and Controls for various systems	Temperature Instrument Systems, Dwgs 102035/108035
V.F.2.6	Instrumentation and Controls for various systems	Multivariable Instrument Systems, Dwgs 102036/108036
V.I.1	**Reactivity Computer**	**Front Panel Controls and Indicators**
V.I.2	**Reactivity Computer**	**Signal Conditioning and Test Panel**
V.I.3	**Reactivity Computer**	**Analog Multiplier/Divider**
V.I.4	**Reactivity Computer**	**Power Supply**
V.I.5	**Reactivity Computer**	**Digital Panel Meter**
V.J.3	**Control Boards**	**Auxiliary Building Control Board**
V.K.1.1	Turbine Generator DEH Control System	Hardware System
V.K.1.1.1	Turbine Generator DEH Control System	Central Processor Unit (including Servo Position Controllers)
V.K.1.1.2	Turbine Generator DEH Control System	Input/Output Subsystem Devices
V.K.1.1.3	Turbine Generator DEH Control System	Power Supplies and Distribution Assemblies
V.K.1.1.4	Turbine Generator DEH Control System	Maintenance Terminal
V.K.3	**Turbine Generator DEH Control System**	**DEH Operator's Panels @ CC3**
V.K.4	**Turbine Generator DEH Control System**	**Governor Valves, Servoactuator Control System**
V.L.4	**Main Annunciator System**	**Control room main annunciator display windows (lamp boxes PK01 through PK20 on vertical boards)**
V.L.7	**Main Annunciator System**	**Remote annunciator cabinet PK011 at elevation 85' Turbine Building**
V.L.8	**Main Annunciator System**	**Remote Main Annunciator Display Windows (lamp box PK21 on panel PGA)**
V.M.1.1	Other Annunciator Systems	Power Supply
V.M.1.2	Other Annunciator Systems	Display Window Modules
V.M.5	**Other Annunciator Systems**	**Fire Alarm System**
V.M.6	**Other Annunciator Systems**	**Radiation Access Alarm System**
V.M.7	**Other Annunciator Systems**	**Main Generator Seal Oil, Stator Cooling and Hydrogen System Annunciator**

Instrumentation & Controls (Continued)

V.M.8	**Other Annunciator Systems**	**Main Turbine Lube Oil Purifier System Local Annunciator**
V.M.9	**Other Annunciator Systems**	**Makeup Water Demineralizers System Local Annunciator**
V.M.12	**Other Annunciator Systems**	**Site Emergency and Containment Evacuation Alarm System**
V.M.14.1	Other Annunciator Systems	25/500-kV Main Transformers
V.M.14.2	Other Annunciator Systems	230/12-kV Standby/Startup Transformers
V.M.14.3	Other Annunciator Systems	23/12-kV Auxiliary Transformer
V.M.14.4	Other Annunciator Systems	25/4-kV Auxiliary Transformer
V.M.14.5	Other Annunciator Systems	12/4-kV Standby/Startup Transformer
V.N.1	**Process Computer Hardware System**	**Data Communication/Ethernet Network (Excludes PDN Section V.BB)**
V.N.2.1	Process Computer Hardware System	Data Processing Servers
V.N.2.2	Process Computer Hardware System	Programmer's Station
V.N.2.3	Process Computer Hardware System	Historian Server
V.N.3	**Process Computer Hardware System**	**Input/Output System (I/O), Data Acquisition and Remote Multiplexers**
V.N.4	**Process Computer Hardware System**	**PPC Room Console (CC5)**
V.P.1	**Fire Detection System**	**Smoke and Flame Detectors**
V.P.2	**Fire Detection System**	**Fire Detection Control Cabinet**
V.P.3	**Fire Detection System**	**CARDOX System Controls**
V.P.5	**Fire Detection System**	**Fire Alarm Control Panel**
V.Q.4	**Reactor Containment System**	**Containment Leak Rate Test Facilities**
V.T.6	**Plant Security System**	**Central Alarm System**
V.T.7	**Plant Security System**	**Secondary Alarm System**
V.T.8	**Plant Security System**	**Door and Gate Intrusion Alarm**
V.T.9	**Plant Security System**	**Lock and Key Control System**
V.T.10	**Plant Security System**	**Security System Perimeter Lighting**
V.V.1.5	Safety Parameter Display System (SPDS & ERFDS)	Signal Cables and Terminations to Interconnect Signals and RRM
V.V.1.8	Safety Parameter Display System (SPDS & ERFDS)	Transient Recording System
V.V.2	**Safety Parameter Display System (SPDS & ERFDS)**	**SPDS Computer and Communication Cabinet**

Instrumentation & Controls (Continued)

V.V.2.4	Safety Parameter Display System (SPDS & ERFDS)	SPDS Computer
V.V.2.7	Safety Parameter Display System (SPDS & ERFDS)	Cabinet Interconnection Wire, Cables, and Terminations
V.V.3.1	Safety Parameter Display System (SPDS & ERFDS)	Master Receivers
V.V.3.2	Safety Parameter Display System (SPDS & ERFDS)	Digital Buffers
V.V.3.3	Safety Parameter Display System (SPDS & ERFDS)	Validyne Interface
V.V.3.5	Safety Parameter Display System (SPDS & ERFDS)	Cabinet Interconnection Wire, Cables, and Terminations
V.W.1.1	Digital Feedwater Control System	Hardware System
V.W.1.1.1	Digital Feedwater Control System	Central Processor Unit
V.W.1.1.3	Digital Feedwater Control System	Power Supplies and Distribution Assemblies
V.W.1.1.4	Digital Feedwater Control System	Maintenance Terminal
V.X.2	**Miscellaneous**	**Turbine Supervisory Instrumentation (TSI)**
V.X.3	**Miscellaneous**	**Barometric Pressure Instrument**
V.Z.2	**Process Radiation Monitor Systems**	**Process Radiation Monitor Systems**
V.AA.1	**Main Feedwater Pump Speed Control System**	**Speed Control Cabinets**
V.AA.2	**Main Feedwater Pump Speed Control System**	**Startup Stations**
V.AA.3	**Main Feedwater Pump Speed Control System**	**Local Operator Stations**
V.AA.4	**Main Feedwater Pump Speed Control System**	**Hydraulic Power Units**
V.AA.5	**Main Feedwater Pump Speed Control System**	**HP Governor Valve Servo Positioner**
V.AA.6	**Main Feedwater Pump Speed Control System**	**LP Governor Valve Servo Positioner**
V.BB.1	**Plant Data Network**	**Data Storage Equipment**
V.BB.3	**Plant Data Network**	**Network Hardware**
V.CC.2	**Power Distribution Monitoring System**	**PDMS Hardware**
V.DD.1	**Aux Bldg Control Board Digital System**	**ABCBDS Power supplies and distribution assemblies**
V.DD.2	**Aux Bldg Control Board Digital System**	**ABCBDS network hardware (servers, switches, printers, work stations, display units and data link communication)**

Instrumentation & Controls (Continued)

V.DD.3	**Aux Bldg Control Board Digital System**	**ABCBDS Central Processor Unit(s)**
V.DD.4	**Aux Bldg Control Board Digital System**	**ABCBDS Input/Output Subsystem Devices**
V.DD.6	**Aux Bldg Control Board Digital System**	**ABCBDS panels and racks (other than item V.J.3)**

HVAC

Item No.	System	SSCs
VI.B.13.1	Cable Spreading Room Air Conditioning System	Air Handling Units
VI.B.13.3	Cable Spreading Room Air Conditioning System	Chilled Water Sub-system (Chillers, Piping, Valves, Fittings, Pipe Mounted Instruments, Expansion Tank and Pumps)

Nuclear Steam Supply

Item No.	System	SSCs
II.A.2.20	Reactor Coolant System	Pressurizer Relief Tank
II.A.4.6	Reactor Coolant System	Remainder of System Piping that connects other systems to the Pressurizer Relief Tank
II.A.4.6.1	Reactor Coolant System	Valves for the above portion of System
II.B.4.3	Chemical and Volume Control System	Portion of system piping that handles letdown from LCV 112A to the Liquid Holdup Tanks, from the LHUTs through the Evaporator Feed Ion Exchangers, and through the Boric Acid Evaporator; concentrates through the Concentrates Holding Tank up to the Boric Acid Tanks, and condensates through the Boric Acid Evaporator Condensates Demineralizers up to the Boric Acid Reserve Tanks; Boric Acid Reserve Tank recirculation and transfer piping up to the Batch Tank and the Boric Acid Tanks
II.B.4.3.1	Chemical and Volume Control System	Valves for the above portion of system
II.B.4.5	Chemical and Volume Control System	Portion of System Piping that pumps condensate from the monitor tanks to the liquid holdup tanks, or back to the evaporator package feed line, the makeup water system (primary water storage tank), or the liquid radwaste system (processed waste receivers)

Nuclear Steam Supply (Continued)

II.B.4.5.1	Chemical and Volume Control System	Valves for the above portion of system
II.G.4.6	Spent Fuel Pool Cooling System	Remainder of System Piping
II.G.4.7	Spent Fuel Pool Cooling System	Remainder of System Valves

Appendix B:
Summary of the Electric Power Research Institute (EPRI)
Earthquake Experience Database

In the early 1980s the Electric Power Research Institute (EPRI) began sponsoring investigations of electric power facilities and industrial sites subjected to strong earthquake shaking. The purpose of the EPRI post-earthquake investigation program was to provide useful information for the nuclear power industry for the seismic qualification of critical equipment in power plants. The intent was to observe the tendency and typical causes of earthquake damage to equipment representative of nuclear plant safety systems. In this way a focus could be made on equipment that appeared susceptible to earthquake damage, versus equipment that did not, and the threshold intensity of ground shaking resulting in equipment damage.

Some two dozen categories of standard mechanical, electrical and electronic equipment were defined that covered most components of safety systems in nuclear plants. These equipment categories are summarized in Table B-1.

Table B-1: Generic Categories of Equipment of Focus in Compiling the EPRI Database

<table>
<tr><th colspan="12">Mechanical Equipment</th></tr>
<tr><td colspan="2">Horizontal Pumps</td><td colspan="2">Vertical Pumps</td><td colspan="2">Air Compressors</td><td colspan="2">Fans</td><td colspan="2">Engine-Generators</td><td colspan="2">Overhead Cranes</td></tr>
<tr><td colspan="2">Air Handlers</td><td colspan="1">Tanks</td><td colspan="3">Motor-Operated Valves</td><td colspan="3">Fluid-Operated Valves</td><td colspan="3">Motor-Generators</td></tr>
<tr><th colspan="12">Electrical Equipment</th></tr>
<tr><td colspan="3">Transformers (<15 Kilovolt)</td><td colspan="5">Medium Voltage Switchgear (<15 Kilovolt)</td><td colspan="4">Low Voltage Switchgear (<500 Volt)</td></tr>
<tr><td colspan="6">Motor Control Centers</td><td colspan="3">Panelboards</td><td colspan="3">Battery Racks</td></tr>
<tr><th colspan="12">Electronic Equipment</th></tr>
<tr><td colspan="4">Control & Instrument Panels</td><td colspan="3">Instrument Racks</td><td colspan="2">Sensors</td><td colspan="3">Rectifiers & Inverters</td></tr>
<tr><th colspan="12">Interconnections</th></tr>
<tr><td colspan="3">Piping & Tubing</td><td colspan="5">Conduit & Cable Tray</td><td colspan="4">Duct</td></tr>
</table>

In the course of post-earthquake investigations it was discovered that these categories of equipment are found in power and industrial facilities throughout the world. Because there are a limited number of principal manufacturers, often the same models of equipment were found at multiple sites. Equipment of course has evolved over the years, especially controls and instrumentation, in the gradual change from pneumatic to analog-electronic to digital-electronic systems. The database included investigations of facilities dating from the 1930s through the

1990s. Thus the evolution of equipment over some six decades, and any corresponding changes in susceptibility to seismic damage, was well represented.

The EPRI database was gradually converted from hard-copy to electronic form, first on compact disk, then as an entry on the EPRI web site. Each of 23 generic categories of equipment listed in Table A-1 includes data sets detailing equipment items (or groups of identical items), and effects or lack-of-effect from their particular earthquake. Each more common categories of equipment include several hundred items, representing a range of sites and earthquake ground motion.

The power and industrial sites investigated, following earthquakes over a period of some 30 years, are listed in Table B-2. In all, the list includes 174 separate sites, and 30 earthquakes. A few sites were struck by different earthquakes in different years, and are therefore listed multiple times. For example, power plants in the San Fernando Valley north of Los Angeles were shaken by earthquakes in 1971 and again in 1994. The Humboldt Bay Power Plant and the City of Pasadena Power Plant were shaken by three and four different earthquakes respectively over the 30-year period.

Each entry in Table B-2 lists the earthquake and site, a brief description of the facility, and the ground shaking intensity according to the Modified Mercalli Intensity (MMI) scale. The intensity rating from the MMI scale for the site location was usually based on published intensity maps developed from studies of the earthquake-affected region. For most sites there is a listing of peak ground acceleration (PGA). The PGA listing is the best estimate of peak ground acceleration for the free field for the particular site. The US Nuclear Regulatory Commission (NRC) sponsored studies of available ground motion records, resulting in estimates based on seismological studies and detailed reviews of the nearest ground motion records. Estimates of PGA from the NRC studies are denoted in the table by an asterisk. Some sites included strong motion recorders at or near the location, so that peak ground acceleration was actually measured, as denoted in the table by a double asterisk. With few exceptions, sites were not considered worth investigation unless they appeared to have experienced at least MMI VII shaking (Intensity Seven) and peak ground acceleration of at least 0.20g. The last column of Table B-2 provides a brief description of the primary damage at the site. This summary does not include all effects from the earthquake, the site description in the EPRI database must be consulted for that, but does provide an indication of the severity of damage at the site.

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1971 San Fernando Earthquake, M = 6.6 **Reverse thrust fault rupture in the San Gabriel Mountains north of the California San Fernando Valley**				
Sylmar Converter Station	Major power supply facility for greater Los Angeles, converting 500-volt DC power to AC. Site included a 230-kV substation switchyard.	VIII	0.69g*	Extensive collapse of ceramic supports for high voltage equipment in the converter building & switchyards. Fire in the converter building. Station required almost a year to rebuild.
Rinaldi Receiving Station	Main switching center for 500-kV power to northern LA basin. Includes 500 & 230-kV switchyards.	VIII	0.66g*	Minor switchyard damage including collapse of two 230-kV live-tank circuit breakers. Station restored to service within days.
Valley Steam Plant	Four-unit gas fired steam generating station, dating from the early 1950s. Total output = 514 megawatts (MW).	VIII	0.29g*	Minor damage, operation restored within a day.
Burbank Power Plant	Total of seven gas-fired steam units in two adjoining plant sites, dating from the 1949 to 1961. Total output = 160 MW.	VII	0.30g	Minor damage, operation restored within a day.
Glendale Power Plant	Five gas-fired steam units dating from 1941 – 1964. Total output = 148 MW	VII	0.25g	The three units in operation at the time remained on line through the earthquake. Minor damage to the plant.
Pasadena Power Plant	Four gas-fired steam units dating from 1949 – 1965. Total output = 206 MW.	VII	0.15g	The two units in operation at the time remained on line through the earthquake. Trivial damage to the plant.
Pardee Substation	Main 220-kV switching center for north Los Angeles	VII	0.35g	Collapse of a lightening arrestor & a disconnect switch column. 220/66-kV transformers sheared anchor bolts.
Vincent Substation	500-kV & 220-kV switchyards	VII	0.15g	Fractured ceramic in five 500-kV circuit breakers. Minor damage to disconnects & surge arrestors.
* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records. ** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.				

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Contiued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1973 Point Mugu Earthquake, M = 5.7, Reverse thrust fault rupture in the Santa Monica Mountains northwest of Los Angeles				
Ormond Beach Power Plant	Two gas/oil-fired steam units dating from 1970 – 1973. Total output = 1500 MW.	VII	0.10g	Minor effects to the plant. Operation restored within day.
1975 Ferndale Earthquake, M = 5.7, Left-lateral-strike-slip on the Russ Fault just south of Ferndale, California				
Humboldt Bay Power Plant	Two gas-fired steam units totaling 100 MW, dating from the 1950s. Retired 60-MW nuclear boiler water reactor.	VII	0.31g**	Minor effects to the plant. The two operating units were restored in ½-hour.
1979 Imperial Valley Earthquake, M = 6.6 Right-lateral-strike-slip on the Imperial Fault trending north-south between the US/Mexico border & Brawley, California				
El Centro Steam Plant	Four gas-fired steam units dating from 1949-1968. Total output = 100 MW.	VIII	0.43g*	Both operating units restored within 6 hours. Minor damage to the plant.
Drop IV Hydroelectric Plant	Two 10-MW hydro-turbine generators on a small concrete dam, dating from 1941 & 1950.	VII	0.30g	Hydro units operated through the earthquake. Damage in buried electrical cable resulted in ground fault months later.
1980 Humboldt County Earthquake, M = 7.0 Left-lateral-strike-slip about 50 kilometers offshore of Cape Mendocino				
Humboldt Bay Power Plant	Two gas-fired steam units totaling 100 MW, dating from the 1950s. Retired 60-MW nuclear boiler water reactor.	VII	0.31g**	Minor effects to the plant. The two operating units were restored in ½-hour.

* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records.
** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1983 Coalinga Earthquake Sequence, M = 6.7 (Initial Event) Thrust of unknown fault, presumably part of the Great Valley Fault Zone.				
Coalinga Water Treatment Plant	Water filtration & chlorination plant for the Coalinga area.	VIII	0.53g*	Minor damage to filtration basins & plant steel frame enclosure. Failure of weld at the wall-base seam of a vertical steel tank. Plant operation restored within a day.
Gates Substation	Large 500-, 230- & 115-kilovolt substation on the main high voltage intertie through the California Central Valley	VII	0.25g	Minor effects including oil squirting through bushing seals on transformers. Operation restored within hours.
Getty Oil Pumping Plant	Primary pumping station for oil pipeline & oil storage tank farm.	VIII*	0.51g*	Sliding & toppling of equipment including anchorage failure. Failure of one out of four large oil storage tanks. Damage to buried conduit. Plant operation restored in 3 days.
Kettleman Compressor Station	Natural gas-engine-driven compressors on main gas pipeline.	VII	0.20g	Essentially no effects. Station operated through the earthquakes.
Pleasant Valley Pumping Plant	Enclosure for nine 7,000 horsepower pumps lifting water to a branch of the San Luis Canal.	VII	0.35g* 0.59g**	Minimal effects to the pumping plant. Nearby vertical steel water surge tank failed by apparent water hammer. Plant restarted within an hour.
San Luis Canal Pump Stations	Some 20 pump stations were visited. Each station consists of several large vertical pumps with associated surge tank & switchgear.	VIII	0.20 – 0.40g	Stretched anchor bolts on surge tanks. Tanks remained intact except at one site. Pipe damage at one site due to soil settlement.

* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records.
** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
Shell Tank Farm No. 29	Oil storage tank farm including six large ground-mounted riveted steel tanks	VIII+	0.60g	Four out of six tanks ruptured their riveted seams in walls or at the wall-base.
Shell Water Treatment Plant	Facility containing water & oil storage tanks, filters, demineralizers & boilers for injecting steam into oil field to enhance production.	VIII+	0.60g*	Sliding of pad-mounted tanks & skids. Elephant's foot buckling of tank walls. Failure of one-out-of-eight large oil storage tanks. Buckling of steel framing supporting diatomaceous earth silo.
Union Oil Butane Plant	Propane & butane extraction plant from oilfield gas, including pressurized tanks, boilers, heat exchangers, engine-driven compressors & fractionation towers.	VIII	0.62g*	Structural damage to wooden cooling tower. Sliding of pad-mounted tanks & skids. Minor pipe leaks. Minor tilting of fractionation towers.
1984 Morgan Hill Earthquake Sequence, M = 6.2 Right-lateral-strike-slip on the Calaveras Fault east of Morgan Hill & Gilroy, California				
IBM Santa Teresa Data Processing Center	Office complex & data center in cluster of four-story steel frame towers.	VII	0.28g* 0.37g**	Minor effects. Power retained to site. Electronic systems continued operating.
Metcalf Substation	Large 500-, 230- & 115-kV substation serving south San Jose.	VII	0.40g	Fracture of one live tank 500-kB circuit breaker column. Toppling lightening arrestor on transformer.
Mirassou Winery	Wine making & storage facility housed in masonry & wood frame high bays	VII	0.20g	Minor sliding of unanchored wine storage vessels.
San Martin Winery	Wine making & storage facility housed in masonry & concrete tilt-up high bays	VII	0.35g	Out of ~100 stainless steel vertical wine storage tanks, 13 suffered leaks due to buckling in walls.

* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records.
** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1985 Chilean Earthquake, M = 7.8 Subduction faulting off the coast of the Port of Valparairso				
Bata Shoe Factory	Tannery & shoe manufacturing facility housed in concrete frame high bays.	VIII	0.60g	Sliding of skid-mounted equipment. Serious structural damage to concrete warehouse. Minor piping damage.
Concon Oil Refinery	Refinery for fuel oil, gasoline, butane, propane & asphalt.	VII	0.30g	Failure in 12 of 120 large oil storage tanks due to wall buckling or wall-base seam failure.
Concon Water Treatment Plant	Water pumping & filtration station.	VII	0.30g	Minor sliding of equipment. Cracks in underground water main.
Laguna Verde Power Plant	Two coal-fires team units dating from 1932 – 1949, totaling 54 MW output.	VII	0.25g	Essentially no damage to the plant. Operation restored in 16 hours.
Las Ventanas Copper Refinery	Large copper smelter and electrolytic refinery.	VII	0.30g	Collapse of refractory brick in smelter oven required 44 days for repair.
Las Ventanas Power Plant	Two coal-fired steam units dating from 1964 – 1965, totaling 330 MW output.	VII	0.22g* 0.18g**	Electrical cabinets failed anchors & overturned. Minor damage to boiler tubes. Minor pipe damage. Settlement beneath certain foundations. Operation restored in two days.
Llolleo Water Pumping Plant	Water pumping & filtration plant.	VIII	0.75g*	Failure in underground piping. Settlement beneath building foundations. Cracking in filtration basins. Sloshing damage to baffles. Damage to three deep well pumps due to settlement. Operation restored in 11 days.
* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records. ** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.				

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1985 Chilean Earthquake (Continued)				
Oxiquim Chemical Plant	Manufacturing facility for plastic, alcohol, formaldehyde & paint ingredients, housed in steel frame, masonry & concrete high bays.	VIII	0.30g	Shifting of unanchored chemical storage tanks with rupture of one out of ten. Minor pipe damage. Buckling in steel framing of buildings. Operations restored in 6 days.
Rapel Hydroelectric Plant	Five hydroelectric units on concrete arch dam, dating from 1968 – 1970, totaling 375-MW output.	VII		Minor shifting of foundations for two of five turbine-generators. Damage to ceramics in 220-kV switchyard. Bridge crane derailed. Three generating units started after 24 hours.
Renca Power Plant	Two coal-fired steam units dating from 1962, totaling 100 MW output.	VII	0.30g	Minor tube damage in one boiler. Operation of plant restored in 5 hours. Minor buckling of steel bracing. Bridge crane derailed. Misalignment in coal conveyor & derailing of tripper car.
1985 Mexico Earthquake, M = 8.1 **Subduction faulting off the coast of Michoacan**				
El Infiernillo Hydroelectric Plant	Six hydroelectric units on earth-filled dam dating from the mid-1960s totaling 1,000 MW output.	VII	0.13g**	Essentially no damage to plant. Leak in an oil-filled transformer in the 230-kV substation. Operation restored within hours.
Fertimex Fertilizer Plant	Large multi-facility complex for the manufacture of chemical fertilizer. Site was nearing completion & undergoing start-up testing at the time of the 1985 earthquake.	VIII	0.25g	Widespread damage to under-reinforced concrete structures. Extensive ground settlement beneath pads & building foundations. Repairs from earthquake delays plant start-up about 9 months.
La Villita Hydroelectric Plant	Four hydroelectric units on earth-filled dam dating from the mid-1960s totaling 304 MW output.	VII	0.14g**	Essentially no damage to plant. Operation restored in ½ hour.
* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records. ** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.				

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1985 Mexico Earthquake (Continued)				
NKS Steel Fabrication Plant	Steel foundry & finishing plant housed in steel frame high bays, dating from the early 1980s.	VIII	0.25g	Misalignment along assembly lines between interconnected machinery. Restart of plant delayed for weeks pending replacement of damaged bushings on the main 230-kV power supply transformers.
PMT Pipe Factory	Fabrication of large steel pipe in large concrete-frame high bay structures, dating from the early 1980s.	VIII	0.25g	Moderate spalling & cracking in concrete frames. Misalignments along certain assembly lines. Production limited for 3 months due to restoration of alignment & leveling of interconnected equipment.
Sicartsa Steel Mill	Large multi-facility steel smelter finishing plant for rebar & steel billets, dating from the mid-1970s.	VIII	0.25g	Sporadic settlement around site. Partial collapse of under-reinforced masonry structures. Rupture of large steel-plate smelter gas holding tank. Provisional operation of plant restored within a few days.
1986 Adak, Alaska Earthquake, M = 7.7 **Subduction faulting in the Aleutian Trench**				
US Navy Base at Adak	Investigations focus on the base diesel & steam boiler power plants, dating from the 1950s.	VII	No nearby record	Misalignments in diesel-generators due to support of pillow-block bearings on a foundation separate from the main skid.
1986 Chalfant Valley Earthquake, M = 6.0 **Normal faulting on the White Mountain Gap in the eastern California Sierras**				
Hi-Head Hydroelectric Plant	Small 0.4-MW hydro generator housed on small concrete block building, dating from 1962.	VII	0.25g	Current surge damage on programmable controller.
* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records. ** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.				

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1986 North Palm Springs Earthquake, M = 5.9 Right-lateral-strike-slip on the Banning Fault north of Palm Springs				
Devers Substation	Large 500-, 230- & 115-kV substation switchyard on main transmission corridor into Los Angeles.	VIII+	0.81g*	Extensive collapse of ceramics in 500-kV switchyard, especially live tank circuit breakers. Switchyard restored in 20 days.
Painted Hills Wind Farm	Array of several hundred wind turbine generators ranging from 50 to 100 kilowatts output each.	VIII	0.50g	Buckling of steel columns supporting wind turbines on a few units. Shifting of pad-mounted unit substation transformers.
Whitewater Trout Farm	Fish hatchery & well field	VII	0.55g**	Fracture in several buried water lines. Minor cracking in concrete basins.
Whitewater Hydroelectric Plant	Small hydro-turbine generator operating from discharge of the Colorado River Aqueduct, dating from 1985, totaling 1.2-MW output.	VII	0.50	Minor cracking in concrete block building. Toppling of unanchored unit substation transformers. Plant restarted following repairs to the aqueduct several days later.
1986 San Salvador Earthquake, M = 5.4 Left-lateral-strike-slip on unknown fault beneath the City of San Salvador				
Rio Acelhuate Pumping Station	Four vertical deep well pumps enclosed in steel frame high adjacent to river.	VIII	0.30g	Failure in the drive motor in one out of four pumps.
San Antonio Substation	One of two 115-kV substations serving the City of San Salvadoe	VIII	0.40g	Two ceramic columns failed on a 115-kV live tank circuit breaker.
Soyopango Substation	One of two 115-kV substations serving the City of San Salvadoe	VIII	0.50g	Soil shifting in switchyard. Failure of ceramic columns on two live tank 115-kV circuit breakers. Unrestrained batteries toppled in the control house.

* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records.
** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1987 Bay of Plenty, New Zealand Earthquake, M = 6.3 Normal faulting & subsidence on graben beneath the Rangitaiki Plains, northern island of New Zealand				
Caxton Paper Mill	Three paper making machines with warehouses, pulp mill, steam plant & water treatment plant, housed in concrete & steel frame high bays.	VIII	035g	Soil settlement up to 12 inches. Rupture of buried water main. Buckling in steel bracing in high bays. Minor pipe & duct damage. Bridge crane derailed. Operation restored in 12 days.
Edgecumbe Substation	Primary substation in region with switchyards for 110 & 220-kV power	IX	0.50g	Most 220/110-kV transformers failed their anchorage & toppled from their rail supports. Ceramic columns failed on two of eight 220-kV live tank circuit breakers. Additional ceramic damage on periperhal switchyard equipment. Control panels failed anchorage & overturned in control house. Substation restored to operation after several weeks.
Kawerau Substation	Primary substation in region with switchyards for 110 & 220-kV power.	VIII	0.35g	One failed column on a 220-kVcircuit breaker. Internal damage on most current transformers. Damage due to differential displacement between rail-mounted main tank & radiator on 220/110-kV transformers. Partial operation of substation restored in 3 days.
Matahina Hydroelectric Plant	Two hydro units of 36-MW each in concrete high bay next to earthen dam, dating from 1967.	VII	0.26g**	Dam required extensive repair due to seepage failure subsequent to quake. Minor damage in 110-kV switchyard. Essentially no damage in hydro plant. Operation restored in 24 hours.

* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records.
** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1987 Bay of Plenty, New Zealand Earthquake (Continued)				
New Zealand Distillery	Distillation system mounted in steel frame tower, with large array of stainless steel tanks.	IX	0.50g	Ground settlement up to 12 inches. Failure of about half of some 26 tanks on the site, including tank overturning. The facility required almost complete rebuild.
Whakatane Cardboard Mill	Combination pulp & paper mill for cardboard manufacture, including three paper machines & peripheral systems housed in concrete & steel frame high bays.	VII	0.25g	Misalignment in Paper Machine No. 2 required extensive repairs. Buckling in steel framing of buildings. Falling of overhead ceiling fixtures. Minor tilting of steel exhaust stack for steam plant. One paper machine restored to operation in 3 days.
1987 Cerro Prieto, Mexico Earthquake, M = 5.4 **Apparently right-lateral-strike-slip on the Cerro Prieto Fault (branch of the Imperial Fault)**				
Geothermal Power Plant	Three adjacent geothermal-powered steam plants dating from 1973 – 1976, totalling 600 MW output.	VI	No nearby record, perhaps 0.10g	Essentially no effects. Plants restarted following trips due to relay actuation.
1987 Superstition Hills Earthquake, M = 6.0 **Right-lateral-strike-slip on the Superstition Hills Fault (branch of the Imperial Fault)**				
El Centro Steam Plant	Four gas-fired steam units dating from 1949-1968. Total output = 100 MW.	VII	0.26g**	One pipe leak. Minor buckling in a large oil storage tank. Unit in operation at the time of the quake restarted in half an hour.
Mesquite Lake Power Plant	Demonstration plant nearing completion at the time of the earthquake. Converts steer manure into burnable fuel to supply a 16-MW steam unit.	VII	0.20g	Minor fracturing of refractory brick liner for combustion furnaces. Minor misalignment in forced draft fans.
* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records. ** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.				

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1987 Whittier Narrows Earthquake, M = 5.9 Compressive thrust on a previously unknown fault north of Whittier, California				
Alhambra Switching Station	Telephone switching center housed in a three-story concrete frame building	VII	0.40g	Minor cracking in concrete walls. Cable trays dislodged from ceiling anchors.
California Federal Data Processing Center	Office complex & data center housed in four-story steel frame building.	VII	0.40g	Shearing of anchor bolts & sliding of electrical switchgear. Buckling of diagonals in building frame. Leaks in fire water piping. Cracking in concrete exterior panels.
Center Substation	Switchyards for 220- and 66-kV power.	VII	0.35g	Loss of SF-6 gas from columns of all six 220-kV live tank circuit breakers. Shattered porcelain on one column.
Commerce Refuse to Energy Plant	Refuse-burning boiler supplying steam to a 11.5-MW generating unit, dating from 1985.	VII	0.39g	Essentially no damage to the plant. Generating unit operated through the earthquake.
Del Amo Substation	Switchyards for 220- and 66-kV power with warehouse & shop.	VI	0.20g	Loss of SF-6 gas from columns on most of the 220-kV live tank circuit breakers. Tripping of a molded case circuit breaker in a distribution panel.
Los Angeles Grand Central Switching Station	Central telephone switch housed in steel frame towers.	VI	0.15g	Cracking at tower interfaces due to pounding. Derailed elevators. Sagging of overloaded cable trays.
Lighthype Substation	Switchyards for 220- and 66-kV power.	VI	0.32g**	Loss of SF-6 gas from columns on two live tank 22-kV breakers. Minor misalignment in rotating condensers.

* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records.
** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1987 Whittier Narrows Earthquake (Continued)				
Mesa Substation	Switchyards for 220- and 66-kV power with garage, warehouse & shops.	VII	0.35g	Dislodged lightening arrestor on a 220/66-kV transformer. Loss of SF-6 gas through leaking seals on one 220-kV live tank circuit breaker.
Olinda Substation	Switchyards for 220- and 66-kV power with garage, warehouse & shops.	VII	0.65g**	Leaks at connection of radiator coils with main tank on 220/66-kV transformers.
Pasadena Power Plant	Four gas-fired steam units dating from 1949 – 1965. Total output = 206 MW.	VII	0.20g	The two units in operation at the time remained on line through the earthquake. No significant effects.
Puente Hills Power Plant	Landfill gas-fired boilers supplying 40 MW steam plant, constructed in 1986.	VII	0.25g	Essentially no effects to the plant. Restarted after a few hours.
Rosemead Phone Switching Station	Telephone switching center housed in two-story steel frame, masonry building.	VII	0.40g	Minor cracking in masonry. Unrestrained circuit boards slid from racks. Gas turbine standby generators overheated and shut off.
Southern Cal Edison Headquarters	Office complex & data center in concrete shear wall buildings.	VIII	0.41g**	Fallen ceiling panels. Cracking in concrete shear walls. Fallen desk & shelf contents. HVAC fans dismounted from spring isolators. One small diesel generator shut down due to a relay burn-out in the control panel.
Southern Cal Edison Dispatch Center	Data processing center housed in two-story concrete frame building, with adjacent steel frame high bay shops.	VII	0.56g**	Cracking in concrete & masonry walls of older shops. One pipe failure. Overhead bridge crane stretched bolts on rails.

* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records.
** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1987 Whittier Narrows Earthquake (Continued)				
Sanwa Data Processing Center	Data center & office complex housed in four-story steel frame building.	VII	0.40g	Leaks in fire piping. Dismount of HVAC fans from spring isolators. Damage to one fan impeller. Fractured casing on chilled water pump.
Ticor Data Processing Center	Data processing & office complex housed in two-story concrete tilt-up.	VII	0.40g	Shear cracks in concrete wall panels. Fallen ceiling fixtures. Rupture in fire sprinkler lines. Dismount of HVAC fans from spring isolators. Damage to one fan impeller.
Wells Fargo Data Processing Center	Data processing & office complex housed in five-story steel frame building.	VII	0.35g	Toppled office furniture. Shifting of computer consoles (no damage). Blown fuses in UPS shuts off standby power.
1989 Loma Prieta Earthquake, M = 6.9 Right-lateral-strike-slip & thrust on the San Andreas Fault				
Electric Power Research Institute Headquarters	Office complex of two-story concrete frame buildings	VII	0.25g	Minor cracking in concrete walls & frame. Overturned furniture. Pipe leaks at three locations. HVAC equipment dismounted from spring isolators.
Gilroy Cogeneration Plant	Combination gas turbine & steam turbine plant, dating from 1988, totalling 120 MW output.	VII	0.39g* 0.32g**	Essentially no effects from the earthquake. Plant restarted seven hours after the earthquake.
Green Giant Cold Storage Plant	Refrigerated storage facility for fresh produce housed in concrete tilt-up.	VIII	0.40g	Cracking of concrete pilasters. Separation of wall panel. Buckling in forced draft cooling tower framing. Rupture of ammonia refrigerant line. Burn-out of refrigerant compressor.

* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records.
** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1989 Loma Prieta Earthquake (Continued)				
IBM Santa Teresa Data Processing Center	Office complex & data center in cluster of four-story steel frame towers.	VII	0.28g* 0.21g**	Moderate damage to office fixtures. Two leaks in chilled water lines beneath computer floors. Pipe leaks in two penthouse air handlers. Leaks in buried firewater line.
Lipton Food Processing Plant	Processing and packaging of dried produce in assembly lines of automatic machinery, housed in concrete tilt-ups	VIII	0.30g	Minor cracking in concrete. Minor shifting of assembly line equipment. Leaks in fire sprinkler lines at two locations.
Lone Star Cement Plant	Heavy industrial facility of concrete & steel frame structures, including ore crushers, conveyors, kilns, furnace tower, warehouses & packaging plant.	VII	0.25g	Bracing buckled in furnace tower. Partial collapse of concrete beams supporting conveyor structure. Minor damage in electrostatic precipitators.
Metcalf Substation	Large 500-, 230- & 115-kV substation serving south San Jose.	VII	0.30g	Ceramic column damage in most of the 500-kV live tank circuit breakers. Oil leakage from current transformers. Oil leaks at radiator connections on 500/220-kV transformers.
Moss Landing Power Plant	Seven gas-fired steam units dating from 1950 – 1968, totaling 2040 MW in output.	VIII	0.30g*	Extensive damage to ceramic columns in the 500-kV switchyard. Overturning of 500-kV live tank circuit breakers. Loss of a welded steel raw water tank. Damage to Unit 7 exhaust stack. Bearing damage in Unit 6 low pressure turbine. One unit started two days after earthquake.

* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records.
** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1989 Loma Prieta Earthquake (Continued)				
National Refractory at Moss Landing	Manufacturing facility for refractory brick & precipitation of magnesium-hydroxide from sea water.	VIII	0.30g	Sloshing damage to wooden framing in sea water basins. Toppling of refractory brick within kilns. Rupture of overhead firewater line.
Potrero & Hunters Point Power Plants	Gas-fired steam units & gas-turbine peaking plants, totaling 810 MW, dating from the 1940s to the 1970s.	VII	0.15g	Minor effects to both plants. Cracking in a concrete shear wall. Units restarted within hours of the earthquake.
San Mateo Substation	Switchyards for 230- and 115-kV power into San Francisco	VII	0.20g	Cracking in ceramic columns on four 230-kV live tank circuit breakers. Cracking in ceramics of potential transformers. Oil leaks at radiator connections in 230/115-kV transformers.
Santa Cruz Switching Station	Telephone switching station for the Santa Cruz area housed in three story concrete frame building.	VIII	0.43g*	Shearing of anchor bolts for roof-mounted turbine generator. Disconnections C voltage converters in switchracks.
Santa Cruz Water Treatment Plant	Water pumping & filtration facility	VIII	0.43g*	Extensive damage in buried water distribution system (260 failures). No significant damage in the filtration plant.
Seagate Watsonville Plant	Manufacturing facility for disk drives housed in concrete tilt-up.	VIII	0.40g	Cracking in concrete walls. Shearing of seven fire sprinkler heads. Shifting of roof-top air handlers. Water spray from fire sprinkler into 480-volt unit substation.
Soquel Water System	System of 17 deep wells serving epicentral area of the earthquake.	VIII		Breaks at 40 locations within water distribution system. Internal disconnections in pump station remote monitoring systems.

* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records.
** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1989 Loma Prieta Earthquake (Continued)				
Stanford Cardinal Cogeneration Plant	Combined gas turbine & steam generator dating from mid-1980s totaling 39 MW output.	VII	0.25g	Essentially no damage to the plant.
University of California, Santa Cruz	Large campus of concrete frame mid-rise buildings. Investigations focused on the campus cogen plant.	VIII	0.43g* 0.45g** 0.37g**	Dismounts of spring-supported HVAC equipment on roofs. Minor damage to buildings. Sporadic leaks in water piping.
Watkins Johnson Scotts Valley	Manufacturing facility for solid state electronic components housed in steel & concrete frame buildings	VIII	0.48g*	Minor cracking in concrete wall panels. Shifting of unanchored equipment. Two leaks in fire sprinkler lines. HVAC equipment dismounted from spring isolators.
Watsonville Switching Station	Telephone switching center housed in four-story concrete frame building.	VIII	0.34g**	Minor cracking in concrete. Minor effects to interior equipment.
Watsonville Wastewater Treatment Plant	Wastewater filtration & disinfection facility	VIII	0.40g	Minor settlement around site. Breaks in sewage collection system. Cracking in concrete outfall to offshore discharge.
1990 Central Luzon Earthquake in the Philippines, M = 7.7 Right-lateral-strike-slip on the Digdig Fault				
Bagio Telephone Switching Station	Telephone switch housed in two-story concrete frame building	VIII	No ground motion records	Loss of DC power due to internal damage to batteries. A second rack pulled anchorage & overturned.
* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records. ** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.				

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1990 Philippine Earthquake (Continued)				
Cabanatuan Substation	Switchyards for 230- and 110-kV power	VII	No records	Oil leaks in four current transformers.
La Tinidad Substation	Switchyards for 230- and 110-kV power	VIII	No records	Failure in ceramic columns of potential transformers & lightening arrestors.
Moog Servo-Controls Manufacturing Plant	Manufacturing operation dating from the mid-1980s housed in concrete frame high bays.	VIII	No records	Leaks in ceiling-mounted fire sprinklers. Internal burn-out in a voltage regulator.
San Manuel Substation	Switchyards for 230- and 110-kV power	VII	No records	No damage to the substation
Texas Instrument Plant, Bagio	Manufacturing facility for solid state components, housed in concrete frame high bays.	VIII	No records.	Cracking in concrete frame & masonry-infill. Toppling of interior racks for testing electronic components.
1991 Sierra Madre Earthquake, M = 5.8 Reverse thrust on the Sierra Madre Fault at the base of the San Gabriel Mountains in Los Angeles				
Goodrich Substation	Switchyards for 230- & 66-kV power	VII	0.30g	Toppling of a ceramic column in a 230-kV live tank breaker. Leaking SF-6 gas in two other breakers.
Pasadena Power Plant	Four gas-fired steam units dating from 1949 – 1965. Total output = 206 MW.	VI	0.15g	Two units on line at the time operated through the earthquake. One 2400-volt circuit breaker disconnected from its bus bars. Minor problems with control systems.
1991 Valle De La Estrella, Costa Rica Earthquake, M = 7.4 Thrust faulting within the Caribbean tectonic plate				
Bomba Water Treatment Plant	Water filtration, disinfection & pumping plant	VIII	No ground motion records	Damage to wooden baffles in filtration basins due to sloshing. Chlorine leak from overturned bottle. Extensive breaks in water distribution system.

* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records.
** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1991 Cost Rica Earthquake (Continued)				
Cachi & Rio Macho Hydroelectric Plants	Eight hydroelectric units downstream of concrete arch & earthen dams, dating from the 1960s – 1970s, totaling 2300 MW output.	VI	0.13g**	Downed power pole. Burned conductor in a diesel generator. Operation restored within ½ hour.
Limon Telephone Station	Central phone switch for the Port of Limon housed in a three-story concrete building.	VII	No nearby records	No serious effects to the switching center. Diesel generators maintained charge in the DC power system.
Moin Diesel Power Plant	Three gas-turbine-generators & four diesel generators, dating from ~1960 – 1990, totaling 140 MW output.	VIII	No nearby records	Lockout of digital control system delayed restart of gas turbines. Vibration problems in diesels following restart due possibly to settlement beneath foundations.
Port of Limon	Piers with container cranes & large concrete high warehouses.	VIII	No nearby records	Settlement & lateral soil spreading beneath concrete pads & warehouses. Collapse of one warehouse. Shifting of cranes on their rails.
Port of Moin	Pumping stations & pipelines for off-loading oil tankers. Oil storage tank farm.	VIII	No nearby records	Collapse of concrete frame warehouse under construction at the time of the quake. Shifting of unanchored oil storage tanks. Elephants foot buckling in some tanks although vessels remained intact.
Recope Oil Refinery	Refinery serving all of Costa Rica, including fractionation columns, steam boilers, heat exchangers, pipeline pumps and an oil storage tank farm.	VIII	No nearby records	Fire from explosion of a waste oil tank. Rupture of one oil storage tank. Serious damage to concrete frame administration building.
Changuinola, Panama Diesel Power Plant	Power plant housed in steel frame high bay, including eight diesel generators totaling about 16 MW output.	VIII	No nearby records	Extensive settlement beneath plant building fractured foundation resulting in failures to piping serving diesel generators.

* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records.
** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1992 Cape Mendocino Three-Earthquake Sequence, Main Event M = 7.0 Reverse thrust at the Mendocino Triple Junction				
Centerville Naval Station	Coastal communications facility & data processing center at Centerville Beach housed in one & two-story wood frame, tilt-up & concrete block buildings.	VIII	0.40g**	Minor cracking in concrete block. Overturning of building interior fixtures. Minor damage to HVAC equipment.
Humboldt Bay Power Plant	Two gas-fired steam units totaling 100 MW, dating from the 1950s. Retired 60-MW nuclear boiler water reactor.	VII	0.38g* 0.24g**	Disconnections in pole-mounted fused switches & cabinet-mounted potential transformers. Minor yielding in boiler tower. Leak in circ. water line. Operations restored in two days.
Pacific Lumber Mill	Large lumber processing facility housed in wood-frame high bays. Site includes a two unit cogen plant dating from 1989 totaling 30 MW output.	VIII	0.46g* 0.47g**	Structural damage in a wooden cooling tower. Buckling of steel frame in cogen plant. Impact damage to electrostatic precipitators. Misalignments in turbine-generator. One unit restarted two weeks after the quake sequence.
1992 Landers/Big Bear Two-Earthquake Sequence, Main Event M = 7.0 Right-lateral-strike-slip on branch of San Andreas Fault northeast of Los Angeles				
Cool Water Power Plant	Two gas-fired steam units dating from the early 1960s& two cogeneration units dating from late 1970s, totaling 666-MW.	VII	0.37g* 0.36g**	Damage at interface of gas turbine & heat recovery steam generator. Oil leaks in 230/13.8-kV transformer. Failure of a water storage tank. One cogen unit restarted after two weeks.
Mitsubishi Cement Plant	Large cement production plant including ore crushers, kiln, preheater tower, storage silos, warehouses & packaging plant, housed in steel frame, concrete frame & shear wall enclosures.	VII	0.30g	Minimal effects to the site. Minor problems in digital control system. Malfunction of a gas fuel control valve. Operations restarted 21 hours after quake.

* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records.
** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1992 Landers/Big Bear Earthquake (Continued)				
Newberry Gas Compressor Plant	Compressor station on natural gas pipeline, with engine-driven compressors housed in steel frame high bay	VII	0.25g	Fallen light fixtures. Trip of DC power supply circuit breaker. Station restarted 6 hours after quake.
Pfizer Ore Processing Plant	Ore processing mill & storage facility housed in steel frame high bays.	VII	0.30g	Collapse of skirt-mounted steel silos for powdered ore.
Solar Electric Generating Stations	Heliostat-powered steam plant (Solar One) & nearby Solar Electric Generating Stations 1 & 2 (SEGs – trough concentrators), dating from the 1980s, totaling 44 MW output.	VII	0.35g	Solar One was down at the time of the earthquake. No effects in the steam system. About 10% of mirror panels dislodged. At SEGs 1 & 2, fiberglass tanks sheared anchorage & slid, resulting in leaks. About 10% of mirror panels dislodged from trough concentrators. SEGs 1 & 2 restarted after three days.
1993 Island of Guam Earthquake, M = 8.0 **Subduction in Marianas Trench south of island**				
Cabras Power Plant	Two oil-fire steam units dating from 1974-75, totaling 132 MW	VIII	0.26g* average PGA for island	Rupture of one oil storage tank. Settlement damage to circ. water line. Minor porcelain damage in 115-kV switchyard. Vibration problems in forced-draft fans. Plant restart in 3 days.
Caterpillar Diesel Generator Plant	Eight 5-MW Caterpillar diesel generators housed in steel frame high bay.	VII	0.26g*	Leak in cooling water line at diesel engine attachment.

* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records.
** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1993 Island of Guam Earthquake (Continued)				
Dededo Gas Turbine & Diesel Generator Plant	New gas turbine generator & four older diesel generators housed in steel frame & concrete shear wall high bays, totaling 32-MW output	VII	0.26g*	Small leaks in oil & water lines. Otherwise no significant effects. Plant restarted within 12 hours.
Apra Harbor Wastewater Plant	Filtration & disinfection station for nearby Navy base, housed in concrete frame structures	VIII	0.26g*	Extensive damage to underground waste collection piping. Misalignments, leaking seals & excess vibration in vertical pumps. Two pump motors burned out.
Guam Water System Well Stations	System of some 90 deep well pumps at various stations around the island.	VII – VIII	0.26g*	Extensive damage to buried piping in distribution system. Total of 19 vertical pumps damaged out of several 100 in the water system.
Harmon Substation	Switchyards for 115- & 34.5-kV power	VII	0.26g*	Toppling of unrestrained batteries. Unanchored transformers shifted on their pads.
Orote Point Diesel Generator Plant	Ten 600-kW diesel generators houses in concrete frame high bay for US Navy port facilities	VIII	0.26g*	Rupture in an oil tank. Diesel generators were undamaged. Diesels started 9 hours after quake.
Piti Power Plant	Five oil-fire steam units dating from 1951 – 1965, totaling 76-MW output.	VIII	0.26g*	Liquefaction crushed circ. water lines & flooded basement of power plant. Turbine generator bearing damage. Toppling of unanchored electrical equipment. Several pipe failures within plant. Two units restarted three weeks after quake.

* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records.
** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1993 Island of Guam Earthquake (Continued)				
Tanguisson Power Plant	Two oil-fired steam units dating from 1971-72, totaling 26 MW.	VII	0.26g*	Bus bar failure in 13.8-kV switchgear. Minor porcelain damage in 34.5-kV switchyard. Plant restarted in two days.
Uguma Water Treatment Plant	Water filtration & disinfection facility	VII	0.26g*	Essentially no effects. Plant restarted when power was restored.
Yigo Gas Turbine Plant	New packaged 22-MW gas turbine generator	VII	0.26g*	Minor pipe leaks in water purifiers. gas turbine restarted two hours after quake.

1994 Northridge Earthquake, M = 6.7 **Thrust fault in San Gabriel Mountains north of San Fernando Valley**				
ARCO Placerita Cogeneration Plant	Gas-turbine-to-steam-turbine cogen plant totaling 42 MW	VIII	0.60g	No significant effects in cogen plant. Damage to oil storage tanks in oil facility adjacent to cogen.
Sylmar Converter Station	Major power supply facility for greater Los Angeles, converting 500-volt DC power to AC. A more-or-less duplicate East Facility had been added to the original site in the 1980s	VIII+	0.75g*	Damage to 20 – 30 ceramic columns in the 500-kV switchyard. Failure of disconnect switch columns in 230-kV yard. Anchorage failure in 230-kV transformer. Damage to DC-AC thyristors. Partial operation restored within a few weeks.
Rinaldi Receiving Station	Main switching center for 500-kV power to northern LA basin. Includes 500 & 230-kV switchyards.	VIII+	0.66g*	Collapse of bus conductor in 230-kV yard. Ceramic column collapse in potential transformers. Oil leaks at transformer radiator connections. Ceramic damage in 500-kV yard in disconnects & transformers.

* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records.
** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1994 Northridge Earthquake (Continued)				
Valley Steam Plant	Units 3 & 4 remained in operation as peaking plants.	VIII	0.40g	Leak in condensate line. Minor damage in steel frame boiler towers. Plant restarted 18 hours after quake.
Burbank Power Plant	Two 1950s steam units plus three gas turbine generators. Original steam units retired. Total output ~100 MW.	VII	0.30g	Steam valve malfunction & minor pipe damage. Plant restarted 14 hours after quake.
Glendale Power Plant	Five gas-fired steam units dating from 1941 – 1964, totaling 148 MW. Five packaged gas turbines added in 1980s, for an additional 100 MW.	VII	0.25g	Damage to bearings in Unit 5 steam turbine generator due to low oil pressure. Leaks in circ. water line to cooling tower. All units except Unit 5 on line within 24 hours.
Pasadena Power Plant	Four gas-fired steam units dating from 1949 – 1965. Total output = 206 MW.	VII	0.20g	No significant effects. All operating units started within hours of quake.
Castaic Hydroelectric Plant	Six hydro-turbine-generator-pumping units, totaling 1247 MW, dating from 1978.	VIII	0.35g**	Cracked ceramic bushings on 230-kV step-up transformers. Leaks in buried water lines. Plant restarted the day following the quake.
Great Western Data Center	Corporate headquarters & data processing center for Great Western Savings housed in steel-frame mid-rise building with concrete frame & tilt-up annexes.	VIII+	0.40g*	Extensive structural damage in concrete frame building. Water damage from failed sprinkler & HVAC water lines. Dismount of HVAC equipment from spring isolators. Toppling of office fixtures.
Ormond Beach Power Plant	Two gas/oil-fired steam units dating from 1970 – 1973. Total output = 1500 MW.	VI	0.10g	Minor effects to the plant. Operation restored within a day.
Olive View Hospital	Six story concrete & steel shear wall building with adjacent cogen plant.	VIII+	0.73g**	Building structures undamaged. Pulled anchor bolts in penthouse HVAC equipment. Toppling of vertical liquid oxygen tank outside hospital.

* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records.
** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1994 Northridge Earthquake (Continued)				
Pitchess Cogeneration Plant	Gas-turbine-to-steam unit of 28-MW dating from 1988.	VIII	0.50g	Misalignment in 12.5-kV switchgear. Otherwise minor effects. Plant restarted 25 hours after quake.
Placerita Cogen Plant	Two gas turbines exhausting to a steam unit, totaling 100 MW output, dating from 1988.	VIII	0.59g*	No significant effects in cogen plant. Sliding of skid-mounted demineralizers & filters in adjacent water treatment plant. Failure of two water storage tanks.
Pardee Substation	Main 220-kV switching center for north Los Angeles	VIII	0.45g**	Damage to all eight 220-kV live tank circuit breakers.
Vincent Substation	500-kV & 220-kV switchyards	VII	0.15g	Collapsed disconnect switches in 500-kV yard. Ceramic damage to capacitor banks. Leaks in transformer radiator connections.
1995 Manzanillo, Mexico Earthquake, M = 7.6 Subduction of the Rivera tectonic plate off the coast of Jallisco				
Manzanillo Power Plant	Two adjoining oil-fired steam plants with six units, totaling 1900 MW, dating from 1980 – 1990.	VIII	0.42g* 0.40g**	Extensive damage to ceramics in 400-kV substation. Liquefaction beneath salt water intake pump collapsed circulating water lines. Buckling of water tubes in one boiler. Damage to impeller of vertical condensate pump. Initial restart of units 6 weeks after quake.
1997 Michoacan, Mexico Earthquake, M = 7.3 Subduction of the Rivera tectonic plate off the coast of Michoacan				
El Infiernillo Hydroelectric Plant	Six hydroelectric units on earth-filled dam dating from the mid-1960s totaling 1,000 MW output.	VII	0.31g**	Essentially no damage to plant. Operation restored within hours.

* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records.
** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1997 Michoacan Earthquake (Continued)				
La Villita Hydroelectric Plant	Four hydroelectric units on earth-filled dam dating from the mid-1960s totaling 304 MW output.	VII	0.16g**	Essentially no damage to plant. Operating units continued through the earthquake.
Petacalco Power Plant	Six oil-fired units dating from 1994, totaling 2100 MW output.	VII	0.28g**	Minor tube damage in boilers. Burn-out of a unit substation transformer. Burn-out of a 400-kV reactor. Minor damage in 400-kV SF-6-gas-insulated switchgear. Plant restarted in two days.
Sicartsa Steel Mill	Large multi-facility steel smelter finishing plant for rebar & steel billets, dating from the mid-1970s.	VIII	0.19g**	Minor tube leaks in power plant steam boiler. Disconnection of a bus bar. Operation of mill restored within hours.
1999 Chi Chi, Taiwan Earthquake, M = 7.6 Subduction of the Philippine Tectonic Plate within the Ryukyu Trench				
Chungliao Substation	Switchyard for 345-kV power.	VIII	0.47g*	Extensive damage to ceramic substation equipment. Ground failure beneath the site damaged piping for gas insulation & foundations for large equipment. Rebuilding of the switchyard required 18 months.
Kukuan Hydroelectric Plant	Four hydro units, dating from 1957 – 1966, totaling 180 MW.	VIII	0.63g*	Explosions in transformers and circuit breakers in the plant switchyard.
Mingtan Hydroelectric Plant	Six hydro units dating from 1987 – 1995, totaling 283 MW.	VII	0.30g*	Minor damage in 345-kV gas-insulated switchgear.
* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records. ** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.				

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1999 Taiwan Earthquake (Continued)				
Takuan Hydroelectric Plant	Five hydro units dating from the 1930s, totaling 110 MW adjacent to a four-unit hydro-pump plant, dating from 1985, totaling 1,000 MW.	VIII	0.45g	Leak in penstock. Sliding boulders damaged exterior piping. Oil leaks in transformer bushings. Ceramic damage in potential transformers & line trap supports. No effects to 345-kV gas-insulated switchgear.
Techi Hydroelectric Plant	Three hydro units dating from 1974, totaling 234 MW.	VIII	0.64g*	Essentially no damage to plant other than minor damage to diesel generator anchors.
Tienlun Hydroelectric Plant	Four hydro units in older plant dating from 1952 – 1978, totaling 90 MW. New unit dating from 1996 is 105 MW.	VII	0.26g*	Rupture of hydraulic oil line serving valve. Extensive damage in the 345-kV switchyard.
Wanta Hydroelectric Plant	Three hydro units dating from 1947 – 1957.	VIII	0.71g*	Oil leaks in transformers in 161-kV switchyard. Damage to ceramic columns. Serious damage to un-reinforced concrete enclosure for air compressors.
1999 Kocaeli, Turkey Earthquake, M = 7.4 Strike-slip along the North Anatolian Fault				
Adapazari Substation	Switchyard for 380- & 154-kV power	VIII	0.43g*	Damage to ceramic columns in six 380-kV circuit breakers. Shifting of rail-mounted transformers resulted in oil leak. Serious damage to three-story concrete buildings.
Ambarli Cogen Power Plant	Three unit combination gas- & steam-turbine-generators, dating from 1989, totaling 1350 MW output.	VII	0.22g*	Minor damage to current transformers in the380-kV switchyard. Bushing oil leaks in startup transformers. Minor damage in the steel frame boiler tower.
Ambarli Steam Power Plant	Five oil-fired units, dating from 1967 – 1971, totaling 630 MW output.	VII	0.22g*	Toppling of masonry from the top of the exhaust stacks. Sloshing damage to a fuel oil storage tank. Minor pipe damage. Toppling of unrestrained batteries.

* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records.
** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1999 Kocaeli Earthquake (Continued)				
Kosekoy Substation	Switchyard for 154 & 34.5-kV power	VII	0.28g*	Toppling of rail-mounted transformers.
Nuh Cimento Cogen Plant	Gas-&-steam turbine adjoining cement plant, totaling 38 MW.	VII	0.24g*	No significant effects to plant, which was down for maintenance at the time.
Pakmaya Gas Turbine Plant	Gas turbine generator of 15 MW output.	VII	0.36g*	Gas turbine dismounted from spring isolators, resulting in misalignment between turbine & generator.
Sultanmurat Substation	Switchyard with gas-insulated switchgear for 154-kV power.	VII	0.12g*	Malfunction in fire suppression system triggered discharge of oil from transformers.
Yarimca Substation	Switchyard for 154- & 34.5-kV power.	VII	0.31g*	Unrestrained transformers shifted along rails, damaging surrounding fire suppression lines. Burn-out of load tap changer on transformer.
2001 Gujarat, India Earthquake, M = 7.7 Thrust faulting on the Kachchh Graben				
Madhapar Substation	Switchyard for 66-kV power	IX	No ground motion recordings in the area	Collapsed columns on one of four circuit breakers. Derailed transformer. Cracking in masonry in-fill of control building. Insulator damage within 11-kV switchgear cabinet.
Anjar Substation	Switchyard for 220, 132 & 66-kV power.	IX	No nearby records	Dismount of rail-mounted transformers. Porcelain damage in 220-kV live tank circuit breakers. Damage in 11-kV vacuum circuit breakers. Toppling of unrestrained batteries.
Digvijay Cement Plant	Cement production plant of steel & concrete structures including preheater tower, kilns, conveyors, storage silos & packaging plant.	VII	No nearby records	Toppling of a large concrete raw material silo. No other significant effects.

* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records.
** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.

Table B-2: Summary of Sites Investigated in Compiling the EPRI Seismic Experience Database (Continued)

Earthquake & Site	Facility Description	Ground Shaking Intensity (MMI)	Peak Ground Acceleration (PGA)	General Damage
1999 Gujarat Earthquake (Continued)				
India Farmers Federation Cooperative Fertilizer Plant	Large production facility for di-ammonium-phosphate (DAP) & nitrogen-potasium-phosphate (NPK).	VIII	No nearby records	Collapse of concrete frame conveyor gallery. Partial collapse of masonry in-fill throughout site. Transformer dismount from rails. Toppling of unrestrained batteries. Bearing damage to ore crushers. Three months required for plant restart.
Agrocell Bromine Plant	Distillation plant for extracting bromine from sea water, housed in steel frame tower & concrete frame high bays.	VIII+	No nearby records	Rupture in earthen dykes for evaporation reservoirs resulted in flooding of site. No other significant effects.
Ballarpur Bromine Plant	Bromine distillation plant housed in concrete towers & high bays.	VIII+	No nearby records	Damage to glass elements in tower-mounted bromine condenser. Seizure within the engines of two diesel generators. Plant restarted about one month after the quake.
Twenty Microns Salt Refinery	Extraction plant for polyvinyl-chloride, housed in concrete frame high bays.	IX	No nearby records	Extensive collapse of masonry in-fill & fracturing of concrete framing. Ground faults resulting in burnout of switchboard & programmable controller.

* Peak ground acceleration estimated from special studies by the Nuclear Regulatory Commission, based on nearest strong motion records.
** Peak ground acceleration measured by a free-field or base-slab-mounted strong motion recorder located at or within one mile of the site.

Appendix C: Summary of Database Sites & Data Sets for Equipment Categories Representative of Possible-Long-Term-Replacement-Time Items for the Diablo Canyon Nuclear Power Plant

Site	MMI	PGA (g)	Large Vertical Pumps	Pumps Damaged	Hydro Units	Hydro Units Damaged	Large Horizontal Pumps	Pumps Damaged	Vertical Steel Tanks	Tanks Replaced
Olive View Hospital	VIII+	0.73							3	1
Sylmar Substatio (San Fernando)	VIII+	0.69								
Sylmar Substation (Northridge)	VIII+	0.75								
Rinaldi Substation (San Fernando)	VIII+	0.66								
Rinaldi Substation (Northridge)	VIII+	0.66								
Manzanillo Power Plant	VIII+	0.42	4	1			4	0.5	10	
Edgecumbe Substation	VIII+	0.5								
Chungliao Substation	VIII+	0.47								
Great Western Data Center	VIII+	0.5								
N.Z. Distillery	VIII+	0.5							26	5
Getty Oil Plant	VIII+	0.51	2				6		4	
Shell Water Injection Plant	VIII+	0.6							8	1
Shell Tank Farm No. 29	VIII+	0.60								
Llolleo Water Plant	VIII+	0.75g								
Devers Substation	VIII+	0.81							4	
Totals & Incremental Failure Rates	VIII+	**0.5891**	**6**	**0.142857**	**0**	**0**	**10**	**0.045455**	**55**	**0.125**
Pitchess Cogen	VIII	0.5								
ARCO Cogen	VIII	0.6								
Placerita Cogen	VIII	0.59							12	1
Pardee Substation (Northridge)	VIII	0.45								

Table C-1: Summary of Sites Investigated in Compiling the EPRI Database & Data Sets for Equipment Categories Representative of Possible-Long-Term-Replacement-Time Items for the Diablo Canyon Nuclear Power Plant (Continued)

Site	MMI	PGA (g)	Large Vertical Pumps	Pumps Damaged	Hydro Units	Hydro Units Damaged	Large Horizontal Pumps	Pumps Damaged	Vertical Steel Tanks	Tanks Replaced
Adapazari Substation	VIII	0.42								
Valley Steam Plant (San Fernando)	VIII	0.3					9		5	
Valley Steam Plant (Northridge)	VIII	0.3							5	
El Centro Steam Plant (Imperial Valley)	VIII	0.42					6			
Union Oil Butane Plant	VIII	0.62								
Coalinga Water Treatment	VIII	0.53	3							
San Luis Canal Pumps	VIII	0.3	7				2		10	
Fertimex Fertilzer Plant	VIII	0.25								
Sicartsa Steel Mill	VIII	0.25								
NKS Steel Frabrication Plant	VIII	0.25								
PMT Pipe Factory	VIII	0.25								
Caxton Paper Mill	VIII	0.4							10	
SCE Headquarters	VIII	0.42								
Cal-Fed Data Center	VIII	0.4								
Ticor Data Center	VIII	0.4								
UCSC Campus	VIII	0.43								
National Refractory Plant	VIII	0.3								
Santa Cruz Water Treatment	VIII	0.43								
Palco Cogen	VIII	0.46							2	
Centerville Navy Base	VIII	0.4								
Cabras Steam Plant	VIII	0.25					3	0.5	5	1

Table C-1: Summary of Sites Investigated in Compiling the EPRI Database & Data Sets for Equipment Categories Representative of Possible-Long-Term-Replacement-Time Items for the Diablo Canyon Nuclear Power Plant (Continued)

Site	MMI	PGA (g)	Large Vertical Pumps	Pumps Damaged	Hydro Units	Hydro Units Damaged	Large Horizontal Pumps	Pumps Damaged	Vertical Steel Tanks	Tanks Replaced
Piti Steam Plant	VIII	0.26	2				4			
Kawerau Substation	0.25g	0.35								
Pleasant Valley Pump Station	VIII	0.35			5				1	1
Trinidad Substation	VIII	0.4								
Watkins-Johnson Manufacturing	VIII	0.48							5	
Whitewater Hydro Plant	VIII	0.74			1					
Takuan Hydro	VIII	0.45			4	0.5				
Techi Hydro	VIII	0.64			2					
Bata Shoe Factory	VIII	0.60g								
Oxiquim Chemical Plant	VIII	0.30g								
Painted Hills Wind Farm	VIII	0.50g								
White Water Trout Farm	VIII	0.55								
Green Giant Cold Storage	VIII	0.4								
Lipton Food Processing	VIII	0.3								
Santa Cruz Switching Station	VIII	0.43								
Seagate Watsonville Plant	VIII	0.4								
Soquel Water System	VIII	0.5							20	
Watsonville Water Plant	VIII	0.4								

Table C-1: Summary of Sites Investigated in Compiling the EPRI Database & Data Sets for Equipment Categories Representative of Possible-Long-Term-Replacement-Time Items for the Diablo Canyon Nuclear Power Plant (Continued)

Site	MMI	PGA (g)	Large Vertical Pumps	Pumps Damaged	Hydro Units	Hydro Units Damaged	Large Horizontal Pumps	Pumps Damaged	Vertical Steel Tanks	Tanks Replaced
Apra Harbor Wastewater Plant	VIII	0.26		0.5						
Rio Acelhuate Pump Station	VIII	0.3								
Wanta Hydro Plant	VIII	0.71			2					
Kukuan Hydro Plant	VIII	0.63			2					
Pakamaya Cogen	VIII	0.36								
Totals & Incremental Failure Rates	VIII	**0.4184**	**18**	**0.026316**	**16**	**0.02941176**	**34**	**0.014286**	**130**	**0.030534**
Moss Landing Power Plant	VII	0.3	1	0.5			2		10	1
Olinda Substation	VII	0.65								
Pardee Substation (San Fernando)	VII	0.35								
Metcalf Substation	VII	0.24								
San Mateo Substation	VII	0.25								
Castaic Hydro Plant	VII	0.35			2					
Goodrich Substation	VII	0.3								
San Manuel Substation	VII	0.2								
Cabanatuan Substation	VII	0.2								
Mesa Substation	VII	0.35								
Center Substation	VII	0.35								
La Villita Hydro Plant	VII	0.15			2					
Infiernillo Hydro Plant	VII	0.15			3					
Vincent Substation	VII	0.15								
Gates Substation	VII	0.25								
Monte Vista Substation	VII	0.24								
Whakatane Paper Mill	VII	0.25							10	

Table C-1: Summary of Sites Investigated in Compiling the EPRI Database & Data Sets for Equipment Categories Representative of Possible-Long-Term-Replacement-Time Items for the Diablo Canyon Nuclear Power Plant (Continued)

Site	MMI	PGA (g)	Large Vertical Pumps	Pumps Damaged	Hydro Units	Hydro Units Damaged	Large Horizontal Pumps	Pumps Damaged	Vertical Steel Tanks	Tanks Replaced
Matahina Hydro Plant	VII	0.26			1				4	
SCE Dispatch Center	VII	0.56							9	
Adak Navy Base	VII	0.25								
Kettlemen Gas Compressors	VII	0.2								
Santa Teresa Data Center	VII	0.37								
Rapel Hydro Plant	VII	0.23								
Concon Water Plant	VII	0.3					4			
Las Ventanas Power Plant	VII	0.25					3			
Sanwa Data Center	VII	0.4					4	1		
Commerce Power Plant	VII	0.3							4	
Puente Hills Power Plant	VII	0.2							5	
Gilroy Cogen	VII	0.32	2				2		5	
Cardinal Cogen	VII	0.25								
EPRI Headquarters	VII	0.25								
IBM Santa Teresa Data Center (Morgan Hill)	VII	0.28							5	
IBM Santa Teresa Data Center (Loma Prieta)	VII	0.21							5	
Mirassou Winery	VII	0.2								
San Martin Winery	VII	0.35								
Cool Water Cogen	VII	0.35	2				2		5	
Mitsubishi Cement	VII	0.3								
Yigo Gas Turbine	VII	0.25								

Table C-1: Summary of Sites Investigated in Compiling the EPRI Database & Data Sets for Equipment Categories Representative of Possible-Long-Term-Replacement-Time Items for the Diablo Canyon Nuclear Power Plant (Continued)

Site	MMI	PGA (g)	Large Vertical Pumps	Pumps Damaged	Hydro Units	Hydro Units Damaged	Large Horizontal Pumps	Pumps Damaged	Vertical Steel Tanks	Tanks Replaced
Dededo Gas Turbines	VII	0.25								
GPA Diesels	VII	0.25								
Burbank Power Plant (San Fernando)	VII	0.3	2				4		6	
Burbank Power Plant (Northridge)	VII	0.3	2				4		6	
Glendale Power Plant (San Fernando)	VII	0.25	3				6		10	
Glendale Power Plant (Northridge)	VII	0.25	2				4		10	
Pasdena Power Plant (San Fernando)	VII	0.2	3				6		5	
Pasdena Power Plant (Whittier)	VII	0.2	3				6		5	
Pasdena Power Plant (Sierra Madre)	VII	0.2	3				6		5	
Pasdena Power Plant (Northridge)	VII	0.2							5	
Ormond Beach Power Plant (Pt. Mugu)	VII	0.1	2				2		10	
Ormond Beach Power Plant (Northridge)	VII	0.1	2				2		10	
Humboldt Bay Power Plant (Ferndale)	VII	0.31	2				4		12	
Humboldt Bay Power Plant (Humboldt)	VII	0.31	2				4		12	
Humboldt Bay Power Plant (Cape Mendocino)	VII	0.38	2				4		12	

Table C-1: Summary of Sites Investigated in Compiling the EPRI Database & Data Sets for Equipment Categories Representative of Possible-Long-Term-Replacement-Time Items for the Diablo Canyon Nuclear Power Plant (Continued)

Site	MMI	PGA (g)	Large Vertical Pumps	Pumps Damaged	Hydro Units	Hydro Units Damaged	Large Horizontal Pumps	Pumps Damaged	Vertical Steel Tanks	Tanks Replaced
Hunters Point Power Plant	VII	0.15	2				6			
El Centro (Superstition Hills)	VII	0.26					3			
Drop IV Hydro Plant	VII	0.30			2					
Petacalco Steam Plant	VII	0.27	2				4			
Hi-Head Hydro	VII	0.25			1					
Mingtan Hydro	VII	0.30			3					
Tienlun Hydro	VII	0.25			3	0.5				
Ambarli Cogen Plant	VII	0.22								
Ambarli Steam Plant	VII	0.22								
Kosekoy Substation	VII	0.28								
Nuh Cemento Cogen	VII	0.24								
NewberryGas Compressor Plant	VII	0.25								
Uguma Water Plant	VII	0.25								
Totals & Incremental Failure Rates	VII	**0.2626**	**55**	**0.008929**	**33**	**0.01470588**	**116**	**0.008547**	**300**	**0.003322**

Table C-1: Summary of Sites Investigated in Compiling the EPRI Database & Data Sets for Equipment Categories Representative of Possible-Long-Term-Replacement-Time Items for the Diablo Canyon Nuclear Power Plant (Continued)

Site	MMI	PGA (g)	220 or 500 kV Trans-formers	Trans-former Repair > 4 Months	220 or 500 kV Switch-yards	Switch-yard Outage > 4 Months	Steam Units (>100 MW) Running at Time of Earthquake	Damage to Steam-Plant-Specific Equipment	Control Panels	Control Panels with Damaged Com-ponents
Olive View Hospital	VIII+	0.73		0.5					3	
Sylmar Substatio (San Fernando)	VIII+	0.69	8		1	1			5	
Sylmar Substation (Northridge)	VIII+	0.75	8		1				5	
Rinaldi Substation (San Fernando)	VIII+	0.66	4		1				4	
Rinaldi Substation (Northridge)	VIII+	0.66	4		1				4	
Manzanillo Power Plant	VIII+	0.42	6		1		4	0.5	14	3
Edgecumbe Substation	VIII+	0.5			1				3	
Chungliao Substation	VIII+	0.47			1	1			2	
Great Western Data Center	VIII+	0.5							1	
N.Z. Distillery	VIII+	0.5							1	
Getty Oil Plant	VIII+	0.51							2	1
Shell Water Injection Plant	VIII+	0.6								
Shell Tank Farm No. 29	VIII+	0.60								
Llolleo Water Plant	VIII+	0.75g							1	1
Devers Substation	VIII+	0.81	8		1				9	1
Totals & Incremental Failure Rates	VIII+	**0.5891**	**38**	**0.014**	**8**	**0.22222**	**4**	**0.1**	**54**	**0.1111**
Pitchess Cogen	VIII	0.5								
ARCO Cogen	VIII	0.6								

Table C-1: Summary of Sites Investigated in Compiling the EPRI Database & Data Sets for Equipment Categories Representative of Possible-Long-Term-Replacement-Time Items for the Diablo Canyon Nuclear Power Plant (Continued)

Site	MMI	PGA (g)	220 or 500 kV Transformers	Transformer Repair > 4 Months	220 or 500 kV Switchyards	Switchyard Outage > 4 Months	Steam Units (>100 MW) Running at Time of Earthquake	Damage to Steam-Plant-Specific Equipment	Control Panels	Control Panels with Damaged Components
Placerita Cogen	VIII	0.59							3	
Pardee Substation (Northridge)	VIII	0.45	2		1	0.5			2	
Adapazari Substation	VIII	0.42	2		1				2	
Valley Steam Plant (San Fernando)	VIII	0.3					3	0.5	4	
Valley Steam Plant (Northridge)	VIII	0.3							4	
El Centro Steam Plant (Imperial Valley)	VIII	0.42					2		6	
Union Oil Butane Plant	VIII	0.62							1	
Coalinga Water Treatment	VIII	0.53							1	1
San Luis Canal Pumps	VIII	0.3								
Fertimex Fertilzer Plant	VIII	0.25	2						3	1
Sicartsa Steel Mill	VIII	0.25	2		1				10	
NKS Steel Frabrication Plant	VIII	0.25								
PMT Pipe Factory	VIII	0.25								
Caxton Paper Mill	VIII	0.4							22	
SCE Headquarters	VIII	0.42								
Cal-Fed Data Center	VIII	0.4							2	
Ticor Data Center	VIII	0.4								
UCSC Campus	VIII	0.43							1	

Table C-1: Summary of Sites Investigated in Compiling the EPRI Database & Data Sets for Equipment Categories Representative of Possible-Long-Term-Replacement-Time Items for the Diablo Canyon Nuclear Power Plant (Continued)

Site	MMI	PGA (g)	220 or 500 kV Transformers	Transformer Repair > 4 Months	220 or 500 kV Switchyards	Switchyard Outage > 4 Months	Steam Units (>100 MW) Running at Time of Earthquake	Damage to Steam-Plant-Specific Equipment	Control Panels	Control Panels with Damaged Components
National Refractory Plant	VIII	0.3								
Santa Cruz Water Treatment	VIII	0.43							2	
Palco Cogen	VIII	0.46							14	
Centerville Navy Base	VIII	0.4								
Cabras Steam Plant	VIII	0.25							3	
Piti Steam Plant	VIII	0.26							4	
Kawerau Substation	0.25g	0.35	2		1				14	
Pleasant Valley Pump Station	VIII	0.35							1	
Trinidad Substation	VIII	0.4	2		1				2	
Watkins-Johnson Manufacturing	VIII	0.48								
Whitewater Hydro Plant	VIII	0.74							1	
Takuan Hydro	VIII	0.45							1	
Techi Hydro	VIII	0.64							1	
Bata Shoe Factory	VIII	0.60g							1	1
Oxiquim Chemical Plant	VIII	0.30g							1	
Painted Hills Wind Farm	VIII	0.50g								
White Water Trout Farm	VIII	0.55								
Green Giant Cold Storage	VIII	0.4								

Table C-1: Summary of Sites Investigated in Compiling the EPRI Database & Data Sets for Equipment Categories Representative of Possible-Long-Term-Replacement-Time Items for the Diablo Canyon Nuclear Power Plant (Continued)

Site	MMI	PGA (g)	220 or 500 kV Trans-formers	Trans-former Repair > 4 Months	220 or 500 kV Switc-hyards	Switch-yard Outage > 4 Months	Steam Units (>100 MW) Running at Time of Earthquake	Damage to Steam-Plant-Specific Equipment	Control Panels	Control Panels with Damaged Com-ponents
Lipton Food Processing	VIII	0.3								
Santa Cruz Switching Station	VIII	0.43							4	1
Seagate Watsonville Plant	VIII	0.4								
Soquel Water System	VIII	0.5							17	1
Watsonville Water Plant	VIII	0.4								
Apra Harbor Wastewater Plant	VIII	0.26								
Rio Acelhuate Pump Station	VIII	0.3								
Wanta Hydro Plant	VIII	0.71							1	
Kukuan Hydro Plant	VIII	0.63	2	1	1				6	
Pakamaya Cogen	VIII	0.36							1	
Totals & Incremental Failure Rates	VIII	**0.4184**	**52**	**0.0189**	**14**	**0.03333**	**9**	**0.05**	**189**	**0.02645**
Moss Landing Power Plant	VII	0.3	12		1	0.5	1	0.5	2	
Olinda Substation	VII	0.65	10		1				2	
Pardee Substation (San Fernando)	VII	0.35	2		1				2	
Metcalf Substation	VII	0.24	6		1				2	
San Mateo Substation	VII	0.25	10		1				2	
Castaic Hydro Plant	VII	0.35	6		1				1	
Goodrich Substation	VII	0.3	2		1				2	

Table C-1: Summary of Sites Investigated in Compiling the EPRI Database & Data Sets for Equipment Categories Representative of Possible-Long-Term-Replacement-Time Items for the Diablo Canyon Nuclear Power Plant (Continued)

Site	MMI	PGA (g)	220 or 500 kV Trans-formers	Trans-former Repair > 4 Months	220 or 500 kV Switch-yards	Switch-yard Outage > 4 Months	Steam Units (>100 MW) Running at Time of Earthquake	Damage to Steam-Plant-Specific Equipment	Control Panels	Control Panels with Damaged Com-ponents
San Manuel Substation	VII	0.2	2		1				2	
Cabanatuan Substation	VII	0.2	2		1				2	
Mesa Substation	VII	0.35	2		1				2	
Center Substation	VII	0.35	10		1				2	
La Villita Hydro Plant	VII	0.15	4		1				4	
Infiernillo Hydro Plant	VII	0.15	6		1				2	
Vincent Substation	VII	0.15	4		1				2	
Gates Substation	VII	0.25	4		1				2	
Monte Vista Substation	VII	0.24	10	1	1				2	
Whakatane Paper Mill	VII	0.25							3	1
Matahina Hydro Plant	VII	0.26							8	
SCE Dispatch Center	VII	0.56								
Adak Navy Base	VII	0.25							11	
Kettlemen Gas Compressors	VII	0.2							2	
Santa Teresa Data Center	VII	0.37								
Rapel Hydro Plant	VII	0.23	8						2	1
Concon Water Plant	VII	0.3							1	
Las Ventanas Power Plant	VII	0.25	2				1		4	
Sanwa Data Center	VII	0.4								
Commerce Power Plant	VII	0.3							4	
Puente Hills Power Plant	VII	0.2							3	

Table C-1: Summary of Sites Investigated in Compiling the EPRI Database & Data Sets for Equipment Categories Representative of Possible-Long-Term-Replacement-Time Items for the Diablo Canyon Nuclear Power Plant (Continued)

Site	MMI	PGA (g)	220 or 500 kV Transformers	Transformer Repair > 4 Months	220 or 500 kV Switchyards	Switchyard Outage > 4 Months	Steam Units (>100 MW) Running at Time of Earthquake	Damage to Steam-Plant-Specific Equipment	Control Panels	Control Panels with Damaged Components
Gilroy Cogen	VII	0.32							8	
Cardinal Cogen	VII	0.25							1	
EPRI Headquarters	VII	0.25								
IBM Santa Teresa Data Center (Morgan Hill)	VII	0.28								
IBM Santa Teresa Data Center (Loma Prieta)	VII	0.21								
Mirassou Winery	VII	0.2								
San Martin Winery	VII	0.35								
Cool Water Cogen	VII	0.35	2		1		1		17	
Mitsubishi Cement	VII	0.3							1	1
Yigo Gas Turbine	VII	0.25							1	
Dededo Gas Turbines	VII	0.25							1	
GPA Diesels	VII	0.25							1	
Burbank Power Plant (San Fernando)	VII	0.3							4	
Burbank Power Plant (Northridge)	VII	0.3							4	
Glendale Power Plant (San Fernando)	VII	0.25							3	
Glendale Power Plant (Northridge)	VII	0.25							3	
Pasdena Power Plant (San Fernando)	VII	0.2							3	

Table C-1: Summary of Sites Investigated in Compiling the EPRI Database & Data Sets for Equipment Categories Representative of Possible-Long-Term-Replacement-Time Items for the Diablo Canyon Nuclear Power Plant (Continued)

Site	MMI	PGA (g)	220 or 500 kV Trans-formers	Trans-former Repair > 4 Months	220 or 500 kV Switch-yards	Switch-yard Outage > 4 Months	Steam Units (>100 MW) Running at Time of Earthquake	Damage to Steam-Plant-Specific Equipment	Control Panels	Control Panels with Damaged Com-ponents
Pasdena Power Plant (Whittier)	VII	0.2							3	
Pasdena Power Plant (Sierra Madre)	VII	0.2							3	
Pasdena Power Plant (Northridge)	VII	0.2							3	
Ormond Beach Power Plant (Pt. Mugu)	VII	0.1	2		1		1		2	
Ormond Beach Power Plant (Northridge)	VII	0.1	2		1		1		2	
Humboldt Bay Power Plant (Ferndale)	VII	0.31							9	
Humboldt Bay Power Plant (Humboldt)	VII	0.31							2	
Humboldt Bay Power Plant (Cape Mendocino)	VII	0.38							9	
Hunters Point Power Plant	VII	0.15					3		2	
El Centro (Superstition Hills)	VII	0.26					1		6	
Drop IV Hydro Plant	VII	0.30							1	
Petacalco Steam Plant	VII	0.27	8	1	1		2		2	
Hi-Head Hydro	VII	0.25							1	1
Mingtan Hydro	VII	0.30	6						1	
Tienlun Hydro	VII	0.25	1						1	
Ambarli Cogen Plant	VII	0.22	6						1	

Table C-1: Summary of Sites Investigated in Compiling the EPRI Database & Data Sets for Equipment Categories Representative of Possible-Long-Term-Replacement-Time Items for the Diablo Canyon Nuclear Power Plant (Continued)

Site	MMI	PGA (g)	220 or 500 kV Trans-formers	Trans-former Repair > 4 Months	220 or 500 kV Switch-yards	Switch-yard - Outage > 4 Months	Steam Units (>100 MW) Running at Time of Earthquake	Damage to Steam-Plant-Specific Equipment	Control Panels	Control Panels with Damaged Com-ponents
Ambarli Steam Plant	VII	0.22							1	
Kosekoy Substation	VII	0.28							2	
Nuh Cemento Cogen	VII	0.24							1	
Newberry Gas Compressor Plant	VII	0.25							1	
Uguma Water Plant	VII	0.25							1	
Totals & Incremental Failure Rates	VII	**0.2626**	**181**	**0.011**	**34**	**0.014285**	**20**	**0.023809**	**361**	**0.01108**

Appendix D:
Summary of the More Seriously Damaged Steam Plants in Past Earthquakes

The focus of this appendix is the few instances of serious damage in power plants included in the EPRI database, delaying recovery for days, weeks or months. Serious seismic damage occurred at six out of some 40 plant sites investigated. The causes of serious damage are of interest where they may have a potential for similar occurrence at the DCNPP. Summaries are presented of each instance of serious power plant damage in the sections that follow.

D.1 Moss Landing

The Moss Landing steam power plant is located on Monterey Bay south of San Francisco (Figure D-1). The plant is operated by PG&E, and is one of the larger generating sites in their system. The Moss Landing site includes three 110-megawatt (MW) units dating from 1950, two 120-MW units dating from 1952, and two 750-MW units from the late 1960s. Two of the oldest units had been retired by the time of the Loma Prieta earthquake in October 1989, and were generally used only a reservoirs of spare parts for the operating units. The third older unit was used for occasional peaks in power demand. Units 4 and 5, dating from 1952, were also used as peaking units. Generation at the Moss Landing site depended primarily on the newer 750-MW Units 6 and 7, dating from the 1960s. The total active generation capacity of Moss Landing was then about 1850 megawatts. The two 750-MW units supplied power to the site's 500 kilovolt switchyard, from which transmission lines are routed northeast to serve the urban area of San Jose.

The Moss Landing site was the closest major generating plant to the fault rupture of the magnitude 6.9 Loma Prieta earthquake. Although the site did not include ground motion accelerometers for measurement of the shaking in the earthquake, the nearest instrument in the town of Watsonville indicated that the plant site experienced about 0.30g peak ground acceleration (PGA).

The major damage at Moss Landing occurred in the 500-kV substation switchyard. More than half of the switchyard equipment, including all of the "live tank" circuit breakers mounted atop tall ceramic columns, required extensive repair or replacement. Rebuilding the 500-kV switchyard required about one month, while replacement circuit breakers and other components were located from PG&E's reserve of replacement equipment or loaned from other utilities.

Damage in the power plant itself was less severe than the high voltage switchyard. Perhaps the most dramatic damage was failure of 300,000-gallon welded steel raw water storage tank, located at ground level adjacent to Units 6 and 7. Rocking of the unanchored tank during the earthquake ruptured the welded seam where the tank wall meets the bottom. Rapid loss of water contents created a vacuum inside the tank that buckled the upper wall. The tank was declared beyond repair and had to be replaced.

The effluent stack serving Unit 7 suffered damage due to interaction between the outer concrete cylinder wall and the "floating" steel liner within the stack. Steel tie rods embedded in the concrete that support the inner liner buckled and fractured, cracking the upper section of the concrete cylinder at their embedment points. In the days following the earthquake repair crews were suspended on platforms from the top of the 500-foot stack to epoxy repair cracks in the concrete cylinder. Stainless steel bands were added to the upper section of the stack for further reinforcement.

At the time of the earthquake, only the 750-MW Unit 6 was in operation. The adjacent Unit 7 was down for extensive overhaul. Loss of all AC power to the site due to damage in the 500-kV switchyard tripped the Unit 6 generator off line. Loss of power to the AC-supplied lube oil pumps caused a momentary drop in lube oil pressure before the DC-powered pumps reached operating speed. This was the apparent cause of damage to the bearings in the Unit 6 low-pressure turbine during coast-down.

Because Units 6 and 7 supply power only to the 500-kV switchyard, repairs to the three points of major damage in the plant were not urgent, as the restoration of the switchyard created the primary delay. Restoring the switchyard to operation required about one month. In the meantime a temporary tank was installed for raw water, the Unit 7 stack was repaired and the Unit 6 low-pressure turbine bearings were replaced.

D.2 Cool Water

The Southern California Edison (SCE) Cool Water generating plant near Barstow, California was the closest major generating station to the magnitude 7.5 Landers earthquake in June 1992

(Figure 4-2). The ground motion instrument at the plant site recorded peak ground acceleration of 0.35g, as an average of the two horizontal components.

The Cool Water site includes two 1960s-vintage gas-fired steam generating units of 70-MW each, and two 260-MW cogeneration units dating from the late 1970s (Figure D-2). The larger cogen units include a gas turbine generator exhausting to a heat recovery steam generator (HRSG) which supplies the unit's steam turbine generator. Power output from the older steam units supplies a 115-kV switchyard. The two cogen units supply the site's 230-kV switchyard.

At the time of the Landers earthquake the two older units were shut down. One of the cogen units was in the process of coming on line, while the other unit was shut down. The operating gas turbine generator was shut down due to excess vibration trips triggered by the earthquake.

Post-earthquake inspection of the site indicated only minor damage in the shutdown steam units. Sway of the suspended boilers buckled the seismic restraints built into the boiler, and also fractured tubing and conduit spanning between the boilers and the steel frame boiler towers. One of the steel water storage tanks serving the older steam units suffered a slow leak through rupture of a one-inch piping attachment.

More serious damage was found in the cogen unit that had just started at the time of the earthquake. The gas turbine and the adjacent HRSG are housed in skid-mounted steel enclosures that adjoin but are independently supported on their own concrete pedestals. Rocking of the two adjoining enclosures in different directions resulted in shearing of duct connections that route the hot exhaust gas from the turbine to the HRSG. The severity of rocking motion of the enclosures during the earthquake was indicated by cracking and spalling in the supporting concrete pedestals. The gas turbine undergoing start-up at the time of the earthquake also suffered damage in the bearings of its DC-powered turning gear. The root cause of damage to the turning gear may or may not have been related to the differential displacement between adjoining enclosures of the turbine and HRSG.

Repairs to the gas turbine and HRSG interconnections and their concrete pedestals required about two weeks.

D.3 Placerita

The AES Placerita cogeneration plant near Newhall, California was perhaps the closest of several generating plants shaken by the magnitude 6.7 Northridge earthquake of January 1994 (Figure D-3). The plant site did not include accelerometers, but peak ground acceleration was estimated at 0.50g based on the nearest records near Newhall.

The 110-MW Placerita cogen was constructed in 1988 near the site of an operating oil field in Placerita Canyon north of the San Fernando Valley. The plant includes two gas turbine generators exhausting to HRSGs supplying steam generators. Output from the generators supplies a 66-kV substation switchyard.

Both cogen units were down at the time of the earthquake for routine maintenance. Most damage from the earthquake occurred not in the generating units themselves, but in the skid-mounted tanks and demineralizers of the adjacent water treatment plant. The lightly anchored skids shifted on their concrete pads, fracturing the interconnecting PVC piping at several locations. The skid-mounted demineralizers, filters and pumps were undamaged despite sliding, but repositioning the skids and repair of piping connections required days following the earthquake.

Two riveted steel tanks located outside the generating units also failed in the earthquake, one an oil-water separation vessel that supplies the water treatment plant, the other the firewater tank serving the power plant. The tanks were secured to their concrete ring foundations with anchor bolts and chair brackets welded to the tank walls. The severity of ground shaking resulted in bolt pull-out, allowing the tanks to lift up and slam down on their ring foundations. The impact opened the riveted seams at the wall-base seam. Damage to the tanks was not so severe to preclude repair.

Damage to the water treatment plant and the water storage tanks was repaired over a period about three weeks, which included completion of maintenance activities on-going in the cogen plant at the time of the earthquake.

D.4 Pacific Lumber

The Pacific Lumber Mill located south of Eureka, California was the closest large industrial facility to the three-earthquake sequence near Cape Mendocino in April 1992 (Figure D-4). The initial earthquake was rated at magnitude 7.0, followed within a 16-hour period by two additional quakes of slightly lower magnitude. Ground motion instruments located near the mill in the initial earthquake recorded a PGA of 0.47g as an average of the two horizontal directions.

The Pacific Lumber Mill includes a cogeneration power plant with two 15-MW steam turbine generators, supplied by three boilers fueled by wood waste. The steam output from the boilers supplies a heat source both for the lumber mill and the steam turbines. The cogen plant was constructed in 1989 as a means of supplying both steam and power to the large mill, and also selling power to the regional PG&E system through a nearby 115-kV substation switchyard.

At the time of the initial earthquake, the Unit 1 steam turbine generator was on line. The Unit 2 generator was down for prolonged overhaul, with the generator itself shipped to a shop in Oakland. Excess vibration sensors tripped the operating Unit 1 generator. The cogen plant shut down for damage inspection. Finding few obvious effects, the plant operators restarted Unit 1 within a few hours of the earthquake. The unit was operating when the second earthquake struck during the late evening hours. Although of lower magnitude than the initial quake, the second event appears to have been centered closer to the mill site, resulting in more serious effects. In the second earthquake the operating Unit 1 generator sheared the restraining steel blocks that secure it to its concrete pedestal. Slight shifting of the generator relative to the steam turbine created a binding moment on the spinning shaft, resulting in damage to the bearings. A check of the generator prompted the decision to ship it to the Oakland shop for a thorough inspection and overhaul as the twin unit was undergoing at the time. Both steam units were therefore out of service following the earthquake sequence.

Other than generator bearing damage, the cogen site experienced damage in one of its two wooden forced-draft cooling towers. The cooling tower in operation at the time of the second earthquake suffered fracture in the lower section of wood columns supporting the fan assembly above. The upper section of the tower did not collapse and damage to the columns was repairable.

Other structural damage included bent and buckled steel members in the boiler support towers due to impact of the swaying boilers. Damaged steel was removed and replacements welded into the tower framing. The concrete foundation pedestals at the base of the boiler tower columns suffered cracking and spalling. Damaged concrete was chipped away and the pedestals re-poured.

The most critical damage to the plant occurred in the electrostatic precipitators for exhaust gas treatment. The precipitators consist of charge plates suspended by insulating hangers from the top of the steel enclosure upstream of the exhaust stack. Sway of the charged plates in the earthquake resulted in impact and damage to the electrical conductor mounted in the plates. An estimated 1,000 person-hours were required in repair of the plates, working in the confined enclosure.

During the time period that the cooling tower, boiler framing and the precipitators were under repair, the Unit 2 generator was returned from the Oakland shop and reinstalled. Unit 2 of the cogen plant was restarted about two weeks after the earthquake. The Unit 1 generator was returned about a week later, allowing installation and restart of Unit 1 about a month after the event.

D.5 Guam

The Pacific island of Guam was struck by a magnitude 8.0 earthquake in August of 1993, centered in the Marianas Trench some 50 miles south of the island (Figure D-5). The island included no accelerometers for measuring motion during the earthquake. However motion was estimated to last about a minute, with peak ground acceleration averaging perhaps 0.25g across the island. As soil conditions vary from rock to soft sand at different locations, the level of shaking obviously varied considerably, with some sites likely experiencing much higher PGA.

The section of the island's harbor operated by the US Navy is located on sandy fill. The Navy base includes four oil-fired steam units, totaling 76 MW. The units range in vintage from the 1950s to the 1960s.

The steam plant site experienced liquefaction near its salt water intake channel. Vertical offset up to three feet were observed between the embedded concrete structures of the intake and the surrounding sandy soil. Severe settlement due to liquefaction crushed the buried concrete salt water lines that supply the plant condensers. Cracking at the interface of the water lines and the subgrade level of the steam plant allowed water to flood the basement, drowning equipment such as the condensate and raw water pumps.

Two of the four units at the steam plant were in operation at the time of the earthquake. Shaking blacked out the island's power grid and tripped both operating generators at the Navy plant off line. Batteries toppled from their unrestrained shelving, eliminating the source of DC power. Without power to the DC lube oil pumps, the two spinning turbines coasted down on minimal lubrication. The larger of the two turbines subsequently required replacement of damaged bearings.

Other effects included overturning of an unanchored motor control center and toppling of an unanchored station service transformer from its concrete pedestal outside the plant. Leaks occurred in several small-bored piping systems within the plant. Settlement within the soft soil resulted in fracture of buried piping, including the supply of makeup water from the island's potable water system. Several of the plant's induced draft and forced draft fans were found to have alignment problems between drive motors and fan impellers once the equipment was restarted. Misalignment may have resulted from minor settlement beneath the equipment foundations. The tall concrete effluent stacks were undamaged, but found to have shifted several inches out of vertical, presumably due to settlement beneath foundations. One unanchored oil storage tank ruptured, spilling its contents into the enclosing berm.

Repairs to the four units stretched for three months before all units were restored to operation. One of the older 12-MW units that had not been operating at the time of the earthquake was restarted three weeks after the event. Restart of the remaining units awaited complete repair of the damaged salt water lines serving the condensers.

D.6 Manzanillo

Two large oil-fired steam generating plants are located on the Pacific shoreline adjacent to the town of Manzanillo, Mexico (Figure 4-6). The original Plant No. 1 includes four 300-MW units dating from the early 1980s. The newer Plant No. 2 includes two 350-MW units completed in 1990. The total generating capacity of the six units is 1900 megawatts, making it one of the major power sources serving Mexico's national power grid.

The Manzanillo site was struck by a magnitude 7.6 earthquake centered in the subduction zone off the coastline in October 1995. Accelerometers at the plant site measured 0.40g peak ground acceleration as an average of two horizontal directions. At the time of the earthquake the two newer units in Plant No. 2 were operating. Actuation of relays in the adjacent 400-kV substation switchyard triggered an automatic shutdown of both units.

As at the Guam power plant discussed in the prior sections, liquefaction of the sandy soil near the salt water intakes was the primary cause of damage at the Manzanillo site. Soil settled as much as three feet near the salt water intake structure adjacent to the lagoon that supplies circulating water for the condensers. Liquefaction-induced settlement crushed the large reinforced concrete circulating water lines routed between the intake pumps and the condensers within the plant.

Within the boiler towers, sway and impact of the boilers resulted in crushing of tubing in the internal water walls. Crushed tubing appeared to be concentrated where the feedwater lines enter the boilers. The feedwater lines may have acted as inadvertent restraints for the swaying boilers, concentrating loads where the water wall tubing takes off from the incoming lines. Repairs to the boilers required that the crushed sections of water wall be cut out and new tubing welded in its place. Boiler repairs were of course limited by the number of personnel that could work in the confined space.

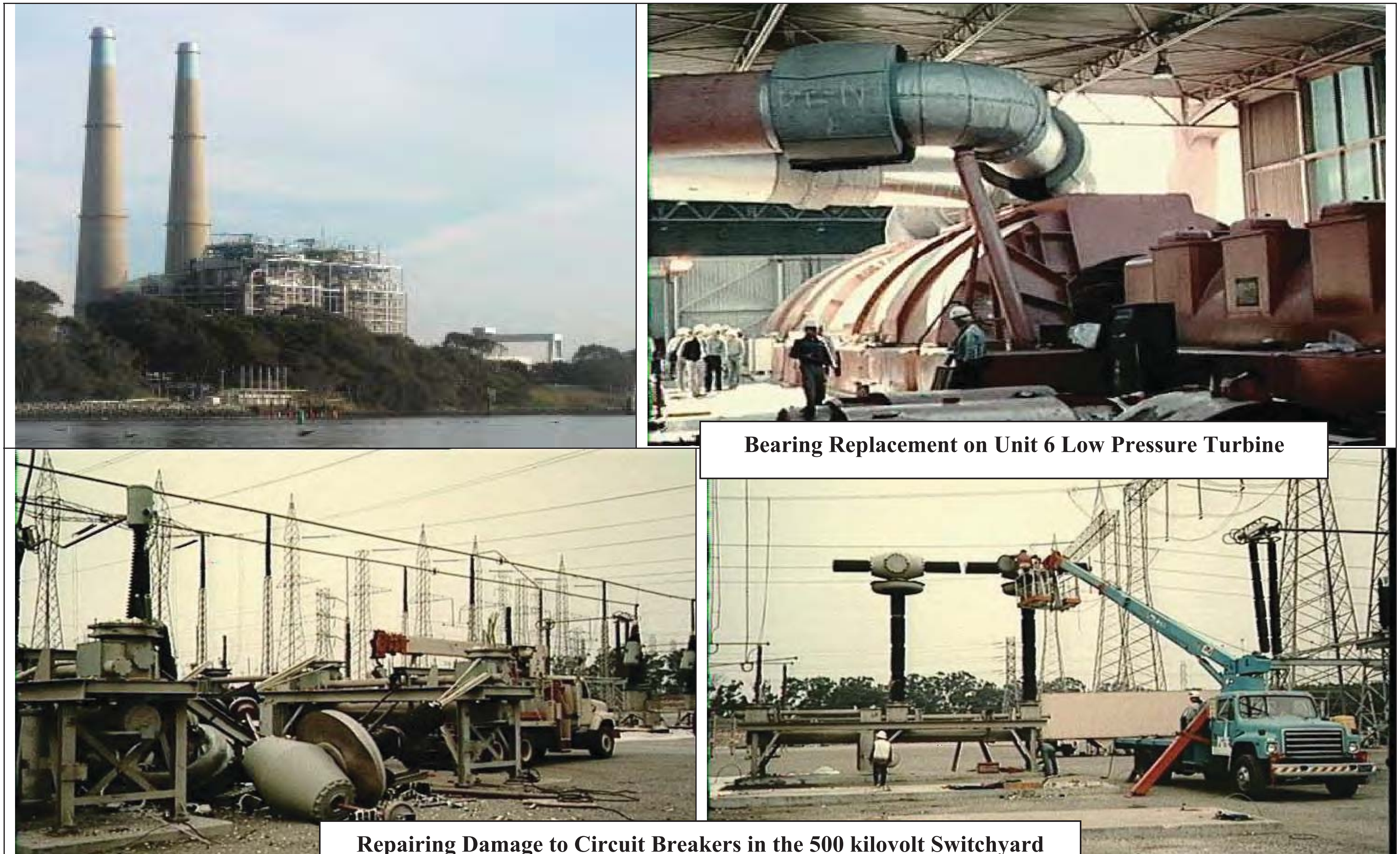
Settlement beneath the turbine pedestal of Unit 1 in Plant No. 1 created a slight tilt in the turbine-generator. The overhead bridge crane for the turbine bay was used to lift the turbine-generator skid, allowing placement of shims beneath for re-leveling.

Other major damage included widespread collapse of ceramic columns in the 400-kV switchyard. Out of 22 live tank circuit breakers in the switchyard, a total of nine breakers required repair or replacement.

The primary delay in restoring the Manzanillo plant to operation was rebuilding the liquefied area near the salt water intake structure. An area of about 50,000 square feet was excavated to remove the uncompacted sandy soil. The removed soil was then replaced by carefully compacted fill to preclude the risk of liquefaction in future earthquakes.

As Plant No. 2 is served by its own salt water intake structure, which was relatively undamaged, it was possible to restart its two 350-MW units once repairs were complete in the 400-kV switchyard. Plant No. 2 was brought back on line about six weeks after the earthquake. Once the soil replacement project was complete for the Plant No. 1 intake, its units were brought back on line about five months following the event.

APPENDIX 3



Bearing Replacement on Unit 6 Low Pressure Turbine

Repairing Damage to Circuit Breakers in the 500 kilovolt Switchyard

Figure D-1: The Moss Landing power plant (upper left) includes seven units dating from the 1950s, of which five were still operating at the time of the 1989 Loma Prieta earthquake.

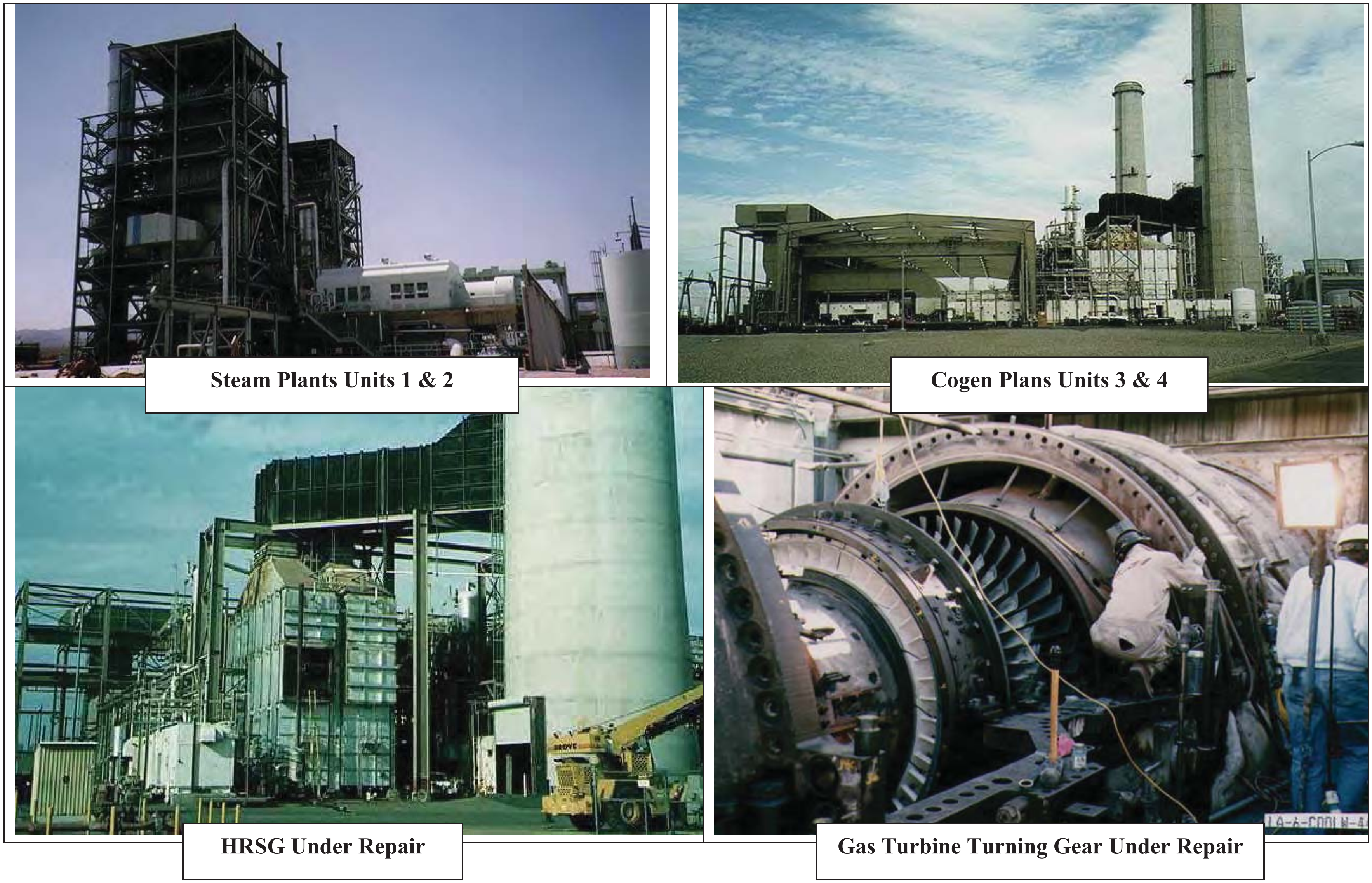


Figure D-2: The Cool Water power plant near Barstow, California recorded an average peak ground acceleration of 0.35g in the Landers earthquake of 1992.

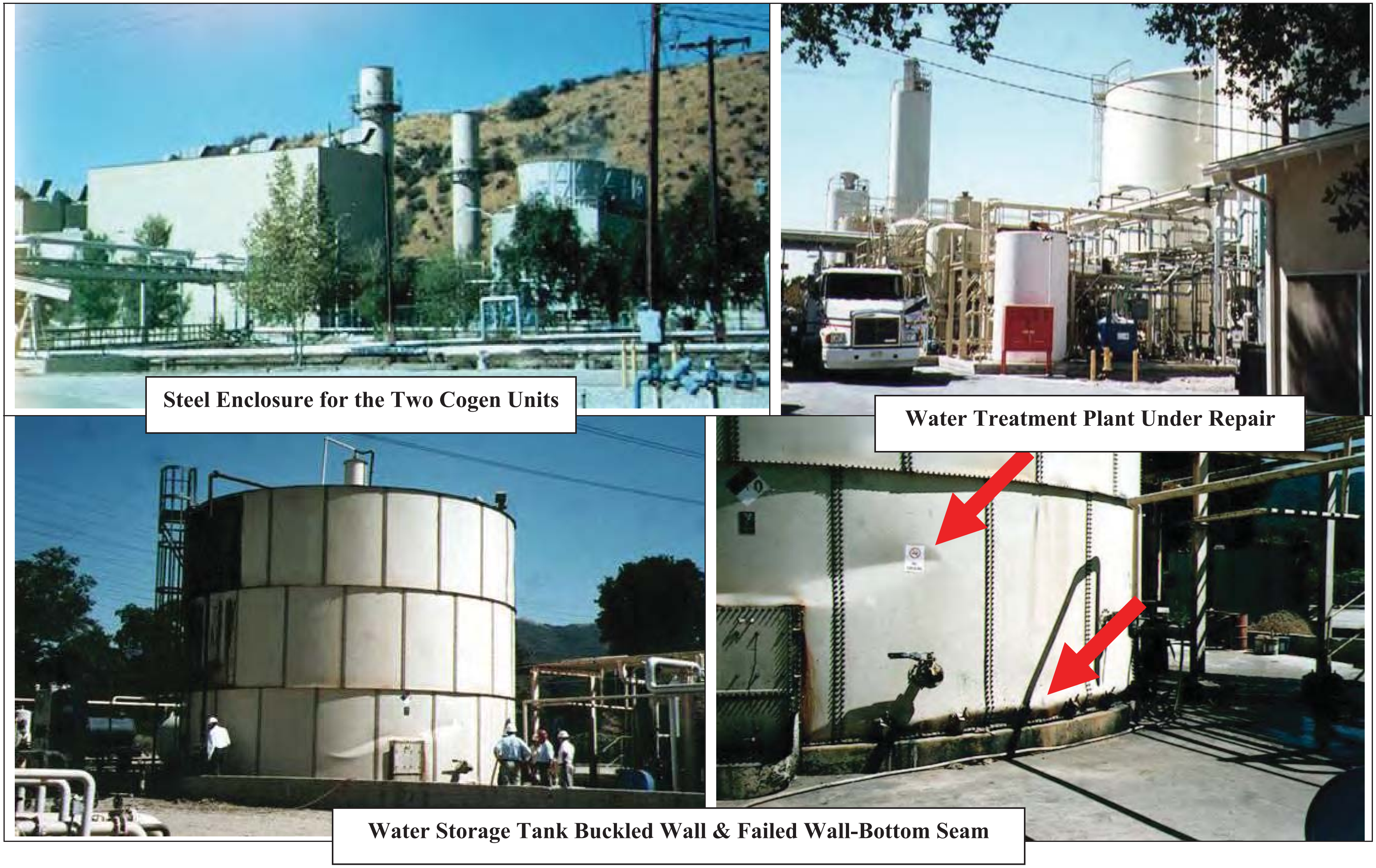
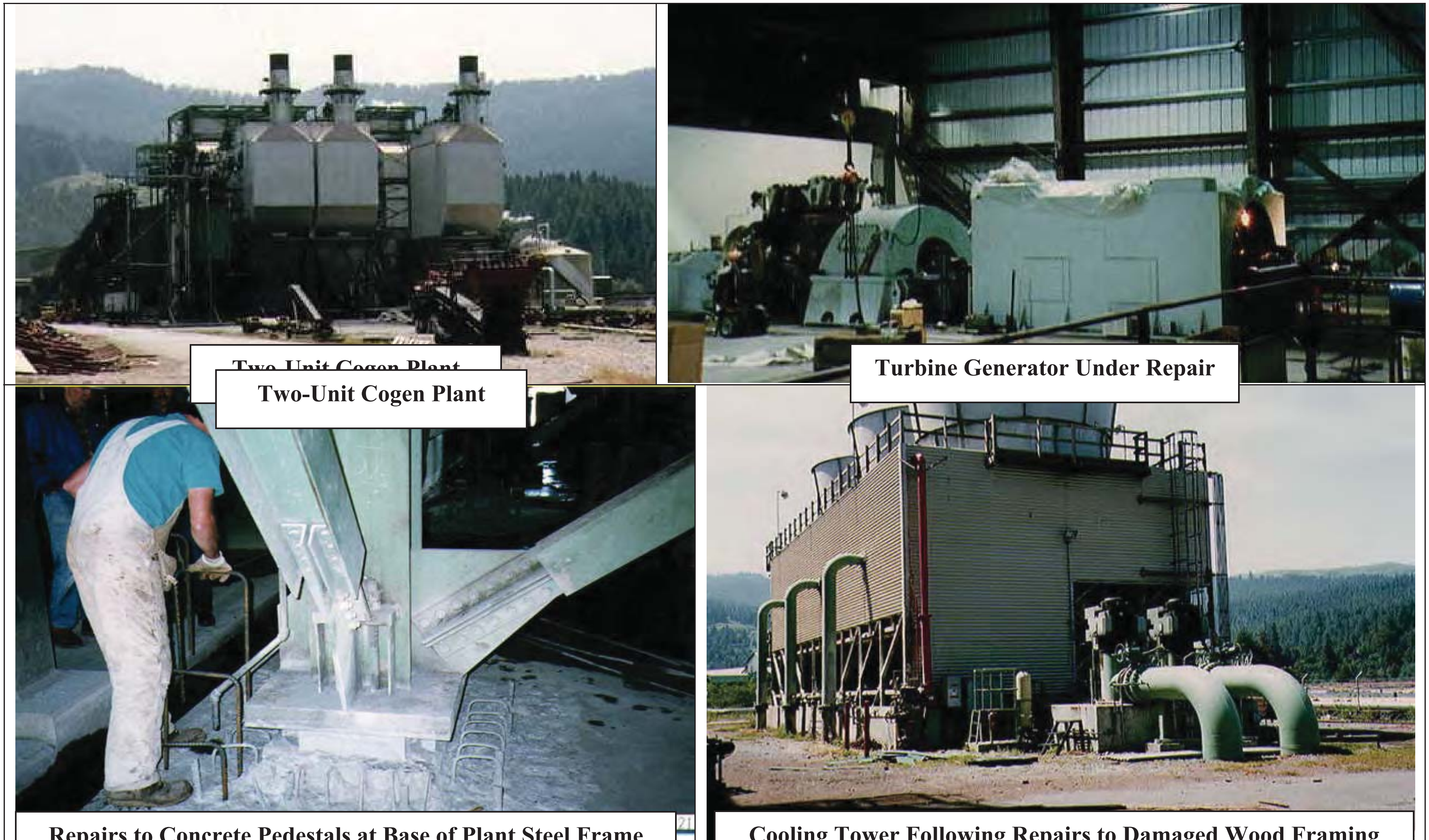


Figure D-3: The Placerita cogeneration plant north of the San Fernando Valley experienced an estimated 0.50g in the 1994 Northridge earthquake.



Two-Unit Cogen Plant

Turbine Generator Under Repair

Repairs to Concrete Pedestals at Base of Plant Steel Frame

Cooling Tower Following Repairs to Damaged Wood Framing

Figure D-4: The Pacific Lumber Mill cogeneration plant (upper left) south of Eureka, California, measured 0.47g peak ground acceleration in the three-earthquake sequence near Cape Mendocino in 1992.

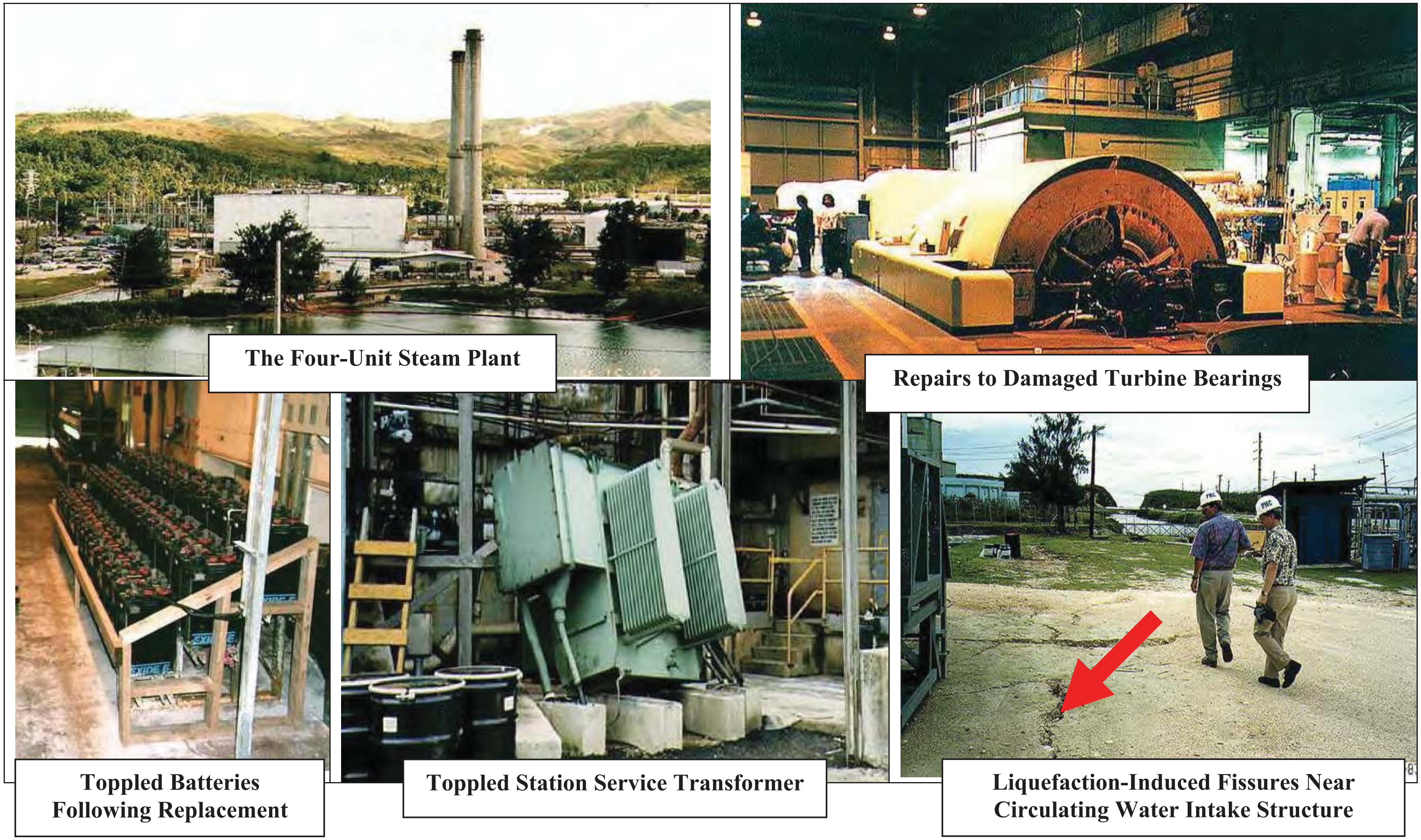
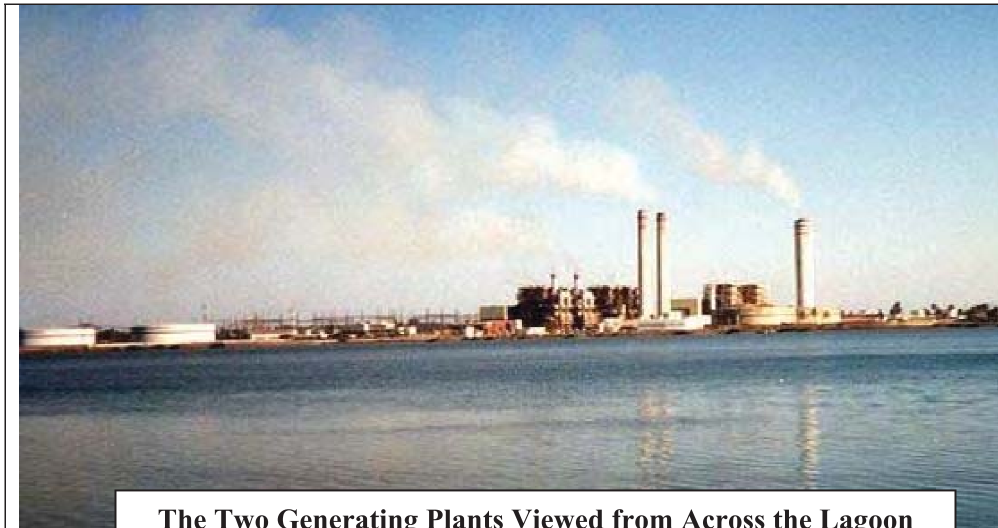
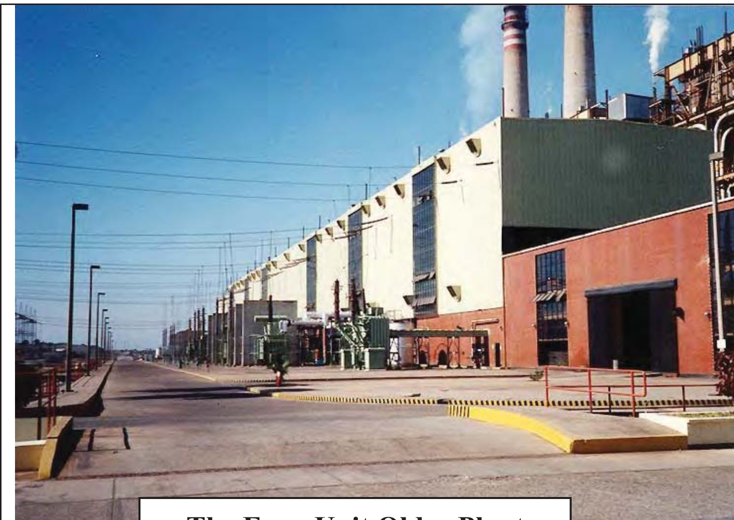


Figure D-5: The US Navy's steam power plant serving the harbor area on the Island of Guam was damaged in the magnitude 8.0 earthquake centered in the Marianas Trench in 1993



The Two Generating Plants Viewed from Across the Lagoon



The Four-Unit Older Plant

Soil Collapse due to Liquefaction Near the Lagoon Circulating Water Intakes

Collapsed Circuit Breaker Ceramic Columns in the 400 kV Switchyard

Figure D-6: The Manzanillo power plant actually includes a four-unit site constructed in the 1970s and a two-unit site constructed in the 1980s. The site measured a peak ground acceleration of 0.40g in the 1995 Colima earthquake off the Pacific coast of Mexico

Structural Assessment of Non-Safety Related Structures

Diablo Canyon Power Plant
San Luis Obispo, CA
31 March 2010

REGISTERED PROFESSIONAL ENGINEER
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SUMMARY OF ASSESSMENT OF
DIABLO CANYON POWER PLANT NON-SAFETY RELATED
STRUCTURES TO A SEVERE SEISMIC EVENT
SAN LUIS OBISPO, CALIFORNIA

1. INTRODUCTION

1.1 Project Information

Client:	Mr. Kent Ferre Pacific Gas & Electric Company
Project Address:	Diablo Canyon Rd San Luis Obispo, CA 93405
Facility Description:	Nuclear Power Plant Non-safety related items including buildings and equipment

1.2 Objective

California State Assembly Bill AB 1632 addresses the potential vulnerability of Diablo Canyon Power Plant (DCPP) to a prolonged outage due to a seismic event. The objective of this assessment is to determine the likelihood of earthquake damage to selected, non-safety-related or balance of plant (BOP) items (structures and components) at the plant causing the plant to be shut down for more than 120 days. Other non-safety-related items are addressed by others.

1.3 Scope of Work

The scope of work is divided into two primary tasks:

- Identify building fragilities and estimated outage times for six non-safety related buildings. We achieved this by:
  - Reviewing available structural drawings to form engineering opinions of expected seismic performance of each building relative to other similar buildings of the same vintage located in the same seismic zone.
  - Modifying HAZUS fragility curves for the appropriate generic building types using engineering judgment.
  - Obtaining acceptable outage times for each building from PG&E.

- Selecting an appropriate HAZUS damage state (e.g., slight, moderate, extensive, complete) for each building based on the outage time and building characteristics.
- Obtaining site-specific hazard curves for two different soil profiles from PG&E.
- Convolving the appropriate hazard curve with the appropriate modified fragility curve for each building to estimate the corresponding annualized probability of the building being in the selected damage state or worse.

- Identify fragilities and estimated outage times for non-safety-related equipment. Mr. Sam Swan of Acceptable Risk achieved this by:

    - Reviewing screened list of non-safety related equipment believed to have seismic vulnerability and the potential to require more than 120 days to repair, or to replace.
    - Categorizing the equipment into eight generic equipment categories in the Electric Power Research Institute (EPRI) experience data base.
    - Estimating fragility functions for the eight generic equipment categories using the EPRI experience data base.
    - Obtaining site-specific hazard curves for two different soil profiles from PG&E.
    - Convolving the appropriate hazard curve with the appropriate fragility function for each generic equipment type to estimate the corresponding annualized probability of the equipment experiencing an outage of 120 days or more.

The results of Task 1 are summarized in this report. The results of Task 2 are summarized in a separate report. Both reports will be included in a larger report in preparation by Enercon and PG&E.

2. INFORMATION FROM OTHERS

2.1 Contract Documents

We reviewed available structural, civil and architectural drawings for the following non-safety-related or Design Class II buildings (see Chapter 4 for complete listing of drawings reviewed):

- Administration Building
- Main Warehouse
- Simulator Building
- Security Building (original plus expansion)
- 500 kV Switchyard Building
- 230 kV Switchyard Building

In addition, we reviewed appropriate portions of Design Criteria Memorandums (DCMs) for the Administration Building, the Simulator Building, the Security Building expansion and the Switchyard Buildings (see Chapter 4 for listing).

2.2 Geotechnical Data

We used probabilistic ground motions in the form of two site-specific hazard curves developed by PG&E (Table 2-1). The first hazard curve is appropriate for the main plant (V_{s30} = 760 m/s), the second hazard curve applies to the softer soil at the switchyard (V_{s30} = 250 m/s).

Table 2-1: Site Specific Hazard Curves (PG&E) for Main Plant and Switchyards

Peak Ground Acceleration (g)	Probability of Exceedence	
	V_{s30} = 760 m/s (Main Plant)	V_{s30} = 250 m/s (Switchyard)
0.001	2.14E-01	2.29E-01
0.1	8.08E-03	1.31E-02
0.2	3.41E-03	5.37E-03
0.3	1.56E-03	2.25E-03
0.4	8.91E-04	1.17E-03
0.5	5.44E-04	6.28E-04
0.6	3.50E-04	3.66E-04
0.7	2.23E-04	2.02E-04
0.8	1.50E-04	1.21E-04
0.9	1.00E-04	6.99E-05
1	7.03E-05	4.28E-05

Peak Ground Acceleration (g)	Probability of Exceedence	
	V_{s30} = 760 m/s (Main Plant)	V_{s30} = 250 m/s (Switchyard)
1.1	5.25E-05	2.97E-05
1.2	3.79E-05	1.92E-05
1.3	2.65E-05	1.14E-05
1.4	1.84E-05	6.26E-06
1.5	1.33E-05	3.71E-06
1.6	1.02E-05	2.56E-06
1.7	7.52E-06	1.64E-06
1.8	5.46E-06	9.43E-07
1.9	3.99E-06	4.94E-07
2	3.13E-06	2.99E-07
2.1	2.59E-06	2.39E-07
2.2	2.11E-06	1.86E-07
2.3	1.68E-06	1.41E-07
2.4	1.30E-06	1.02E-07
2.5	9.76E-07	0.00E+00
2.6	7.07E-07	0.00E+00
2.7	4.94E-07	0.00E+00
2.8	3.41E-07	0.00E+00
2.9	2.47E-07	0.00E+00
3	2.16E-07	0.00E+00

2.3 Acceptable Building Outage Durations

We used acceptable building outage times developed by PG&E (Table 2-2) to select the appropriate fragility curves or damage states from HAZUS. These outages were developed by taking into consideration the importance of the building to post-earthquake recovery of the DCPP. Note that outage durations are time required to allow for critical functions in a building.

Table 2-2 – Acceptable Building Outage Durations

Building	Building Outage Duration
Main Warehouse	Two weeks – need to retrieve parts for repair efforts for rest of the plant.
Administration Building	There are no functions in the Administration Building that could not be relocated or are not backed up elsewhere. Required performance is to protect occupants and not to endanger adjacent Turbine or Security Buildings.
Simulator Building	One month to allow for training for operations. Training could be contracted out to other facilities if required.
Security Building	Two weeks – manual security checks and backup facilities at other locations in the plant could be used in short term.
500 kV Switchyard Building	Two weeks – restoration to coincide with expected switchyard repair time desirable.
230 kV Switchyard Building	Two weeks – restoration to coincide with expected switchyard repair time desirable.

3. FIELD OBSERVATIONS

A walk through of portions of the Diablo Canyon Power Plant (DCPP) was performed on 16 November 2009. Our subconsultant Mr. Sam Swan of Acceptable Risk joined other consultants Mr. Dave Miklush (Consulting Engineer), Richard Clark (Enercon), and Francis Ling (Enercon). The purpose of the walk through was to observe representative screened items to verify that they fit into generic equipment categories defined in the EPRI experience data base and to assess their as-installed conditions. Items in general are well anchored, more so than in typical power plants or industrial facilities that comprises the EPRI database.

The buildings were only briefly viewed. The interior of buildings in the scope of this project were entered only when equipment inside the buildings was observed. An exception is the Main Warehouse where storage racks and cabinets that hold critical spare parts for the remainder of the plant were viewed. Photos of the buildings taken during the walk through are included in Appendix A.

4. BUILDING DOCUMENT REVIEW

Design Class II building structures required for operation of the plant were identified by Enercon. These structures include:

- Main Warehouse (Figure A-1 in Appendix A)
- Administration Building (Figure A-2)
- Simulator Building (Figure A-3)
- Security Building (Figure A-4)
- 500 kV Switchyard Building (Figure A-5)
- 230 kV Switchyard Building (Figure A-6)

Mr. Francis Ling of Enercon provided us with the drawings for the six buildings we studied. We reviewed the drawings briefly to develop an engineering opinion about the quality of the seismic design features compared with those of other similar buildings of the same vintage and seismic zone (during the time of the design of these buildings, seismic zones in the Uniform Building Code (UBC) were still in use). Summaries of our review are included below.

Mr. Kent Ferre of PG&E provided us with Design Criteria Memorandums (DCMs) for all of the buildings except the Main Warehouse. We reviewed these memorandums to find information regarding seismic design criteria used.

4.1 Description of Project

The Diablo Canyon Power Plant (DCPP) is located on a 750 acre site in Avila Beach in San Luis Obispo County. Construction at the site began in 1968 and the original plant was built using the provisions of the 1968 Uniform Building Code (UBC). The buildings included in the scope of this project were constructed in the 1970s and 1980s.

4.2 Main Warehouse

4.2.1 Information Reviewed

We used the following drawings to perform this review:

- Structural (Civil) drawings titled "…NPO Permanent Warehouse", sheets 472116 dated 29 April 2008, 472117 & 472118 dated 22 August 1997, 472119 dated 24 May 1985, 472120 dated 14 June 1985, 472121 dated 15 May 1987, 472122 dated 12 April 1985, 472123 10 April 2006, 472124 dated 24 May 1985, and 472125 dated 24 May 1985.

The following drawings were available but we did not review them:

- Architectural drawings 472085, 472087 through 42089.
- Architectural drawing for equipment layout drawing 472181.

No DCM was available to review.

4.2.2 Building Description

The Main Warehouse is rectangular in plan with overall plan dimensions of approximately 207 ft by 475 ft. The building is two stories tall and also has several mezzanines. The second story is located in the northwest corner and has approximate plan dimensions of 75 ft by 250 ft. The building was constructed circa 1985.

4.2.2.1 Gravity Load-Resisting System

The gravity load-resisting system of the Main Warehouse includes a metal deck roof supported by steel framing. The second floor is a concrete fill on metal deck supported by steel framing. The steel framing is supported by a grid of 24 in. deep wide flange (W24) columns which are in turn supported by concrete spread footings. The ground floor consists of a reinforced concrete slab-on-grade.

4.2.2.2 Lateral Load-Resisting System

The lateral load-resisting system in the north-south direction consists of steel concentric braced frames at the east and west elevations, as well as one interior grid line. The braced frames are either in an X or chevron brace configuration with WT7x13 braces. The details for the braced frames are not shown on the drawings; the general notes indicate that they are to be designed for the specified forces shown in the drawings.

The lateral load-resisting system for east-west seismic loading consists of steel moment frames. The columns are W24 and the beams are typically W24 with some W36 beams. The moment frame connection details are typical pre-Northridge, with beam flanges welded to columns with full penetration welds, and beam webs bolted to the shear plate (WUF-B).

4.2.3 Discussion

There was no design criteria provided on the drawings. As a result it is difficult to form an opinion as to how well the building will perform. However, based on the amount of braced and moment frame bays provided, we believe that the building has a reasonable lateral load-resisting system. Most likely, the performance of the moment connections will be that of typical of pre-Northridge connections. The design loads provided on the drawings for the braced frames suggest that the connections are designed for the code loads, and clearly won't develop the brace member capacities.

Using the terminology of HAZUS, the Main Warehouse is an S2 – Steel Braced Frame Building in the north-south direction an S1 – Steel Moment Frame Building in the east-west direction.

4.2.4 Recommendations

For north-south loading for the Main Warehouse, we recommend a quality factor of 1.25 be used. For east-west loading, we recommend that a quality factor of 1.0 be used. Quality factors are discussed in Section 7 – Discussion. A quality factor over 1.0 indicates that we believe the building will not perform as well as a typical building of similar vintage.

4.3 Administration Building

4.3.1 Information Reviewed

We used the following drawings to perform this review:

- Structural drawings titled "…Administration Building", sheets 515972 to 516000 and 517735 to 517738 with various revision dates.

The following drawings were listed on the drawing list but were not available for review:

- Structural drawing titled "Raised Access Floor & Details," sheet 517739.
- Structural drawing titled "Penthouse Roof Framing & Details," sheet 517740.

We reviewed DCM C-8, dated 7 January 1999.

4.3.2 Building Description

The Administration Building is a steel frame structure, nearly rectangular in plan with radiuses corners and overall plan dimensions of approximately 94 ft by 252 ft. The building is six stories tall and has a mezzanine in the eastern third. There is both an elevator machine penthouse and regular penthouse at the roof level. The story heights are typically approximately 13 ft except at the first story which is approximately 16 ft and the 5th story which is approximately 15 ft. The building was constructed circa 1985 using the seismic provisions of the 1982 Uniform Building Code (UBC).

4.3.2.1 Gravity Load-Resisting System

The gravity load-resisting system of the Administration Building consists of a complete steel space frame supporting lightweight concrete fill on metal deck roof and floors which are cast compositely with the beams. The steel beams are supported by two lines of steel wide flange columns above the 3rd floor and boxed wide flange columns below the 3rd floor. The main columns are setback from the north and south elevations by approximately 16 ft; tapered wide flange steel beams cantilever out in the north-south directions. The north-south beams span approximately 94 ft column to column while the east-west beams typically span 12 ft. The two main lines of columns are supported by longitudinal strip footings.

The mezzanine between the first and second floors at the east end is of similar construction and is supported by wide flange columns supported on either strip or spread footings.

4.3.2.2 Lateral Load-Resisting System

The lateral load-resisting system of the Administration Building includes steel moment frames in both primary directions. The beams in the north-south aligned frames are W30 or W33 and the beams aligned in the east-west direction are W18. The frame columns above the second floor are oriented such that the strong axis is oriented in the north-south direction. At the 4th through roof floors, the moment connections are typical of pre-Northridge connections with a web doubler plate. The shear tabs are detailed as welded to the beam webs (WUF-W) but the notes provide for an alternate bolted connection (WUF-B). At the 2nd and 3rd floors, the moment connections are similar to pre-Northridge connections except that the details include provisions for welding to the column cover plates in the minor direction due to the boxed wide flange columns. Based on our review of the minor axis connection at the boxed wide flange, the details as drawn are not constructible as access to weld the continuity plates is not possible without somehow splicing the cover plates; no details or locations for a cover plate splice are provided.

The column base connection at the moment frame columns is detailed as fixed using a stiffened base plate with 1.5 in. diameter anchor rods. Both the stiffener plates and the column flanges are welded to the base plate with partial penetration welds. The anchor rods are embedded into the foundation approximately 10 in.

4.3.3 Discussion

Based on our review of the moment connections, we expect that they will have a performance similar to pre-Northridge connections of similar vintage. Due to the deep transverse beams (W30 or W33), the connection plastic rotation capacity will be relatively low. Brief calculations of the column strength relative to the beam strength show that for the strong axis column bending, the columns are stronger than the beams and for the weak axis bending, the columns are slightly stronger than the beams. For biaxial bending, the columns are weaker than the beams. The embedment of the anchor rods at the frame columns is not adequate to develop the column flexural capacity and is not ductile. Due to this and the tall first story, the first story is both a soft and weak story as defined by the current building code.

DCM C-8 indicates that the Administration Building was designed using the 1982 UBC. Seismic loads associated with an importance factor of 1 and seismic zone 3 were used for the design, except that a seismic coefficient of 0.07 was used to check drift (deflections), and a seismic coefficient of 0.20 (without torsion) was used to determine the base shear. We interpret this to mean that the code-based seismic coefficient is 0.07 and that the base shear used to design the columns is thus conservative. The degree of conservatism is unknown and can only be determined if calculations are performed to determine the building fundamental period, but we believe we can conservatively assume that the base shear used was 50-100% higher than required by the building code.

Using the terminology of HAZUS, the Administration Building is an S1 – Steel Moment Frame Building.

4.3.4 Recommendations

We would recommend that a quality factor of 0.9 be used for transverse loading for the Administration Building and 0.8 for longitudinal loading relative to similar vintage moment frame buildings. Consequently a single quality factor of 0.85 will be used.

4.4 Simulator Building

4.4.1 Information Reviewed

We used the following drawings to perform this review:

- Structural drawings titled "N.P.O. Training Facility Bldg. (Simulator)…", sheets 514479 through 514490. All sheets are dated 30 June 1982 except for sheets 514481, 514486 and 514490 which are dated 30 April 1984.
- Architectural drawings titled "Training Facility Bldg. 109 (Simulator)", sheets 514116 dated unknown, 514118 through 514120 dated 21 July 2006, sheet 514135 dated 1 June 1989 and sheet 514136 dated 6 February 1984.

The following drawings were available but we did not review them:

- Civil finish grading drawing titled "Finish Grading Plan Training Building Bldg. 109" sheet 514191 dated 19 March 2007.

We reviewed DCM C-19, dated 04 January 1982.

4.4.2 Building Description

The Simulator Building is a two-story steel frame structure approximately rectangular in plan with overall plan dimensions of 194 ft by 98 ft. The building was constructed circa 1982 using the seismic provisions in the 1979 UBC. At the east side, the middle third projects out in plan from the main portion. The slab is a recessed 5 ft in the middle third of the ground floor.

4.4.2.1 Gravity Load-Resisting System

The gravity load-resisting system of both the roof and second floor of the Simulator Building include a concrete-filled metal deck supported by steel framing and columns. The typical steel deck details indicate that welded headed studs were provided so the framing is composite with the slab. Most of the steel columns are supported at the foundation level by a grid of grade beams. Four columns are supported on isolated spread footings. The ground floor consists of a concrete slab-on-grade.

4.4.2.2 Lateral Load-Resisting System

The lateral load-resisting system for the Simulator Building consists of steel moment resisting frames in combination with the roof and floor diaphragms. The moment resisting girders vary from W18 to W36 sections and are typically not braced at the bottom flange near the ends. The columns are W14x82 or W14x145. The base of the columns in the lateral load-resisting system are typically detailed as a fixed base about the major axis and at most locations are detailed as fixed base about the minor axis. The column base fixity is typically accomplished by the use of anchor rods in pipe sleeves welded to the columns. The grade beams that support the columns are typically provided along the major and minor axis of the supported columns apparently in order that they can resist the column base moment.

The columns that are detailed as effectively pinned base about the minor axis occur in the recessed slab area away from the corners. Major axis fixity is provided at the columns away from the recessed slab corners through the use of plates embedded into the upper and lower slab levels that are welded to the column flange. Major and minor axis column base fixity is provided at the corners of the recessed slab through the use of plates embedded into the upper and lower slab levels that are welded to the columns at the recessed slab locations.

4.4.3 Discussion

The general notes on drawing 514479 indicate that the frames were designed to the requirements of the 1979 UBC as ductile moment frames. The connection details between the beams and columns are not provided on the drawings. Instead, a note on drawing 514479 states that the “girder to column connections shall be moment connections U.O.N.” and that they are to develop the full moment capacity of the member. The definition of a girder is provided on drawing 514485 as any beam connected to the columns in the column schedule on drawing 514485. Based on this definition, we believe that the moment resisting connections frame into both the column major and minor axis directions.

Because the moment frame connection details are not on the drawings, we could not review them. However, based on the building’s vintage, we assume that the construction and thus the performance will be similar to typical pre-Northridge connection details. Based on a review of the beam sections relative to the column sections, the columns do not meet the current weak-beam strong-column requirements at either the roof or second floor. The columns also have a weak panel zone relative to the beam flexural capacity (we assume no panel zone web doubler plates were provided). We performed brief calculations to determine the column strength as compared to the base connection for the columns away from the recessed slab. At these columns, the anchor rods cannot develop the W14x145 column capacity but are close to developing the W14x82 column capacities for major axis bending. The strength of the rods in the concrete and the strength of the embed connections at the recessed slab locations were not evaluated but are likely deficient as compared to current standards.

We believe the Simulator Building will most likely have a poorer performance as compared to other steel moment frame buildings of similar vintage. This conclusion is based on the weak-column and strong-beam and weak panel zone conditions. In addition, at least half of the frame columns are oriented in the minor axis direction which will likely result in higher building drifts. These higher drifts in combination with the pre-Northridge connection will lead to more connection damage. Given all the existing connection detailing deficiencies, the building performance is expected to be more like an ordinary moment resisting frame (OMRF) compared to the assumed ductile moment frame (SMRF). The design loading specified in the building code for an OMRF versus an SMRF is approximately 50% higher.

Using the terminology of HAZUS, the Simulator Building is an S1 – Steel Moment Frame Building.

4.4.4 Recommendations

Based on these findings, the recommended quality factor for the Simulator Building relative to similar vintage buildings is 1.2.

4.5 Security Building

4.5.1 Information Reviewed

We used the following drawings to perform this review:

- Structural drawings titled "…Permanent Security Building", sheets 463890 dated 31 August 2006, 463891 and 463892 dated 29 March 1991, 43893 dated 22 July 1993, 463894 dated 13 September 1984, 463895 dated 16 December 1977.

- Structural drawings titles “…Security Building Expansion”, sheets 490986 and 490987 dated 29 March 1991.
- Architectural drawings 490977 date unknown, 490978 dated 28 April 2006, 490979 dated 27 December 2005, and 490980 dated 9 July 1996.

We reviewed DCM CA-98, dated 04 December 1987. This DCM appears to apply to the expansion only.

4.5.2 Building Description

The one-story Security Building was originally constructed circa 1977 and was expanded to the south circa 1991. The building is irregularly shaped in plan with overall plan dimensions of approximately 127 ft by 139 ft. The original construction consists of steel frame with concrete infill walls or concrete shear walls at selected locations and a steel framed roof with concrete on metal deck. The expansion construction consists of steel braced frames at selected locations with steel framed roof and metal deck roof. The expansion was designed using the provisions of the 1985 UBC for seismic zone 3 with an importance factor (I) = 1.5.

4.5.2.1 Gravity Load-Resisting System

The gravity load-resisting system of the original Security Building includes a steel framed roof that supports a concrete-filled metal deck. Except for the center portion, the framing consists of steel beams and girders, some of which were designed to act composite with the normal weight concrete-filled deck. The center portion consists of a design-build steel space frame that supports a lightweight metal deck. The space frame is supported by steel beams. The steel roof framing is supported by steel columns which are in turn supported by either strip or spread footings. The ground floor consists of a reinforced concrete slab-on-grade.

The gravity load-resisting system of the expansion includes a steel frame roof consisting of beams and girders that support a metal roof deck. The beams and girders are supported by steel columns which are in turn supported by spread footings. The ground floor consists of a reinforced concrete slab-on-grade.

4.5.2.2 Lateral Load-Resisting System

The lateral load-resisting system of the original Security Building consists of the concrete on metal deck roof diaphragm and either steel frame with concrete infill walls or concrete shear walls. There is approximately 40% more length of shear wall in the north-south direction as compared with the east-west direction. Collectors do not align with most of the east-west shear walls. Reinforcing for shear transfer is provided between the concrete fill on metal deck and the concrete shear walls. The concrete fill over metal deck at the space frame steel framing is unreinforced, while the other concrete fill is reinforced. The concrete shear walls are typically supported on continuous strip footings and are doweled into the reinforced concrete slab-on-grade.

The lateral load-resisting system of the expansion includes the metal roof deck, horizontal roof bracing and steel braced frames at three sides. At the east and west elevations, the braced frames include tension-only double angles. (We determined that the braces are tension-only based on the positive signs on the design forces provided on the elevations). At the north elevation, the braced frames consist of a double angle chevron braced frames. The drawings do not provide the bracing connection details but provide the required design-build brace connection forces. The foundations at the steel braced frame columns consist of either new spread footings or the existing original building footings. Where the original footings were used, new concrete piers are doweled into the existing foundations and connected to the new steel columns. Where new footings are used, the columns are connected to a thickened slab above the footing which is doweled into the footing.

4.5.3 Discussion

We consider the lateral load-resisting system of the original building close to typical design quality for a building of its vintage. Except where the steel columns are cast in the walls, the ends of the walls do not have boundary element detailing and therefore do not have significant ductility. However, most of the walls have a low height-to-length ratio. We believe the total length of wall appropriate for the seismic hazard. However, the lack of defined collector members in the east-west direction results in about one third of the walls reduces their effectiveness in resisting lateral loads. We judge the out-of-plane anchorage of the walls adequate.

Using the terminology of HAZUS, the original Security Building is a C2 – Concrete Shear Wall Building.

Based on our drawing review we would consider the lateral load-resisting system of the expansion is somewhat worse than a typical circa 1991 braced steel frame building. However, this opinion is partially mitigated because of the use of an importance factor of 1.5 for the design. Based on the connection design loads provided on the drawings, it is clear that the connections do not develop the strength of the bracing members. The north elevation is of particular concern given the chevron configuration of the braced frame. The beam at the chevron frame is not capable of resisting the unbalanced load that would be developed by the buckling of the compression brace. However, the brace connection design force shown on the drawings is less than the buckling brace force so this failure mode will not occur providing the brace connections were not overdesigned. A final concern is that the building is only braced on three sides with the south elevation unbraced. Inspection of the brace connection design forces shows that the north elevation was designed for approximately the same shear as both the east and west elevations. This suggests that the available resistance capacity in the east-west direction is approximately half of the capacity in the north-south direction.

Using the terminology of HAZUS, the expansion is a S2 – Steel Braced Frame Building.

4.5.4 Recommendations

Based on our review of the drawings, we recommend a quality factor of 1.1 be used for the seismic risk analysis of the original Security Building. The recommended quality factor for the expansion is also 1.1.

4.6 500 kV Switchyard Building

4.6.1 Information Reviewed

We used the following drawings to perform this review:

- Architectural drawings titled “500KV Control Building…” sheets 59616 and 59617, dated 6 October 1978.
- Architectural drawings titled “230KV and 500KV Control Buildings…” sheet 59619 dated 6 October 1978 and sheets 59620 and 59621 dated 12 November 1971.
- Structural drawings titled “230KV & 500KV Control Building…” sheets 438183 dated 21 December 1978,
- Structural drawings titled “500KV Control Building…” 438184 dated 30 September 1971, 438185 dated 29 October 1971, 438186 dated 30 September 1971, 438189 and 438190 dated 3 November 1971.

The following drawings were available but we did not review them:

- Grading plan titled “Civil Switchyard Grading Plan” sheet 438012 dated 17 February 2009.
- Communication equipment bracing drawing titled “Earthquake Bracing For Communication Equipment Racks 500KV Switchyard Control Building” sheet 448373 dated 24 April 1972.

We reviewed DCM S-61B, dated 7 January 1999. This DCM appears to apply to switchyard equipment only.

4.6.2 Building Description

The 500 kV Switchyard Building is a one-story building with a basement constructed circa 1971. The building is nearly rectangular in plan with overall dimensions of approximately 63 ft by 84 ft which includes a stair well pop out at the south end. The above grade portion is steel framed and is supported by a concrete basement level.

4.6.2.1 Gravity Load-Resisting System

The gravity load-resisting system of the roof of the 500 kV Switchyard Building includes long span open web roof joists that support an unfilled metal deck. The joists are supported at the perimeter by steel wide flange beams and columns. The steel columns are supported by the perimeter concrete basement foundation walls.

The gravity load-resisting system of the first floor consists of a one-way reinforced concrete slab system that is supported by reinforced concrete beams at the interior column lines and by the perimeter concrete walls. The concrete beams are supported by reinforced concrete columns at the interior and by exterior concrete pilasters cast with the perimeter concrete basement walls. The columns are supported by isolated spread footings and the perimeter walls are supported by strip footings. The footings are shown to be cast monolithically with a concrete slab on grade.

4.6.2.2 Lateral Load-Resisting System

The lateral load-resisting system of the first story for the 500 kV Switchyard Building consists of the metal deck roof diaphragm and perimeter tension-only rod braced frames. Braced frames are provided at the four sides of the main building; two steel braced bays are provided on the east and west elevations and one steel braced bay each is provided on the north and south elevations. Steel wide flange beams serve as collectors to the braced frames.

The stairwell pop out has braced frames at the three exterior sides. There are no collector beams aligned with the east and west stairwell braced frames extending into the main building.

The lateral load-resisting system of the basement level consists of the ground floor slab and perimeter reinforced concrete basement shear walls.

4.6.3 Discussion

The lateral load-resisting system of the 500 kV Switchyard Building is typical for the type of construction and vintage. The lack of collectors to the braced frame walls at the stairwell is not a substantial concern as the diaphragm can span to the main building braced frames. It is not clear why there are more braced frames provided for north-south loading than the east-west loading except that the braces in this direction are inclined at a slightly steeper angle, making them less efficient at resisting lateral loads. Except for the column base plate detail, details of the steel frame connections are not provided on the drawings including the rod bracing connections, collector connections, gravity connections etc. A note on drawing sheet 438189 states “connections to develop full strength of members.”

Using the terminology of HAZUS, the Switchyard Building is an S3 – Light Metal Building. The stairwells could be considered S2 – Steel Braced Frame Building, but it seems appropriate to characterize the overall building behavior like that expected of a Light Metal Building

4.6.4 Recommendations

Based on our review of the drawings, we would recommend a quality factor of 1.0 be used for the 50 kV Switchyard Building HAZUS analysis.

4.7 230 kV Switchyard Building

4.7.1 Information Reviewed

We used the following drawings to perform this review:

- Architectural drawings titled “230KV Control Building…” sheet 59618 dated 6 October 1978.

- Architectural drawings titled “230KV and 500KV Control Buildings…” sheet 59619 dated 6 October 1978 and sheets 59620 and 59621 dated 12 November 1971.

- Structural drawings titled “230KV & 500KV Control Building…” sheets 438183 dated 21 December 1978.

- Structural drawings titled “230 KV Control Building…” sheets 438181 dated 18 October 1971, 438182 dated 5 April 2004, 438183 dated 21 December 1978, 438188 dated 1 August 1971.

The following drawings were available but we did not review them:

- Grading plan titled “Civil Switchyard Grading Plan” sheet 438012 dated 17 February 2009.

- Communication equipment bracing drawing titled “Earthquake Bracing for Communication Equipment Racks 500KV Switchyard Control Building” sheet 448373 dated 24 April 1972.

We reviewed DCM S-61B, dated 07 January 1999. This DCM appears to apply to switchyard equipment only.

4.7.2 Building Description

The 230 kV Switchyard Building is a one-story building with a basement constructed circa 1971. The building is rectangular in plan with overall dimensions of approximately 29 ft by 49 ft. The above grade portion is steel framed and is supported by a concrete basement level. It is very similar in construction to the 500kV Switchyard Building.

4.7.2.1 Gravity Load-Resisting System

The gravity load-resisting system of the roof of the 230 kV Switchyard Building includes open web roof joists that support an unfilled metal deck. The joists are supported at the perimeter by steel wide flange beams and columns. The steel columns are supported by the perimeter concrete basement foundation walls.

The gravity load-resisting system of the first floor consists of a one-way reinforced concrete slab system that is supported by reinforced concrete beams at the interior column lines and by the perimeter concrete walls. The concrete beams are supported at the center by a reinforced concrete column and at then ends by exterior concrete pilasters cast with the perimeter concrete basement walls. The columns are supported by isolated spread footings and the perimeter walls are supported by strip footings.

4.7.2.2 Lateral Load-Resisting System

The lateral load-resisting system of the first story for the 230 kV Switchyard Building consists of the metal deck roof diaphragm and perimeter tension-only rod braced frames. Braced frames are provided at the four sides of the main building; two steel braced bays are provided on the east and west elevations and one steel braced bay each is provided on the north and south elevations. Steel wide flange beams serve as collectors to the braced frames.

The lateral load-resisting system of the basement level consists of the ground floor slab and perimeter reinforced concrete basement shear walls.

4.7.3 Discussion

The lateral load-resisting system of the 230 kV Switchyard Building is typical for the type of construction and vintage. It is not clear why there are more braced frames provided for north-south loading than the east-west loading except that the braces in this direction are inclined at a slightly steeper angle, making them less efficient at resisting lateral loads. Except for the column base plate detail, details of the steel frame connections are not provided on the drawings including the rod bracing connections, collector connections, gravity connections etc. A note on drawing sheet 438189 states "connections to develop full strength of members."

Using the terminology of HAZUS, the Switchyard Building is an S3 – Light Metal Building.

4.7.4 Recommendations

Based on our review of the drawings, we would recommend a quality factor of 0.9 be used for the 230 kV Switchyard Building HAZUS analysis.

5. BUILDING FRAGILITY

5.1 HAZUS Fragility Data

HAZUS is national consensus software developed by FEMA to help estimate damage to the built environment as the result of future scenario earthquakes. One of its primary purposes is to help government agencies evaluate risks and includes national databases embedded within. This software is described in the Technical Manual (Reference 1). There is also an Advanced Engineering Building Module (AEBM) Manual (Reference 2) which is an extension of the general methods in HAZUS intended for use in estimating individual building losses.

In developing HAZUS, fragility curves for different model building types (e.g., steel moment frame buildings) were developed. An example of a fragility curve is shown in Figure 5-1. Generally the cumulative probability of reaching a damage state for a given level of deformation (drift) or severity of shaking (e.g., peak ground acceleration) is plotted. This plot is usually done assuming a lognormal distribution of damage, with a corresponding median and beta (log of the standard deviation).

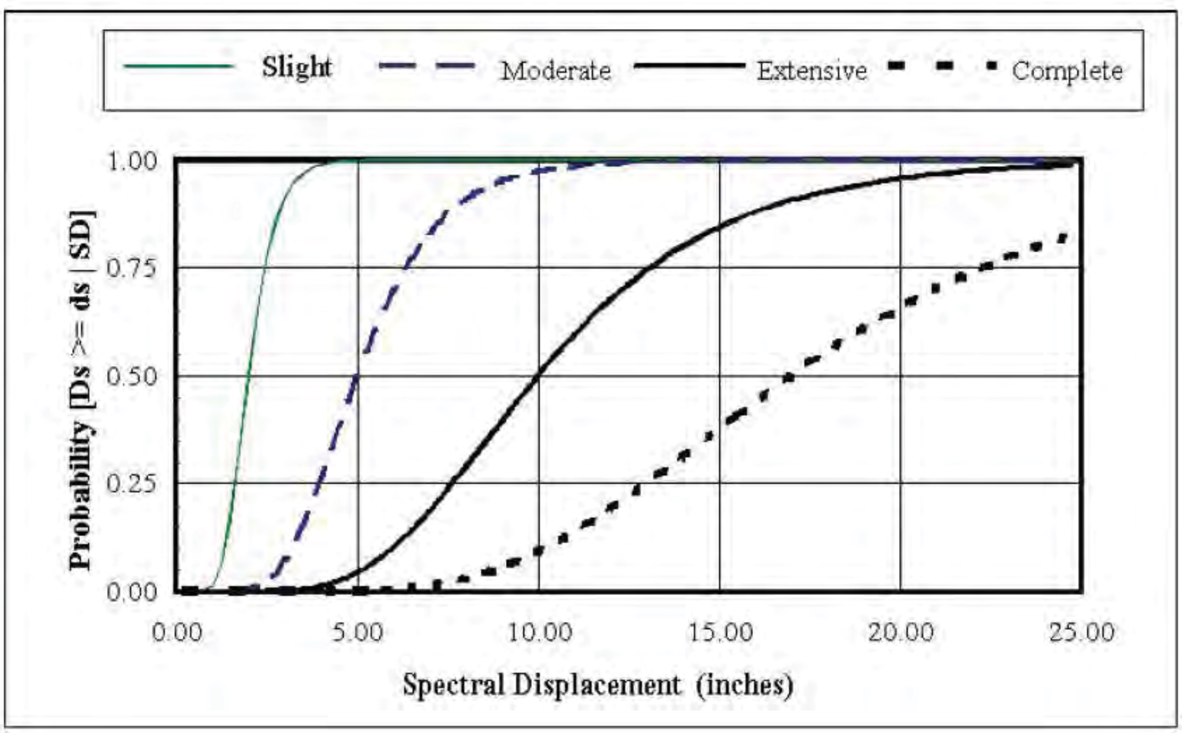

Figure 5-1: Sample fragility curves

For a building, if different damage states are defined, fragility curves can be developed for each damage state. In HAZUS the damage states defined are slight, moderate, extensive and complete. Verbal descriptions for these damage states are provided in Section 5.3.1 of the Technical Manual.

As indicated above, fragility curves for different model building types are included in HAZUS. Model building types of relevance for this study are steel moment frame buildings (S1), steel braced frame buildings (S2), lightweight steel buildings (S3) and concrete shear wall buildings (C2). HAZUS differentiates between low-rise, mid-rise and high-rise buildings. All but the Administration Building qualify as a low-rise building.

For each model building type, HAZUS also provides fragility data corresponding to different seismic design levels. The fragility data was developed in the 1990s when seismic zones defined in the Uniform Building Code (UBC) were still in use. High-Code is intended to reflect design practice in seismic zone 4 after 1975, Moderate-Code is representative of the design practice in seismic zone 2B after 1975, and Low-Code is intended to reflect design practice in seismic zone 1 after 1975. The AEBM Manual indicates that for buildings constructed between 1941 and 1975 the appropriate design levels should be reduced one. Only the Switchyard Buildings fall into the category, but we believe that there was little change in the design of lightweight metal buildings between the 1970s and 1980s, and consequently believe Moderate Code is the appropriate design level for these buildings. Often the design forces for these buildings are governed by wind. Buildings constructed prior to 1941 are considered pre-Code, and have a different set of fragility data. Thus there are fragility data for four seismic design levels included in HAZUS.

HAZUS does indicate that the above design levels can be modified as appropriate if superior construction quality is achieved. An example of superior construction is the good inspection and plan checking achieved for a hospital in California.

Without any further work, the fragility data could in HAZUS for each model building type and design level could be used to estimate the likelihood of each building being in each of the four damage states.

5.2 Fragility Data for Generic Building Types

The following median peak ground acceleration (PGA) and beta values are provided in Table 5.16b of the HAZUS Technical Manual for the fragility curves for Moderate-Code Seismic Design Level.

Table 5-1: Fragility Data for Generic Building Types for Moderate-Code Design Level

Building Type	Damage State							
	Slight		Moderate		Extensive		Complete	
	Median	Beta	Median	Beta	Median	Beta	Median	Beta
S1L	0.15	0.64	0.22	0.64	0.42	0.64	0.80	0.64
S1M	0.13	0.64	0.21	0.64	0.44	0.64	0.82	0.64
S2L	0.20	0.64	0.26	0.64	0.39	0.64	0.84	0.64
S3	0.13	0.64	0.19	0.64	0.33	0.64	0.60	0.64
C2L	0.18	0.64	0.30	0.64	0.49	0.64	0.87	0.64

In Table 5-1, the following abbreviations are used:

- S1 – Steel moment frame building
- S2 – Steel braced frame building
- S3 – Light metal building
- C2 – Concrete shear wall building

The L and M designations indicate low- and mid-rise, respectively.

The following median PGA and beta values are provided in Table 5.16a of the HAZUS Technical Manual for the fragility curves for High-Code Seismic Design Level.

Table 5-2: Fragility Data for Generic Building Types for High-Code Design Level

Building Type	Damage State							
	Slight		Moderate		Extensive		Complete	
	Median	Beta	Median	Beta	Median	Beta	Median	Beta
S1L	0.19	0.64	0.31	0.64	0.64	0.64	1.49	0.64
S1M	0.14	0.64	0.26	0.64	0.62	0.64	1.43	0.64
S2L	0.24	0.64	0.41	0.64	0.76	0.64	1.46	0.64
S3	0.15	0.64	0.26	0.64	0.54	0.64	1.00	0.64
C2L	0.24	0.64	0.45	0.64	0.90	0.64	1.55	0.64

Review of the data in the above tables reveals that HAZUS predicts a small difference in performance between Moderate-Code and High-Code at lower damage states and a large difference in performance in high damage states. Note that the beta value of 0.64 is common for all damage states and both code design levels.

6. CALCULATIONS

We have convolved the HAZUS fragility curves for general building types that we modified based on our judgment with the hazard curves provided by PG&E. The result is a probability on an annual basis of each of the six non-safety-related buildings experiencing damage corresponding to being in a HAZUS damage state or higher. As discussed in Section 7.4, the probability values in Tables 6-1 to 6-4 include use of a 0.05g threshold.

6.1 Moderate Damage

The likelihood of each of the six structures being in the moderate damage state or above assuming either Moderate-Code or High-Code design is listed in Table 6-1.

Table 6-1 – Probability of Experiencing Damage Corresponding with Moderate Damage State or Above as Defined by HAZUS on an Annualized Basis

Building	Description	HAZUS Building Type	Moderate-Code	High-Code
Main Warehouse	Direction 1	S1L	0.80%	0.39%
	Direction 2	S2L	0.89%	0.35%
Administration Building		S2M	0.64%	0.40%
Simulator Building		S1L	1.13%	0.58%
Security Building	Original	C2L	0.52%	0.21%
	Expansion	S2L	0.70%	0.26%
500 kV Switchyard Building		S3	1.33%	0.75%
230 kV Switchyard Building		S3	1.11%	0.61%

For Moderate-Code the chance of being in the moderate damage state or above varies from approximately 0.5% to 1.3% chance per year for the six structures. For High-Code, the range reduces significantly to approximately 0.2% and 0.75%. Note that the switchyard buildings are located on fill and thus are subjected to more severe shaking than the remainder of the buildings.

More than one entry is included in Table 6-1 for several of the buildings. The Main Warehouse has a steel moment frame in one direction and a steel braced frame in the other. The Security Building was built in two phases, with different lateral load-resisting systems for each phase.

Although the 500 kV Switchyard Building has two different structural systems, it is primarily a light metal building; only the stairwell would be considered a steel braced frame. Thus only one structural type is entered in Table 6-1 for this building.

The Administration Building relies on steel moment frames in both primary directions. The performance in the north-south direction is expected to be slightly better than the east-west direction, but we decided the difference did not justify two separate values in Table 6-1, and we simply used the average of the values we derived for each direction.

6.2 Extensive Damage

The likelihood of each of the six structures being in the extensive damage state or above assuming either Moderate-Code or High-Code design is listed in Table 6-2.

Table 6-2 – Probability of Experiencing Damage Corresponding with Extensive Damage State or Above as Defined by HAZUS on an Annualized Basis

Building	Description	HAZUS Building Type	Moderate-Code	High-Code
Main Warehouse	Direction 1	S1L	0.20%	0.08%
	Direction 2	S2L	0.27%	0.09%
Administration Building		S2M	0.13%	0.06%
Simulator Building		S1L	0.30%	0.12%
Security Building	Original	C2L	0.18%	0.05%
	Expansion	S2L	0.20%	0.07%
500 kV Switchyard Building		S3	0.47%	0.16%
230 kV Switchyard Building		S3	0.37%	0.13%

For Moderate-Code the chance of being in the extensive damage state or higher varies from approximately 0.13% to 0.45% chance per year for the six structures. For High-Code, the range reduces significantly to approximately 0.05% and 0.15%. These values are approximately 0.20 to 0.3 times those for moderate damage.

6.3 Complete Damage

The likelihood of each of the six structures being in the complete damage state assuming either Moderate-Code or High-Code design is listed in Table 6-3.

Table 6-3 – Probability of Experiencing Damage Corresponding with Complete Damage State or Above as Defined by HAZUS on an Annualized Basis

Building	Description	HAZUS Building Type	Moderate Code	High Code
Main Warehouse	Direction 1	S1L	0.048%	0.011%
	Direction 2	S2L	0.071%	0.020%
Administration Building		S2M	0.031%	0.008%
Simulator Building		S1L	0.072%	0.017%
Security Building	Original	C2L	0.049%	0.012%
	Expansion	S2L	0.053%	0.014%
500 kV Switchyard Building		S3	0.125%	0.036%
230 kV Switchyard Building		S3	0.098%	0.027%

For Moderate-Code the chance of being in the complete damage state varies from approximately 0.03% to 0.13% chance per year for the six structures. For High-Code, the range reduces significantly to approximately 0.008% and 0.036%. These values are approximately 0.15 to 0.3 times those for extensive damage.

6.4 Moderate Damage with No Damage Threshold

The values in Tables 6-1 to 6-3 were calculated by neglecting any contribution due to damage resulting from PGAs less than 0.05g. This will be discussed further in Section 7. Table 6-4 shows the effect of this assumption on the likelihood of reaching the moderate damage state. The values in each column include those calculated with the 0.05g threshold, and those without (in parentheses). In general the effect of including the threshold is to reduce the probability by 10-15% for Moderate-Code buildings, and 5-10% for High-Code buildings. The effect is more pronounced for the more vulnerable buildings.

Table 6-4 – Probability of Experiencing Damage Corresponding with Moderate Damage State or Higher as Defined by HAZUS on an Annualized Basis – No Threshold

Building	Description	HAZUS Building Type	Moderate-Code	High-Code
Main Warehouse	Direction 1	S1L	0.80% (0.95%)	0.39% (0.42%)
	Direction 2	S2L	0.89% (1.07%)	0.35% (0.37%)
Administration Building		S2M	0.64% (0.72%)	0.40% (0.44%)
Simulator Building		S1L	1.13% (1.42%)	0.58% (0.65%)
Security Building	Original	C2L	0.52% (0.57%)	0.21% (0.22%)
	Expansion	S2L	0.70% (0.80%)	0.26% (0.27%)
500 kV Switchyard Building		S3	1.33% (1.61%)	0.75% (0.83%)
230 kV Switchyard Building		S3	1.11% (1.30%)	0.61% (0.66%)

Note: Numbers without parentheses are those with 0.05g threshold and those in parentheses are those without 0.05g threshold.

A similar table could be generated for the extensive and complete damage states but as would be expected, the reduction in probability associated with using the 0.05g threshold is much smaller (less than 5%). The buildings are not expected to experience extensive of complete damage with such minor shaking.

7. DISCUSSION

We presented the annualized probabilities of each of the buildings experiencing different damage states or higher in the previous section. In this section we discuss various assumptions and details of our evaluation.

7.1 Damage States

Table 6-1 of the Technical Manual indicates that the moderate damage state corresponds with 5 to 25% damage, and that it corresponds with a green tag after an earthquake. Moderate damage may be localized. A green tag means that the building has been inspected and that no significant weakening of the structure has occurred. There are no restrictions on occupancy.

Further, Table 6-1 indicates that the extensive damage state correspond with 25% to 100% damage, and corresponds with a yellow tag after an earthquake. A yellow tag means occupancy is restricted but that sufficient reserve capacity exists that collapse in an aftershock is not expected. The building cannot be occupied by the occupants as it was before the earthquake before some action is taken. Some portion of the building may be unsafe. Generally occupants are permitted to remove important belongings through brief visits until damage is mitigated, or until the likelihood of a significant aftershock decreases.

Finally, Table 6-1 indicates that the complete damage state corresponds with 100% damage, and corresponds with a red tag. A red tag indicates an unsafe building that could collapse on its own or due to an aftershock. No entry into the building is permitted, even to achieve repairs or remove important belongings.

Complete damage does not correspond with collapse. Table 7-2 indicates the likelihood of collapse given the complete damage state for different building types. The values range from 3% (wood frame buildings) to 15% (unreinforced buildings). For the model building types in this study the collapse rates are listed in Table 7-1.

Table 7-1: Collapse Rates from HAZUS for Model Building Types

Model Building Type	Collapse
Light Metal Building (S3)	3%
Mid-Rise Steel Moment Frame Building (S1M)	5%
Low-Rise Steel Moment Frame Building (S1L)	8%
Low-Rise Steel Braced Frame Building (S2L)	8%
Low-Rise Concrete Shear Wall Building (C2L)	13%

If the acceptable building outages in Table 2-2 are reviewed, we believe that the desired performance for the buildings is the extensive damage state or better (or stated in another way, the probability of not having a complete damage state). Clearly the Administration Building performance can be closer to the complete damage state than the others (since the performance objective is no collapse or displacements that would impact the Turbine Building), and some of the smaller buildings could be repaired more quickly than others, but for the purpose of this study, we consider the complete damage state as unacceptable performance,

7.2 Design Level

At the time these six buildings were constructed (in the 1970s and late 1980s), the region that DCPP is located in was considered seismic zone 3 according to the UBC. Using the HAZUS terminology, these buildings would fall into the range between Moderate-Code and High-Code seismic design, probably closer to moderate. Thus to be conservative, we have decided to assume fragility data associated with the Moderate-Code level is appropriate.

It could be argued that the type of quality control exercised at the DCPP during construction and design could increase the design level from Moderate-Code to High-Code, but we have chosen to conservatively ignore the effect of superior construction.

7.3 Quality Factor

HAZUS fragility data are intended to represent the average building type of a certain height, age and designed using specific building code provisions. However, not all buildings designed under such conditions will perform equally in an earthquake. Based on our drawing reviews, we judged whether a building was better or worse than the average building. We assigned a quality factor that is used to scale the median of the fragility data. Generally the quality factors range from 0.8 to 1.25 with 1.25 representing a building with a median that is 1/1.25 lower than the average. Quality factors assigned for each building were presented in Section 4.

The quality factor not only is used to reflect to superior or inferior detailing or configurations, it also incorporates what we learned by reviewing the drawings or design criteria about the importance factors used in the design. Thus we decreased the quality factors for the Administration Building and Security Building expansion appropriately. An alternative approach for the Administration Building and Security Building is to use High-Code with a quality factor higher than 1.0 to reflect some detailing issues.

7.4 Multiple Fragility Curves

We assigned multiple fragility curves for buildings with multiple types of lateral load systems (e.g., steel moment frames in one direction and steel braced frames in the other). Conservatively, we have assumed the one with the highest annualized probability of occurring reflects the value that should be used for each building. Thus, we reported the higher annualized probability for steel braced frames for the Main Warehouse in Section 8. Similarly, we reported the higher annualized probability associated with the expansion for the Security Building.

7.5 Damage Threshold

When a fragility curve and a hazard curve are convolved, it is possible for a significant contribution of the computed risk (e.g., annualized loss) to come from the more common, lower ground motions even though there is very little risk that such ground motions will damage a building. This in part is the result of assuming the fragility data is lognormally distributed. It is common to introduce a damage threshold level below which no damage is assumed to occur. A common threshold is 0.05g. In the case of DCPP, this is a threshold with some meaning as the Paso Robles Earthquake of 2003 generated no significant damage and produced ground shaking of 0.05g. The values of the annualized probabilities listed in Tables 6-1 to 6-3 include the 0.05g threshold. As discussed in Section 6.5, the effect of introducing this threshold is to reduce the damage at most 10-15%.

It could be argued that larger thresholds are appropriate for the higher damage states. For example, it is very unlikely that PGAs up to 0.1g will cause extensive of complete damage.

However, we have conservatively ignored the effect of increasing the damage threshold for higher damage states.

7.6 New Buildings

The fragilities for new buildings of standard importance can be derived using the HAZUS fragilities if improvements since the 1994 building codes are considered. This can be done using engineering judgment to assign appropriate quality factors. We estimate appropriate quality factors are 0.8 for steel braced frames, 0.85 for steel moment frames, 0.95 for light metal buildings, and 1.0 for concrete shear wall buildings.

7.7 Structural vs. Nonstructural

The HAZUS damage states used in this evaluation correspond with the structural damage states. We did not consider nonstructural components within the building as no walkthroughs to identify nonstructural items and their installation quality were performed.

Repair of all nonstructural components may not be necessary to achieve the functions that make each of the buildings important. Further, alternatives to repairing some of the nonstructural components exist including temporary setups or redundant facilities.

7.8 Displacement vs Peak Ground Acceleration

Most of the fragility data in the Technical Manual is based on building displacements. In order to use this data directly we would need to perform analyses of the buildings to determine approximate building periods and understand expected performance. Such analyses are beyond the scope of our work. Instead, we have used the fragility data developed in the Technical Manual in Table 5.14 which is based on PGAs. In order to develop this table certain assumptions have been made including using a standard spectrum shape a magnitude 7 event more than 15 km distant on western U.S. type soils. Such assumptions are not unreasonable for the DCPP.

7.9 Generic Building Fragilities

The approach for deriving building fragilities used in this report is acknowledged to be approximate and could vary with results obtained using building-specific fragilities. However, we anticipate that resulting probabilities of being in different damage states derived from detailed analyses will be of a similar order of magnitude.

8. CONCLUSIONS

We have combined the modified fragility information for each of the six buildings with the required performance provided by PG&E in Table 2-2 to determine the annualized probability of an unacceptable outage for each. We have assumed this corresponds with the probability of reaching the complete damage state, as listed in Table 8-1. As discussed previously, we have conservatively assumed Moderate-Code design.

Table 8-1: Probability of Experiencing Damage That Will Cause Unacceptable Outage Duration on an Annualized Basis

Building	Moderate- Code
Main Warehouse	0.071%
Administration Building	0.031%
Simulator Building	0.072%
Security Building	0.053%
500 kV Switchyard Building	0.125%
230 kV Switchyard Building	0.98%

Although the buildings evaluated as part of this project were constructed in the 1970s and 1980s, the annualized probability of structural damage that will cause unacceptable outages is predicted to be 0.125% or less for each of the buildings. These relatively low probabilities are due to:

- The use of seismic design criteria in excess of that required by the building codes current during the time of construction.
- The relatively small size of some of the buildings.
- The use of structural steel as opposed to concrete or concrete block for most of the structures.
- The relatively low hazard for a California site.

For comparison purposes, the same values were derived for typical new, code-compliant buildings of the same construction. These values are listed below.

Table 8-2: Probability of New Buildings Experiencing Unacceptable Outage on an Annualized Basis

Building	Moderate Code
Main Warehouse	0.033%
Administration Building	0.031%
Simulator Building	0.033%
Security Building	0.039%
500 kV Switchyard Building	0.111%
230 kV Switchyard Building	0.111%

By comparing Tables 8-1 and 8-2 we noted that newer construction designed to criteria for structures of standard importance using the current building code is generally less likely to experience an unacceptable outage, but the difference between the values in the two tables is not significant.

I:\SF\Projects\2009\097210.00-PDIA\WP\001DLMcCormick-R-097210.00.jdi__Diablo Canyon Report.doc

9. REFERENCES

1. Multi-hazard Loss Estimation Methodology, Earthquake Model, HAZUS-MH MR3. Technical Manual. Developed by: Department of Homeland Security and Response Directorate, FEMA, Mitigation, Division, Washington, D.C. 2003.

2. Multi-hazard Loss Estimation Methodology, Earthquake Model, HAZUS-MH MR1. Advanced Engineering Building Module. Developed by: Department of Homeland Security and Response Directorate, FEMA, Mitigation, Division, Washington, D.C. 2003.

APPENDIX A

Photographs

Photo 1

Main Warehouse from Parking Lot.

Photo 2

Administration Building with walkway to Turbine Building.

Photo 3

Simulator Building.

Photo 4

Security Building in foreground with Administration Building behind.

Photo 5

500 kV Switchyard Building.

Photo 6

230 kV Switchyard Building.

EXHIBIT L

CIVIL NUCLEAR

CREDIT REDEMPTION AGREEMENT

dated as of [_________]

between

[___________________][1],

and

U.S. DEPARTMENT OF ENERGY,

for

[__________________][2]

1 Insert name of Owner, Operator, or Authorized Representative.

2 Insert name of Nuclear Reactor.

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Exhibit D	DOE Instructions for Delivery of Payment Certificate and Notices (Section 2.4.4)
Exhibit E	Owner/Operator Instructions for Payment of Credits and Notices (Section 2.4.4)

CIVIL NUCLEAR CREDIT REDEMPTION AGREEMENT

This CIVIL NUCLEAR CREDIT REDEMPTION AGREEMENT (the "Agreement"), dated as of [_________], but effective as of October 1, 2023 (the "Effective Date"), is by and among (i) [_____________], a [__________] organized and existing under the laws of the State of [_____________] (the "Owner/Operator"), acting on behalf of [__________________] (the "Nuclear Reactor") and (ii) the U.S. DEPARTMENT OF ENERGY, acting by and through the Secretary of Energy (or appropriate authorized representative thereof) ("DOE").

WHEREAS, the Infrastructure Investment and Jobs Act (Public Law 117-58; 42 U.S.C. § 18753) ("IIJA") directs the DOE to establish a civil nuclear credit program (the "CNC Program") to evaluate and certify nuclear reactors that are projected to cease operations due to economic factors and to allocate civil nuclear credits ("Credits") to selected certified nuclear reactors via a sealed bid process;

WHEREAS, DOE has certified the Nuclear Reactor to be eligible for the allocation of Credits under the CNC Program and DOE has allocated Credits to the Nuclear Reactor pursuant to the process set forth in the U.S. Department of Energy Guidance for the Civil Nuclear Credit Program dated April 19,2022, and subject to the execution and delivery of this Agreement and the performance of the terms hereof;

NOW, THEREFORE, in consideration of the foregoing and other good and valid consideration, the receipt and adequacy of which are hereby expressly acknowledged, the parties hereby agree as follows:

ARTICLE 1
DEFINITIONS

Except as otherwise expressly provided herein, capitalized terms used in this Agreement and its exhibits and schedules have the meanings given in Exhibit A.

ARTICLE 2
OPERATION OF THE NUCLEAR REACTOR; CREDITS

SECTION 2.1. Operation of the Nuclear Reactor.

The Owner/Operator agrees to operate the Nuclear Reactor in accordance with Prudent Industry Practice for fiscal years 2023–2026. During the term of this Agreement, the Owner/Operator shall not terminate operations for economic reasons and shall use commercially reasonable best efforts to produce the MWh commitment identified in Section 2.2. The Owner/Operator shall provide written notice to DOE (a) not later than five business days prior to the commencement of a planned outage and (b) not later than five business days following the occurrence of an unplanned outage. The Owner/Operator shall promptly notify DOE following the completion of the outage and the resumption of electricity generation.

SECTION 2.2. Awarded Credits.

Pursuant to the Auction and this Agreement, DOE has awarded Credits to the Nuclear Reactor for fiscal year 2023 ("FY 2023 Credits"); for fiscal year 2024 ("FY 2024 Credits"); for fiscal year 2025 ("FY 2025 Credits"); and for fiscal year 2026 ("FY 2026 Credits") in the amounts set forth below.

(a) The FY 2023 Credits are in the amount of $ ___________, calculated as follows: $_______ per Megawatt-hour ("MWh") multiplied by the Nuclear Reactor's commitment for fiscal year 2023 of _________ MWh.

(b) The FY 2024 Credits are in the amount of $ ___________, calculated as follows: $_______ per MWh multiplied by the Nuclear Reactor's commitment for fiscal year 2024 of ___________ MWh.

(c) The FY 2025 Credits are in the amount of $ ___________, calculated as follows: $_______ per MWh multiplied by the Nuclear Reactor's commitment for fiscal year 2025 of ___________ MWh.

(d) The FY 2026 Credits are in the amount of $ ___________, calculated as follows: $_______ per MWh multiplied by the Nuclear Reactor's commitment for fiscal year 2026 of ___________ MWh.

SECTION 2.3. Voucher.

Upon execution of this Agreement by DOE and the Owner/Operator, DOE shall deliver to the Owner/Operator a voucher (the "Voucher") in the form of Exhibit D entitling the Owner/Operator to payment of the value of the Credits corresponding to the fiscal year identified in the Voucher on the terms set forth herein.

SECTION 2.4. Payment of Credits.

2.4.1. Presentation of Payment Certificate.

Not later than ninety (90) days following the completion of a fiscal year for which the Nuclear Reactor holds a Voucher, the Owner/Operator shall present to DOE a payment certificate (the "Payment Certificate") in the form of Exhibit E requesting payment for Credits up to the amount set forth in the Voucher, completed and signed by the Owner/Operator and accompanied by the information required therein. The Payment Certificate shall include a comparison of the Award Period Financial Projections for that fiscal year (including Projected Enhancement Capital Cost, Projected Sustaining Capital Cost, and Projected Revenue) with the actual results of operation of the Nuclear Reactor for the fiscal year (including Actual Enhancement Capital Cost, Actual Sustaining Capital Cost, and Actual Revenue).

2.4.2. Review of Payment Certificate; Audit.

DOE shall review the Payment Certificate, including the information required to be provided with the Payment Certificate, in order to audit the Nuclear Reactor's performance of its obligations under this Agreement. DOE may require that the Owner/Operator provide additional information as DOE may request to undertake its audit of the Nuclear Reactor's performance of its obligations under this Agreement.

2.4.3. Credit Adjustment Requests.

Owner/Operator may request an adjustment of current or future fiscal year Credits. This adjustment shall not increase the maximum redeemable value of Credits available to the Owner/Operator. Credit Adjustment Requests must be submitted in writing to DOE no later than thirty (30) days prior to completion of a fiscal year for which the Owner/Operator holds a Voucher. This request will include: the reasons for the adjustment request; the amount of the requested adjustment for the current fiscal year; and the amount to be adjusted for future affected fiscal years. DOE shall review and notify the Owner/Operator in writing of its decision regarding the Credit Adjustment Request within thirty (30) days of receipt of the Request. The Credit Adjustment Request cannot be used by the Owner/Operator to redistribute credits that have been reduced in prior fiscal years as explained in 2.4.4.

2.4.4. Annual Adjustment of Credits.

(a) If based upon its audit of the Payment Certificate and such other information as DOE may deem relevant, DOE determines that the Nuclear Reactor's Actual Revenue exceeds the Projected Revenue for such fiscal year, such amount shall be the "Revenue Adjustment."

(b) If based upon its audit of the Payment Certificate and such other information as DOE may deem relevant, DOE determines that the sum of the Nuclear Reactor's Actual Enhancement Capital Cost and Actual Sustaining Capital cost exceeds the sum of the Projected Enhancement Capital Cost and Projected Sustaining Capital Cost, such amount shall be the "Capital Adjustment."

(c) The Credits awarded in the Voucher for the fiscal year of the Payment Certificate shall be reduced by the sum of the Revenue Adjustment and Capital Adjustment, except that the amount may not be less than zero. Such amount shall be the "Credit Adjustment."

2.4.5. Payment of Credits.

DOE shall pay to the Owner/Operator the amount of the Credits requested in the Payment Certificate net of any reduction of Credits by the amount of the Credit Adjustment. Exhibit F sets forth the address and other specifications for the submission by the Owner/Operator of the Payment Certificate. Exhibit G sets forth the Nuclear Reactor's instructions for payment of Credits payable by DOE. Notwithstanding anything to the contrary herein, DOE shall have no obligation to pay out any Credits if the Nuclear Reactor is in an outage at the time that payment would otherwise be made. DOE shall pay any Credit amount due following completion of the outage and resumption of electricity generation.

SECTION 2.5. Uprates

If the Owner/Operator determines to undertake a project to increase the output of the Nuclear Reactor after the Effective Date, the Owner/Operator may propose to DOE a revision to the calculation of the annual adjustment described in Section 2.4.4 such that the revenues attributable to the incremental output resulting from the project are not included in the Nuclear Reactor's Actual Revenues for the calculation period, and the Owner/Operator shall provide a detailed description of the project and supporting information. In no event shall any such revision increase the maximum redeemable value of Credits available to the Owner/Operator. The decision whether or not to negotiate a revision to the calculation of the annual adjustment as described in this Section 2.5 shall be at the sole discretion of DOE.

SECTION 2.6. Recapture.

All or part of Credits paid to the Owner/Operator pursuant to this Agreement may be subject to recapture by DOE (a) if the Nuclear Reactor has terminated operations during the Award Period or (b) at the conclusion of the Award Period if the Nuclear Reactor would not have operated at an annual loss in the absence of the Credits.

2.6.1 Recapture Following Termination of Operations.

If DOE determines that the Nuclear Reactor has terminated operations during the Award Period, then DOE shall rescind the award of credits for the fiscal year in which the termination of operations occurred and for any remaining fiscal years in the Award Period, and the Owner/Operator shall have no further rights to any Credits under this Agreement. Credits that have been paid to the Owner/Operator with respect to a prior fiscal year during which the Nuclear Reactor has not terminated operations shall not be subject to recapture. DOE shall provide the Owner/Operator with written notice of its determination that the Nuclear Reactor has terminated operations and shall include the calculation of Credits that are being recaptured.

2.6.2 Recapture at the End of the Award Period.

At the conclusion of the Award Period, DOE shall conduct a review as part of its annual review process and using the same methodology as employed in the annual review process described in Section 2.4 to determine whether in any year during the Award Period the Nuclear Reactor would not have operated at an annual loss in the absence of the Credits. DOE shall provide the Owner/Operator with written notice of the results of its recapture analysis, including the value of Credits previously paid to the Owner/Operator that are required to be remitted by the Owner/Operator, if any. The Owner/Operator shall pay to DOE any amounts required to be repaid within thirty (30) days of receipt of such notice.

ARTICLE 3
ANNUAL REPORT

Not later than thirty days following the completion of a fiscal year for which the Nuclear Reactor holds a Voucher, the Owner/Operator shall provide to DOE a report containing the following information for the fiscal year:

(a) An estimate of emission of air pollutants avoided by the continued operation of the Nuclear Reactor compared to the emission of air pollutants reasonably expected had the Nuclear Reactor terminated operation prior to the commencement of the fiscal year;

(b) A description of the Nuclear Reactor's contribution to the reliability of the electric transmission and distribution grid to which it is connected during the fiscal year;

(c) An estimate of the change in the wholesale cost of capacity, energy, and ancillary services in the applicable market attributable to the continued operation of the Nuclear Reactor compared to the costs reasonably expected had the Nuclear Reactor terminated operation prior to the commencement of the fiscal year, and the resulting impact on retail rates;

(d) A description of capital projects undertaken during the fiscal year including the percentage of raw materials acquired from domestic sources and manufacturers;

(e) A summary of staffing, including the number of individuals employed by the Nuclear Reactor and information on those employee's job classifications, wages, benefits, demographics, veteran status, union representation, residence, and training opportunities, for those direct hires and contractor employees, working at the Nuclear Reactor during the fiscal year and any changes from the baseline data contained in the Workforce Narrative submitted in the Owner/Operator's Certification Application;

(f) An assessment of the Nuclear Reactor's implementation of its Diversity, Equity, Inclusion, and Accessibility (DEIA) Plan that describes the actions the Owner/Operator is currently taking or will take to foster a welcoming and inclusive environment, support people from underrepresented groups, advance equity, and encourage the inclusion of individuals from these groups, and describes the extent the project activities will benefit underserved communities; and accounts for whether the Nuclear Reactor is meeting the milestones established in its DEIA Plan submitted as part of its Certification Application;

(g) A measurable description of how the continued operation of the Nuclear Reactor benefits Disadvantaged Communities (DACs) through either

(1) decreasing energy burden;

(2) decreasing environmental exposure and burdens; or

(3) increasing energy resilience;

(h) A description of the outages experienced by the Nuclear Reactor and a comparison of the actual output of the Nuclear Reactor compared to the MWh commitment for that year. The methodology and data sources used to calculate each of these pieces of information should also be provided;

(i) The number of stakeholder or community engagement events and their attendance, number of attendees or organizations participating from or who represent disadvantaged, energy, rural, or tribal communities (report separately), any community benefits agreements created, and any changes from the baseline data contained in the Community Engagement Narrative submitted in the Owner/Operator's Certification Application; and

(j) A description of any state credits Nuclear Reactors did not utilize as a result of receiving credits through this program, including the value of each credit.

(k) DOE will make the Annual Report available to the public, subject to the limitations specified in Section 6.2, Confidential Business Information.

ARTICLE 4
REPRESENTATIONS AND WARRANTIES

The Owner/Operator makes the following representations and warranties as of the date of this Agreement and as of the date of each Payment Certificate:

SECTION 4.1. Organization.

The Owner/Operator (a) is a [________] organized, validly existing and in good standing under the laws of the State of [________], (b) is duly qualified to do business in the State of [________] and in each other jurisdiction where the failure to so qualify could reasonably be expected to have a material adverse effect and (c) has all requisite [corporate] [limited liability company] [partnership] power and authority to execute, deliver, perform and observe the terms and conditions of this Agreement on its own behalf and on behalf of any Person holding an interest in the Nuclear Reactor.

SECTION 4.2. Authorization; No Conflict.

The Owner/Operator has duly authorized, executed, and delivered this Agreement, and neither its execution and delivery nor its consummation of the transactions contemplated hereby nor its compliance with the terms of this Agreement does or will (a) contravene its Organizational Documents or any Applicable Laws, (b) contravene or result in any breach or constitute any default under any Governmental Judgment, (c) require the consent or approval of any Person other than the consents or approvals that have been obtained and are in full force and effect.

SECTION 4.3. Legality; Validity; Enforceability.

This Agreement is a legal, valid, and binding obligation of the Owner/Operator, enforceable in accordance with its terms, subject to Bankruptcy Laws and general principles of equity regardless of whether enforcement is considered in a proceeding at law or in equity.

SECTION 4.4. Applicable Law.

The Owner/Operator is in compliance with all Applicable laws, including all Environmental Laws, in all material respects. Further, that no citations, fines, or penalties have been asserted against the Nuclear Reactor under any Environmental Law or by the regulatory authority or jurisdiction in which the Nuclear Reactor operates. The Nuclear Reactor has not received notice (verbal or written) of, nor is it aware of, any person making allegations that all or any part of the Nuclear Reactor as a whole, or the use, operation or ownership thereof, are in violation of any applicable Environmental Law.

SECTION 4.5. Insurance.

The Nuclear Reactor shall keep in force all existing policies of insurance, or comparable replacement policies of insurance at existing levels of coverage related to the Nuclear Reactor, including the ownership and operation thereof, throughout the duration of this Agreement.

SECTION 4.6. Tax.

(a) The Owner/Operator has filed all tax returns required by Applicable Laws to be filed by it and has paid (i) all income Taxes payable by it that have become due pursuant to such tax returns and (ii) all other material Taxes and assessments payable by it that have become due (other than those Taxes that it is contesting in good faith and by appropriate proceedings, for which reserves have been established to the extent required by generally accepted accounting principles).

(b) The Owner/Operator does not owe any delinquent Indebtedness to any Governmental Authority of the United States, including any Tax liabilities, unless the delinquency has been resolved with the appropriate Governmental Authority in accordance with Applicable Law and, to the Knowledge of the Owner/Operator, the standards of the Debt Collection Improvement Act.

SECTION 4.7. Defects.

The Owner/Operator warrants that there are no known issues, defects, problems, or other issues involving or related to ownership and/or operation of the Nuclear Reactor that would preclude or prevent it from fully performing its duties and obligations in accordance with this Agreement.

SECTION 4.8. Commercially Reasonable Efforts.

The Owner/Operator shall use commercially reasonable efforts, consistent with Prudent Industry Practice, to maximize Actual Revenue.

SECTION 4.9. Uranium Best Efforts.

(a) In any procurement of reactor fuel undertaken during fiscal years 2023–2026, Owner/Operator shall use best efforts to maximize the procurement of uranium that is produced in the United States and the procurement of conversion services, enrichment services, and fabrication into fuel assemblies in the United States; provided, however, that Owner/Operator will be deemed to perform under this subsection in the event that: (i) DOE determines, in writing, that under the circumstances such procurement is not in the public interest; (ii) Owner/Operator establishes through reasonable diligence that no U.S.-produced uranium, U.S. conversion services, U.S. enrichment services, and/or U.S. fabrication services, as applicable, is available in sufficient quantity and satisfactory quality to meet Owner/Operator's need; or (iii) the selection of a U.S.

product or service would increase the overall cost of the fuel assembly by more than twenty-five (25) percent.

(b) Owner/Operator shall retain all books and records necessary to substantiate its performance under subsection (a) and will make such books and records available to DOE promptly upon request.

SECTION 4.10. U.S. Manufacturing Best Efforts.

The Owner/Operator will use best efforts to maximize U.S.-manufactured content acquired or used in Nuclear Reactor facilities and components, taking into account availability, cost, technical performance, reliability, efficiency, warranty coverage and related commercial terms during the Award term.

SECTION 4.11. Award Period Financial Projections.

(a) The Owner/Operator has provided a hard copy of, and a computer disk, CD-ROM, or other customary computer storage media, containing the Award Period Financial Projections for the Nuclear Reactor setting forth the projected operating results and the underlying models and assumptions (which assumptions are believed by the Owner/Operator to be reasonable) and explanations thereto for the Nuclear Reactor for fiscal years 2023–2026.

(b) The Award Period Financial Projections:

(i) are complete and based on reasonable assumptions;

(ii) are the same as those submitted in the Nuclear Reactor's Certification Application, consistent with the requirements of the set forth in the U.S. Department of Energy Guidance for the Civil Nuclear Credit Program dated April 19, 2022;

(iii) have been prepared in good faith and with due care; and

(iv) fairly represent the Owner/Operator's expectation as to the matters covered thereby as of any date on which this representation is made.

SECTION 4.12. U.S. Government Requirements.

(a) Central Contractor Registration. The Owner/Operator has registered in the CCR database.

(b) Foreign Asset Control Regulations. Neither the payment of Credits nor the use of the proceeds thereof by the Owner/Operator or at the direction of the Owner/Operator will violate the Foreign Asset Control Regulations.

(c) Prohibited Persons. Neither the Owner/Operator nor any of their respective Principal Persons is a Prohibited Person. No event has occurred and no condition exists that is likely to result in Owner/Operator nor any of its respective Principal Persons becoming a Prohibited Person.

(d) Anti-Terrorism Order. The Owner/Operator and of its respective Principal Persons is in compliance with the Anti-Terrorism Order and has not previously violated the Anti-Terrorism Order.

(e) Lobbying and Political Activity Costs. No proceeds of the Credits have been or will be expended by the Owner/Operator or any of its Affiliates to pay any Person for influencing or attempting to influence an officer or employee of any agency, a member of Congress, an officer or employee of Congress, or an employee of a member of Congress, or other political activity costs. The Owner/Operator shall provide DOE a Standard Form LLL "Disclosure of Lobbying Activities" on the date of signature of this Agreement.[3]

ARTICLE 5
TERM; EVENTS OF DEFAULT; REMEDIES

SECTION 5.1. Term

The term of this Agreement shall commence as of the Effective Date and shall remain in effect until DOE has made a determination whether to recapture any Credits as provided in Section 2.6 following completion of fiscal year 2026.

SECTION 5.2. Events of Default.

The occurrence of any of the following events shall constitute an Event of Default:

(a) Termination of Operation of the Nuclear Reactor. The Nuclear Reactor shall terminate operation with the intent to permanently cease operation by filing a notice of intent to permanently cease operations with the Nuclear Regulatory Commission (NRC) consistent with the requirements of 10 C.F.R. § 50.4(b)(8) or 10 C.F.R. § 52.3(b)(8) and beginning cessation of operations. No credits may be redeemed during the award year when a notice is filed with NRC and all prior awarded credits will be subject to recapture. A scheduled outage for maintenance, refueling, or other activity in the normal course of operation shall not be considered to be termination of operation provided that the Owner/Operator acts diligently and in good faith to recommence operation in accordance with the outage schedule. An unscheduled outage shall not be considered to be termination of operation provided that the Owner/Operator acts diligently and in good faith to recommence operation as promptly as reasonably possible.

(b) Misstatements; Omissions. Any representation or warranty made by or on behalf of the Owner/Operator or the Nuclear Reactor in this Agreement or the Payment Certificate was false, or misleading in any material respect when made or deemed to have been made and such false or misleading representation or warranty is not cured within ten (10) days after Owner/Operator discovers the error.

(c) Other Agreements. The Owner/Operator shall fail to perform or observe any term, covenant, or agreement contained in this Agreement, where such default has not been remedied

[3] In accordance with 31 U.S.C. § 1352.

within thirty (30) days if such default is remediable after the Owner/Operator receives notice or should reasonably have known of such failure.

(d) Waiver. The failure to exercise any remedy or to enforce any right provided in this Agreement or Applicable Law shall not constitute a waiver of such remedy or right or of any other remedy or right. A party shall be considered to have waived any remedies or rights only if the waiver is in writing and signed by the party against whom such waiver is to be enforced.

SECTION 5.3. Remedies for Event of Default.

Upon the occurrence and during the continuance of an Event of Default, DOE may, without further notice of default, exercise any or all rights and remedies at law or in equity (in any combination or order that DOE may elect), including without prejudice to DOE's other rights and remedies, the following:

(a) DOE may withhold payment of any Credits otherwise due or becoming due to the Owner/Operator;

(b) DOE may undertake recapture of any Credits as provided in Section 2.5;

(c) DOE may terminate this Agreement;

(d) DOE may seek disgorgement of redeemed credits if DOE determines that the Owner/Operator made material misrepresentation of the status of operations or economic condition of the Nuclear Reactor; and

(e) DOE may proceed to protect and enforce its rights and remedies by appropriate proceedings, whether for damages or the specific performance of any provision of this Agreement, or proceed to enforce the payment of any amount due and payable.

ARTICLE 6
MISCELLANEOUS

SECTION 6.1. Indemnity.

(a) General Indemnity. Except as relates to indemnification for a nuclear incident or precautionary evacuation pursuant to the Price-Anderson Act, the Owner/Operator shall indemnify the United States and its officers, agents, and employees for any and all liability, including litigation expenses and fees, arising from suits, actions, or claims of any character for death, bodily injury, or loss of or damage to property or to the environment, resulting from the performance of this Agreement or the ownership and operation of the Nuclear Reactor.

(b) Price-Anderson Act. This Agreement does not constitute a contract or agreement of indemnification between the Owner/Operator and the Department of Energy as defined under 42 U.S.C. § 2210(d), the Price-Anderson Act (PAA), nor does this Agreement alter or change the indemnification requirements of NRC licensees as defined in the PAA and related regulations.

SECTION 6.2. Confidential Business Information.

DOE acknowledges that the Owner/Operator may provide to DOE confidential or proprietary business, technical, or financial information. DOE will manage this information consistent with the Trade Secrets Act, 18 U.S.C. § 1905. DOE will process any request for release of this information to the public consistent with the Freedom of Information Act ("FOIA"), 5 U.S.C. § 552 and DOE's FOIA regulations, 10 C.F.R. Part 1004. Owner/Operator will clearly mark all such information prior to submittal to DOE. DOE is responsible for the final determination with regard to disclosure or nondisclosure of the information.

SECTION 6.3. Amendment or Termination.

This Agreement may not be amended or terminated unless such amendment or termination is in writing and signed by the DOE and the Owner/Operator.

SECTION 6.4. Entire Agreement.

This Agreement, including any agreement, document or instrument attached to this Agreement or referred to herein, integrates all the terms and conditions mentioned herein or incidental to this Agreement and supersedes all oral negotiations and prior agreements and understandings of the parties to this Agreement in respect to the subject matter of this Agreement.

SECTION 6.5. Governing Law.

This Agreement and the rights and obligations of the parties hereunder shall be governed by, and construed and interpreted in accordance with, the Federal law of the United States of America.

SECTION 6.6. Severability.

In case any one or more of the provisions contained in this Agreement should be invalid, illegal, or unenforceable in any respect, the validity, legality, and enforceability of the remaining provisions shall not in any way be affected or impaired thereby, and the parties thereto shall enter into good faith negotiations to replace the invalid, illegal, or unenforceable provision.

SECTION 6.7. Waiver of Jury Trial.

Each of the parties to this Agreement hereby knowingly, voluntarily, and intentionally waives any rights it may have to a trial by jury in respect of any litigation based hereon, or arising out of, under, or in connection with, this Agreement, or any course of conduct, course of dealing, statements (whether verbal or written), or actions of the Owner/Operator. This provision is a material inducement for each party to enter into this Agreement.

SECTION 6.8. Consent to Jurisdiction.

By execution and delivery of this Agreement, the Owner/Operator irrevocably and unconditionally:

(a) submits for itself and its property in any legal action or proceeding against it arising out of or in connection with this Agreement, or for recognition and enforcement of any judgment in respect thereof, to the non-exclusive general jurisdiction of (i) the courts of the United States of America for the District of Columbia; (ii) any other federal court of competent jurisdiction in any other jurisdiction where it or any of its property may be found; and (iii) appellate courts from any of the foregoing;

(b) consents that any such action or proceeding may be brought in or removed to such courts, and waives any objection, or right to stay or dismiss any action or proceeding, that it may now or hereafter have to the venue of any such action or proceeding in any such court or that such action or proceeding was brought in an inconvenient court and agrees not to plead or claim the same;

(c) agrees that service of process in any such action or proceeding may be affected by mailing a copy thereof by registered or certified mail (or any substantially similar form of mail), postage prepaid, to the Owner/Operator at its address set forth in Exhibit G; and

(d) agrees that judgment against it in any such action or proceeding shall be conclusive and may be enforced in any other jurisdiction within or without the U.S. by suit on the judgment or otherwise as provided by law, a certified or exemplified copy of which judgment shall be conclusive evidence of the fact and amount of the Owner/Operator's obligation.

SECTION 6.9. Successors and Assigns.

(a) The provisions of this Agreement shall be binding upon and inure to the benefit of the parties to this Agreement and their respective successors and permitted assigns.

(b) The Owner/Operator may not assign or otherwise transfer any of its rights or obligations under this Agreement without the prior written consent of DOE. DOE will determine if it is in the best interest of the Government to recognize a named third party as successor at interest to this Agreement. DOE reserves the right to request all requisite information to make this determination including: eligibility information as defined in the U.S. Department of Energy Guidance for the Civil Nuclear Credit Program. Consent to assign this Agreement is at DOE's sole discretion.

(c) In the event that DOE does not consent to the assignment of this agreement, DOE will adjust or recapture credits as DOE deems appropriate.

SECTION 6.10. No Third-Party Beneficiaries.

Nothing in this Agreement, whether express or implied, nor any action taken hereunder shall be construed to create any duty, liability, or standard of care to any Person not a signatory to this Agreement and their respective successors and assigns, nor is anything in this Agreement intended to relieve or discharge obligations or liability of any third-party, nor give any third-person any rights of subrogation or action against any signatory to this Agreement.

SECTION 6.11. Disputes.

Except as otherwise provided in this contract, any dispute concerning a question of fact arising under this Agreement which is not disposed of by agreement shall be decided by the Contract Management Division Director, Department of Energy Office of Nuclear Energy.

SECTION 6.12. Counterparts.

This Agreement may be executed in one or more duplicate counterparts and when signed by all of the parties shall constitute a single binding agreement.

IN WITNESS WHEREOF, the parties to this Agreement have caused this Agreement to be executed and delivered by their respective officers or representatives hereunto duly authorized as of the date first written above.

[NAME OF OWNER/OPERATOR]

____
Name:
Title:

U.S. DEPARTMENT OF ENERGY

____
Name:
Title:

<u>Exhibit A</u>
to Civil Nuclear Credit Agreement

DEFINITIONS

"<u>Actual Enhancement Capital Cost</u>" means the total actual enhancement capital cost of the Nuclear Reactor for the same fiscal year of that as the Payment Certificate, calculated consistent with the methods used to determine Projected Enhancement Capital Cost.

"<u>Actual Revenue</u>" means the total actual revenue of the Nuclear Reactor for the same fiscal year of that as the Payment Certificate, calculated consistent with the methods used to determine Projected Revenue.

"<u>Actual Sustaining Capital Cost</u>" means the total actual sustaining capital cost of the Nuclear Reactor for the same fiscal year of that as the Payment Certificate, calculated consistent with the methods used to determine Projected Sustaining Capital Cost.

"<u>Affiliate</u>" means with respect to any Person, any other Person that directly or indirectly Controls, or is under common Control with, or is Controlled by, such Person.

"<u>Agreement</u>" means the Civil Nuclear Credit Agreement between [____________] and the U.S. Department of Energy.

"<u>Anti-Terrorism Order</u>" means Executive Order No. 13,224, 66 Fed. Reg. 49,079 (2001), issued by the President of the United States of America (Executive Order Blocking Property and Prohibiting Transactions With Persons Who Commit, Threaten to Commit, or Support Terrorism).

"<u>Applicable Law</u>" means, with respect to any Person, any constitution, statute, law, rule, regulation, code, ordinance, treaty, judgment, order or any published directive, guideline, requirement or other governmental rule or restriction which has the force of law, by or from a court, arbitrator or other Governmental Authority having jurisdiction over such Person or any of its Properties, whether in effect as of the Effective Date of this Agreement or as of any date hereafter.

"<u>Award Period</u>" means the period beginning October 1, 2022, up to and including September 30, 2026.

"<u>Capital Adjustment</u>" is defined in Section 2.4.4.

"<u>Credit Adjustment</u>" is defined in Section 2.4.4.

"<u>Bankruptcy Code</u>" means Title 11 of the United States Code entitled "Bankruptcy."

"<u>Bankruptcy Law</u>" means the Bankruptcy Code and any similar federal, state or foreign law for the relief of debtors, conservatorship, bankruptcy, general assignment for the benefit of creditors, moratorium, rearrangement, receivership, insolvency, reorganization or similar debtor relief laws of the U.S. or other applicable jurisdictions from time to time in effect and any similar federal, state or foreign law for the relief of debtors affecting the rights of creditors generally.

"Award Period Financial Projections" are the projections delivered pursuant to Section 2.4.1.

"Buy American Provisions" means Section 1605 of Title XVI of Division A of the Recovery Act 2 C.F.R. Sections 176.140 and 176.160, Office of Management and Budget's Initial Implementing Guidance for the Recovery Act, M 09 10 (February 18, 2009) and Updated Implementing guidance for the Recovery Act, M 09 15 (April 3, 2009) and, in each case, any amendment, supplement or successor thereto, including any relevant regulation or guidance that may be issued by DOE that has the force of law.

"CCR" means the Central Contractor Registration database, established in accordance with the Federal Acquisition Streamlining Act of 1994.

"Certification Application" means the application and all supporting documentation submitted to DOE in accordance with the Guidance for the Civil Nuclear Credit Program and 42 U.S.C. § 18753(c)(1).

"CNC Program" is defined in the recitals.

"Control" means the power, directly or indirectly, to direct or cause the direction of the management or business or policies of a Person (whether through the ownership of voting securities or partnership or other ownership interests, by contract, or otherwise); provided that "controlling", "controlled", and similar constructions shall have corresponding meanings.

"Corrupt Practices Laws" means (i) the Foreign Corrupt Practices Act of 1977 (Pub. L. No. 95-213, §§101-104), as amended, and (ii) any equivalent U.S. or foreign Applicable Law.

"Credits" is defined in the recitals.

"Davis-Bacon Act" means Subchapter IV of Chapter 31 of Part A of Subtitle II of Title 40 of the United States Code, including and as implemented by the regulations set forth in Parts 1, 3 and 5 of title 29 of the Code of Federal Regulations.

"Debarment Regulations" means all of the following:

the Government-wide Debarment and Suspension (Non-procurement) regulations (Common Rule), 53 Fed. Reg. 19204 (May 26, 1988),

Subpart 9.4 (Debarment, Suspension, and Ineligibility) of the Federal Acquisition Regulations, 48 C.F.R. 9.400 - 9.409, and

the revised Government-wide Debarment and Suspension (Non-procurement) regulations (Common Rule), 60 Fed. Reg. 33037 (June 26, 1995).

"DOE" is defined in the recitals.

"Environmental Laws" means any Applicable Law in effect as of the Effective Date or thereafter, and in each case as amended, regulating, relating to or imposing obligations, liability or standards of conduct concerning or otherwise relating to (a) environmental impacts (including but not limited to impacts on cultural resources) resulting from the use of the Project Site or environmental conditions present on, in or under the Project Site, (b) pollution, protection of human or animal health or safety or the environment, including flora and fauna, or Releases or threatened Releases of pollutants, contaminants, chemicals, radiation or industrial, toxic or hazardous substances or wastes, including without limitation Hazardous Substances, or (c) the generation, manufacture, processing, distribution, use, treatment, storage, recycling, disposal, transport, or handling of pollutants, contaminants, chemicals, or industrial, toxic or hazardous substances or wastes, including without limitation Hazardous Substances.

"Event of Default" means any of the events described in Section 5.2.

"Fiscal year" means the 12-month accounting period for the United States government beginning on October 1 and ending on September 30 of the following calendar year.

"FOIA" means the Freedom of Information Act, 5 U.S.C. § 552.

"Foreign Asset Control Regulations" means the United States Trading with the Enemy Act, as amended, or any of the foreign assets control regulations of the United States Treasury Department (31 C.F.R. Subtitle B, Chapter V, as amended), or any ruling issued thereunder or any enabling legislation or Presidential Executive Order granting authority therefore.

"FY 2023 Credits" is defined in Section 2.2.

"FY 2024 Credits" is defined in Section 2.2.

"FY 2025 Credits" is defined in Section 2.2.

"FY 2026 Credits" is defined in Section 2.2.

"Governmental Approval" means any approval, consent, authorization, license, permit, order, certificate, qualification, waiver, exemption, or variance, or any other action of a similar nature, of or by a Governmental Authority, including any of the foregoing that are or may be deemed given or withheld by failure to act within a specified time period.

"Governmental Authority" means any federal, state, county, municipal, or regional authority, or any other entity of a similar nature, exercising any executive, legislative, judicial, regulatory, or administrative function of government.

"Governmental Judgment" means with respect to any Person, any judgment, order, decision, or decree, or any action of a similar nature, of or by a Governmental Authority having jurisdiction over such Person or any of its properties.

"Hazardous Substance" means any hazardous or toxic substances, chemicals, materials, pollutants or wastes defined, listed, classified or regulated as such in or under any Environmental Laws, including (i) any petroleum or petroleum products (including gasoline, crude oil or any fraction thereof), flammable explosives, radioactive materials, asbestos in any form that is or could become friable, urea formaldehyde foam insulation and polychlorinated biphenyls, (ii) any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "extremely hazardous wastes," "restricted hazardous wastes," "toxic substances," "toxic pollutants," "contaminants" or "pollutants," or words of similar import, under any applicable Environmental Law and (iii) any other chemical, material or substance, import, storage, transport, use or disposal of, or exposure to or Release of which is prohibited, limited or otherwise regulated under, or for which liability is imposed pursuant to, any Environmental Law.

"IIJA" is defined in the Recitals.

"Internal Revenue Code" means The United States Internal Revenue Code of 1986, as amended from time to time, and the regulations promulgated and rulings issued thereunder. Section references to the Internal Revenue Code are to the Internal Revenue Code as in effect at the Effective Date and any subsequent provisions of the Internal Revenue Code, amendatory thereof, supplemental thereto or substituted therefor.

"Knowledge" means the actual knowledge of any Principal Persons of the Owner/Operator or any knowledge that should have been obtained by any Principal Person of the Owner/Operator upon reasonable investigation and inquiry.

"MWh" means Megawatt-hours.

"Nuclear Reactor" means the nuclear power reactor unit(s) that have received a notice that it is considered a Certified Nuclear Reactor by the Secretary of Energy in accordance with 42 U.S.C. § 18753(c)(2)(B).

"OFAC" means the Office of Foreign Assets Control, agency of the U.S. Department of the Treasury under the auspices of the Under Secretary of the Treasury for Terrorism and Financial Intelligence.

"Organizational Documents" means with respect to any Person, (a) to the extent such Person is a corporation, the certificate or articles of incorporation and the by-laws of such Person, (b) to the extent such Person is a limited liability company, the certificate of formation or articles of formation or organization and operating or limited liability company agreement of such Person and (c) to the extent such Person is a partnership, joint venture, trust or other form of business, the partnership, joint venture or other applicable agreement of formation or organization and any agreement, instrument, filing or notice with respect thereto filed in connection with its formation or organization with the applicable Governmental Authority in the jurisdiction of its formation or organization and, if applicable, any certificate or articles of formation or organization or formation of such Person.

"Owner/Operator" means ________________________.

"Patriot Act" means the Uniting and Strengthening America by Providing Appropriate Tools Required to Intercept and Obstruct Terrorism Act of 2001, and all regulations promulgated thereunder.

"Payment Certificate" is defined in Section 2.4.1.

"Person" means any individual, firm, corporation, company, voluntary association, partnership, limited liability company, joint venture, trust, unincorporated organization, Governmental Authority, committee, department, authority or any other body, incorporated or unincorporated, whether having distinct legal personality or not.

"Principal Persons" means any officer, director, beneficial owner of 10% or more of equity interests that are not publicly traded securities, other natural person (whether or not an employee) with primary management or supervisory responsibilities over the Owner/Operator or the Nuclear Reactor or who has critical influence on or substantive control over the Nuclear Reactor, and each of their respective successors or assigns.

"Prohibited Jurisdiction" means any jurisdiction that:

is subject to U.S. or multilateral economic or trade sanctions in which the U.S. participates, including the trade sanctions and economic embargoes administered by OFAC;

has been designated by the Secretary of the Treasury under Section 311 or 312 of the Patriot Act, as warranting special measures due to money laundering concerns; or

has been designated as non-cooperative with international anti-money laundering principles or procedures by an intergovernmental group or organization of which the U.S. is a member, such as the Financial Action Task Force on Money Laundering, and with which designation the U.S. representative to the group or organization continues to concur.

"Prohibited Person" means any person or entity that is:

named, identified, or described on the list of "Specially Designated Nationals and Blocked Persons" (Appendix A to 31 CFR chapter V) as published by OFAC at its official website, http://www.treas.gov/offices/enforcement/ofac/sdn/, or at any replacement website or other replacement official publication of such list;

named, identified or described on any other blocked persons list, designated nationals list, denied persons list, entity list, debarred party list, unverified list, sanctions list or other list of individuals or entities with whom U.S. persons may not conduct business, including lists published or maintained by OFAC, lists published or maintained by the U.S. Department of Commerce, and lists published or maintained by the U.S. Department of State;

debarred or suspended from contracting with the U.S. government or any agency or instrumentality thereof;

debarred, suspended, proposed for debarment with a final determination still pending, declared ineligible or voluntarily excluded (as such terms are defined in any of the Debarment Regulations) from contracting with any U.S. federal government department or any agency or instrumentality thereof or otherwise participating in procurement or nonprocurement transactions with any U.S. federal government department or agency pursuant to any of the Debarment Regulations;

indicted, convicted or had a Governmental Judgment rendered against it for any of the offenses listed in any of the Debarment Regulations;

subject to U.S. or multilateral economic or trade sanctions in which the U.S. participates;

owned or controlled by, or acting on behalf of, any governments, corporations, entities or individuals that are subject to U.S. or multilateral economic or trade sanctions in which the U.S. participates; or

an Affiliate of a Person listed above.

"Projected Enhancement Capital Cost" shall be equal to the amount of the projected enhancement capital costs submitted by the Owner/Operator for the Certification Application and Bid of the Nuclear Reactor for the same fiscal year as that of the Payment Certificate.

"Projected Revenue" shall be equal to the amount of the projected revenue submitted by the Owner/Operator for the Certification Application and Bid of the Nuclear Reactor for the same fiscal year as that of the Payment Certificate.

"Projected Sustaining Cost" shall be equal to the amount of the projected sustaining capital costs submitted by the Owner/Operator for the Certification Application and Bid of the Nuclear Reactor for the same fiscal year as that of the Payment Certificate.

"Prudent Industry Practice" shall mean those practices, methods, equipment, specifications and standards of safety and performance, as are commonly accepted in the nuclear power generation industry as good, safe and prudent practices in connection with the design, construction, operation, maintenance, repair and use of the Project. "Prudent Industry Practice" as defined herein does not necessarily mean one particular practice, method, equipment specification or standard in all cases, but is, instead, intended to encompass a broad range of acceptable practices, methods, equipment specifications and standards. "Prudent Industry Practice" shall include the applicable operating policies, standards, criteria, practices and/or guidelines of FERC, NERC, NRC, the Nuclear Reactor's relevant regional transmission organization or independent systems operator, and any other Governmental Authority.

"Release" means disposing, discharging, injecting, spilling, leaking, leaching, dumping, pumping, pouring, emitting, escaping, emptying, seeping, placing and the like, into or upon any land or water or air, or otherwise entering into the environment.

"Required Approvals" means all Governmental Approvals and other consents and approvals of third parties necessary or required under Applicable Law or any Contractual Obligation for (a) the due execution, delivery, or performance by the Owner/Operator of this Agreement; (b) the operation or maintenance of the Nuclear Reactor; or (c) the Owner/Operator's ownership of the Nuclear Reactor.

"Revenue Adjustment" is defined in Section 2.4.4.

"Taxes" means all taxes, levies, imposts, duties, deductions, charges or withholdings imposed by any Governmental Authority, including any interest, penalties or additions thereto imposed in respect thereof.

"Uprate" means any investment to increase the generating capacity of the Nuclear Reactor.

"Voucher" is defined in Section 2.3.

EXHIBIT M

U.S. Department of Energy Guidance for the Civil Nuclear Credit Program
Revision 1

June 30, 2022
~~April 19, 2022~~

Guidance Issue Date	April 19, 2022
Guidance Revision 1 Date	June 30, 2022
Deadline for submission of Certification Application and Sealed Bids	September 6, 2022 ~~May 19, 2022~~ ~~Thirty (30) days after issuance of Guidance~~

Red text indicates additions to the April 19, 2022, Guidance; strikethroughs indicate deletions from the April 19, 2022, Guidance.

Table of Contents

I. General Announcement

The U.S. Department of Energy (DOE) is publishing this Guidance for the Civil Nuclear Credit Program (CNC Program), enacted by Section 40323 of the Infrastructure Investment and Jobs Act (IIJA), Public Law 117-58, signed November 15, 2021, also known as the Bipartisan Infrastructure Law.

The IIJA is a once-in-a-generation investment in infrastructure, which will grow a more sustainable, resilient, and equitable economy through enhancing U.S. competitiveness in the world, creating good jobs, and ensuring stronger access to economic and other benefits for disadvantaged communities. The IIJA appropriates more than $62 billion to DOE[1] to deliver a more equitable clean energy future for the American people.

As part of this effort, the IIJA authorizes and appropriates $6 billion for Fiscal Years 2022 through 2026 to establish the CNC Program to prevent closures of nuclear power plants by providing financial support for existing Nuclear Reactors projected to cease operations due to economic factors.[2]

As implemented through this Guidance, the CNC Program will make meaningful progress towards a carbon pollution-free electricity sector by 2035, help "deliver an equitable, clean energy future, and put the United States on a path to achieve net-zero emissions, economy-wide, by no later than 2050"[3] to the benefit of all Americans.

Nuclear power currently provides 52 percent of the nation's clean electricity, and the current fleet of reactors are a vital resource to achieve a 100 percent carbon pollution-free electricity sector by 2035 and net-zero emissions economy-wide by 2050. Shifting energy markets and other economic factors have already resulted in the closure of 12 commercial reactors across the United States since 2013.[4] These closures have led to an increase in carbon emissions, poorer air quality, and the loss of thousands of high-paying jobs.[5] The CNC Program is a critical element of meeting clean energy goals by helping to preserve the existing nuclear fleet and the clean energy it provides.

This Guidance describes the timelines, deliverables, and other requirements for Owners or Operators of Nuclear Reactors that are projected to cease operations due to economic factors to submit Certification Applications to be eligible to become Certified Nuclear Reactors, and instructions on formulating and submitting sealed Bids to be eligible to receive Credit allocations. This Guidance

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[1] U.S. Dep't of Energy, *DOE Fact Sheet: The Bipartisan Infrastructure Deal Will Deliver For American Workers, Families and Usher in the Clean Energy Future* (Nov. 9, 2021) https://www.energy.gov/articles/doe-fact-sheet-bipartisan-infrastructure-deal-will-deliver-american-workers-families-and-0.

[2] *See* 42 U.S.C. § 18753.

[3] Exec. Order No. 14,008, 86 Fed. Reg. 7619 (Jan. 27, 2021) (Tackling the Climate Crisis at Home and Abroad).

[4] Cong. Research Serv., R46820*, U.S. Nuclear Power Plant Shutdowns, State Interventions, and Policy Concerns* at 3 (June 10, 2021), https://crsreports.congress.gov/product/pdf/R/R46820/2.

[5] U.S. Energy Information Administration, *Fort Calhoun becomes fifth U.S. nuclear plant to retire in past five years*, (Oct. 31, 2016), https://www.eia.gov/todayinenergy/detail.php?id=28572; The Nuclear Decommissioning Collaborative, Inc., *Socioeconomic Impacts from Nuclear Power Plant Closure and Decommissioning: Host Community Experiences, Best Practices and Recommendations* (Oct. 2020), Socioeconomic-Impacts-from-Nuclear-Power-Plant-Closure-and-Decommissioning-15-October-2020-Final.pdf (decommissioningcollaborative.org).

will clarify the certification criteria, application content requirements, evaluation process and methodologies, eligibility periods, and anticipated timeline of the CNC Program.

This Guidance is applicable to the first in a series of annual Award Periods that DOE will conduct to implement the CNC Program. The first Award Period is limited to Nuclear Reactors that are projected to cease operations imminently and with a high degree of certainty. Accordingly, this Award Period will be implemented on a more rapid timeline than future Award Periods and will be limited to Nuclear Reactors that have already publicly announced their intention to cease operations. Future Award Periods—including for Award Period 2, which is estimated to commence in the first quarter of FY 2023—will be executed over a longer timeline and will not be limited to Nuclear Reactors that have publicly announced their intentions to cease operations. Nuclear reactors that are eligible to apply for the first Award Period but nonetheless wish to wait until the second Award Period are free to do so.

For this Award Period, DOE is accepting Certification Applications and Bid submissions as a single submission from April 19, 2022, to September 6, 2022. ~~May 19, 2022~~ Application information and Bid submissions must be submitted at https://proposalscnc.inl.gov by 23:59 MDT, September 6, 2022 ~~May 19, 2022~~, or they will not be considered timely filed for the first Award Period and will not be evaluated.

A detailed Certification Application and Bid submission checklist for Award Period 1 is included in **APPENDIX A** to this Guidance. DOE may revise the information requested and other aspects of the application process for future Award Periods, including additional consideration of emissions impact, labor, and environmental justice considerations.

II. Authority

The authorizing statute for the CNC Program is Section 40323 of the IIJA, codified at 42 U.S.C. § 18753.

The CNC Program is neither procurement nor financial assistance and will not be administered pursuant to those authorities. The CNC Program furthers a public purpose and DOE's determination under the program to certify Applicants and select bids does not constitute an acquisition process nor an acquisition of goods or services. DOE is implementing the CNC Program pursuant to authorities granted in 42 U.S.C. § 18753.

III. Acronyms and Definitions

A. Acronyms

CNC means Civil Nuclear Credit.

DOE means the U.S. Department of Energy.

eGRID means EPA's Emissions & Generation Resource Integrated Database.

EGU means Electric Generating Unit.

EIA means the U.S. Energy Information Administration.

EPA means the U.S. Environmental Protection Agency.

EUCG means the Electric Utility Cost Group.

FERC means the Federal Energy Regulatory Commission.

GAAP means Generally Accepted Accounting Principles.

IIJA means the Infrastructure Investment and Jobs Act.

ISO means an Independent System Operator.

NRC means the U.S. Nuclear Regulatory Commission.

RTO means Regional Transmission Organization.

SEC means the U.S. Securities and Exchange Commission.

B. Definitions

Air Pollutants means the criteria air pollutants and greenhouse gases provided in EPA's eGRID. Air pollutants include carbon dioxide (CO_2), nitrogen oxides (NO_x—available both at annual resolution and only for ozone season), sulfur dioxide (SO_2), methane (CH_4), nitrous oxide (N_2O), and fine particulate matter (PM2.5).

Annual Payments mean the amount of Payments the Selected Nuclear Reactor submitted in a Payment Certificate to the DOE by the Selected Nuclear Reactor for the prior 12-month period.

Applicant means an entity or collection of entities, at least one of which is an Owner or Operator of an NRC-licensed Nuclear Reactor that submits a Certification Application. Multiple Owners or Operators of one Nuclear Reactor are permitted to submit a joint Certification Application as an Applicant, but under no circumstances will multiple Certification Applications for the same Nuclear Reactor be accepted.

Award Period means a period of four (4) consecutive years ~~Fiscal Years~~ that begins on the date of Final Award Selection. ~~with the first Fiscal Year in which Credits are allocated to the Certified Nuclear Reactor.~~ For the purposes of Certification Application calculations, Applicants may assume that Award Period 1 will be October 1, 2022, through September 30, 2026. Award Period 2 will be October 1, 2023, through September 30, 2027, and so on.

Award Year means a Fiscal Year within the Award Period. For the purposes of Certification Application calculations, Applicants may assume that Award Year 1 of Award Period 1 will be October 1, 2022, through September 30, 2023. Award Year 2 of Award Period 1 will be October 1, 2023, through September 30, 2024, and so on.

Auction means the process outlined in Section X.B of this guidance.

Average Domestic Fuel Content means the average percentage of known domestic content across the four fuel supply chain steps as outlined in Section VII.G of this guidance.

Bid means the information Applicant provides in the bid sheet, as outlined in Appendix C of this guidance.

Bid Cap means the estimated average operating loss in dollars per megawatt hour as calculated per Section VII.D and submitted with Applicant's Certification Application.

Bidder means a Certified Nuclear Reactor that submits a valid bid.

Certification Application means an application submitted to DOE by an Applicant for a Nuclear Reactor that is projected to cease operations due to economic factors to become a Certified Nuclear Reactor in accordance with this Guidance and 42 U.S.C. § 18753(c)(1).

Certification Decision means the process as set out in Section XI.A.

Certified Nuclear Reactor means a Nuclear Reactor for which the Applicant has been provided a Notice of Certification by the Secretary of Energy and is eligible to participate in the Auction.

Committed Megawatt-hours (MWh) means the number of MWh identified in a Certified Nuclear Reactor's sealed Bid for which Credits may be allocated.

Conditional Award Decision means the initial decision to award Credits to a Selected Nuclear Reactor, subject to the finalization and execution of the Credit Redemption Agreement review and other conditions that DOE may identify.

Credits means credits allocated to an Owner or Operator pursuant to an Auction and represented by a voucher for the sum total of Payments the Selected Nuclear Reactor may receive over the Award Period, listed separately by the maximum amount of Payments the Selected Nuclear Reactor may redeem for each individual Award Year.

eGRID Subregion means one of the 27 subregions in the United States used by the Emissions & Generation Resource Integrated Database (eGRID) as defined by the EPA. *See* https://www.epa.gov/system/files/images/2022-01/egrid2020_subregion_map.png.

Enhancements means capital expenditures for life-extension, uprates, or for other purposes as defined by the EUCG.

Final Award Selection means the date upon which the Selected Nuclear Reactor is awarded Credits.

Fiscal Year means the period beginning October 1 and ending on September 30 of the following calendar year.

Notice of Certification means the notice provided in accordance with Section XI.A.

Nuclear Reactor means each individual nuclear power reactor unit seeking Credits, except where the Applicant attests that there are multiple reactor units at a given site with substantially identical or interdependent financial situations, ownership and operations structures, and costs in which case the Applicant may submit a single Certification Application for multiple units. In the latter circumstances, the Applicant should delineate in the single Certification Application the attributes of each individual reactor unit.

Owner or Operator means an individual entity that is, or will be during the applicable Award Period, authorized to possess, use, or operate a reactor unit at the Nuclear Reactor under an NRC facility license.

Payment Certificate means the form submitted by the Selected Nuclear Reactor to DOE at the completion of a Fiscal Year requesting redemption of the completed Fiscal Year's Credit.

Payments means the U.S. dollar payments made to a Selected Nuclear Reactor over the Award Period upon the redemption of Credits.

Post-Award Period means the four-year period immediately following the Award Period.

Secretary means the Secretary of the U.S. Department of Energy or such officers or employees of the U.S. Department of Energy as designated by the Secretary of the U.S. Department of Energy.

Selected Nuclear Reactor means a Certified Nuclear Reactor that is selected for allocation of Credits via Auction pursuant to the sealed bid process.

State-Supported Reactor means a Nuclear Reactor that receives a payment from a State zero-emission credit, a State clean energy contract, or any other State program with respect to that Nuclear Reactor.

Sustaining Capital Costs are costs for the replacement or refurbishment of major equipment, as defined by the EUCG survey.

Uprate means any investment to increase the generating capacity of the Nuclear Reactor.

IV. Program Timeline

DOE intends to conduct the first credit award cycle for Nuclear Reactors on the timeline set forth below in Table 1. The identified activities and dates are subject to revision but are intended to provide guidance on the sequence of program activities from the initial certification of Nuclear Reactors to payment of Credits through the first Award Period. For those Nuclear Reactors anticipating future participation, the timeline for the second award cycle is included in Table 2 below.

Note that, over the life of the program, DOE has the authority to obligate up to $6,000 million of Credits that were appropriated in IIJA. Of that amount, DOE has authority and appropriations sufficient to obligate $1,200 million of Credits for the first Award Year of the first Award Period. Any Credits allocated in excess of $1,200 million during the first Award Period would be conditioned on the availability of appropriations and availability of funds for future Award Years.

To be clear, however, DOE does not anticipate awarding the full available amount in the first award cycle. In deciding how much to award in the first award cycle, DOE will consider, among other factors, the following objectives: (a) allocating Credits to as many Certified Nuclear Reactors as possible, to the maximum extent practicable, (b) maximizing the cost effective use of available funding, and (c) ensuring that sufficient funding remains to provide a reasonable opportunity for Nuclear Reactors to be awarded Credits in future award cycles during the term of the CNC Program.

Table 1. Civil Nuclear Credit Program Timeline – First Award Cycle

Action	Date
DOE issues Guidance and requests Certification Applications and Sealed Bids	April 19, 2022
Deadline for submission of Certification Applications and Sealed Bids for Award Period 1	September 6, 2022 ~~May 19, 2022~~ ~~Thirty (30) days after issuance of Request for Certification Applications.~~
DOE notifies Selected Nuclear Reactors of Conditional Award Decision for Award Period 1	As soon as thirty (30) days after deadline for submission of Certification Applications and Sealed Bids for Award Period 1
DOE executes Credit Redemption Agreement, makes Final Award Selection and issues Credits for Award Period 1 to Selected Nuclear Reactors	As soon as reasonably practicable after the announcement of Conditional Award Decisions for Award Period 1 ~~October 1, 2022~~
Selected Nuclear Reactors submit Payment Certificates for Payments of Annual Credits for Award Year 1	~~On or before December 30, 2023~~ ~~(~~90 days after close of Award Year 1 ~~Fiscal Year)~~
Selected Nuclear Reactors submit Payment Certificates for Payments of Annual Credits for Award Year 2	~~On or before December 30, 2024~~ ~~(~~90 days after close of Award Year 2 ~~Fiscal Year)~~

Selected Nuclear Reactors submit Payment Certificates for Payments of Annual Credits for Award Year 3	~~On or before December 30, 2025~~ ~~(~~90 days after close of Award Year 3 ~~Fiscal Year)~~
Selected Nuclear Reactors submit Payment Certificates for Payments of Annual Credits for Award Year 4	~~On or before December 30, 2026~~ ~~(~~90 days after close of Award Year 4 ~~Fiscal Year)~~

Table 2. Civil Nuclear Credit Program Timeline – Second Award Cycle

Action	**Date**
DOE issues Updated Guidance and Announces Open Application Period for Award Period 2	Estimated publication first quarter of Fiscal Year 2023
Deadline for submission of Certification Applications	Thirty (30) days after issuance of Request for Certification Applications.
Certified Nuclear Reactors submit sealed Bids for Credits	Thirty (30) days after notification to the Nuclear Reactors of certification designation.
DOE notifies Selected Nuclear Reactors of Conditional Award Decision for Award Period 2	Thirty (30) days after submission of sealed bids.
DOE executes Credit Redemption Agreement, makes Final Award Decision and issues Credits for Award Period to Selected Nuclear Reactors	October 1, 2023
Selected Nuclear Reactors submit Payment Certificates for Payments of Annual Credits for Award Year 1	On or before December 30, 2024 (90 days after close of Fiscal Year)
Selected Nuclear Reactors submit Payment Certificates for Payments of Annual Credits for Award Year 2	On or before December 30, 2025 (90 days after close of Fiscal Year)
Selected Nuclear Reactors submit Payment Certificates for Payments of Annual Credits for Award Year 3	On or before December 30, 2026 (90 days after close of Fiscal Year)
Selected Nuclear Reactors submit Payment Certificates for Payments of Annual Credits for Award Year 4	On or before December 30, 2027 (90 days after close of Fiscal Year)

V. Who May Apply?

In addition to the Certification requirements described in Section VI ~~**Error! Reference source not found.**~~, an Applicant eligible to apply under this Guidance must establish that it (1) meets the imminence requirement described in this Section, and (2) that it will compete in a competitive electricity market during the Award Period.

1. In accordance with the discretion granted to the Secretary in 42 U.S.C. § 18753(c)(1)(A), the Secretary has determined that it is appropriate to require Applicants in the first award cycle to submit documentation demonstrating they have publicly announced their intention to cease

operations. Specifically, to ensure the first award cycle of the CNC Program is directed toward Nuclear Reactors most at risk of imminent closure, the Applicant must demonstrate that it has made a public filing on or before November 15, 2021, the date of enactment of the IIJA, announcing its intention to permanently cease operations of the Nuclear Reactor on or before September 30, 2026. By limiting eligibility in the first award cycle as set forth in this Guidance, DOE will direct Credits to those Nuclear Reactors most at risk of imminent closure in the very near term, while retaining Credits for future award cycles to assist as many additional Nuclear Reactors as possible that are projected to cease operation due to economic factors in a future period. This approach is consistent with many of the public comments DOE received in response to the DOE's Request for Information.[6]

An Owner or Operator will be deemed to have announced an intention to cease operations if prior to November 15, 2021, it has (1) made a public filing (not later withdrawn or contradicted) that the Nuclear Reactor will cease operations prior to September 30, 2026, or (2) made a public filing (not later withdrawn or contradicted) that the Nuclear Reactor will cease operations prior to September 30, 2026 if specific and verifiable market conditions occur, and can establish through its Certification Application that such market conditions have occurred or will occur prior to September 30, 2026.

Public filings may include, but are not limited to, Certifications of Permanent Cessation of Power Operations filed with the NRC, SEC 10-K or 10-Q filings, or filings with state regulators.

The DOE wishes to emphasize that the requirement to submit a public filing noticing the Nuclear Reactor's premature retirement is limited to the first award cycle. Such public filings or statements will be neither necessary nor sufficient for subsequent award cycles.

2. The Applicant must demonstrate that the Nuclear Reactor competes in a competitive electricity market during the Award Period.[7] An Applicant can do so by showing that the Nuclear Reactor will receive a material amount of its total revenue ~~50 percent or more of total revenue~~ from sources that are exposed to electricity market competition. These sources include but are not limited to:

    a. Sales of energy, capacity and/or ancillary services into organized wholesale markets;
    b. bilateral agreements with non-affiliated purchasers on competitively negotiated terms.

~~Notwithstanding the amount of revenue a Nuclear Reactor receives as a result of clearing in energy, capacity or ancillary services markets, or through bilateral agreements, a Nuclear Reactor for which an Applicant recovers more than 50 percent of the Nuclear Reactor's cost~~

[6] Notice of Intent and Request for Information Regarding Establishment of a Civil Nuclear Credit Program, 87 Fed. Reg. 8570 (Feb. 15, 2022).
[7] 42 U.S.C. § 18753(a)(1)(A).

~~from cost-of-service regulation or regulated contracts will not be deemed to compete in a competitive electricity market.~~

The Applicant should address this requirement by (1) providing the most recent completed year's revenue sources, percentage of total revenue represented by each source, and identification of which sources are derived from competitive electricity markets as described above, ~~and~~ (2) identifying what, if any, changes to its existing commercial and/or corporate organizational arrangements affecting the sources of revenues it anticipates will occur between the most recent completed year and the conclusion of the Award Period, and (3) demonstrating that cost-of-service regulatory pathways that may be available to reduce the amount of revenue exposed to market risk such as tracking or balancing accounts, construction work in progress (CWIP) policies, or other rate recovery methods for the Nuclear Reactor are unavailable, exhausted, or already accounted for.

VI. Certification Requirements

An eligible Applicant's Nuclear Reactor, as defined in Section V, must meet the following minimum criteria to be eligible for certification:

1. The Applicant has demonstrated that, at the time of the submission of the Certification Application, the Nuclear Reactor is projected to cease operations due to economic factors;

2. The Applicant has demonstrated that Air Pollutants would increase if the Nuclear Reactor were to cease operations and be replaced with other types of power generation;

3. The NRC has provided the Secretary with reasonable assurance that the Nuclear Reactor will continue to be operated in accordance with its current licensing basis (as defined in 10 C.F.R. § 54.3);

4. The NRC has provided the Secretary with reasonable assurance that the Nuclear Reactor poses no significant safety hazards; and

5. The Applicant has provided a timely, completed Certification Application, including:

    a. A detailed plan to sustain operations at the conclusion of the Award Period. This plan must include a planning basis of either receiving additional Credits at a reduced level than anticipated for the Award Period or one where no additional Credits are received;

    b. Information on the source of the Nuclear Reactor's uranium and the location of where it is or will be processed and manufactured into fuel, including information on the countries of origin of the uranium planned to be used in the Award Period to the extent known, where it was/will be converted and enriched, and where the fuel was/will be fabricated, to the extent this is known or can be reasonably estimated; and

c. Confirmation the Applicant will use best efforts to maximize the procurement of uranium that is produced in the United States and the procurement of conversion services, enrichment services, and fabrication into fuel assemblies in the United States as set out in Section 4.9 of the Credit Redemption Agreement in Appendix B.

VII. Guidance on Certification Application and Criteria

C. Basic Application Requirements

A Certification Application must be filed during the application period defined by DOE in this Guidance (Table 1) at https://proposalscnc.inl.gov.

Certification Applications must be properly completed and submitted to DOE, meaning:

- Each Certification Application must include all information set forth in each deliverables section of this Guidance, which are summarized in the checklist in Appendix A;

- Applicants must respond to any request for supplemental information relating to their application within five (5) business days of receiving such a request from DOE. Failure to respond within the 5-day period will disqualify the Certification Application from further consideration;

- DOE will perform review of the Certification Applications to ensure all information is submitted as necessary. Incomplete Certification Applications will be disqualified from further consideration; and

- DOE's review of the Certification Application will include consideration of whether Applicant's economic factors, including operational and market risk, are reasonable and appropriate, including:

    - Whether it is the type of cost or risk generally recognized as ordinary and necessary for the conduct of the Applicant's business or the Nuclear Reactor's performance;

    - Generally accepted sound business practices, arm's-length bargaining, and Federal and State laws and regulations;

    - The requirements for the continued operation of the Nuclear Reactor both during the Award Period and in the Post-Award Period; and

    - Any significant deviation from Applicant's established practices or previously developed financial assessments.

In the event DOE finds one or more of an Applicant's economic factors unreasonable or inappropriate, DOE will request the Applicant to submit supplemental information or revised economic factors based on that finding.

Unless otherwise specified, Certification Applications should conform to the following general criteria:

- Calculate all requests for information past or future from the date of the Certification Application;
- Unless noted otherwise herein, information should be presented on an annual basis rather than averaged or aggregated over the time period indicated;
- Represent all costs in nominal dollars;
- Provide sources of all data; and
- Provide copies of all workbooks, with no locked content and all formulae intact, which are used to generate the attachments provided in applications.
- Files should be named according to the following format. If a naming convention and format is not provided for a part of a deliverable, the information will be requested as part of the application submission form on the website.
    - File naming Format: UEI Number_Reactor Name_Section Name from Checklist_Year if Required_Workbook
    - Examples:
        - 742A11324601_Chicago Pile 1_Operating License.pdf
        - 742A11324601_Chicago Pile 1_Historic Expenditures_1942.pdf
        - 742A11324601_Chicago Pile 1_Projected Operating Costs_2023_Workbook

Each Applicant is required to:

- Be registered in the System for Award Management (SAM) at https://www.sam.gov before submitting its Certification Application;
- Provide a Unique Entity Identifier (UEI) in its Certification Application; and
- Continue to maintain an active SAM registration with current information at all times during which it has an active Certification Application or Credit Redemption Agreement.

DOE may not certify a Nuclear Reactor or allocate Credits to an Applicant until the Applicant has complied with all applicable UEI and SAM requirements and, if an Applicant has not fully complied with the requirements by the time DOE is ready to make such an award, the DOE may determine the Applicant is not qualified to receive the award and use that determination as a basis for denying certification.

Finally, DOE anticipates that as it gains further experience with the certification process described herein, it may revise and refine the specific information and data requested and evaluated in future certification cycles.

D. Economic Factor Guidance

<u>*Narrative Description*</u>: The Certification Application must include a narrative description with references to supporting documentation and economic calculations that clearly and in detail identifies the basis for the claim that the Nuclear Reactor is projected to cease operations due to economic reasons. The narrative should:

- Describe key factors, assumptions, and inputs used in calculation of average annual operating loss, the sensitivity of the calculation to these key factors, and the relative certainty associated with the projection of each cost and revenue component;

- Describe the key factors, assumptions, and inputs used in allocation of any overhead costs, shared costs, transfer-pricing, or intercompany services charged between the entities in the chain of ownership of the Owners or Operators of the Nuclear Reactor, including parent companies, holding companies, subsidiaries, and affiliates;

- Justify the assumptions and inputs used in the calculation of operating loss;

- If internal projections for electricity market prices are used, include a comparison and discussion of any significant deviation to any available and forwards or futures market prices relevant to the Nuclear Reactor, or other public or commercially available price projections may be used;

- Describe and justify any substantial differences between historical financial trends and projections included in the average annual operating loss calculation;

- Describe and justify any costs that would be avoidable if the Nuclear Reactor ceases operations but that would be necessary to sustain operations through the Award Period and after the Award Period consistent with the Post-Award Period Plan. Such costs may include but are not limited to maintenance and capital projects deferred in anticipation of retirement, retention of skilled labor, and any unavoidable outages associated with extending the operating life of the Nuclear Reactor;

- Describe how the method or outcome of the estimation of projected average annual operating loss is consistent with that used for other decision-making or why there would be a difference in the method or outcome of calculation;

- Describe any contractual, tariff, or regulatory obligation that the Nuclear Reactor has undertaken to sell energy, capacity, ancillary services, or environmental attributes for future delivery, including the period of performance and the consequences of non-performance due to cessation of operations;

- Clearly state the operational and market risks relevant to the Nuclear Reactor, present and justify the methodology used to monetize those risks, and describe any current hedging contracts; and

- Identify and describe how the expenditures and risks included in the projected operating loss would be avoided or reduced by retirement of the Nuclear Reactor. Include a description and estimate of what costs the Nuclear Reactor's decommissioning trust fund would cover.

The Applicant must demonstrate that the Nuclear Reactor is projected to operate at an average annual operating loss during the Award Period. The application must include the details of the calculation, supporting information, and quantitative estimates for both the previous five (5) calendar years and the next four (4) fiscal years of the Award Period for the following categories:

- Revenue streams. All revenue from any market or out-of-market sales or service. This should include:
  - Electricity and related sales, including short-term power sales, long-term power contracts, capacity payments, and other power services (e.g., ancillary services) relevant to the Nuclear Reactor;
  - Non-electricity market products or services (e.g., heat energy, desalinated water, hydrogen, environmental attributes sold on the voluntary market);
  - Amounts collected through cost-of-service regulation or regulated contracts; and
  - All payments and tax credits from State, regional, and Federal support programs. If such funds, or a portion of such funds, would cease if an award is made by the CNC Program, then this expected change should be reflected in an additional calculation along with supporting documentation identifying the relevant existing statute or regulation.

- Expenditures. Any expenditure that would be avoided if the Nuclear Reactor were to retire. This may include expenditures in the categories listed below:
  - Operating & maintenance costs;
  - Fuel costs;
  - Going forward capital costs, depreciated according to Generally Accepted Accounting Principles (GAAP); and
  - Other costs not covered in categories above

- Operational and market risks. Monetization of operational and market risk faced over the Award Period that may result in early closure of a Nuclear Reactor may be calculated using reasonable and appropriate methods and included in the assessment of future operating loss. These risks include but are not limited to risk factors that would affect future costs and revenues, such as:

- Market risk arising from volatility in energy and capacity market prices, resulting in lower than projected revenues; and
- Operational risk arising from unplanned outages or equipment failures resulting in lost revenues, performance penalties, contractual obligations, in additional to the risk of new regulatory mandates or fuel supply challenges.

Deliverables: The Applicant must provide other supporting documentation as listed in the deliverables section below that indicates the Nuclear Reactor is at risk of closure due to economic factors or relevant to the decision to retire the Nuclear Reactor. This includes any other documents, presentations, or financial analyses developed for internal or external purposes from the preceding five (5) years used in decision-making (e.g., rate cases, tax filings, insurance statements, investor presentations, filings with the SEC, presentations to management).

(i) Economic Factor Deliverables

1. The narrative as described in Section VII.D above.

   Name File: UEI Number_Reactor Name_Economic Narrative
   Format: PDF

2. Historical annual costs, revenue, and operating loss or gain calculation. The cost categories, sub-categories, and methodology are intended to align with those used for the Electric Utility Cost Group (EUCG) survey. Include:

   a. A table of annual historical expenditures and revenues for the Nuclear Reactor for the previous five (5) calendar years. Include line items for the following categories and sub-categories:
      i. Revenue:
         1. Electricity sales into organized markets;
         2. Electricity sales via out-of-market contracts such as power purchase agreements or hedges;
         3. Capacity revenues;
         4. Other electricity product revenues such as reserves or ancillary services;
         5. Non-electricity related revenues including sales of environmental attributes;
         6. Retail rates or amounts collected through cost-of-service rate recovery;
         7. Federal, state, or other governmental tax credits, grants, subsidies, or payments;
         8. Any other revenues, including a description of their sources.

      ii. Fuel costs associated with procuring the uranium fuel, including conversion, enrichment, and fabrication, reported and allocated consistent with the

Electric Utility Cost Group (EUCG) methodology.

iii. Operating Costs, reported by the following sub-categories:
   1. Engineering, costs for technical work associated with study, design, implementation of plant modifications and for monitoring and testing for standards compliance;
   2. Loss Prevention, costs for providing site security and access control, safety, emergency preparedness, and related costs;
   3. Materials and Services, costs arising from inventory planning, control, optimization, and procedures;
   4. Fuel Management, costs of managing fuel procurement, conversion, enrichment, and fabrication not captured in the Fuel costs reported in ii above;
   5. Operations costs from using equipment, chemistry and environmental monitoring and controls, radiation protection, and processing of low-level waste;
   6. Support Services, costs for business services such as human resources, pensions and benefits, payroll taxes, nuclear officers and executives, and employee incentives;
   7. Training, costs arising for development and implementation of training programs; and
   8. Work Management, costs for planned, periodic, preventative maintenance of structures, systems, and components.

iv. Capital costs as spent, reported by the following sub-categories:
   1. Enhancements, as defined in Section III.B;
   2. Sustaining, as defined in Section III.B ;
   3. Regulatory, costs required to meet current or new regulations;
   4. Infrastructure, costs to build or replace assets on site not associated with power generation
   5. Capital Spares, costs for spares of major equipment; and
   6. Information Technology, costs for software, computer equipment, telecommunications, and other related equipment.

v. Other costs of ownership attributable to the Nuclear Reactor, not covered by the categories above:
   1. Non-dedicated costs, such as allocated overhead;
   2. Property taxes and payments in lieu of taxes (PILOTs);
   3. Legal costs, fines, penalties resulting from violations or failure to comply with Federal, State, local, and foreign laws;
   4. Lobbying and political activity costs;[8] and

[8] The Credit Redemption Agreement prohibits the use of proceeds of the Credits for costs related to lobbying or political activity.

5. Any other cost not covered above, with a description of such costs.

b. Annual net electricity generation for the previous five years, in units of MWh, as reported to the Energy Information Administration on form 923.

c. The number of planned and unplanned outages over the previous five years including the duration of each outage.

d. A calculation of historical annual net operating gain or loss over the previous five years in $/MWh, using the revenue and cost data provided in point (a) and the generation from point (b).

Name File: UEI Number_Reactor Name_Historic Annual Operating Conditions_Year
Format: Excel

3. Projected annual average operating loss for each Fiscal Year of the Award Period. If the Nuclear Reactor is scheduled to retire before or during the Award Period, assume the Nuclear Reactor stays operational during the Award Period and include estimates of costs necessary to maintain operations. Include:
Name File: UEI Number_Reactor Name_Projected Operating Conditions_Year
Format: Excel
   a. Projected annual generation in MWh for the Award Period.

   b. Assumptions about the projected planned and unplanned outages over the four-year Award Period.

   c. Projected annual revenues in total dollars for the Award Period, with line items for the categories and subcategories as defined in deliverable 2 above.

   d. Projected annual costs in total dollars, with line-items for the categories and subcategories and using the same methodology as defined in in deliverable 2 above.

   e. Projected annual going-forward capital costs for the Award Period reported in point (c.) above, by the amount annually depreciated or amortized and recorded in accordance with GAAP and consistent with the Owner or Operator’s financial accounting. Include only going-forward capital costs projected to be incurred after date of submission of Certification Application.

   f. Identification of which costs projected above are avoidable costs of retirement. If a cost is partially avoidable by retiring, estimate the fraction that is avoidable. To the extent a cost would be covered by the Nuclear Reactor’s Decommissioning Trust Fund it may be identified as such and considered an avoidable cost of retirement.

   g. Projected monetized annual operating and market risk in dollars. This may include but is not limited to:

   i. Energy and capacity price volatility
   ii. Fuel cost uncertainty
   iii. Energy performance risk
   iv. Capacity performance penalty or buyback risk
   v. New regulatory requirement risk

h. A detailed explanation, including supporting workbooks and calculations, of how the costs of operational risks and market risks were calculated for each Award Year of the Award Period.

Name File: UEI Number_Reactor Name_Risk Explanation_Year
Format: PDF
Name File: UEI Number_Reactor Name_Risk Explanation_Year_Workbook
Format: Excel

i. Projected operating loss over the Award Period. Use only the portion of costs identified as avoidable by retiring in point (c) above. Use the annual amount of going-forward capital costs depreciated or amortized according to GAAP in point (d) above. Calculate in terms of:

   i. Annual dollars;
   ii. Total dollars for the Award Period; and
   iii. Average $/MWh (total dollars divided by total projected generation over the Award Period). This amount will be the Nuclear Reactor's Bid Cap.[9]

Name File: UEI Number_Reactor Name_Projected Annual Operating Loss
Format: Excel

4. Supporting documentation and descriptions:

a. An attestation from the Owner or Operator that the submitted forecasts are consistent with market analysis, operations cost assessments, risk monetization and analyses, and other standards used by the Owner or Operator in their standard business process associated with the Nuclear Reactor.

Name File: UEI Number_Reactor Name_Appendix E
Format: PDF

b. Any analyses, presentations, or assessments of past or projected financial performance of the Nuclear Reactor by the Applicant from the previous five (5) years. These include but are not limited to information made by the Applicant for investors, equity analysts, rating agencies, internal management, or to the SEC.

Name File: UEI Number_Reactor Name_Financial Performance
Format: PDF

c. Identify and describe any obligations/commitments under which the Nuclear Reactor has operated in the past five (5) years and/or currently operates in any relevant RTO/ISO markets, the duration of such obligations and/or commitments,

[9] *See* 42 U.S.C. § 18753(d)(1)(A).

and supporting documentation and calculations.
Name File: UEI Number_Reactor Name_Obligations
Format: PDF

d. Provide a list of all active and anticipated contracts for capacity, energy, ancillary services, or environmental attributes and/or energy supply by the Nuclear Reactor. Include a description of the product provided, counterparty, type of market, period of performance, and any provisions addressing termination or non-performance by the seller. Be prepared to provide documentation upon request.
Name File: UEI Number_Reactor Name_List of Contracts
Format: PDF

e. Provide the annual average Nuclear Reactor bid price in the annual capacity auctions over the past five (5) years in $/MW, including all capacity auction bids by year, as well as any cost data submitted to relevant RTO/ISO and the relevant RTO/ISO Independent Market Monitor as part of a unit-specific review process.
Name File: UEI Number_Reactor Name_Capacity Auctions
Format: PDF

Name File: UEI Number_Reactor Name_Capacity Auctions_Workbook
Format: Excel

f. A list of all data provided by the Applicant and related to the Nuclear Reactor to the FERC and NRC, as well as State utility and environmental regulators, over the past five (5) years. Be prepared to provide documentation upon request.
Name File: UEI Number_Reactor Name_Data Provided to FERC - NRC
Format: PDF

g. A list of all audits performed by internal employees, commissioned, or performed by any governmental agency on the Nuclear Reactor over the past five (5) years. Be prepared to provide documents upon request.
Name File: UEI Number_Reactor Name_Audits Completed
Format: PDF

h. A statement of all the assumptions used in the revenue and cost projections. Include projected annual average bulk power market prices including electricity and capacity prices used in the calculation projected annual revenues for the relevant ISO/RTO markets. If internal projections are used, provide a comparison to any relevant forward or futures market prices, or other public or commercially available projections and describe any substantive differences.
Name File: UEI Number_Reactor Name_Assumptions Statement
Format: PDF

5. Additional calculations and documentation for State-Supported Reactors:

a. A description of and citation to the state statute, regulation, or public contract that describes how payments from state programs would be reduced or replaced entirely

if the Nuclear Reactor is allocated Credits.
Name File: UEI Number_Reactor Name_State Program Information
Format: PDF

b. A recalculation of the average annual operating loss as described in deliverable 3.i with the payments from state programs appropriately reduced or removed as defined by the applicable state statute, regulation, or public contract.

Name File: UEI Number_Reactor Name_State Funding Operating Loss
Format: Excel

6. Other economic factors relevant to Nuclear Reactor retirement, including:

a. The remaining useful life of the generating Nuclear Reactor.

b. Information on any planned license extension requests for the Nuclear Reactor, including any financial modeling done in association with such planning.

Name File: UEI Number_Reactor Name_License Extension Requests
Format: PDF
Name File: UEI Number_Reactor Name_License Extension Requests_Workbook
Format: Excel

c. Estimates of the costs that would be incurred by the Applicant to shut down the Nuclear Reactor, including identifying the portion of costs that would be funded by the Nuclear Reactor's decommissioning trust funds and the costs would be funded by the Applicant.

Name File: UEI Number_Reactor Name_Costs for Shut Down
Format: Excel

d. Demonstrate the impact on ownership and Applicant's earnings during each of the next four (4) years, assuming the Nuclear Reactor shuts down. Include any financial impact(s) to the parent organization.

Name File: UEI Number_Reactor Name_Shut Down Impacts_Year
Format: PDF

e. Describe the status of decommissioning trust funds for the Nuclear Reactor as of the date of the application, include decommissioning status reports filed with the NRC, and identify any shortfall of decommissioning trust funds resulting from early retirement of the Nuclear Reactor.

Name File: UEI Number_Reactor Name_Decommissioning Fund
Format: PDF

f. Identify and describe all of the Applicant's commitments and obligations to the NRC that would be required in advance of a unit shutdown.

Name File: UEI Number_Reactor Name_Decommissioning Reports
Format: PDF

g. Indicate the earliest date the Applicant could access decommissioning trust funds in excess of three (3) percent for the Nuclear Reactor.

h. Indicate the earliest date the Applicant could realistically shut down the Nuclear Reactor per NRC, relevant RTO/ISO, or other commitments and obligations.

E. Emissions Impact Guidance

The Applicant must demonstrate via calculation that if the Nuclear Reactor were to cease operations, emissions of air pollutants would increase over the Award Period. The Certification Application must include the details of the calculation, supporting information, and quantitative estimates using public information available in EPA's eGRID for each air pollutant:[10]

- Historical annual emissions. The Certification Application must include both information available in eGRID regarding historical emissions for the eGRID subregion where the Nuclear Reactor is located and historical emissions at the plant level for the Nuclear Reactor as well as a calculation of historical emissions if the Nuclear Reactor were to have ceased operation as specified in Section VII.E.1 below.

- Annual regional estimates of electric generating unit (EGU) emissions for each Air Pollutant should the Nuclear Reactor cease operation in the next four (4) years. For purposes of the Certification Application for this award period, Applicants should calculate future emissions should the Nuclear Reactor cease operation as the product of current average emissions per megawatt hour generated by all generation sources in an eGRID region multiplied by the annual megawatt hours projected to be generated by the Nuclear Reactor if it continued to operate. The Applicant should provide this calculation for pollutants that EPA has available in eGRID as specified in Section VII.E(i) below:

- DOE is not requiring the Applicant to provide air quality modeling results. If the Applicant has easily accessible information, e.g., completed internal or public reports or data with information that would be useful for estimating the potential incremental air pollutants that would result if the Nuclear Reactor were to cease operations, the Applicant is encouraged to submit this information. This information would be in addition to the information required to be submitted from eGRID and cannot substitute for the other data requirements in this section.

(i) Emissions Impact Deliverables

1. Applicants must provide a spreadsheet that includes the following information:

Name File: UEI Number_Reactor Name_Emissions Spreadsheet
Format: Excel

[10] The eGRID data file is regularly updated. *See* EPA, *eGRID Download Data*, https://www.epa.gov/egrid/download-data (last visited Apr. 17, 2022). The eGRID data explorer can be found here: EPA, *eGRID Data Explorer*, https://www.epa.gov/egrid/data-explorer (last visited Apr. 17, 2022). At the time of publication, CO_2, NO_x (annual), NO_x (ozone season), SO_2, CH_4, and N_2O information can be found in the main data links.

For the requested data for CO_2, NO_x (annual), NO_x (ozone season), SO_2, CH_4, and N_2O in this section, the Applicant must use the eGRID2020 data file for the year 2020 data, the eGRID2019 data file for the year 2019 data, and the eGRID 2018v2 data file for the year 2018 data.[11] For the requested data for $PM_{2.5}$ in this section, the Applicant must use the eGRID2018 PM2.5 data file.[12]

a. A quantitative estimate using EPA's eGRID of total emissions (in tons) of each Air Pollutant in the eGRID subregion where the Nuclear Reactor is located. Three (3) years of annual estimates must be provided for the years 2018–2020 for CO_2, NO_x (annual), NO_x (ozone season), SO_2, CH_4, and N_2O and one year of annual estimates for the year 2018 must be provided for PM2.5.

b. A quantitative estimate using EPA's eGRID of total emissions (in tons) of each Air Pollutant at the plant level for the Nuclear Reactor.

c. A quantitative estimate using EPA's eGRID of output emission rates (in lb/MWh) for CO_2, NO_x (annual), NO_x (ozone season), SO_2, CH_4, and N_2O for all fuels[13] for the eGRID subregion where the Nuclear Reactor is located for the years 2018, 2019, and 2020.

d. A quantitative estimate using EPA's eGRID of output emission rates (in lb/MWh) in eGRID for $PM_{2.5}$ for all fuels[14] for the eGRID subregion where the Nuclear Reactor is located for the year 2018.

e. The Facility ID, Plant State, eGRID subregion, and Total Generation (in MWh) at the plant level for the Nuclear Reactor for the years 2018, 2019, and 2020.

f. A quantitative estimate of historical annual emissions of each Air Pollutant should the Nuclear Reactor have ceased operation, calculated by multiplying the output emission rates in (c) or (d) by total generation in (e) for the Nuclear Reactor for each year of requested data in (a) – (e) for the specific Air Pollutant.

g. A quantitative estimate for each Air Pollutant of future emissions should the Nuclear Reactor cease operation defined as the product of the annual emission rate for each Air Pollutant either averaged across three (3) years from (c) or for $PM_{2.5}$ the 2018 annual emission rate from (d) multiplied by annual projected generation for the next

[11] *See* EPA, *eGRID Download Data*, https://www.epa.gov/egrid/download-data (last visited Apr. 17, 2022).
[12] *See* EPA, *eGRID Related Materials*, https://www.epa.gov/egrid/egrid-related-materials#eGRID%20PM2 (last visited Apr. 17, 2022) ($PM_{2.5}$ data can be found in the eGRID2018 PM2.5 data file).
[13] The term "all fuels" is a term used in EPA's eGRID Data Explorer. *See* EPA, *eGRID Data Explorer*, https://www.epa.gov/egrid/data-explorer (last visited Apr. 17, 2022). If viewing an eGRID data file (eGRID_Data.xls), the correct unit is found in the eGRID subregion sheet (e.g., SRL20, SRL19, SRL18, etc.) and entitled "eGRID subregion annual [air pollutant] total output emission rate (lb/MWh)." Per EPA's 2020 Technical guidance, the output emission rates are calculated as total annual adjusted emissions divided by annual net generation. *See* EPA, *The Emissions & Generation Resource Integrated Database: eGRID Technical Guide with Year 2020 Data* at 27 (2022), https://www.epa.gov/system/files/documents/2022-01/egrid2020_technical_guide.pdf.

four (4) years (i.e., four annual estimates for each Air Pollutant) of the Nuclear Reactor.

2. Provide a narrative, with supporting data if available, discussing which generation assets would be likely to fulfill the capacity and energy requirements currently served by the Nuclear Reactor if the Nuclear Reactor were to shut down. Compare and describe any differences between the expected replacement generation emissions rates with the historical emissions rates reported in 1c above. Include consideration of known or expected future capacity additions in the relevant eGRID region, Federal and applicable regional, state, and local energy policies, as well as anticipated market trends, that may result in increased clean energy supply, energy efficiency, and electrification. Include assumptions, supporting data, and source information.

Name File: UEI Number_Reactor Name_Shutdown Emissions Narrative
Format: PDF

3. Provide a list of submissions of data and documentation provided by the Applicant and related to the Nuclear Reactor and its surrounding property to state and Federal regulators, including permits, permit violations, enforcement actions, outstanding environmental compliance requirements, and remedial actions planned, ongoing, and completed over the past five (5) years to demonstrate that all standards and requirements are being met. DOE may require additional documentation of the Applicant.

Name File: UEI Number_Reactor Name_List of Regulatory Submissions
Format: PDF

F. NRC Assurance

Upon request from the DOE, the NRC will indicate to the DOE whether they have reasonable assurance that the Nuclear Reactor will continue to operate in accordance with their current licensing basis (as defined in 10 C.F.R. § 54.3) and pose no significant safety hazards.

G. Uranium and Fuel Source Guidance

The Applicant must provide known information on the source of produced uranium, and the location where the uranium is converted, enriched, and fabricated into fuel assemblies, for the Nuclear Reactor for the four-year period for which Credits are sought. The IIJA requires the Secretary to give priority in certification to a Nuclear Reactor that uses, to the maximum extent available, uranium that is produced, converted, enriched, and fabricated into fuel assemblies in the United States. The information provided here will inform the Bid ranking and Auction as described in Section X.

Information provided by the Applicant with respect to the U.S. supply chain content of uranium loaded or under contract for the Nuclear Reactor should be based on the actual knowledge of the responsible officer(s) of the Applicant or any knowledge that should have been obtained by such person(s) upon reasonable investigation and inquiry.

The Applicant will be required to report actual U.S. supply chain content by fuel component in its annual filing made with DOE, compared to the information submitted in its application, for any Nuclear Reactor for which DOE has awarded Credits to the Applicant, and DOE will audit such information.

(i) Uranium and Fuel Source Deliverables

1. Information on the known source of the fuel to be used in the Nuclear Reactor during the Award Period.
    a. Provide to the extent known, information on the location of:
        i. the source of procured uranium;
        ii. where the uranium was converted;
        iii. where the uranium was enriched;
        iv. where the uranium was fabricated into fuel assemblies;

    b. Provide separate information as appropriate for fuel currently loaded in the reactor and will be used during the Award Period, and fuel under contract as of the date of the bid and planned to be loaded in the reactor and used during the Award Period.

Name File: UEI Number_Reactor Name_Uranium Sources
Format: PDF

    c. Provide any supporting documentation for the information reported above.

Name File: UEI Number_Reactor Name_Uranium Sources_Supporting
Format: PDF, Excel

2. A calculation of the domestic content for produced uranium, conversion, enrichment, and fabrication services related to the nuclear fuel that would be used in the Nuclear Reactor during the Award Period.

    a. Provide the percentage of:
        i. uranium that was produced in the United States
        ii. uranium converted at a facility located in the United States
        iii. uranium enriched at a facility located in the United States
        iv. uranium fabricated into fuel assemblies at a facility located in the United States

    b. Include separate calculations as appropriate for produced uranium, conversion, enrichment, and fabrication for nuclear fuel currently loaded in the Nuclear Reactor that would be used during the Award Period and produced uranium, conversion, enrichment, and fabrication for nuclear fuel that is under contract as of the date of the bid and planned to be loaded in the Nuclear Reactor during the Award Period.

c. Estimate the percentage of total fuel consumed in the Nuclear Reactor during the Award Period that is currently loaded in the Nuclear Reactor and that is under contract and planned to be loaded in the Nuclear Reactor.

d. If the Applicant does not have sufficient knowledge to determine the U.S. supply chain content for any element of the uranium supply chain in above, report that element as zero percent domestic content.

e. If the Applicant owns or operates more than one Nuclear Reactor for which it is submitting a bid, the Applicant must submit in its Certification Application the U.S. supply chain content attributable specifically to the Nuclear Reactor for which it is seeking Credits.

3. A calculation of the Average Domestic Fuel Content.

Name File: UEI Number_Reactor Name_Uranium Content
Format: Excel

a. Separately calculate the average of the four percentages provided in deliverable (1) for fuel currently loaded in the Nuclear Reactor and used in the Award Period and fuel under contract that would be consumed in the Nuclear Reactor during the Award Period.

b. Calculate the weighted average of the two averages calculated in point (a) above, weighting by the percentages of each fuel represents of the total amount of fuel consumed in the Nuclear Reactor during the award period as calculated in deliverable 1(c) above. This is the Average Domestic Fuel Content.

H. Post-Award Period Operations Plan

Applicants must submit a detailed plan with references to supporting documentation and calculations describing how the Nuclear Reactor would sustain operations in the Post-Award Period (I) without receiving additional Credits; or (II) with the receipt of additional Credits of a lower amount than the Credits allocated during the Award Period.

The Post-Award Period Operations Plan must provide sufficient detail to enable DOE to assess how changes to the Nuclear Reactor's business model translate to lower costs and/or higher revenue sufficient to sustain operations beyond the Award Period. In particular, the Applicant must describe any changes to its business model that result in a lower operating loss than that estimated in Section VII.D. All information requested in this section refers to the four-year period immediately following the Award Period.

(i) Post-Award Period Operations Plan Deliverables

1. A narrative description of the Applicant's plan to sustain operations in the Post-Award Period (I) without receiving additional Credits; or (II) with the receipt of additional Credits of a

lower amount than the Credits allocated during the Award Period. Applicant's analysis should be consistent with the economic factor calculations submitted in accordance with Section VII.D.

Name File: UEI Number_Reactor Name_Post-Award Sustainability Plan
Format: PDF

2. Estimate of revenue in $/MWh that the Nuclear Reactor must achieve to sustain operations in the Post-Award Period given forecasts of future market conditions in the absence of additional Credits.

3. Any existing policy barriers that prevent the Applicant from making changes to its business model or operations that would otherwise contribute to the Nuclear Reactor's ability to sustain operations after the Award Period.

Name File: UEI Number_Reactor Name_Policy Barriers
Format: PDF

I. Workforce and Labor Considerations

In alignment with the policy set forth in Sections XV and XVI, Applicants must submit a brief description of their plan with clear milestones that align to the award period to provide their workforce with high quality jobs, the free and fair opportunity to join a union, and family supporting wages. Additionally, Applicants should submit a Diversity, Equity, Inclusion, and Accessibility plan with clear milestones that align to the Award Period.

(i) Workforce and Labor Considerations Deliverables

1. A written narrative describing workforce development and retainment efforts and plans, as well as labor standards and practices, along with clear milestones that align with the Award Period. Please include information on any of the following, as applicable:
    a. Please include the following baseline data:
        i. Jobs that would be created and/or protected by CNC Program support;
        ii. Workforce demographics including average wage by job category; and
        iii. For each of the past three years, the number of employees who were eligible to join a union and the number of employees who are union members.
    b. Union neutrality agreements;
    c. Project labor agreements (PLAs) and community workforce agreements (CWAs);
    d. Local hire practices;
    e. Utilization of registered apprenticeship programs or other joint labor-management training programs;
    f. Assurances to prevent worker misclassification as independent contractors rather than employees;
    g. Professional certifications and licenses;
    h. Responsible contractor screen to ensure compliance with labor laws and labor standards; and
    i. Improved access to employment opportunities for underrepresented and

disadvantaged communities by:

i. community workforce agreements with specified targets for local hire of priority populations; and
ii. first-source hiring from supported community-based pre-apprenticeship programs.

Name File: UEI Number_Reactor Name_Workforce Narrative
Format: PDF

2. Diversity, Equity, Inclusion, and Accessibility (DEIA) Plan that describes the actions the Nuclear Reactor is currently taking or will take to foster a welcoming and inclusive environment, support people from underrepresented groups, advance equity, encourage the inclusion of individuals from these groups, and to ensure equal access to employment and participation in activities for people with disabilities. DEIA plan should also describe the extent to which the Nuclear Reactor benefits underserved communities.

Name File: UEI Number_Reactor Name_DEIA Plan
Format: PDF

J. Community Engagement and Impact

In alignment with the policies set forth in Section XVI, Applicants must submit a brief description of existing community engagement plans along with clear milestones that align with the Award Period and identify additional community engagement activities related to the continued operation of the facility, including any targeted outreach to environmental justice communities or other underserved populations. At a minimum, the community engagement plan should identify communities in the vicinity, describe specific outreach to these communities, explain engagement opportunities, summarize feedback received, and outline steps to address such feedback.

(i) Community Engagement and Impact Deliverables

1. A written narrative describing existing and proposed community engagement efforts related to the ongoing operation of the facility, along with clear milestones that align with the Award Period including the following information:
   a. Communities in the vicinity of the facility;
   b. Financial support to communities and community organizations in the vicinity of the facility, including local taxes, PILOTs, and other contributions;
   c. Description of outreach to external non-project partners/stakeholders including Community Based Organizations (CBO), Disadvantaged Communities (DAC),[14]

[14] The Justice40 initiative, created by Executive Order 14008, establishes a goal that 40% of the overall benefits of certain federal investments flow to (DACs). The Justice40 Interim Guidance provides a broad definition of DACs. *See Memorandum on Interim Implementation of Guidance for the Justice40 Initiative*, M-21-28 (Jul 20, 2021), https://www.whitehouse.gov/wp-content/uploads/2021/07/M-21-28.pdf#:~:text=The%20following%20Interim%20Implementation%20Guidance%20for%20the%20Justice40,existing%20authorities%20in%20order%20achieve%20the%2040-percent%20goal. Additional J40 guidance is forthcoming and will be reflected in the CNC Program.

federally recognized Indian Tribes, state and local governments, economic development organizations, and labor representatives;

d. Current and future engagement opportunities;
e. Feedback received from stakeholders and federally recognized Indian Tribes
f. Steps to address feedback where necessary

Name File: UEI Number_Reactor Name_Community Engagement Narrative
Format: PDF

2. Worker and community transition plans to prepare for the eventual closure of the plant.

Name File: UEI Number_Reactor Name_Closure Transition Plans
Format: PDF

K. Credit Redemption Agreement

Applicants that are selected for a Conditional Award of Credits will be required to enter into a Credit Redemption Agreement in order for DOE to make a Final Award. The Credit Redemption Agreement will govern the relationship of DOE and the Selected Nuclear Reactor following final redemption of Credits in exchange for Payments. A draft copy of the Credit Redemption Agreement is attached as Appendix B.

DOE will not execute any Credit Redemption Agreement or make any Final Award until it has completed its obligations pursuant to the National Environmental Policy Act (NEPA),[15] Section 106 of the National Historic Preservation Act,[16] and any other obligations pursuant to relevant environmental laws (e.g., Endangered Species Act).[17]

Each Applicant is directed to include with its Certification Application a redline draft showing any requested changes to the Credit Redemption Agreement with margin notations explaining the basis for its requested changes, or to affirmatively state that it has no requested changes to the Credit Redemption Agreement. Any Applicant comments should be directed at improving the clarity of the Credit Redemption Agreement and promoting the effective administration of the Credits. Applicants are expressly directed not to request a change that alters the commercial terms set forth in this Guidance or in the Credit Redemption Agreement. DOE at its discretion may accept or reject the requested changes to the Credit Redemption Agreement, or determine to conduct negotiation of any requested changes. DOE's decision to extend a Conditional Award to an Applicant does not mean that DOE has accepted or will accept any of the redline edits that the Applicant has included with its Application.

Name File: UEI Number_Reactor Name_CRA Redline
Format: MS Word

[15] 42 U.S.C. § 4321 *et seq*.
[16] 54 U.S.C. § 306108.
[17] 16 U.S.C. § 1531 *et seq*.

VIII. Review of Applications for Certification

Certification Applications will be evaluated using the certification criteria set forth in Section VII of this Guidance. The evaluation is an assessment of the Applicant against the criteria.

DOE uses independent judgment to certify Applicants whose applications meet the criteria. The evaluation of the Certification Applications together with the recommendations of any external reviewers DOE deems appropriate to consult will be considered by DOE in performing an integrated assessment of the Certification Applications to determine which meet the certification criteria. The certification designation will be documented in the Certification Decision.

IX. Guidance on Bid Submissions

While both the Certification Application and Bid for Award Period 1 are due on or before September 6, 2022 ~~May 19, 2022~~, only those Nuclear Reactors that are certified will be eligible to participate in the Bid process and Auction. The Bids of Applicants who are not certified shall remain sealed and will not be returned by DOE. Moreover, certification does not guarantee that DOE will allocate Credits to a Certified Nuclear Reactor.

The Applicant shall submit its sealed Bid for Award Years 1–4 via the bid sheet provided in Appendix C, including, for each Award Year, the Credits desired, committed generation, and the average Credit price per megawatt-hour. As specified in 42 U.S.C. § 18753(d)(1)(A), the Applicant's average price per megawatt-hour of the Credits desired shall not exceed the average projected annual operating loss in dollars per megawatt-hour the Applicant submitted in its Certification Application.

The Applicant will also submit its Average Domestic Fuel Content calculated as directed in Section VII.G. This will be used to adjust the bid ranking during the auction as described in Section X below.

An Applicant that submits a Certification Application for multiple reactor units located at the same site may choose to submit a single bid covering all reactor units contained in the Certification Application or individual bids for each reactor unit. If the Applicant chooses to submit individual bids for each reactor unit, the Applicant assumes the risk that not all units at the site will clear the auction.

The Applicant must submit a letter certifying that they did not share bid amounts, strategies, or other bidding information with other potential Applicants using the certification in Appendix D.

X. Review of Bids, Auction, and Allocation of Credits

A. Overview

Note that, over the life of the program, DOE has the authority to obligate up to $6,000 million of Credits that were appropriated in IIJA. Of that amount, DOE has authority and appropriations sufficient to obligate $1,200 million of Credits for the first Award Year of the first Award Period. Any Credits allocated in excess of $1,200 million during the first Award Period would be conditioned, in the Credit Redemption Agreement, on the availability of appropriations and availability of funds for future Award Years.

To be clear, however, DOE does not anticipate awarding the full available amount in the first award cycle. In deciding how much funding to award in the first award cycle, DOE will consider, among other factors, the following objectives: (a) allocating Credits to as many Certified Nuclear Reactors as possible, to the maximum extent practicable, (b) maximizing the cost effective use of available funding, and (c) ensuring that sufficient funding remains to provide a reasonable opportunity for Nuclear Reactors to be awarded credits in future award cycles during the term of the CNC Program.

Further, the value of those Credits that are issued but not paid out in accordance with the adjustment mechanisms specified in Section XI.B will remain available for use in future award cycles.

B. Auction Process

Credits will be allocated via a pay-as-bid auction as described here, to allocate Credits to as many Certified Nuclear Reactors as possible as directed by the statute.

The Average Desired Credit Price over the Award Period in dollars per megawatt-hour included in Bids from Certified Reactors will be adjusted downwards to preference Certified Reactors with higher domestic fuel content. This Adjusted Bid Credit Price will only be used to determine the ranking of bids and will be calculated as defined by the formula below.

Adjustment Factor = 1 – (Average Domestic Fuel Content × 0.05)

Adjusted Bid Credit Price = Adjustment Factor × Average Desired Credit Price

Bids will be ranked according to their Adjusted Bid Credit Price in dollars per megawatt-hour from lowest to highest. In the situation that two Bids have the same Adjusted Bid Credit Price, the one with the larger amount of committed generation will be ranked lower. Starting with the lowest ranked Bid, the total Desired Credits in dollars over the Award Period for each Bid will be subtracted from the total Credits available in the auction. This will be repeated for each subsequent Bid until either all Bids are fully allocated or there are insufficient Credits remaining in the auction to fully allocate to the next ranked bid. Subsequent higher ranked bids may be allocated Credits if there are sufficient credits remaining available in the auction to fully allocate to a Bid. Any unused Credits that remain after the first auction and allocation of Credits will be retained by DOE and may be allocated in future auctions.

Nuclear Reactors that are issued Conditional Award Decisions will be publicly announced along with the number of credits allocated and the average $/MWh credit price. Nuclear Reactors that submitted a Bid but were not allocated Credits will not be publicly announced. If a Certified Nuclear Reactor is not allocated any Credits, it may reapply for certification in subsequent award periods.

DOE reserves the right, without qualification, to reject any or all Bids. In the event that (1) fewer than three Nuclear Reactors are Certified in the award cycle, or (2) all Certified Nuclear Reactors in an award cycle share an Owner, Operator, or parent company of an Owner or Operator, DOE reserves the right to select any submitted Bid as a basis for negotiation and award if it determines that acceptance of one or more Bids is not in the public interest.

DOE may modify this auction process described here for future Award Periods and would explain such modifications in updated Guidance published in advance of those Award Periods.

XI. Award Administration Information

A. Award Notices

1. Certification Decision: In accordance with 42 U.S.C. § 18753(c)(2)(B), DOE shall issue a written notice of the Certification Decision to each Applicant with the following content:

    a. a Notice of Certification that the Applicant's Nuclear Reactor is a Certified Nuclear Reactor; or

    b. if the Applicant does not meet the certification requirements of this program, a written notice denying the Certification Application with an explanation of the basis for denial.

2. Conditional Award Decision: The initial announcement of award after DOE has conducted the Auction but prior to Credit Redemption Agreement review and signature by the Selected Nuclear Reactor, is a conditional award decision. Execution of the Credit Redemption Agreement by the Selected Nuclear Reactor and DOE is a necessary precondition of a Final Award Selection.

3. Final Award Selection: The date upon which the Selected Nuclear Reactor's Credit Redemption Agreement becomes effective, and it would be awarded Credits.

B. Payments

1. Credit Voucher. A Selected Nuclear Reactor shall receive Credits in the form of a voucher for Payment. The amount of the Credits will be no more than the product of (a) the price per

megawatt-hour and (b) the committed megawatt-hours of generation for Award Years 1–4, each as set forth in the Selected Nuclear Reactor's Bid. The Award Period covered by the Credits will begin on the date that DOE issues the Final Award Selection.

2. Adjustment of Annual Payments. Payments of Credits will be adjusted downwards if, at the end of an Award Year, either the:

   a. Total actual revenue for the Award Year exceeds the amount of revenue projected for that Award Year in the Nuclear Reactor's Certification Application and Bid; or

   b. Total actual capital expenditures categorized as Enhancements or Sustaining for the Award Year do not exceed the projected expenditures for those two categories for that Award Year as projected in the Nuclear Reactor's Certification and Bid.

   If either one or both of the above cases occur, then the Payments for the Award Year will be reduced according to the formulas below. Capital costs should be reported as the amount annually depreciated or amortized and recorded according to GAAP and not as spent.

   Revenue Adjustment = Actual Revenue – Projected Revenue

   Capital Adjustment = (Projected Enhancement and Sustaining Capital Costs) – (Actual Enhancement and Sustaining Capital Costs)

   Annual Payment
   = Annual Credits –Revenue Adjustment – Capital Adjustment

   The Selected Nuclear Reactor may request adjustment of current and future year Payments, not to exceed the maximum value of the award. DOE may decide whether or not to approve such requests.

3. Request for Payments. A Selected Nuclear Reactor shall submit a Payment Certificate to make a request for Payments. The Payment Certificate shall be submitted to DOE within ninety (90) days after the completion of the applicable Award Year. The Payment Certificate shall include:

   a. The actual generation, costs, revenues for the applicable Award Year, itemized according to the same categories Section VII.D(i);

   b. The amount of Credits in dollars for which payment is requested, adjusted as appropriate according to the equations listed in (2) above;

   c. An attestation from a responsible representative of the Selected Nuclear Reactor that (1) the Selected Nuclear Reactor did not terminate operations during the Award Year that is the subject of the Payment Certificate, together with supporting data that sets forth the capacity factor, availability factor, and megawatt-hours of the Selected Nuclear Reactor for the Award Year, and (2) the Selected Nuclear Reactor would have operated at an annual loss, including risk as used in the Nuclear Reactor's Certification Application, during the Award Year that is the subject of the Payment Certificate in the absence of the allocation of Credits included in the Payment Certificate; and

d. Supporting calculations demonstrating that the Selected Nuclear Reactor would have operated at a loss for the Award Year, prepared in a manner in all material respects consistent with the information and calculations included in the Selected Nuclear Reactor's Certification Application as defined in Section VII.D(i).

4. Payments. DOE shall pay to the Selected Nuclear Reactor, within thirty (30) days of submission by the Selected Nuclear Reactor of a complete Payment Certificate, the amount of Payments supported by the Payment Certificate less any adjustments as described above. Payments for any Award Year is subject to the availability of appropriations for such purpose.

5. Credit Adjustment Requests by the Nuclear Reactor. Section 2.4.3 of the Credit Redemption Agreement identifies limited circumstances under which the Selected Nuclear Reactor may request a shift of Credits allocated between fiscal years. Section 2.5 of the Credit Redemption Agreement describes the process whereby the Selected Nuclear Reactor may request that increased revenues attributable to a project that increases its production of electricity not be factored into the payment adjustment for the applicable fiscal year. The decision whether to accommodate any such request is at the sole discretion of DOE, and in no event will any increase in the total amount of Credits awarded to the Selected Nuclear Reactor be considered.

C. Oversight

1. Annual Reporting Requirements. Not later than thirty (90) days following the completion of an Award Year for which the Nuclear Reactor has been allocated Credits, the Owner or Operator shall provide to DOE an annual report containing the information as set out in Article 3 of the Credit Redemption Agreement.

2. Audit. DOE will audit the Selected Nuclear Reactor as part of DOE's review of the Payment Certificates submitted for Annual Payments as provided in the Credit Redemption Agreement. Such audit may include the operation of the Nuclear Reactor, the financial condition of the Selected Nuclear Reactor, and such other areas of inquiry as determined by DOE. The Selected Nuclear Reactor shall be obligated to cooperate with any such audit as a condition to continued Payments.

D. Recapture

1. Recapture. DOE may recapture the allocation of Credits by canceling all or any portion of the unpaid Credits, if during the Award Period the Selected Nuclear Reactor (a) terminates operations; or (b) does not operate at an annual loss in the absence of the allocation of Credits awarded by DOE. DOE may determine to recapture Credits on the basis of a Payment Certificate

submitted by a Selected Nuclear Reactor, information developed in an audit, or such other information as may become available to DOE from time to time. In addition to canceling all or any portion of the unpaid Credits, DOE may require the Selected Nuclear Reactor to disgorge any Payments previously received if DOE determines that the Payment Certificate contained a material misrepresentation of the status of operations or economic condition of the Selected Nuclear Reactor. DOE shall provide to the Selected Nuclear Reactor written notice of a determination to recapture Credits or Payments. The Credit Redemption Agreement contains further detail regarding recapture.

2. Duration of Credit Awards. A Selected Nuclear Reactor will be allocated Credits for the Award Period, which may be subject to appropriations sufficient to fund such Credits. A Selected Nuclear Reactor may seek to be recertified and receive an award of Credits for one or more subsequent Award Periods following the completion of any applicable Award Period for which it has been awarded Credits. In no event may DOE allocate any Credits after September 30, 2031, but any Credits that have been allocated to a Selected Nuclear Reactor on or before September 30, 2031, pursuant to an Auction completed under the CNC Program and for which appropriated funds are available will be paid out pursuant to the terms of the selected Bid and in accordance with the terms of the CNC Program.

E. Assignment

1. Assignment. A Selected Nuclear Reactor may not assign or otherwise transfer any of its rights or obligations under a Credit Redemption Agreement without the prior written consent of DOE. DOE reserves the right to request all requisite information to make this determination including eligibility information as defined in this Guidance. Consent to assign or transfer is at DOE's sole discretion.

XII. Appeals

Applicants who are not certified or whose bids were not selected may appeal these determinations to the Contract Management Division Director, Department of Energy Office of Nuclear Energy, within ten (10) business days of the Applicant receiving the Certification Determination or bid rejection. These appeals must be in writing and shall contain:

- A concise statement of the ground(s) upon which the Applicant contests the written notice of DOE;
- A copy of the DOE notice; and
- Any data, documentation, or other relevant information supporting a showing by the Applicant that the denial of certification or rejection of bid was inappropriate, incorrect, or otherwise unwarranted.

The Contract Management Division Director shall make a final decision upon this appeal within ten (10) business days and notify the Applicant in writing of the final decision.

XIII. Confidentiality

Security of Certification Applications and Bid submissions are primary considerations. Computer security measures in the evaluation process have been taken. DOE is committed to keeping the number of Certification Applications received and the identities of Applicants and Bidders confidential unless and until a Conditional Award Decision is made. Any external reviewers employed by DOE will execute conflict of interest (COI)/non-disclosure agreements (NDA) to ensure privacy of business practices, trade secrets, or other details that, if revealed, may cause competitive injury. DOE is committed to keeping the number of Certification Applications received and the identities of Applicants and Bidders confidential unless and until a Conditional Award Decision is made.

If a Certification Application includes trade secrets or information that is commercial or financial, or information that is confidential or privileged, it is furnished to the DOE in confidence with the understanding that the information shall be used or disclosed only for evaluation of the Certification Application. Such information will be withheld from public disclosure to the extent permitted by law, including the Freedom of Information Act. Without assuming any liability for inadvertent disclosure, DOE will seek to limit disclosure of such information to its employees and to outside reviewers when necessary for review of the Certification Application or as otherwise authorized by law. This restriction does not limit the DOE's right to use the information if it is obtained from another source.

Full Certification Applications, and other submissions containing confidential, proprietary, or privileged information must be marked as described below. Failure to comply with these marking requirements may result in the disclosure of the unmarked information under the Freedom of Information Act or otherwise. The U.S. Government is not liable for the disclosure or use of unmarked information and may use or disclose such information for any purpose.

The Certification Application and any attachments must be marked as follows and identify the specific pages containing trade secrets, confidential, proprietary, or privileged information:

> **Notice of Restriction on Disclosure and Use of Data:**
>
> Pages [list applicable pages] of this document may contain trade secrets, confidential, proprietary, or privileged information that is exempt from public disclosure. Such information shall be used or disclosed only for evaluation purposes or in accordance with a financial assistance or loan agreement between the submitter and the DOE. The DOE may use or disclose any information that is not appropriately marked or otherwise restricted, regardless of source. [End of Notice]

The header and footer of every page that contains confidential, proprietary, or privileged information must be marked as follows: “Contains Trade Secrets, Confidential, Proprietary, or Privileged Information Exempt from Public Disclosure.” In addition, each line or paragraph containing proprietary, privileged, or trade secret information must be clearly marked with double brackets or highlighting.

XIV. Infrastructure Investment and Jobs Act

The IIJA helps DOE deliver a more equitable clean energy future for the American people by:

- Investing in American manufacturing and workers;
- Expanding access to energy efficiency and clean energy for families, communities, and businesses;
- Delivering reliable, clean, and affordable power to more Americans;
- Building the technologies of tomorrow through clean energy demonstrations; and
- Ensuring that all communities receive the benefits of the transition to a clean energy economy.

Be advised that special terms and conditions may apply to projects funded by the IIJA relating to:

- Reporting, tracking and segregation of incurred costs;
- Reporting on job creation and preservation;
- Publication of non-confidential information on the Internet;
- Access to records by Inspectors General and the Government Accountability Office;
- Protecting whistleblowers and requiring prompt referral of evidence of a false claim to an appropriate inspector general; and
- Certification and Registration.

Recipients of funding appropriated by the IIJA must comply with requirements of applicable Federal, State, and local laws, regulations, DOE policy and guidance, and instructions in this Guidance, unless relief has been granted by DOE.

XV. Job Growth and Quality

Strengthening prosperity—by expanding good, safe jobs and supporting job growth through investments in domestic manufacturing—are key goals set by the President, discussed in depth in his Executive Orders on Ensuring the Future Is Made in All of America by All of America's Workers (E.O. 14005), Tackling the Climate Crisis at Home and Abroad (E.O. 14008), Worker Organizing and Empowerment (E.O. 14025), Boosting Quality of Federal Construction Contracts (E.O. 14063), and Promoting Competition in the American Economy (E.O. 14036).

In keeping with the Administration’s goals, and as an agency whose mission includes strengthening our country’s energy prosperity, the Department of Energy strongly supports investments that improve job quality through the adoption of strong labor standards, support responsible employers, improve job access, foster safe, healthy, and inclusive workplaces and communities, and develop a diverse workforce well-qualified to build and maintain the country's energy infrastructure and grow domestic manufacturing.

As part of the Annual Reporting Requirements, Selected Nuclear Reactors will be required to provide information about how their project will support these goals, specifically:

- The number of individuals employed by the Nuclear Reactor and information on those employee's job classifications, wages, benefits, demographics, veteran status, union representation, and residence; and
- Information on training programs provided to employees, or options for inclusion in employee ownership systems.

XVI. Diversity, Equity, Inclusion and Accessibility and Justice40 Initiative

It is the policy of the Administration that:

> [T]he Federal Government should pursue a comprehensive approach to advancing equity[18] for all, including people of color and others who have been historically underserved, marginalized, and adversely affected by persistent poverty and inequality. Affirmatively advancing equity, civil rights, racial justice, and equal opportunity is the responsibility of the whole of our Government. Because advancing equity requires a systematic approach to embedding fairness in decision-making processes, executive departments and agencies must recognize and work to redress inequities in their policies and programs that serve as barriers to equal opportunity.
>
> By advancing equity across the Federal Government, we can create opportunities for the improvement of communities that have been historically underserved, which benefits everyone.[19]

As part of this whole of government approach, this Guidance seeks to encourage the participation

[18] The term "equity" means the consistent and systematic fair, just, and impartial treatment of all individuals, including individuals who belong to underserved communities that have been denied such treatment, such as Black, Latino, and Indigenous and Native American persons, Asian Americans and Pacific Islanders and other persons of color; members of religious minorities; lesbian, gay, bisexual, transgender, and queer (LGBTQ+) persons; persons with disabilities; persons who live in rural areas; and persons otherwise adversely affected by persistent poverty or inequality. *See* Exec. Order No. 13,985, 86 Fed. Reg. 7009 (Jan. 20, 2021).

[19] Exec. Order No. 13,985, 86 Fed. Reg. 7009 (Jan. 20, 2021) (Advancing Racial Equity and Support for Underserved Communities Through the Federal Government).

of underserved communities[20] and underrepresented groups. As part of the Annual Reporting Requirements, Selected Nuclear Reactors will be required to submit a DEIA Plan that describes the actions the Selected Nuclear Reactor is currently taking or will take to foster a welcoming and inclusive environment, support people from underrepresented groups, advance equity, encourage the inclusion of individuals from these groups, and to ensure equal access to employment and participation in activities for people with disabilities. DEIA plan should also describe the extent to which the Nuclear Reactor benefits underserved communities.

Related to the DEI Plan, the Justice40 Initiative[21] aims to provide 40 percent of the overall benefits of certain Federal investments—including investments in clean energy and energy efficiency— to Disadvantaged Communities (DAC)[22] to support DOE's commitment to the Justice40 Initiative, and the projects should have minimal negative impacts on communities with environmental justice concerns.

DOE identified the following eight policy priorities to guide DOE's implementation of Justice40 in DACs: (1) decrease energy burden; (2) decrease environmental exposure and burdens; (3) increase access to low-cost capital; (4) increase the clean energy job pipeline and job training for individuals; (5) increase clean energy enterprise creation (e.g., minority-owned or diverse business enterprises); (6) increase energy democracy, including community ownership; (7) increase parity in clean energy technology access and adoption; and (8) increase energy resilience.

As part of the Annual Reporting Requirements, Selected Nuclear Reactors will be required to report how project benefits flow to applicable DACs for a subset of the eight policy priorities above, as specified in the Credit Redemption Agreement.

XVII. Other Information

1. Evaluation and Administration by Non-Federal Personnel. In conducting the review of the Certification Application, the DOE may seek the advice of qualified non-federal personnel as reviewers. The DOE may also use non-federal personnel to conduct routine, nondiscretionary administrative activities, including DOE contractors. The Applicant, by submitting its Certification Application, consents to the use of non-federal reviewers/administrators. Non-federal reviewers must sign an COI/NDA prior to reviewing an application. Non-federal personnel conducting administrative activities must sign an NDA.

[20] The term "underserved communities" refers to populations sharing a particular characteristic, as well as geographic communities, that have been systematically denied a full opportunity to participate in aspects of economic, social, and civic life, as exemplified by the list of in the definition of "equity." *Id.* For purposes of this Guidance, as applicable to geographic communities, Applicants can refer to economically distressed communities identified by the Internal Revenue Service as Qualified Opportunity Zones; communities identified as disadvantaged or underserved communities by their respective States; communities identified on the Index of Deep Disadvantage referenced at https://news.umich.edu/new-index-ranks-americas-100-most-disadvantagedcommunities/, and communities that otherwise meet the definition of "underserved communities" stated above.

[21] The Justice40 initiative, created by Executive Order 14008, establishes a goal that 40% of the overall benefits of certain federal investments flow to DACs. *See supra* note 14. Additional J40 guidance is forthcoming and will be reflected in the CNC Program.

[22] *Supra* note 14.

2. Requirement for Full and Complete Disclosure. Applicants are required to make a full and complete disclosure of all information requested. Any failure to make a full and complete disclosure of the requested information may result in:

    - Nullification of certification;
    - The modification, suspension, and/or termination of Credits;
    - The initiation of debarment proceedings, debarment, and/or a declaration of ineligibility for receipt of federal contracts, subcontracts, and financial assistance and benefits; and
    - Civil and/or criminal penalties.

3. Retention of Submissions. DOE expects to retain copies of all Certification Applications and other submissions. No submissions will be returned. By submitting a Certification Application, the Applicant consents to DOE's retention of its submissions.

4. Personally Identifiable Information (PII). All information provided by the Applicant must to the greatest extent possible exclude PII. The term "PII" refers to information which can be used to distinguish or trace an individual's identity, such as their name, social security number, biometric records, alone, or when combined with other personal or identifying information which is linked or linkable to a specific individual, such as date and place of birth, mother's maiden name.

5. Environmental Data. In order to meet its NEPA obligations, DOE anticipates adopting, or adopting and supplementing, the Final Environmental Impact Statement prepared for the Selected Nuclear Reactor by the NRC. DOE may request, and the Nuclear Reactor may not unreasonably refuse to provide, information necessary to complete this process, as well as any information necessary to satisfy DOE's obligations under Section 106 of the National Historic Preservation Act or other environmental laws (e.g., Endangered Species Act).

CONFIDENTIAL EXHIBIT N

CONFIDENTIAL EXHIBIT O

CONFIDENTIAL EXHIBIT P

CONFIDENTIAL EXHIBIT Q

EXHIBIT R

John Geesman

From: CALIFORNIADWR Support <californiadwr@mycusthelp.net>
Sent: Wednesday, May 31, 2023 8:29 AM
To: John Geesman
Subject: [Records Center] Public Records Request :: R000299-051723

--- Please respond above this line ---

STATE OF CALIFORNIA – CALIFORNIA NATURAL RESOURCES A
DEPARTMENT OF WATER RESO

RE: PUBLIC RECORDS REQUEST of May 17, 2023, Reference # R000299-051723.

Dear John Geesman:

This is in response to your May 17, 2023 request, pursuant to the California Public Records Act, Government Code Section 7920 et seq. to the Department of Water Resources (DWR) regarding:

"Regarding the PG&E-DWR October 18, 2022 Loan Agreement for Diablo Canyon Nuclear Power Plant, please provide
(1) Copies of any information received by DWR since April 1, 2022 from PG&E disclosing that the company's 2014 indictment and 2016 conviction for violation of 18 U.S.C § 1505 conflicts with the definition of "Prohibited Person" contained in the draft Credit Redemption Agreement included in DOE's June 30, 2022 Guidance for the Civil Nuclear Credit Program (Revision 1) or its successor document, the Credit Award and Redemption Agreement.
(2) Copies of any information received by DWR since April 1, 2022 from PG&E reporting whether the company has, or has not, informed DOE of the company's 2014 indictment and 2016 conviction for violation of 18 U.S.C § 1505.
(3) Copies of any information received by DWR since April 1, 2022 from PG&E identifying the date of any disclosure to DOE of the company's 2014 indictment and 2016 conviction for violation of 18 U.S.C § 1505.
(4) Copies of any information received by DWR since April 1, 2022 from PG&E concerning any request by the company to DOE for a waiver of enforcement of the "Prohibited Person" provisions in the draft Credit Redemption Agreement included in DOE's June 30, 2022 Guidance for the Civil Nuclear Credit Program (Revision 1) or its successor document, the Credit Award and Redemption Agreement.
(5) Copies of any information received by DWR since April 1, 2022 from PG&E concerning any request by the company to DOE for modification of the definition of "Prohibited Person" in the draft Credit Redemption Agreement included in DOE's June 30, 2022 Guidance for the Civil Nuclear Credit Program (Revision 1) or its successor document, the Credit Award and Redemption Agreement."

Following a diligent search, it has been determined that DWR does not have records responsive to the criteria described in your request.

Sincerely,

Public Records Act Team
Department of Water Resources

To monitor the progress or update this request please log into the Public Records Center

Powered by GovQA

CONFIDENTIAL EXHIBIT S

CONFIDENTIAL EXHIBIT T

CONFIDENTIAL EXHIBIT U

EXHIBIT V

Loan Agreement for
Diablo Canyon Nuclear Power Plant

THIS AGREEMENT ("Agreement") is entered into by and between the California Department of Water Resources ("DWR") and Pacific Gas and Electric Company ("PG&E"), each of which may be referred to herein separately as a "Party" or together as the "Parties." This Agreement shall be effective upon the date of full execution by both Parties ("Effective Date").

WHEREAS, PG&E is the owner and current operator of the Diablo Canyon Nuclear Power Plant ("DCPP"), including reactor Units 1 and 2, in the County of San Luis Obispo, California;

WHEREAS, the order of the California Public Utilities Commission ("CPUC") that approved PG&E's proposal to retire DCPP Unit 1 no later than November 2, 2024 and DCPP Unit 2 no later than August 26, 2025 (the "Current Expiration Dates") has been invalidated by California Senate Bill 846, Chapter 239, Statutes of 2022, ("SB 846"), the Legislature of the State of California (the "State");

WHEREAS, SB 846 determined the continued operation of DCPP to be in all respects an essential governmental purpose, for the welfare and benefit of the people of the State and to protect public peace, health and safety, and as such the operating period was permitted to be extended subject to a license renewal to be granted by the United States Nuclear Regulatory Commission ("NRC") and any other licensing, permitting or approvals by federal or state authorities necessary to allow continued operations of DCPP until a new date that shall be no later than November 1, 2029 for Unit 1 and no later than November 1, 2030 for Unit 2 (such extended period of operations beyond the Current Expiration Dates, is referred to as the "Extended Operating Period"); and

WHEREAS, SB 846 appropriated funds from the General Fund to establish a Diablo Canyon Extension Fund within the Treasury of the State for the purpose of making loans to DWR, and directed DWR to loan such amounts, subject to the satisfaction of the terms and conditions herein, in an aggregate amount not to exceed one billion four hundred million dollars ($1,400,000,000) (the "Maximum Amount") to PG&E, which may be forgiven under certain circumstances, to extend the operations of DCPP, and to maintain electrical reliability during the Extended Operating Period (the "Purpose"). Consistent with SB 846, the Maximum Amount is inclusive of all Performance-Based Disbursements (defined below) (pursuant to California Public Resources Code section 25548.3, subdivision (c)(16)) expected to be disbursed under the Agreement, and all DWR costs incurred in the administration of the loan not to exceed five percent (5%) of the amount disbursed (pursuant to California Public Resources Code section 25548.5, subdivision (a)(6)) which will not be available as loan proceeds.

NOW, THEREFORE, in consideration of the mutual promises and covenants contained in this Agreement, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties agree as follows:

1. Defined Terms and Interpretation.

a. As used herein, capitalized terms not otherwise defined within the context of this Agreement shall have the meaning set forth in Exhibit A.

b. For all purposes of this Agreement, except as otherwise expressly provided herein or unless the context otherwise requires, (a) the terms defined in this Agreement include the plural as well as the singular and vice versa; (b) words importing gender include all genders; (c) any reference to a Section or Exhibit refers to a Section of or Exhibit to this Agreement; (d) any reference to "this Agreement" refers to this Agreement, including all Schedules and Exhibits hereto, and the words herein, hereof, hereto and hereunder in whole and not to any particular Section, Exhibit or any other subdivision; (e) references to days, months and years refer to calendar days, months and years, respectively; (f) all references herein to "include" or "including" shall be deemed to be followed by the words "without limitation"; (g) the word "from" when used in connection with a period of time means "from and including" and the word "until" means "to but not including"; (h) the words "asset" and "property" shall be construed to have the same meaning and effect and to refer broadly to any and all assets and properties, whether tangible or intangible, real or personal, including cash, securities, rights under contractual obligations and permits and any right or interest in any such assets or property; (i) accounting terms not specifically defined herein (other than "property" and "asset") shall be construed in accordance with GAAP; (j) the word "will" shall have the same meaning as the word "shall"; (k) where any provision in this Agreement refers to an action to be taken by any Person, or an action which such Person is prohibited from taking, such provision shall be applicable whether such action is taken directly or, to the knowledge of such Person, indirectly; and (l) references to any Law will include all statutory and regulatory provisions amending, consolidating, replacing, supplementing or interpreting such Law from time to time.

c. Unless otherwise expressly provided herein, references to organizational documents, agreements (including this Agreement) and other contractual instruments shall be deemed to include all subsequent amendments, restatements, extensions, supplements and other modifications thereto permitted by the terms hereof. If any obligation to pay any amount pursuant to the terms and conditions of this Agreement falls due on a day which is not a Business Day, then such required payment date shall be extended to the immediately following Business Day.

2. Term. This Agreement shall begin on the Effective Date and shall terminate upon the earlier of (a) eight months after the last day of the Extended Operating Period, or (b) the date on which DWR terminates its obligation to make Disbursements under this Agreement pursuant to Section 9 below ("Termination Date"). Notwithstanding the preceding sentence, DWR may also in its sole discretion terminate this Agreement upon thirty (30) Business Days' written notice to PG&E pursuant to a determination by DWR that PG&E is a target of economic sanctions or is conducting prohibited transactions with sanctioned individuals or entities as prohibited by Executive Order N-6-22 – Russia Sanctions ("DWR Termination"). In order for DWR to initiate DWR Termination pursuant to Executive Order N-6-22 – Russia Sanctions ("EO N-6-22"), DWR shall first provide PG&E a notice and a period of thirty (30) days to provide a written response to DWR with (i) a description

of a process to remedy the concern raised by DWR, or (ii) an explanation of reasons why PG&E believes that the concerns raised by DWR pursuant to EO N-6-22 does not apply in the context raised.

3. Use of Funds. PG&E shall use the proceeds of the Disbursements (defined below) and funds received from the United States Department of Energy ("DOE") pursuant to the Civil Nuclear Credit Program established by Section 18753 of Title 42 of the United States Code ("DOE Funds"), to the extent permitted by the DOE award agreement, for expenses, costs and fees incurred by PG&E that are necessary or appropriate to preserve the option to extend and to extend DCPP operation during the Extended Operating Period, including without limitation, the following activities to the extent necessary or appropriate to promote the Purpose, provided that, (i) the CPUC, or any other regulatory body, has not authorized rate recovery for such expenses, costs and fees, (ii) PG&E shall not seek rate recovery from the CPUC, or any other regulatory body, for such expenses, costs and fees as part of any future ratemaking proceeding, and (iii) such expenses, costs and fees shall not be paid from funds previously disbursed by DWR pursuant to that certain Reliability Reserve Reimbursement Agreement for Diablo Canyon Nuclear Power Plant, by and between the Parties effective as of August 15, 2022 ("Authorized Expenses"):

a. *Project Costs*. Those necessary to preserve the option of extending DCPP or to extend DCPP's operation to maintain electric reliability, including: relicensing, permitting, development, construction, operation and maintenance of DCPP, including necessary or appropriate improvements necessary for the NRC Application, other state or local government permitting processes, and safe and reliable operations during the Extended Operating Period.

b. *Fuel Purchases*. Procurement of materials, products, and services necessary or appropriate to manufacture nuclear fuel for use in DCPP.

c. *Spent Fuel Management*. Procurement of materials, products, and services necessary or appropriate to manage the DCPP spent fuel inventory, including by transferring spent fuel to dry cask storage to support the required full core offload capability during extended DCPP operations.

d. *Contract Labor*. All necessary or appropriate contracted labor ("Contract Labor"), including specialized nuclear, regulatory, legal and other professional services required to (i) pursue a potential NRC license renewal application ("NRC Application") and related regulatory filings and required state approvals necessary or appropriate for continued operations of DCPP, (ii) perform required inspections and analyses needed for a complete and technically sufficient NRC Application or required state approvals and to support implementation of renewed NRC licenses, and (iii) take all other actions necessary or appropriate to promote the Purpose. Contract Labor costs include costs of material, equipment, and services needed to perform inspections or analyses. Contract Labor costs also include reasonable and necessary travel costs incurred by Contracted Labor in accordance with Contracted Labor agreements, including lodging, meals, transportation (*e.g.*, airfare, automobile mileage reimbursement, rental car, taxicabs, parking), and related fees and taxes consistent with Exhibit B, "PG&E Reimbursable Expense Guidelines for Contractors."

e. *Project Team.* All necessary or appropriate internal PG&E employee labor required to (i) pursue the NRC Application and related regulatory filings and required state approvals necessary or appropriate for continued operations of DCPP, including development of contracts for required inspections and analyses needed for a complete and technically sufficient NRC Application or required state approvals, (ii) support implementation of renewed NRC licenses, and (iii) take all other actions necessary or appropriate to promote the Purpose (the "Project Team"). Project Team costs include costs of material, equipment, and services needed to perform inspections or analyses and licensing, permitting and other regulatory compliance costs. Project Team costs also include reasonable and necessary travel costs at an "at-cost" rate, including for lodging, meals, transportation (*e.g.*, airfare, automobile mileage reimbursement, rental car, taxicabs, parking), and related fees and taxes consistent with Exhibit C, Utility Standard: FIN-2210S, "Employee Business Expenses and Travel Standard", provided that "meals and incidental" expenses, as defined in Exhibit C, for more than $110 per day shall be accompanied with a written explanation for the excess amount from PG&E to DWR.

f. *Other Costs.* All other costs and expenses that are necessary or appropriate for promoting the Purpose, including all costs and expenses in connection with this Agreement such as fulfilling any indemnification obligations and payment of tax liabilities, among other costs and expenses.

g. Under no circumstances are shareholder dividends to be treated as Authorized Expenses under this Agreement.

4. Records. PG&E shall maintain detailed cost-tracking and accounting, consistent with standard utility practice, for all Authorized Expenses committed, incurred, and paid for with Disbursements ("Records"). PG&E shall provide or make available Records to DWR or any other authorized state oversight agency upon thirty (30) days prior written notice. PG&E shall maintain Records as specified in this paragraph for at least three (3) years from the date of expiration, cancellation, or other termination of this Agreement. PG&E shall maintain records adequate to demonstrate that each Authorized Expense is not duplicative of expenditures authorized in previous or future ratemaking proceedings.

5. Disbursements.

a. *Tranches.* Subject to the terms and conditions of this Agreement, upon receipt of written requests from PG&E, in substantially the form attached hereto as Exhibit D (a "Disbursement Request"), DWR agrees to make disbursements from the Maximum Amount to PG&E from time to time in multiple tranches, as follows:

i. on the Effective Date, DWR shall initiate a disbursement to PG&E in an amount equal to Three Hundred Fifty Million Dollars ($350,000,000) to the account designated by PG&E in Section 14 and complete the full transfer of such funds as soon as possible, but by no later than November 10, 2022 (such disbursement is referred to herein as the "Tranche A Disbursement");

ii. after the Effective Date and until the date of the Additional State Fund Authorization (defined below), or in the absence of the occurrence of the Additional State Fund Authorization until the Termination Date, DWR shall make additional disbursements to PG&E, which when taken together with the Tranche A Disbursement and all Performance-Based Disbursements paid by DWR, shall not exceed an aggregate original principal amount of Six Hundred Million Dollars ($600,000,000) (each such disbursement is referred to herein as a "Tranche B Disbursement" and collectively, the "Tranche B Disbursements");

iii. following legislative authorization of the transfer of up to an additional Eight Hundred Million Dollars ($800,000,000.00) to the Diablo Canyon Extension Fund ("Additional State Fund Authorization") and until the Termination Date, DWR shall make disbursements to PG&E, which when taken together with the Tranche A Disbursement, all Tranche B Disbursements and all Performance-Based Disbursements paid by DWR shall not exceed an aggregate amount of the Maximum Amount (each such disbursement is referred to herein as a "Tranche C Disbursement"). The Tranche A Disbursement, the Tranche B Disbursements, and the Tranche C Disbursements each shall be referred to herein as a "Disbursement" and collectively, as the "Disbursements;" and

iv. PG&E and DWR acknowledge that the Maximum Amount may be reduced by up to 5% of the amount of funds disbursed for costs and expenses that may be incurred by DWR in its efforts to develop, negotiate, and administer this Agreement and activities related to such effort ("DWR Costs"), and by the amount of Performance-Based Disbursements disbursed under this Agreement pursuant to California Public Resources Code section 25548.3, subdivision (c)(16), all as permitted by SB 846.

b. *Procedure for Requesting Tranche B Disbursements and Tranche C Disbursements.*

i. Semiannual Disbursement Requests. No later than fifteen (15) days after PG&E's receipt of the results of each semiannual true up from DWR, as described in Section 6, PG&E shall submit a Disbursement Request to DWR. Each Disbursement Request shall include (A) the amount of the requested Disbursement which shall be the aggregate amount of Authorized Expenses incurred, anticipated to be incurred, or to be committed by PG&E during the period commencing on the date of the prior semi-annual true-up and ending on the date immediately prior to the next semi-annual true-up (the "Disbursement Period"), (B) milestones expected to be achieved during the Disbursement Period, and (C) a written expenditure plan, all in substantially the form attached hereto as Exhibit D. DWR may submit a request for additional information reasonably necessary or appropriate to evaluate the Disbursement Request from PG&E within fifteen (15) days after receiving the Disbursement Request from PG&E ("Additional Information"). Upon receipt of such Disbursement Request and PG&E's submission of any Additional Information requested by DWR, DWR shall promptly, and in no event later than fifteen (15) days after receipt of the Disbursement Request and PG&E's submission of any Additional Information requested by DWR, submit an appropriate written expenditure plan to request the release of additional funding, in the amount requested by the Disbursement Request submitted by PG&E, to the Department of Finance ("DOF") and the Joint Legislative Budget Committee ("JLBC") . Following such submission, the DOF may provide funds to DWR for disbursement to PG&E not sooner than 30 days after notifying, in writing, the JLBC, or any lesser time determined by the chairperson of the JLBC, or the chairperson's designee. Notwithstanding the above provisions of this paragraph, in the event DWR, after requesting and receiving Additional Information, disputes the amount requested by the Disbursement Request, DWR shall submit an appropriate written expenditure plan to request the undisputed amount requested by the Disbursement Request in accordance with the terms of this Section 5.b(i), and shall by no later than three (3) Business Days initiate the dispute resolution process of Section 10. Upon resolution of any such dispute, DWR shall by no later than three (3) Business Days submit an appropriate written expenditure plan to the DOF and the JLBC to request the amount no longer disputed. Following the submission, the DOF may provide funds to DWR for disbursement to PG&E not sooner than 30 days after notifying, in writing, the JLBC, or any lesser time determined by the chairperson of the JLBC, or the chairperson's designee. Within thirteen (13) Business Days after the release of funds from the DOF, DWR shall disburse the amount of funds no longer disputed to PG&E and transfer such funds to the account designated by PG&E in Section 14 or as otherwise specified by PG&E in the applicable Disbursement Request.

ii. Supplemental Disbursement Requests. In addition to the semiannual Disbursement Requests, in the event PG&E incurs additional Authorized Expenses during any Disbursement Period which were not reasonably foreseeable when the prior Disbursement Request was submitted, PG&E shall be entitled to submit one or more additional Disbursement Requests to DWR setting forth the amount then needed for Authorized Expenses and a reasonably detailed explanation of the circumstances giving rise to such additional need. Upon receipt of any such supplemental Disbursement Request from PG&E, DWR may submit a request for Additional Information within five (5) days. DWR shall promptly, and in no event later than ten (10) days after receipt of such supplemental Disbursement Request and PG&E's submission of any Additional Information requested by DWR, submit an appropriate written expenditure plan to request the release of additional funding, in the amount of the Disbursement requested in such supplemental Disbursement Request submitted by PG&E, to the DOF and the JLBC. Following such submission, the DOF may provide funds to DWR for disbursement to PG&E not sooner than 30 days after notifying, in writing, the JLBC, or any lesser time determined by the chairperson of the JLBC, or the chairperson's designee. Notwithstanding the above provisions of this paragraph, in the event DWR, after requesting and receiving Additional Information, disputes the amount requested by the Disbursement Request, DWR shall submit an appropriate written expenditure plan to the DOF and the JLBC to request the undisputed amount requested by the Disbursement Request in accordance with the terms of this Section 5.b(ii), and shall by no later than three (3) Business Days initiate the dispute resolution process of Section 10. Upon resolution of any such dispute, DWR shall by no later than three (3) Business Days submit an appropriate written expenditure plan to the DOF and the JLBC to request the amount no longer disputed. Following the submission, the DOF may provide funds to DWR for disbursement to PG&E not sooner than 30 days after notifying, in writing, the JLBC, or any lesser time determined by the chairperson of the JLBC, or the chairperson's designee. Within thirteen (13) Business Days after the release of such additional funding, DWR shall disburse the amount of funds no longer disputed PG&E and transfer such funds to the account designated by PG&E in Section 14.or as otherwise specified by PG&E in such supplemental Disbursement Request.

In each Tranche B or Tranche C Disbursement transmittal, DWR shall include a statement of the amount of Disbursements paid to the date of that Disbursement. DWR shall also include a statement of the amount of Performance-Based Disbursements and DWR Costs paid as of the date of such Disbursement.

For the avoidance of doubt, the funds disbursed pursuant to this Agreement are the sole source of funds available to PG&E to carry out the Purpose, accordingly DWR shall disburse Disbursements to PG&E in accordance with the disbursement schedule for each Disbursement as provided in this Agreement prior to PG&E committing to, or incurring, Authorized Expenses.

c. *Conditions Precedent.*

i. DWR's obligation to make the Tranche A Disbursement as soon as possible, but by no later than November 10, 2022, after the Effective Date is subject to the satisfaction of the following conditions:

1. Both Parties shall have fully executed the Agreement; and

2. On or prior to the Effective Date PG&E shall have submitted to DWR a plan setting forth in reasonable detail the estimated Authorized Expenses to be committed or incurred and the milestones expected to be achieved during the period from the Effective Date to April 15, 2023.

ii. DWR's obligation to make the Tranche B Disbursements and the Tranche C Disbursements are subject to the satisfaction of the following conditions:

1. PG&E shall have submitted a Disbursement Request pursuant to the provisions of Section 5(b);

2. No Suspension Event or Event of Repayment shall have occurred and be continuing;

3. With respect to a Tranche B Disbursement, the DOF and the JLBC shall have approved the written expenditure plan submitted by DWR to request the release of additional funding; and

4. With respect to a Tranche C Disbursement, legislative approval of additional funds being transferred to DWR for the purpose of loaning such funds to PG&E pursuant to this Agreement in furtherance of the Purpose shall have occurred. The Parties shall in good faith negotiate any appropriate or necessary amendments to this Agreement in connection with any such legislative approval.

d. *Other State Approvals; Ratemaking*. It is the Parties' intention and agreement that funds reimbursed for Authorized Expenses under this Agreement shall not be duplicative of capital or expenses authorized by the CPUC, or any other regulatory body, in any previous ratemaking proceeding or a part of any future ratemaking proceeding. Accordingly, PG&E shall not record as Authorized Expenses activities previously authorized in a ratemaking proceeding, and PG&E shall not seek recovery of Authorized Expenses reimbursed under this Agreement in future ratemaking proceedings.

e. *Performance-Based Disbursement*. DWR shall pay to PG&E a monthly performance-based disbursement equal to Seven Dollars ($7) for each megawatt hour generated by each of Unit 1 and Unit 2 as measured by the California Independent System Operator's revenue meters for each unit ("CAISO Meters") during the period commencing on September 2, 2022, the effective date of SB 846, and ending on, and inclusive of, the Current Expiration Dates for each of Unit 1 or Unit 2, as applicable (the "Performance-Based Disbursement"). By the tenth (10th) day of each month PG&E shall deliver an invoice to DWR setting forth its calculation of the Performance-Based Disbursement for the preceding month including the amount of generation for such month recorded by the CAISO Meters. The first such invoice shall be issued on the tenth (10th) day of November 2022, such invoice shall include a calculation of the Performance-Based Disbursement for the period beginning on September 2, 2022 through October 31, 2022 and shall include the amount of generation recorded during such period. Upon the delivery of such invoice by PG&E, the Performance-Based Disbursement shall be due and payable. DWR shall (i) disburse the amount set forth in PG&E's invoice within thirteen (13) Business Days after receipt of such invoice, or for the period September 2, 2022 through May 2023 (ii) issue notice to PG&E authorizing release of the invoiced amounts to be used by PG&E as Performance-Based Disbursements from amounts previously disbursed by DWR to be held by PG&E for such purpose with its disbursement of the Tranche A Disbursement for Authorized Expenses; provided that PG&E continues efforts to pursue activities necessary or appropriate to achieve the Extended Operating Period and DCPP is operated in a safe and reliable manner. The aggregate total amount of Performance-Based Disbursements under this Agreement shall not exceed Three Hundred Million Dollars ($300,000,000). Once paid, PG&E may use the proceeds of the Performance-Based Disbursements for any business purpose, except as otherwise prohibited by SB 846, or Section 8.b. Performance-Based Disbursements shall be fully subject to the Repayment and Forgiveness provisions of Section 7.

f. *Sources of Disbursement Payments; No Debt of State.* The DWR obligation to make Disbursements under this Agreement shall be limited solely to funds appropriated by the State for the Purpose. Any liability of DWR arising in connection with this Agreement shall be satisfied solely from appropriated funds. DWR is entering into this Agreement pursuant to its responsibilities under SB 846, separate and apart from its powers and responsibilities with respect to the State Water Resources Development System or any other responsibilities of the Department. Neither the full faith and credit nor the taxing power of the State are or may be pledged for any payment under this Agreement.

6. True-Up.

a. *True-Up*. All Disbursements shall be subject to a semiannual true-up. Semiannual true-ups shall occur on April 15 and October 15 in each year, with the first true-up to occur on April 15, 2023 and the last true-up to occur on December 15, 2026. For each semiannual true-up date, either Party may, through written notice to the other no later than thirty (30) days in advance of such semiannual true-up date extend the true-up date for up to sixty (60) calendar days. An exercise of such extension for each semiannual true-up date may occur only once by either Party.

The semiannual true-up methodology and process to conduct the semiannual true-up shall be determined by DWR, in collaboration with the CPUC, within one hundred eighty (180) days after the Effective Date.

DWR shall provide PG&E a copy of such true up methodology and process no later than thirty (30) days after its completion.

The semiannual true up shall be used to determine the following:

i. Whether PG&E used proceeds of the Disbursements to pay only for Authorized Expenses for the semiannual true up period and did not retain any revenues for shareholders from funds associated with the loan;

ii. Whether the Authorized Expenses were reasonable;

iii. Whether the Authorized Expenses committed or incurred for the semiannual true up period are in the public interest;

iv. Whether the CPUC has not authorized rate recovery of the same costs for Authorized Expenses committed or incurred for the semiannual true-up period;

v. Whether Performance-Based Disbursements have been used in a manner consistent with the requirements of SB 846; and

vi. Other considerations deemed appropriate by the CPUC.

To develop the semi-annual true-up, PG&E shall provide information to DWR and the CPUC monthly and as-requested.

DWR shall provide a copy of the results of each semiannual true-up to PG&E no later than fifteen (15) days after its completion.

b. *Disallowed Costs*. If, upon completion of a semiannual true-up review, DWR determines that PG&E's use of the Disbursements did not meet the requirements set forth in Sections 3 and 6.a, those amounts shall not be deemed Authorized Expenses ("Disallowed Costs"). If DWR finds Disallowed Costs pursuant to this Section 6, DWR shall notify PG&E of the amount of Disallowed Costs as promptly as possible. PG&E may, no later than thirty (30) days after receipt of notice from DWR, provide a written response to DWR with an explanation regarding why PG&E believes that the costs identified are not Disallowed Costs. DWR shall within thirty (30) days of receipt of PG&E's response provide a final determination and notice of acceptance or rejection of PG&E's explanation. If DWR issues an acceptance notice, the matter shall be deemed cured. If DWR issues a rejection notice, or PG&E fails to timely provide a response, DWR may deduct the amounts under question from any future Disbursements.

7. Repayment and Forgiveness.

a. *Repayment and Escrow Arrangement.* Upon PG&E's receipt of any DOE Funds, PG&E shall promptly transfer such funds to an escrow account opened with Bank of New York Mellon Corporation, or a similar financial institution reasonably acceptable to DWR, as escrow agent (the "Escrow Agent") on behalf of PG&E. Prior to execution of the escrow agreement between PG&E and the Escrow Agent, PG&E shall provide such agreement to DWR for it to review and confirm that the terms of the escrow agreement are consistent with the terms of this Agreement. DWR's review and confirmation shall not be unreasonably withheld or delayed. The Escrow Agent shall hold such funds, including any interest earned on such funds (the funds together with any interest earned on such funds shall be referred to herein as the "Escrow Funds"), on behalf of PG&E and shall release such Escrow Funds only upon the occurrence of the following circumstances:

i. at any time prior to the end of the DOE award period and the completion of the final annual review process by DOE, expected to be completed by December 2027 (which, when both completed, marks the expiration of the period during which DOE may initiate a recapture process) ("DOE Recapture Period"), if PG&E receives a recapture notice from the DOE, the amount required to be repaid to the DOE shall be released and transferred from the Escrow Funds by the Escrow Agent to the account set forth in any notice from DOE.

ii. following the DOE Recapture Period, the Escrow Agent shall release and transfer the Escrow Funds to DWR to an account designated by DWR to be disbursed by DWR to PG&E in the amount of Authorized Expenses incurred or committed by PG&E and not already funded through this Agreement, in accordance with the Supplemental Disbursement Request procedure of Section 5(b)(ii).

iii. in the event an Additional State Fund Authorization in the amount of Eight Hundred Million Dollars ($800,000,000) does not occur by September 30, 2023, the Escrow Agent shall release and transfer Escrow Funds to PG&E for PG&E's use in accordance with the DOE award agreement, up to an amount equal to Eight Hundred Million Dollars ($800,000,000) minus the sum of any Additional State Fund Authorization.

b. *Repayment of Excess Revenues.* If excess funds remain in a balancing account as a result of market revenues exceeding costs and expenses in the final year of the Extended Operating Period, after truing up the final operating year's market revenues against costs and expenses, the remaining funds shall be transferred to DWR and applied to repay Disbursements and Performance-Based Disbursements made under this Agreement in accordance with Section 712.8(h)(3) of the Public Utilities Code.

c. *Application of Payments.* All funds transferred from the Escrow Fund to DWR shall be applied by DWR as a repayment of the Disbursements and Performance-Based Disbursements.

d. *Repayments Available for Disbursement.* Repayments of Disbursements and Performance-Based Disbursements by PG&E to DWR for any period prior to the expiration of the Extended Operating Period shall be deposited into the Diablo Canyon Extension Fund and shall remain available for further disbursement.

e. *Forgiveness.* Notwithstanding any other provision of this Agreement, the only source of funds to satisfy any PG&E repayment obligation under this Agreement shall be the DOE Funds, pursuant to the provisions of Section 7(a), any other federal funds received for Authorized Expenses, and any excess funds remaining in a balancing account as a result of market revenues exceeding costs and expenses in the final year of the Extended Operating Period, as provided in Section 7(b). All other Disbursements and Performance-Based Disbursements received by PG&E under this Agreement shall be deemed forgiven, provided that any amount forgiven is limited to amounts already committed or incurred and that any unspent or uncommitted Disbursement and Performance-Based Disbursements amounts shall be repaid to DWR.

8. Covenants. Each of the Parties covenants and agrees that, until the Termination Date:

a. PG&E shall take all steps necessary to secure a grant or other funds available for the operation of a nuclear powerplant from the DOE, and any other potentially available federal funds, to repay the Disbursements.

b. PG&E shall not treat the proceeds of any Disbursement as shareholder profits, nor use the proceeds of any Disbursement to pay any dividends.

c. PG&E shall allocate the equivalent amount of all federal or state tax credits or incentives received, excluding funds specifically allocated by a federal program for the costs of extending power plant operations, on a cost-share basis of 10 and 90 percent between PG&E as the operator corporation and the ratepayers of a load-serving entity responsible for the costs of the continued operation, respectively.

d. PG&E shall keep DWR reasonably apprised of the status of any relicensing activities for DCPP and shall promptly inform DWR upon the occurrence of any event that materially impacts the ability of DCPP to operate during the Extended Operating Period.

e. PG&E shall conduct an updated seismic assessment for DCPP and shall commission a study by independent consultants to catalog and evaluate any deferred maintenance at DCPP and to provide recommendations as to any risk posed by the deferred maintenance, potential remedies, and cost estimates of those remedies, and a timeline for undertaking those remedies.

f. PG&E shall report to the Commission no later than March 1, 2023, on the available capacity of existing wet and dry spent fuel storage facilities and the forecasted amount of spent fuel that will be generated by powerplant operations through the retirement dates for both units as of August 1, 2022, and November 1, 2029, for Unit 1 and November 1, 2030, for Unit 2.

g. PG&E and DWR shall cooperate and take all actions appropriate or necessary to ensure timely disbursement of Disbursements in accordance with the disbursement schedule provided in Section 5, including submitting all notices, requests, forms and taking any other action appropriate or necessary to ensure the Maximum Amount is made available for disbursement under this Agreement, including providing any information to any State Agency, office, or regulatory body.

h. PG&E and DWR shall cooperate and take all actions appropriate or necessary to support efforts to see that the funds anticipated to be disbursed as Tranche C Disbursements are authorized by future state legislative action.

i. Notwithstanding the foregoing, during the process of relicensing the DCPP, in the event the NRC or any State Agency requires seismic safety or other safety modifications to the DCPP that would exceed the Maximum Amount, DWR shall submit a written request to the Commission to promptly evaluate whether the extension of the DCPP remains a cost-effective means to meet the State's mid-term reliability needs, before any subsequent authorization and appropriation by the California State Legislature of an amount in excess of the Maximum Amount.

j. PG&E shall operate DCPP for the welfare and the benefit of the people of the State, to protect public peace, health and safety.

k. Interest on Disbursements shall be at zero (0) percent.

l. PG&E and DWR shall cooperate and use commercially reasonable efforts to ensure that the amounts paid, imputed, or forgiven, under this Agreement are exempt from taxation to the extent permitted under applicable Law. All Disbursements will be treated consistently (for accounting and tax reporting purposes) by the Parties as debt and the expenditures of disbursed funds will be treated as deductible, capitalizable, depreciable, or amortizable for federal and state income tax purposes.

9. Suspension Events and Events of Repayment.

a. *Suspension Events*. If a "Suspension Event" shall occur, then DWR shall provide written notice to PG&E that all future Disbursements will be suspended immediately. No later than thirty (30) Business Days after receipt of such notice from DWR, PG&E may provide a written response to DWR with a remediation plan that timely and appropriately resolves the issue giving rise to the Suspension Event and such remediation shall be completed to the reasonable satisfaction of DWR by no later than sixty (60) Business Days from the date of PG&E's response. DWR shall provide a final determination and notice of acceptance or rejection of PG&E's remediation plan within thirty (30) days of receipt of PG&E's response. If DWR issues an acceptance notice, the Suspension Event shall be deemed to have been cured. If DWR issues a rejection notice, or PG&E fails to timely provide a response or fails to timely resolve the issue giving rise to the Suspension Event in accordance with its remediation plan all as required by this Section 9(a), DWR may immediately issue an early termination notice to PG&E. Upon receipt of such early termination notice, PG&E shall at once terminate all activities to pursue extended operations and shall take all reasonable measures in accordance with Section 9(c).

Each of the following events is a "Suspension Event":

i. PG&E is not deemed eligible by the DOE for a federal funding program by March 1, 2023, or the earliest date set by the DOE for determining eligibility pursuant to the Civil Nuclear Credit Program established by Section 18753 of Title 42 of the United States Code;

ii. DWR has given written notice to PG&E of its determination that PG&E has not obtained the necessary license renewal, permits and approvals for the Extended Operating Period or that such license renewal, permit or approval conditions are too onerous, or will generate costs that exceed the Maximum Amount, and PG&E has failed to obtain such license renewal, permit or approval or deliver a remediation plan to DWR that offers a plan to timely and appropriately resolve the concern raised in the notice from DWR within sixty (60) days after receipt of such written notice from DWR;

iii. the CPUC issues a final determination that an extension of DCPP is not cost effective, or imprudent, or both;

iv. a final determination by the Commission, pursuant to Section 25233.2 of the Public Resources Code and voted upon at a Commission's business meeting, that the State's forecasts for the calendar years 2024 to 2030, inclusive, do not show reliability deficiencies if DCPP is retired by 2025, or that the Extended Operating Period is not necessary for meeting any potential supply deficiency;

v. an unexpected early retirement of DCPP by PG&E;

vi. DWR has given written notice to PG&E that it has determined that permitted timeframes are not viable to accomplish the Purpose;

vii. DWR has given written notice to PG&E that it has determined that expenses are unexpected or too large, or that repayment is less likely than initially anticipated; or

viii. a final determination by DOE that DCPP is not eligible for the Civil Nuclear Credit Program established by Section 18753 of Title 42 of the United States Code.

b. *Event of Repayment.* If an "Event of Repayment" shall occur, then DWR shall provide written notice to PG&E that all future Disbursements will be suspended immediately. PG&E may by no later than ten (10) Business Days after receipt of notice from DWR, provide a written response to DWR with an explanation reasonably acceptable to DWR explaining why PG&E believes that an Event of Repayment has not occurred. DWR shall within thirty (30) days of receipt of PG&E's response provide a final determination and notice of acceptance or rejection of PG&E's explanation. If DWR issues an acceptance notice, the Event of Repayment shall be deemed to have been cured. If DWR issues a rejection notice, or PG&E fails to timely provide a response or fails to take other measure to timely resolve the issue giving rise to the Event of Repayment all as required by this Section 9(b), DWR may immediately issue an early termination notice to PG&E. Upon receipt of such early termination notice, PG&E shall at once terminate all activities to pursue extended operations and shall take all reasonable measures in accordance with Section 9(c).

Each of the following events is an "Event of Repayment":

i. Failure of PG&E to submit a timely and complete application for funding from the Department of Energy for determining eligibility pursuant to the Civil

Nuclear Credit Program established by Section 18753 of Title 42 of the United States Code;

ii. Failure by PG&E to disclose to DWR any known safety risk, seismic risk, environmental hazard, or material defect that would disqualify the application of PG&E for grants or funds for the operation of a nuclear power plant from a funding program of the DOE or otherwise disallow or substantially delay any necessary permitting or approvals necessary for the Extended Operating Period; or

iii. Any change in ownership of DCPP, as determined by the CPUC pursuant to Section 851 of the Public Utilities Code, before August 26, 2025.

c. *Winding Down Costs*. If DWR provides a notice of early termination pursuant to Section 9(a) or 9(b), PG&E shall, upon receipt of such notice, take all reasonable, diligent, and timely measures to terminate all activities to pursue extended operations of DCPP, including winding down and terminating such activities, and paying any Authorized Expenses owed then or owing for other financial commitments subject to later payment in connection with Authorized Expenses ("Winding Down Costs"). PG&E shall return any unused Disbursements to DWR after payment of all Winding Down Costs. In addition, PG&E shall take reasonable steps to remarket, resell or salvage fuel, materials or equipment purchased by PG&E with the proceeds of Disbursements made under this Agreement and shall use the proceeds thereof to satisfy any outstanding Winding Down Costs first and return any remaining balance of such proceeds to DWR thereafter. In the event any Winding Down Costs balance remains owed by PG&E to third parties after the application of all Disbursements previously made, including the application of any proceeds from PG&E's remarketing efforts, in such event DWR shall reimburse PG&E for any then-outstanding Winding Down Costs. Performance-Based Disbursements will only be paid through and including the date of the notice of early termination by DWR pursuant to Section 9(a) or 9(b). For the avoidance of doubt, and without limiting the applicability of the dispute resolution provisions of Section 10 to any other dispute arising under this Agreement, any dispute among the Parties arising under this Section 9(c) shall be resolved pursuant to the dispute resolution provisions of Section 10.

10. Dispute Resolution. At all times during the period of this Agreement the Parties will work together in good faith to accomplish the goals set out in this Agreement. In the event of a dispute between the Parties, the Parties shall first attempt to resolve the dispute informally. If the Parties are unable to resolve the dispute informally then either Party may deliver to the other Party a notice of dispute with a detailed description of the underlying circumstances for the dispute. The dispute notice shall include a schedule of availability of the notifying Party's officers having a title of senior vice president, deputy director or person of equivalent title, or higher duly authorized individual to settle the dispute during the thirty (30) Business Day period following delivery of the dispute notice. The recipient Party shall, within five (5) Business Days of receipt of the dispute notice, provide to the notifying Party a parallel schedule of availability of its officers having a title of senior vice president, deputy director or a person of equivalent title or higher duly authorized to settle the dispute. The senior officers or equivalent of the Parties

shall meet and confer as often as reasonably necessary or appropriate during the thirty (30) Business Day period in good faith negotiations to resolve the dispute. In the event the dispute is not resolved within the thirty (30) Business Day period and the Parties do not mutually agree to continue negotiations, then the parties may pursue mediation pursuant to JAMS' then-applicable commercial mediation rules, in Sacramento County, California or either party may pursue other options as they see fit to resolve the dispute.

11. Limitation of Liability; Indemnity.

a. *Limitation of Liability.* In no event shall PG&E or DWR be liable to the other or any third party claiming by or through the other for incidental, indirect, special, punitive, or consequential damages including, but not limited to, loss of use, cost of delays, replacement of power, or loss of profits, even if such party is advised by the other party of the possibility of such damages.

PG&E shall not be held liable to DWR or to any party claiming by or through DWR by reason of PG&E's failure to perform Section 3.

b. *Indemnity.* PG&E shall defend, indemnify and hold harmless DWR its directors, officers, employees, agents, trustees, administrators, managers, advisors and representatives (each, an "Indemnitee") against any and all losses, claims, damages, and liabilities related to (i) the performance by PG&E of its obligations hereunder or under any other agreement entered into by PG&E in connection with this Agreement or the consummation of the transactions contemplated hereby or thereby, or (ii) any Disbursement or use of the proceeds therefrom by PG&E provided that such indemnity shall not, as to any Indemnitee, be available to the extent that such losses, claims, damages, liabilities or related expenses are determined by a court of competent jurisdiction by final and non-appealable judgment to have resulted from the gross negligence or willful misconduct of such Indemnitee or to have been caused by a breach by such Indemnitee of its material obligations hereunder.

12. Confidentiality. This Agreement shall be subject to the confidentiality requirements of that certain Non-Disclosure Agreement by and between the Parties effective as of September 22, 2022 ("Non-Disclosure Agreement"). The Non-Disclosure Agreement is incorporated herein for all purposes. Any conflict between the provisions of this Agreement and the Non-Disclosure Agreement shall be resolved in favor of this Agreement.

13. Amendments. Amendments to this Agreement are enforceable only if in writing and signed by duly authorized representatives of both Parties.

14. Notices. Any notices, requisitions for payment, or communications required under this Agreement must be (a) in writing and (b) delivered or mailed by prepaid, certified, or registered mail or overnight courier, or transmitted by electronic mail to the other Party's contact information provided below:

If to PGE&E | If to DWR

Name: Brian Ketelsen	Name: Behzad Soltanzadeh
Title: Director, Nuclear Decommissioning	Title: Executive Manager, Statewide Water and Energy
Mailing Address: 9 MI N/W of Avila Beach San Luis Obispo, California 93424-0056	Mailing Address: 715 P Street, 5th Floor Sacramento, California 95814
Email: Brian.Ketelsen@pge.com	Email: Behzad.Soltanzadeh@water.ca.gov
Phone: (805) 545-6006	Phone: (916) 425-4815
Wire Transfer: [redacted]	Wire Transfer: [redacted]

Notices shall be deemed to have been given on (i) the date it is personally delivered, (ii) three (3) Business Days after it is mailed by prepaid certified or registered mail, (iii) one (1) Business Day after it is sent by overnight courier or (iv) the date that it is sent by electronic mail.

Either Party may update its contact information listed above pursuant to thirty (30) days advance notice to the other Party.

15. Assignments. This Agreement is binding upon and shall inure to the benefit of the Parties and their respective successors and assigns. Neither Party may assign its rights or obligations hereunder without the prior written consent of the other Party.

16. Survivability. The provisions of Sections 4 (Records), 11 (Limitation of Liability; Indemnity), and 12 (Confidentiality) shall survive for a period of three (3) years from the date of expiration, cancellation, or other termination of this Agreement. Any other provisions of this Agreement that would generally be construed as intended to survive the expiration, cancellation or other termination of this Agreement shall also survive for such three (3) year period.

17. Governing Law. This Agreement shall be governed by, and construed in accordance with, the laws of the State of California.

18. Waiver. A Party's failure to enforce any rights under this Agreement is not a waiver of that Party's rights, and no waiver constitutes a waiver of any subsequent breach or default. A waiver is effective only if in writing and signed by the waiving Party.

19. Entire Agreement. This Agreement and the Non-Disclosure Agreement constitute the entire agreement between the Parties for purposes of the promises and obligations of this Agreement and the Non-Disclosure Agreement. This Agreement and the Non-Disclosure Agreement replaces and supersedes any and all oral agreements between the Parties in connection with the requirement of SB 846 and disbursements of Maximum Amount, as well as any prior writings.

20. Severability. If any provision of this Agreement is rendered invalid or unenforceable under any circumstance, the remainder of this Agreement shall continue to be in full force and effect and the provision declared invalid or unenforceable shall continue to be in full force and effect as to other circumstances in accordance with the laws of the State of California.

21. Execution in Counterparts, Electronic Signatures and Document Transmission. This Agreement may be executed in counterparts, and, upon execution by each signatory, each executed counterpart shall have the same force and effect as an original instrument and as if all signatories had signed the same instrument. The Parties may execute this Agreement by manual signature or by electronic signature, each of which shall have the same force and effect. A signed copy of this Agreement transmitted by facsimile, email or other means of electronic transmission shall be deemed to have the same legal effect as delivery of an original executed copy of this Agreement for all purposes, to the extent provided under applicable law, including California's Uniform Electronic Transactions Act.

[*Signature Page Follows*]

IN WITNESS THEREOF, the Parties have caused this Agreement to be executed as of the date last signed below.

CALIFORNIA DEPARTMENT OF WATER RESOURCES (with respect to its responsibilities pursuant to Senate Bill 846 (Stats. 2022, ch. 239), and separate and apart from its powers and responsibilities with respect to the State Water Resources Development System or any other responsibilities of the Department)	**PACIFIC GAS AND ELECTRIC COMPANY**
By: Behzad Soltanzadeh Name: BEHZAD SOLTANZADEH Title: Acting Deputy Director Date: october 18, 2022	By: [signature] Name: Adam L. Wright Title: EVP Operations & COO Date: October 18, 2022
OFFICE OF GENERAL COUNSEL (DWR)	
By: Katharine S Killeen Name: Katharine S. Killeen Title: Assistant General Counsel Date: October 18, 2022	

EXHIBIT A

Defined Terms

"Business Day" means any day Monday through Friday, excluding any federal or state holidays.

"Commission" means the State Energy Resources Conservation and Development Commission.

"GAAP" means generally accepted accounting principles in the United States as in effect from time to time.

"Governmental Authority" means any nation or government, any state or other political subdivision thereof, any agency, authority, instrumentality, regulatory body, court, central bank or other entity exercising executive, legislative, judicial, taxing, regulatory or administrative functions of or pertaining to government, any securities exchange and any self-regulatory organization.

"Law" means, collectively, all statutes, laws, rules, regulations, ordinances, writs, judgments, orders, decrees, treaty and injunctions of any Governmental Authority, and common law, affecting PG&E or DCPP, and all permit, license, authorization, plan, directive, consent order, approval, registration and exemption or consent decree of or from any Governmental Authority relating thereto.

"State Agency" means any agency, department, board, office, commission, or district of the State, including but not limited to the State Lands Commission, the California Coastal Commission, the State Water Resources Control Board, the California Public Utilities Commission, the Commission and the State Office of Historic Preservation, or any local government.

[redacted]

[redacted]

EXHIBIT D

Form of Disbursement Request

California Department of Water Resources
715 P Street, 5th Floor
Sacramento, California 95814
Attention: Behzad Soltanzadeh
Title: Executive Manager, Statewide Water and Energy

Re: Disbursement Request No. [____]

This request for a [semiannual][supplemental] Disbursement (this "***Disbursement Request***"), dated as of [________], 20[_], is delivered to the California Department of Water Resources ("***DWR***") pursuant to Section 5.b. of the Loan Agreement for Diablo Canyon Nuclear Power Plant, dated as of [______], 2022 (as amended, restated, supplemented or otherwise modified from time to time, the "***Agreement***"), between Pacific Gas and Electric Company ("***PG&E***") and DWR. Capitalized terms used herein but not otherwise defined herein shall have the respective meanings set forth in the Agreement.

1. PG&E hereby requests a Tranche [B][C] Disbursement (the "***Disbursement Requisition***") in the aggregate amount of [_____] Dollars ($[_____]), the proceeds of which shall be used to pay for the Authorized Expenses described on Schedule 1 hereto and that have been incurred, are anticipated to be incurred, or are to be committed prior to the next semiannual true-up under the Agreement.

2. PG&E requests that on [_______], 20[_] (the "***Disbursement Date***") DWR deliver by wire transfer, in immediately available funds, the proceeds of such Disbursement Requisition to the [account specified in Section 14 of the Agreement] [following account: [_____]].

3. The Disbursement Requisition, when taken together with the Tranche A Disbursement [, all Tranche B Disbursements] and all Performance-Based Disbursements paid by DWR to PG&E prior to the Disbursement Date, will be $[__________].

4. PG&E certifies that as of the date hereof PG&E is in compliance with all required conditions set forth in Section 5.c.ii. of the Agreement that are applicable to it.

5. **[NTD: This provision should only be included for supplemental Disbursement Requests]** [PG&E certifies that the Authorized Expenses that are the subject of this Disbursement Request were not reasonably foreseeable when the prior semiannual request for Disbursement was submitted. This supplemental Disbursement Request is being submitted because [*insert a reasonably detailed explanation of the circumstances giving rise to such additional Authorized Expenses*].]

IN WITNESS WHEREOF, the undersigned has caused this Disbursement Request No. [__] to be duly executed and delivered as of the day and year first written above.

PACIFIC GAS AND ELECTRIC COMPANY

By: ______________________________

Name:

Title:

Schedule 1 to Disbursement Request No. [__] dated [______]

Expenditure Plan

This expenditure plan includes a list of expected milestones to be achieved, and Authorized Expenses and amount expected to be incurred, anticipated to be incurred, or to be committed prior to the next semiannual true-up period.

Expected Milestones:

[list of milestones]

Authorized Expenses and Amounts:

[list of Authorized Expenses and amounts therefor]

CONFIDENTIAL EXHIBIT W

CONFIDENTIAL EXHIBIT X

CONFIDENTIAL EXHIBIT Y

CONFIDENTIAL EXHIBIT Z

EXHIBIT Z1

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Retirement Joint Proposal
Application 16-08-006
Data Response

PG&E Data Request No.:	A4NR_004-Q002		
PG&E File Name:	DiabloCanyonRetirementJointProposal_DR_A4NR_004-Q002		
Request Date:	October 17, 2022	Requester DR No.:	004
Date Sent:	November 1, 2022	Requesting Party:	Alliance for Nuclear Responsibility
PG&E Witness:	Various	Requester:	John Geesman

QUESTION 002

Please provide a copy of the “executed loan agreements with the Department of Water Resources pursuant to SB 846 and AB 180,” mentioned on page 5 of PG&E’s October 7, 2022, Comments on Assigned Commissioner and Assigned Administrative Law Judge Amended Scoping Memo and Ruling.

ANSWER 002

PG&E objects to this data request as seeking information that is outside the scope of, and therefore not relevant to, the Amended Scoping Memo and Ruling, which is limited to the consideration of “[w]hether one or more new accounts needs to be established, and/or whether one or more existing cost tracking accounts needs to be modified, for PG&E to be able to track ‘all costs associated with the continued and extended operations of Diablo Canyon Units 1 and 2.’” Under SB 846, the Department of Water Resources (DWR) has the explicit statutory role for reviewing the use of loan proceeds by PG&E through a semi-annual true-up process. See Public Resources Code 25548.4. Accordingly, issues of contract implementation are beyond the scope of, and not relevant to, this limited proceeding.

Notwithstanding, and without waiving, this objection, PG&E clarifies that there is no “loan” agreement with DWR pursuant to AB 180.

EXHIBIT Z2

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response

PG&E Data Request No.:	TURN_002-Q004		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_TURN_002-Q004		
Request Date:	May 20, 2023	Requester DR No.:	002
Date Sent:	June 7, 2023	Requesting Party:	The Utility Reform Network
PG&E Witness:	Brian Ketelsen	Requester:	Matthew Freedman

The following questions relate to PG&E's May 19, 2023, testimony:

QUESTION 004

Have employee retention and severance payments been included in the data shown in Tables 1 or 2? If not, identify the amount of such payments by historic year and for each forecasted future year.

ANSWER 004

PG&E objects to this data request on grounds that it is irrelevant and outside the scope of this proceeding. Notwithstanding the aforementioned objection and without waiving the objection, PG&E responds as follows:

In regard to historical costs, employee retention and severance payments are not included in PG&E's Table 1.

In regard to forecast costs, PG&E assumes this question refers to an employee retention program beyond what was already approved in D.18-11-024. As stated in PG&E's May 19, 2023, testimony, costs associated with such an employee retention program are not included in the forecast table (Table 2) of the testimony. PG&E anticipates submitting a new application to present PG&E's proposal of the employee retention program, pursuant to Pub. Util. Code § 712.8(f)(2) in the future. PG&E will provide an update to its forecasted costs following submission of this application in accordance with guidance by the CPUC.

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response

PG&E Data Request No.:	TURN_002-Q011		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_TURN_002-Q011		
Request Date:	May 20, 2023	Requester DR No.:	002
Date Sent:	June 7, 2023	Requesting Party:	The Utility Reform Network
PG&E Witness:	Brian Ketelsen	Requester:	Matthew Freedman

The following questions relate to PG&E's May 19, 2023, testimony:

QUESTION 011

Identify the amounts expected to be recovered in rates by PG&E in each future year tied to the $13/MWh (in 2022 dollars) volumetric payment authorized pursuant to Public Utilities Code §712.8(f)(5)

a. Are these ratepayer obligations included in any line item shown in Table 2? If yes, identify the specific line item and the amounts included for each year.

ANSWER 011

PG&E objects to this data request on the grounds that it is irrelevant and outside the scope of this proceeding. Subject to and notwithstanding the foregoing objection, PG&E clarifies that any payment amounts related to the referenced volumetric payment would be presented in a future application for extended operations cost recovery. Notwithstanding and without waiving the foregoing objection, PG&E responds as follows. Payment amounts related to the referenced volumetric payment are not included in Table 2.

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response

PG&E Data Request No.:	TURN_002-Q012		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_TURN_002-Q012		
Request Date:	May 20, 2023	Requester DR No.:	002
Date Sent:	June 7, 2023	Requesting Party:	The Utility Reform Network
PG&E Witness:	Brian Ketelsen	Requester:	Matthew Freedman

The following questions relate to PG&E's May 19, 2023, testimony:

QUESTION 012

Identify the amounts expected to be recovered in rates by PG&E in each future year tied to the $50 million/unit (in 2022 dollars) fixed payment authorized pursuant to Public Utilities Code §712.8(f)(6)(A).

a. Are these ratepayer obligations included in any line item shown in Table 2? If yes, identify the specific line item and the amounts included for each year.

ANSWER 012

PG&E objects to this data request on the grounds that it is irrelevant and outside the scope of this proceeding. Subject to and notwithstanding the foregoing objection, PG&E clarifies that any payment amounts related to the referenced fixed payment would be presented in a future application for extended operations cost recovery. Notwithstanding and without waiving the foregoing objection, PG&E responds as follows. Payment amounts related to the referenced fixed payment are not included in Table 2.

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response

PG&E Data Request No.:	TURN_002-Q013		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_TURN_002-Q013		
Request Date:	May 20, 2023	Requester DR No.:	002
Date Sent:	June 7, 2023	Requesting Party:	The Utility Reform Network
PG&E Witness:	Brian Ketelsen	Requester:	Matthew Freedman

The following questions relate to PG&E's May 19, 2023, testimony:

QUESTION 013

Identify the amounts expected to be recovered in rates by PG&E in each future year for the liquidated damages balancing account authorized pursuant to Public Utilities Code §712.8(g). Provide the expected collection schedule for these amounts.

a. Are these ratepayer obligations included in any line item shown in Table 1 or Table 2? If yes, identify the specific line item and the amounts included for each year.

ANSWER 013

PG&E objects to this data request on the grounds that it is irrelevant and outside the scope of this proceeding. Subject to and notwithstanding the foregoing objection, PG&E clarifies that any payment amounts related to the referenced liquidated damages balancing account would be presented in a future application for extended operations cost recovery. Notwithstanding and without waiving the foregoing objection, PG&E responds as follows. Payment amounts related to the referenced liquidated damages balancing account are not included in Table 1 and Table 2.

EXHIBIT Z3

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response

PG&E Data Request No.:	A4NR_003-Q009		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_A4NR_003-Q009		
Request Date:	April 26, 2023	Requester DR No.:	003
Date Sent:	May 10, 2023	Requesting Party:	Alliance for Nuclear Responsibility
PG&E Witness:		Requester:	John Geesman

QUESTION 009

The Diablo Canyon Independent Safety Committee ("DCISC") report of its December 6-7, 2022 fact-finding visit contains the following discussion at p. D.6-6:

> Nuclear Fuel Management Engineering is responsible for new fuel procurement and spent fuel storage. DCPP refers to it as its "Bundled Fuel Process," which means that they perform the following:
>
> • Procure uranium ore
>
> • Have the ore processed into yellow cake
>
> • Have the yellow cake converted to uranium hexafluoride (UF6) gas
>
> • Have the UF6 enriched into a higher percentage of U-235
>
> • Have the enriched UF6 converted to uranium oxide (UO2)
>
> • Have the UO2 made into ceramic pellets and enclosed into Zircaloy tubes and fabricated into fuel assemblies and shipped to the plant.

a) For each refueling which will be necessary to extend plant operations for five years, please identify the status of PG&E commitments for each of the above steps.

b) If contractual commitments are presently lacking for any of the steps identified in response to the preceding question, please estimate when PG&E expects to execute the applicable contractual commitment.

c) For each applicable refueling, please estimate the aggregated cost for completion of all of the steps.

ANSWER 009

PG&E objects to this data request as irrelevant to and outside the scope of this proceeding. Subject to and without waiving that objection, PG&E responds that nuclear fuel procurement costs will be included in the historic and forecast costs presented in PG&E's May 19, 2023 testimony.