Application: 12-12-004
(U 39 E)
Exhibit No.: ____________
Date: September 9, 2013
Witnesses: Various

PACIFIC GAS AND ELECTRIC COMPANY

EMBARCADERO-POTRERO 230 KV TRANSMISSION PROJECT

PREPARED TESTIMONY

PUBLIC VERSION

VOLUME 1

PACIFIC GAS AND ELECTRIC COMPANY
EMBARCADERO-POTRERO 230 KV TRANSMISSION PROJECT
PREPARED TESTIMONY
VOLUME 1

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PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

INTRODUCTION AND OVERVIEW

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
INTRODUCTION AND OVERVIEW

A. Introduction

1. Scope and Purpose

The purpose of the Embarcadero-Potrero 230 kilovolt (kV) Transmission Project Application and Testimony is to provide support for Pacific Gas and Electric Company's (PG&E) request for a Decision and Order from the California Public Utilities Commission (CPUC or Commission) granting PG&E a Certificate of Public Convenience and Necessity (CPCN) to construct, operate and maintain the Embarcadero-Potrero 230 kV Transmission Project (Project or proposed Project).

2. Support for Request

Support for PG&E's request is presented in testimony as follows:

- Chapter 1 – Introduction and Policy: This chapter summarizes PG&E's request, introduces the testimony, explains the purpose of each of the subsequent chapters, provides an overview of the existing transmission system in San Francisco, risks facing the existing transmission system, and an overview of the proposed Project and its associated benefits.
- Chapter 2 – PG&E's Existing Transmission Systems: This chapter provides an overview of PG&E's existing 230 kV and 115 kV transmission systems in San Francisco.
- Chapter 3 – PG&E's Embarcadero Substation: This chapter provides information regarding the geographical area and customers served by PG&E's Embarcadero Substation in downtown San Francisco.
- Chapter 4 – PG&E's Proposed Embarcadero-Potrero Project: This chapter provides information about PG&E's proposed Embarcadero-Potrero 230 kV Transmission Project.
- Chapter 5 – PG&E's Cost Estimate for the Proposed Project: This chapter provides PG&E's current cost estimates for the Project and the methodologies used to develop those cost estimates.
- Chapter 6 – Seismic Risk to PG&E's Existing San Francisco 230 kV Transmission System: This chapter provides an assessment of the

seismic risk to the existing HZ transmission lines that are the sole source of power to Embarcadero Substation.

- Chapter 7 – Seismic Risk to New Embarcadero-Potrero 230 kV Transmission Line: This chapter provides an assessment of the seismic risk to the proposed Project's new ZA-1 transmission line that would be a third line to Embarcadero Substation. This chapter also assesses the Project's reduction of the risk of an outage of Embarcadero Substation as a result of a seismic event.
- Chapter 8 – Seismic Risk to Other System Components Serving Embarcadero Substation: This chapter provides an assessment of the likelihood that, after the Project is constructed, Embarcadero Substation will be able to supply power to downtown San Francisco after a major earthquake.
- Chapter 9 – Potential Non-Seismic Outages of Existing San Francisco 230-kV Transmission Lines: This chapter discusses potential non-seismic outages of the existing HZ transmission lines.
- Chapter 10 – Potential Non-Seismic Outages of New Embarcadero-Potrero 230-kV Transmission Lines: This chapter discusses potential non-seismic outages of the proposed Project's new ZA-1 transmission line.
- Chapter 11 – Restoration Time for Transmission Line Outages: This chapter discusses the estimated time to restore to service an existing HZ or the new ZA-1 line, depending on the nature of an outage.
- Chapter 12 – Economic and Social Impacts of an Embarcadero Substation Outage: This chapter provides an assessment of economic and social impacts of an Embarcadero Substation outage.
- Chapter 13 – Cost and Benefits of the Project: This chapter provides PG&E's assessment of the costs and benefits of the Project.
- Chapter 14 – Purpose and Need for Embarcadero-Potrero Project: This chapter provides PG&E's analysis of the purpose and need for the Project.
- Chapter 15 – Energy Division Variance Authority: This chapter discusses PG&E's request that the Commission authorize Energy Division to approve requests by PG&E for minor project modifications

that Energy Division finds do not result in new significant environmental effects or a substantial increase in the severity of previously identified significant effects.

3. Organization of the Remainder of This Chapter

- Section B – Project Purpose and Need Overview
- Section C – Conclusion

B. Project Purpose and Need Overview

The Project is needed to provide reliable electric service to downtown San Francisco, now and in the future. The Project will construct a new, single circuit, 230 kV transmission line between PG&E's Embarcadero Substation and PG&E's Potrero Switchyard. The proposed Project will be capable of delivering up to 400 megawatts (MW) of power to Embarcadero Substation. The purpose of the Project is to enhance the reliability of PG&E's electric service to San Francisco, and particularly to the downtown area served by Embarcadero Substation, given the significant adverse impacts that a service outage would have on the citizens and economy of San Francisco and the Bay Area.

1. PG&E's Existing 230 kV Transmission System

PG&E's Embarcadero Substation is the sole source of electricity to much of downtown San Francisco, including the Financial District, Union Square, North Beach, The Embarcadero, Chinatown, Nob Hill, Telegraph Hill, and the South of Market and North of AT&T Park areas. Embarcadero will be the source of electricity to future development on Rincon Hill and the TransBay Terminal. Embarcadero (and Substation J, fed by Embarcadero) serve about 30,000 customer accounts, including many of San Francisco's financial and professional services industries, shopping and restaurant districts, major office buildings, hotels, and tourist destinations, as well as approximately 25,000 residential accounts. An even higher number of residents, workers, clients, customers, and visitors depend each day on electrical service to downtown San Francisco.

Embarcadero Substation is currently fed solely by two underground, high-pressure fluid-filled pipe-type 230 kV cables, installed in 1974, constructed under city streets from Martin Substation. PG&E's Martin-Embarcadero 230 kV cables (known as HZ-1 and HZ-2), like PG&E's

underground transmission lines generally, have been very reliable to date. At present, and projected through at least 2030, either one of the two existing 230 kV cables can deliver enough electricity to meet current and expected demand at Embarcadero Substation.

There are various low-probability, but very high impact, scenarios under which both Martin-Embarcadero cables would be out of service, causing a potentially lengthy loss of electricity in downtown San Francisco. For example, as discussed in Chapter 6, both existing Martin-Embarcadero cables cross areas of high liquefaction potential and a major earthquake has a high probability of causing overlapping failures of both cables. The estimated time to restore a damaged HZ cable to service is up to eight weeks or more (to repair a single point of physical damage to the cable), assuming PG&E has available skilled labor, equipment and replacement cable. If an earthquake damaged both HZ cables, there may be multiple damaged pipe and cable segments that are difficult to find, and insufficient skilled manpower, equipment and spare cable available.

2. Economic and Social Impacts Due to Outage of Existing 230 kV System

As discussed in Chapter 12, based upon a survey of San Francisco businesses, Freeman Sullivan & Co. estimates that, if Embarcadero Substation lost power for seven weeks, the total direct and indirect cost to business would range from $4.4 billion to nearly $8.8 billion. A significant number of businesses would permanently close and many employees would lose their jobs, at least for the duration of the outage. People living in most of the 25,000 residential units would have to find another place to live during the outage, at additional cost that could be very significant to the affected families. Government agencies also would incur costs to respond to the outage and its impacts.

3. Project Benefits

The Project benefits the public in the short term by addressing the immediate reliability risks to service from Embarcadero Substation, and also by reinforcing PG&E’s 115 kV transmission system in San Francisco. Moreover, in the longer term, PG&E will be required by Federal Energy Regulatory Commission (FERC)-approved reliability criteria to add a third cable to Embarcadero to accommodate forecasted load growth or replacement of an existing cable. By constructing the Project now, rather than waiting, PG&E will provide its customers and downtown San Francisco a much greater assurance of continued reliable electric service.

The immediate reliability risks arising from Embarcadero's reliance on the two existing HZ 230 kV cables as its sole source of electricity include:

- As discussed in Chapter 6, a major earthquake poses a significant risk of damage to both HZ transmission lines because, although the cables are not co-located, both cables are located in areas of San Francisco expected to be subject to significant liquefaction. Physical damage to each pipeline or cable could take weeks to months to fix. As discussed in Chapter 7, PG&E's proposed new Embarcadero-Potrero cable would avoid the areas of high liquefaction potential traversed by the existing cables and will be designed to meet a performance objective of remaining operational after a major earthquake. The Project significantly increases the probability that at least one of three cables will remain operational.
- As discussed in Chapter 9, one existing HZ cable may be out of service due to a planned outage for maintenance or to accommodate construction of other infrastructure. For example, the city of San Francisco recently requested that one of the HZ cables be de-energized for approximately four months to accommodate a City sewer project. This project has been deferred temporarily to allow for the permitting and construction of the proposed Project. Without the Project, whenever one HZ cable is on a planned outage, a forced outage of the other HZ cable will force Embarcadero Substation out of service. With the third cable proposed by the Project, a planned outage of a single cable would not pose that risk.
- An existing HZ cable may be forced out of service due to mechanical damage to the fluid-filled pipe containing the cable or also to the cable itself (such damage may occur from a "dig-in" caused by a third-party construction project, or a break of a nearby water main). Depending upon the nature of the forced outage, it could take hours to months to restore the cable to service. Without the Project, during this time period,

a forced outage of the other existing cable will force Embarcadero Substation out of service. Again, with the third cable proposed by the Project, a planned outage of a single cable would not pose that risk.

Another immediate benefit of the Project is that it will connect PG&E's San Francisco 230 kV and 115 kV transmission systems at the Potrero Switchyard. As discussed in Chapter 14, such an interconnection would provide a number of benefits to PG&E operations and reliability, including: (a) provide the 115 kV system with an additional source of power when the HZ cables are in operation; (b) facilitate the eventual replacement of the 115 kV cables, some of which are now 55-65 years old; and (c) provide power from the 115 kV system to the 230 kV system if the 115 kV system were operational, but both the TransBay Cable and the Martin-Embarcadero HZ cables were not.

In addition to providing an immediate assurance of increased reliability to customers served through Embarcadero Substation, the Project has additional reliability benefits in the long run. At some point in the future, PG&E will be required to install a third cable to Embarcadero Substation to meet the FERC-approved North American Electric Reliability Corporation (NERC) transmission planning reliability standards:

- At some point, after approximately 2030, unless downtown San Francisco energy usage stops growing, the customer load served by Embarcadero Substation will exceed the capability of one of the existing HZ cables. At that point, PG&E could be forced to drop service to some Embarcadero customers if only one of the HZ cables were out of service, depending upon the demand at the time of outage. Having to drop load following the loss of a single transmission line would be a violation of NERC Reliability Standard TPL-002-0b (Category B). Given that current peak load is approximately 280 MW and each existing cable's capability is approximately 400 MW, this situation is not expected soon. However, without the Project, this situation is expected if Embarcadero continues to be served by only two cables. The Project will mitigate this future reliability risk while having the immediate benefits noted above.

- At some point, the existing HZ cables will need to be replaced. The cables were installed 39 years ago in 1974, have functioned reliably, and many pipe-type transmission cables have continued operating long past the manufacturer's estimated 40-year useful life. However, it is reasonable to expect that, at some point, each will need to be replaced. As the need for replacement becomes evident, PG&E will need to construct a third cable to Embarcadero Substation to ensure reliable electric service. Without the Project, when one HZ cable fails, Embarcadero would be forced out of service if the other existing HZ cable failed. As noted above, that situation would violate NERC Reliability Standard TPL-002-0b (Category B). Constructing a third cable now would address the eventual need for a third cable when the existing cables must be replaced, as well as reduce or eliminate the current risk of overlapping outages of the existing cables.

PG&E has concluded that the value of making the reliability investment reflected in the Project now is warranted based upon the risk of an overlapping outage of both existing Martin-Embarcadero cables; the length of time it likely would take to repair damaged HZ cables; the impact that such an outage would have upon PG&E's customers and others in downtown San Francisco; the reduction of risk resulting from the Project; and the estimated cost of mitigating the risk through the Project. The Project will provide a third cable into Embarcadero Substation from Potrero Switchyard rather than Martin Substation, both diversifying Embarcadero's sources of energy to include the TransBay Cable and interconnecting PG&E's 230 kV and 115 kV systems in San Francisco.

4. California Independent System Operator's Ruling on the Need for the Proposed Project

In its 2011-2012 Transmission Plan, the California Independent System Operator Corporation's (CAISO) similarly concluded: "While the likelihood of the simultaneous loss of both circuits is low, the consequences of the outage are severe and require mitigation." (CAISO, 2012, p. 107.) With respect to the project, the Transmission Plan states: "The ISO has determined that this project is needed to address the reliability requirements of the area and is expected to be in-service in 2015." (CAISO, 2012, p. 108.)

C. Conclusion

As supported by the overview above and in the subsequent chapters, PG&E requests that the CPUC:

- Find that the public convenience and necessity does now and will in the future require the proposed Project.
- Issue a Decision and Order granting PG&E a CPCN for the proposed Project.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

PG&E'S EXISTING SAN FRANCISCO TRANSMISSION SYSTEMS

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CHAPTER 2
PG&E'S EXISTING SAN FRANCISCO TRANSMISSION SYSTEMS

A. Introduction

1. Scope and Purpose

The purpose of this chapter is to provide an overview of Pacific Gas and Electric Company's (PG&E) existing 230 kilovolt (kV) and 115 kV transmission systems in the City of San Francisco (City).

2. Organization of the Remainder of This Chapter

- Section B – Overview of PG&E's Existing Transmission Systems
- Section C – PG&E's Existing San Francisco 230 kV Transmission System
- Section D – PG&E's Existing San Francisco 115 kV Transmission System
- Section E – San Francisco Depends on Transmission of Electricity Generated Elsewhere

B. Overview of PG&E's Existing San Francisco Transmission Systems

These systems are not currently interconnected within San Francisco. The 230 kV system is supplied from PG&E's Martin Substation in Brisbane.[1] The 115 kV system is supplied from Martin Substation and also by the Trans Bay Cable (TBC) connection at PG&E's Potrero Switchyard. Because no large central power generation station is located within its borders, San Francisco is almost entirely dependent on electric transmission lines to provide electricity to its residents, businesses, public agencies, workers, customers and visitors.

C. PG&E's Existing San Francisco 230 kV Transmission System

PG&E's 230 kV transmission system in San Francisco consists of two 230 kV underground cables running roughly 7 miles from PG&E's Martin Substation to Embarcadero Substation in San Francisco. Embarcadero Substation is not connected to PG&E's 115 kV San Francisco transmission grid.

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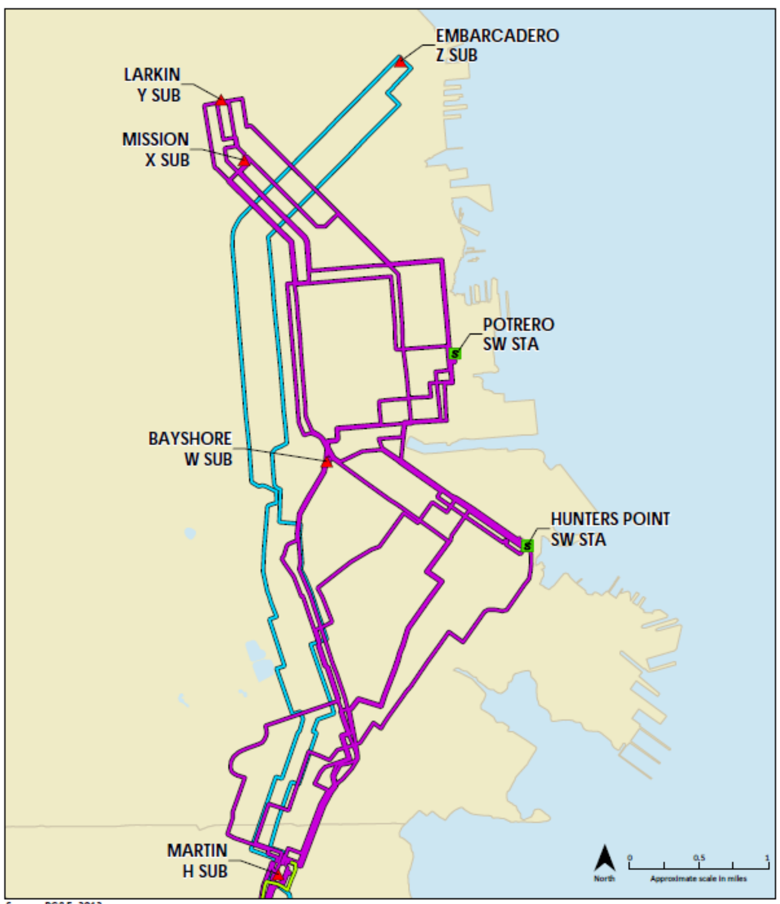
[1] The Martin Substation address is 731 Schwerin St., Daly City, CA 94014, but the majority of the substation itself is located in Brisbane.

The two existing 230 kV transmission lines (referred to as HZ-1 and HZ-2) were placed in-service in 1974 and are the sole source of power to Embarcadero Substation.

The HZ-1 and HZ-2 underground transmission lines exit Martin Substation and follow separate but generally parallel routes to Embarcadero Substation. For most of these routes from Martin up into San Francisco, the two lines are located under different streets. Figure 2-1 below shows the routes of the cables from Martin to Embarcadero. (The 230 kV cables are shown in blue.)

FIGURE 2-1
PACIFIC GAS AND ELECTRIC COMPANY
MAP OF THE 230 KV AND 115 KV UNDERGROUND TRANSMISSION SYSTEMS SERVING SAN FRANCISCO



Source: PG&E, 2012.

HZ-1 and HZ-2 are of the High Pressure Fluid Filled (HPFF) Pipe Type design. This cable design uses conductors wound with oil-impregnated insulating paper, with all three phases placed in a single 10-inch diameter steel pipe containing a pressurized dielectric fluid. The steel pipe supports the high operating pressure of the cable fluid; protects the conductors from mechanical damage and water infiltration, and minimizes the potential for oil leaks; and is itself protected from the chemical and electrical environment of the soil with a coating and cathodic protection. The pipes are encased in a limestone and concrete slurry that adheres to the pipe like a concrete duct bank. The slurry is weaker than concrete and can be knocked off to allow work on the pipe or coating. The slurry also helps conduct heat from line losses away from the pipe. The pipe is enclosed in a steel casing under railroad tracks and deep crossings, and connects to a splice casing inside of splice vaults. The cable insulating fluid is automatically pressurized, pumped to, and returned from each line pipe during thermal expansion and contraction of the cable fluid inside. Two pumping stations, one each at PG&E's Embarcadero and Martin Substations, are connected to each line pipe through a single four-inch steel pipe. The pumping stations monitor and maintain the pressure of the fluid, and can be operated in an oscillating mode to smooth out temperatures along the circuit.

The conductor size in each cable is 2,500 thousand circular mil copper conductor, with a capability of 1,050 amperes (418.3 MVA at 230 kV). With the current peak demand at Embarcadero Substation less than 300 megawatts (MW), each cable has the capability to supply all of the current demand in the downtown area.

D. PG&E's Existing San Francisco 115 kV Transmission System

PG&E's 115 kV transmission system in San Francisco consists of 13 underground transmission lines.[2] Six of these lines, with a total length of almost 30 circuit-miles[3] of cable, are "import" lines that bring power into the city from Martin Substation: three 115 kV import lines run from Martin Substation to Hunters Point Substation; two 115 kV import lines run from Martin Substation to Bayshore Substation and then on to Potrero Switchyard; and one 115 kV import line runs from Martin Substation to Larkin Substation.

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2 There are short overhead sections on the Martin-Hunters Point No. 3 115 kV Cable and the Hunters Point-Mission No. 2 115 kV Cable just south of Hunters Point.

3 A circuit-mile includes all conductors for that circuit, which are three conductors for alternating current (AC) transmission lines such as these. Therefore, each circuit-mile of AC line contains 3 miles of cable.

PG&E's Potrero Switchyard and Larkin, Mission and Hunters Point Substations are interconnected within San Francisco by seven "internal" 115 kV lines (with a total length of 20 circuit-miles). These internal lines primarily deliver power to Larkin and Mission Substations from Potrero Switchyard and Hunters Point Substation. The internal lines can also provide an alternative path for power to flow to the various substations if the import line(s) running directly from Martin Substation to any given substation should be subject to a planned or forced outage.

Construction of the 115 kV system started in the late 1940s, and approximately 50 circuit-miles of underground cable were installed at various times between 1948 and 2009, as follows:

- 16.7 circuit-miles were installed by 1948
- 7.4 circuit-miles were installed between 1948 and 1958
- 12 circuit-miles were installed in the early 1960s
- 3.5 circuit-miles were installed in the early 1970s
- 2.9 circuit-miles were installed in 1989
- 2.5 circuit-miles were installed in 2006
- 5 circuit-miles were installed in 2009

The 115 kV underground system utilizes two types of cable design. The cables installed prior to 1990 are all of the High Pressure Gas Filled (HPGF) Pipe Type design. This cable design has the three phase conductors wound with oil-impregnated insulating paper, which are then placed in a steel pipe and pressurized with a nitrogen blanket. The pipelines are similar in construction to the HPFF 230 kV cables, except that there are no pumping plants. The HPGF design utilizes a static high pressure of nitrogen and requires an occasional charge of makeup gas.

The last two cables installed in 2006 and 2009 (Potrero – Hunters Point No. 1 (AP-1) and Martin – Hunters Point No. 4 (HP-4)) utilize a different design; the three phase conductors are each extruded with cross-linked polyethylene (XLPE) solid dielectric insulation and are placed in a concrete-encased polyvinyl chloride duct bank.

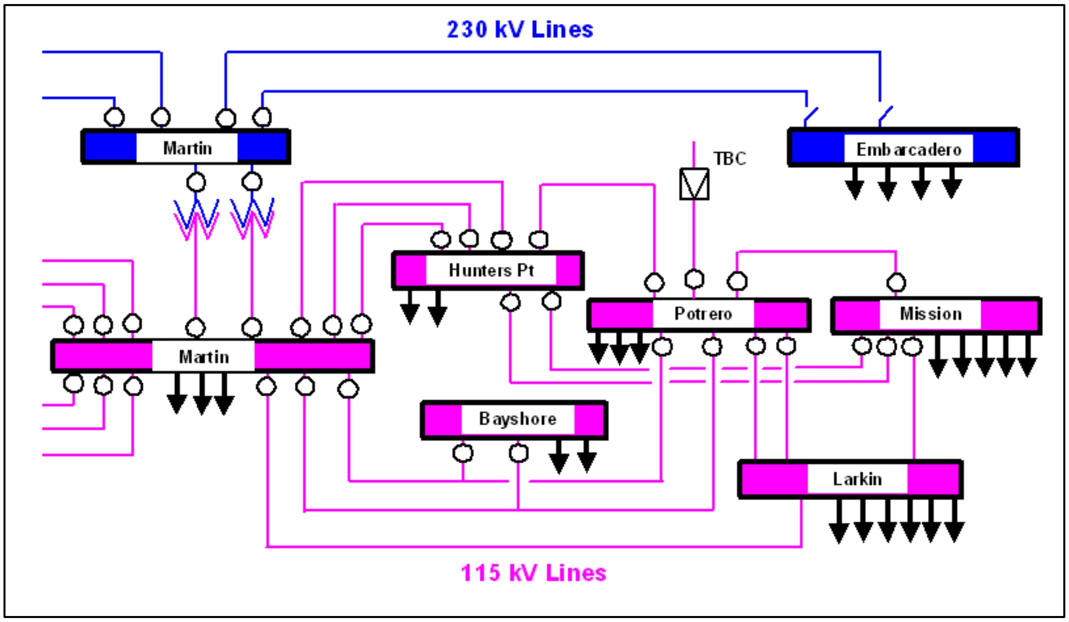
PG&E recently completed a re-cabling project between Martin Substation and Potrero Switchyard, which replaced 10 circuit-miles of cable circuits in the two import lines from Martin Substation to Bayshore Substation and Potrero

Switchyard. The replacement work also allowed PG&E to inspect the two HPGF pipes for pipe and coating integrity and to make necessary repairs to external damage caused by others. With completion of this work, PG&E's 115 kV system in San Francisco still has 13 circuit-miles of cable that are more than 60 years old and another 7 circuit-miles of cable that are more than 50 years old.

The 115 kV system has a load-serving capability of about 900 MW, with the TBC out of service. This capability assumes that the 115 kV cables can utilize their higher, short-term emergency ratings during an outage of the TBC that lasts no more than a couple of days. If the TBC is out for longer than several days, then the cables can only be loaded up to their long-term ratings, and the load-serving capability of the 115 kV system drops to about 800 MW. The total load served through the five substations that are part of the 115 kV network (which does not include Embarcadero Substation) reaches about 600 MW on hot days, and up to 630 MW on cold winter evenings. With continuing growth in San Francisco, particularly in the Mission Bay and Bay View-Hunters Point areas, the peak load on the 115 kV network is expected to exceed 650 MW within the next several years.

The routes of the 115 kV cables are shown in purple in Figure 2-1; and Figure 2-2 shows a single-line diagram of the layout of the electric transmission system in San Francisco.

FIGURE 2-2
PACIFIC GAS AND ELECTRIC COMPANY
SINGLE LINE DIAGRAM OF THE TRANSMISSION SYSTEM IN SAN FRANCISCO



The table in Attachment A lists the design, age, length and ratings of the underground electric transmission cables in San Francisco.

E. San Francisco Depends on Transmission of Electricity Generated Elsewhere

PG&E's electric transmission in the City was originally designed to bring power into the City from Martin Substation to supplement power generated in the City at the Hunters Point and Potrero Power Plants. Over the past decade or so, there was a community desire to close those power plants. In response, PG&E upgraded its electric transmission system, adding new lines such as the Jefferson – Martin 230 kV line and new 115 kV cables in the City, to eliminate reliance on these old power plants. With the addition of these new cables, the Hunters Point Power Plant was shut down in 2006. Following the completion of the TBC Project and PG&E's 115 kV Recabling Project in the City, the Potrero Power Plant also was closed in late 2010. At this time, there is no central station generation serving PG&E load in the City, and PG&E is not aware of any planning for such generation.

Today, the City is supplied with power generated elsewhere and conveyed by transmission lines into the City. The City is served by electricity transmitted from PG&E's Martin Substation via PG&E's 230 kV and 115 kV transmission systems described above. The City also is served via the TBC, a high-voltage direct-current (HVDC) line to PG&E's Potrero Substation. TBC is a 53-mile, 200 kV HVDC line from Pittsburg to Potrero. TBC can be scheduled to transmit from 0 MW up to 400 MW of power from Pittsburg to Potrero to help supply substations connected to the 115 kV system. Because TBC's HVDC line has a maximum power transfer level of 400 MW, all of the remaining power to supply the City currently comes through Martin Substation.

The total City electric demand can range from 450 MW during off-peak hours to over 960 MW on hot days and cold winter evenings. (Note: Some of the City's electric demand is supplied directly from distribution transformers located at Martin Substation. This amounts to roughly 100 MW during peak load conditions.) Electric demand at Embarcadero Substation ranges from 100 MW during off-peak hours to over 270 MW on hot days. Demand on the 115 kV system in the City ranges from a minimum of 300 MW to over 600 MW on cold winter evenings. (Note: This does not include the load served directly from Martin Substation.)

PG&E's 230 kV and 115 kV systems within the City are not interconnected. As a result, neither PG&E's 115 kV network nor the TBC can directly supply Embarcadero Substation. All power to Embarcadero Substation must come from Martin Substation via the two existing 230 kV cables. The TBC line can supply up to 400 MW to the 115 kV network. Should the TBC be unavailable or should demand levels on the 115 kV network exceed 400 MW, power to the 115 kV network must be supplied from Martin Substation.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT A

LENGTH AND AGE DATA FOR UNDERGROUND ELECTRIC TRANSMISSION CABLES IN SAN FRANCISCO

TABLE 2-1
PACIFIC GAS AND ELECTRIC COMPANY
ATTACHMENT A – LENGTH AND AGE DATA
FOR UNDERGROUND ELECTRIC TRANSMISSION CABLES IN SAN FRANCISCO

	Cable Design	Length (Miles)	Installation Date(s)			Existing Ratings (MVA)		Recabled Ratings (MVA)	
						Normal	Emerg.	Normal	Emerg.
Import 115 kV Lines									
Potrero-Martin-Bayshore No.1 (AHW-1) Line	HPGF	4.9	1961	1972		144.4	165.3	172.3	221.5
Potrero-Martin-Bayshore No.2 (AHW-2) Line	HPGF	5.1	1948	1965	1972	129.5	151.8	172.3	221.5
Martin-Hunters Point No. 1 (HP-1) Line	HPGF	3.9	1948			129.5	158.1		
Martin-Hunters Point No. 3 (HP-3) Line	HPGF	3.6	1958	1975		129.5	150.0		
Martin-Hunters Point No. 4 (HP-4) Line	XLPE - DB	5.0	2009			275.0	275.0		
Martin-Larkin No. 1 (HY-1) Line	HPGF	7.2	1948	1971		139.4	153.0		
		29.7							
Internal 115 kV Lines									
Potrero-Mission No. 1 (AX-1) Line	HPGF	2.7	1948	1961		139.4	139.4		
Potrero-Hunters Point No. 1 (AP-1) Line	XLPE - DB	2.5	2006			212.0	239.1		
Potrero-Larkin No. 1 (AY-1) Line	HPGF	3.3	1963	1968		149.4	149.4		
Potrero-Larkin No. 2 (AY-2) Line	HPGF	2.9	1989			159.3	159.3		
Hunters Point-Mission No. 1 (PX-1) Line	HPGF	4.0	1948			139.4	139.4		
Hunters Point-Mission No. 2 (PX-2) Line	HPGF	4.0	1958			144.4	144.4		
Mission-Larkin No. 1 (XY-1) Line	HPGF	0.6	1963			139.4	139.4		
		20.0							
Embarcadero 230 kV Lines									
Martin-Embarcadero No. 1 (HZ-1) Line	HPFF	6.9	1974			418.3	418.3		
Martin-Embarcadero No. 2 (HZ-2) Line	HPFF	6.9	1974			418.3	418.3		
		13.8							

Notes:

(a) The cells shaded in grey show the two 115 kV lines that PG&E recabled in 2010.

(b) Some lines have multiple installation dates. This is because the electric transmission system in the City has been reconfigured over the years. For example, the Potrero-Martin-Bayshore Cables were the Potrero-Martin Cables up until 1972, when the new Bayshore Substation was installed to serve the BART system.

(c) Cable design nomenclature: HPGF = high pressure, gas-filled, pipe-type cable; HPFF = high pressure, fluid-filled, pipe-type cable; XLPE – DB = cross-linked, polyethylene cable in duct bank.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

PG&E'S EMBARCADERO SUBSTATION

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CHAPTER 3
PG&E'S EMBARCADERO SUBSTATION

A. Introduction

1. Purpose and Scope

The purpose of this chapter is to provide an overview Pacific Gas and Electric Company's (PG&E) Embarcadero Substation, which is located in downtown San Francisco.

2. Organization of the Remainder of This Chapter

- Section B – The HZ Cables are the Sole Power Source to Embarcadero Substation
- Section C – Embarcadero Substation Serves a Significant Portion of Downtown San Francisco
- Section D –PG&E Customers Served by Embarcadero Substation
- Section E – Loss of Service if Both HZ Cable Are Out of Service

B. The HZ Cables Are the Sole Power Source to Embarcadero Substation and Substation J

PG&E's 230 kilovolt (kV) transmission system in San Francisco consists of two 230 kV underground cables (the HZ cables) running roughly 7 miles from PG&E's Martin Substation in Daly City to Embarcadero Substation in San Francisco. Embarcadero Substation is not connected to PG&E's 115 kV San Francisco transmission grid. The two existing 230 kV HZ transmission lines were placed in-service in 1974 and are the sole source of power to Embarcadero Substation.

PG&E's Substation J, located on Leidesdorff Street near the Transamerica Building, is fed through Embarcadero Substation and also has no other source of power. Through a series of 12 kV distribution circuits, Embarcadero Substation and Substation J together (hereinafter simply referred to as Embarcadero Substation) serve approximately 30,000 PG&E account holders, including roughly 25,000 residential accounts.

C. Embarcadero Substation Serves a Significant Portion of Downtown San Francisco

Embarcadero Substation provides electricity to a significant portion of downtown San Francisco. The geographical areas served by Embarcadero Substation include: South of Market and Rincon Hill; China Basin; Nob Hill; Chinatown; the Embarcadero; North Beach; Union Square; Telegraph Hill; and the Financial District. The area of service is shown in Figures 3-1 and 3-2 below. The geographical area of service is roughly bounded by 7th Street north to Pine Street, west along Pine Street to Larkin Street, north along Larkin Street to Vallejo Street, east on Vallejo Street to Jones Street, north to Greenwich Street, then east to Grant Street and north along Grant Street to the Bay, then south and east along the shoreline to China Basin.

FIGURE 3-1
PACIFIC GAS AND ELECTRIC COMPANY
EMBARCADERO SUBSTATION SERVICE AREA

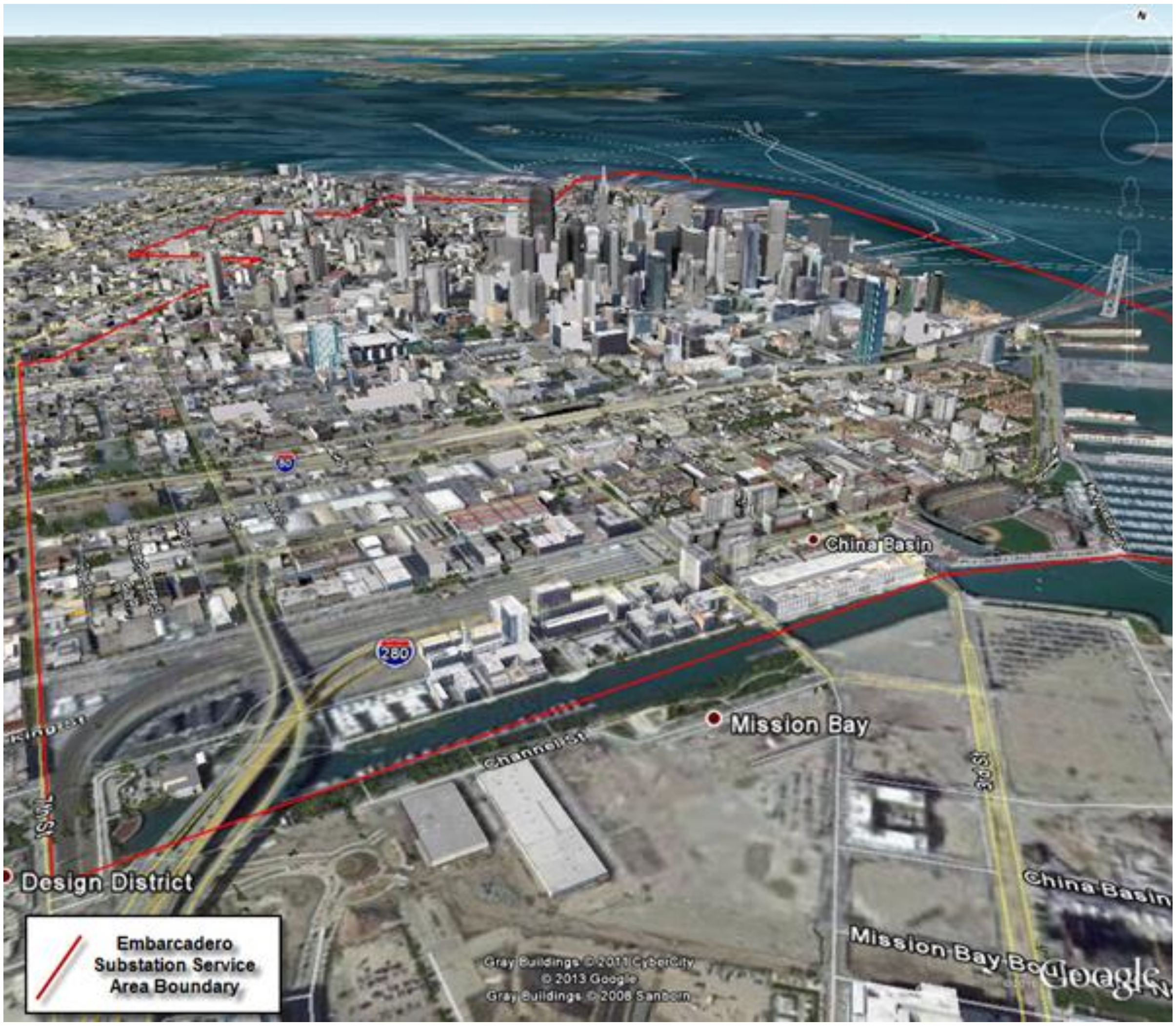
Source: PG&E 2012.

LEGEND

Substation

Area Served by Embarcadero Substation
Embarcadero-Potrero 230 kV Transmission Project
San Francisco, CA

FIGURE 3-2
PACIFIC GAS AND ELECTRIC COMPANY
CITY VIEW OF EMBARCADERO SUBSTATION SERVICE AREA



The peak demand on Embarcadero Substation has grown from about 160 megawatt (MW) in 1992 to 270 MW in 2008 – a growth rate of about 6 MW/year. Peak demand at Embarcadero Substation declined from the 270 MW peak in 2008 to between 250 and 260 MW in 2009-2012 due to the economic downturn and cooler weather. Based upon PG&E's current projections, the peak demand in 2016 will be approximately 305 MW. When in service, each of the existing HZ 230 kV cables can provide 400 MW of power to Embarcadero Substation.

D. PG&E Customers Served by Embarcadero Substation

As of 2013, PG&E customers served by Embarcadero Substation are 86 percent residential accounts (25,843), 9 percent commercial accounts

(2,769), and 5 percent industrial accounts (1,500). Approximately 22,000 of these accounts are served from Embarcadero Substation directly and 8,000 indirectly through Substation J.

The number of PG&E account holders served by Embarcadero Substation undercounts the number of individuals and businesses served by Embarcadero Substation for at least three reasons.

First, there are office and retail commercial buildings in downtown San Francisco that house multiple tenants, but have only one PG&E account holder, usually the building owner. Thus, while PG&E may have only one account for that building, there are multiple businesses in that building.

Second, for new residential buildings, constructed after approximately 1980, there are individual accounts (meters) for each residence in the building. However, before approximately 1980, some residential buildings have only one account (and one meter) for the entire building. Thus, for example, a nine story building with three units per floor might have only one account if constructed before approximately 1980 or 27 accounts if constructed later.

Third, PG&E's information about customer accounts does not identify the number of persons served by electricity at that account. Thus, a residential account may serve a single individual, a couple, or a family. Similarly, business accounts provide electricity to business employees, clients, customers and visitors.

E. Loss of Service if Both HZ Cables Are Out of Service

If both of the HZ cables were out of service, Embarcadero Substation would lose power and be unable to serve PG&E's approximately 30,000 customer accounts, and the people and businesses that those accounts serve. Approximately 4,000 out of 30,000 (13%) customer accounts, about 10 MW of the currently estimated peak 280 MW load served by Embarcadero Substation, would be able to be picked up from adjacent distribution circuits from other substations. This applies only to customer accounts on the 12 kV radial circuits and will require manual switching in the field, which will take several hours of switching time depending on the situation. None of the Network load can be picked up by other substations due to the inherent design of the Network system.

Residential, commercial and industrial buildings dependent on electricity to power their Heating, Ventilation and Air Conditioning (HVAC) equipment, elevators and lighting will not be habitable until power is restored. Businesses reliant on electricity to power their equipment, such as computers, checkout registers, lighting, refrigerators, etc., will not be able to operate unless they have sufficient backup generation.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

PG&E'S PROPOSED EMBARCADERO-POTRERO

230 KV TRANSMISSION PROJECT

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
PG&E'S PROPOSED EMBARCADERO-POTRERO
230 KV TRANSMISSION PROJECT

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A. Introduction

1. Purpose and Scope

The purpose of this chapter is to provide an overview of the proposed Embarcadero-Potrero 230 kilovolt (kV) Transmission Project (the Project or proposed Project).

2. Organization of the Remainder of This Chapter

- Section B – Overview of the Project
- Section C – Pacific Gas and Electric Company's (PG&E) Proposed Project
- Section D – Construction Duration and Workforce
- Section E – PG&E's Compliance With California Public Utilities Commission (CPUC or Commission) Electro Magnetic Field (EMF) Policies

B. Overview of the Project

The proposed Project consists of installing a new, approximately 3.5 miles transmission line in San Francisco between PG&E's Potrero Switchyard and Embarcadero Substation. Embarcadero Substation is located near the corner of Fremont and Folsom Streets, and Potrero Switchyard is located on Illinois Street between 22nd and 23rd Streets. The proposed Project will be capable of delivering up to 400 megawatts of electricity to Embarcadero Substation.

This new line, also referred to as ZA-1, includes approximately 2.5 miles to be installed offshore in the San Francisco Bay (the Bay), approximately 0.4 miles to be installed in horizontal directional drilling (HDD) from the Bay to the transition points on land, and approximately 0.6 mile to be installed underground in paved areas. The submarine portion will typically be buried 6 to 10 feet underneath the Bay floor, roughly 1,500 to 2,500 feet off the western shoreline. At each end of the submarine portion of the route, transitional sections totaling approximately 0.4 miles will be installed in HDD conduits where the submarine cable transitions from offshore to onshore. At the northern end, the transition from the Bay to underground cable in city streets will be located in the lower Embarcadero area south of the Bay Bridge, with the HDD passing between Piers 28 and Piers 30-32 to end inland at Spear Street. At the southern end, the cable transition from the Bay will be located along 23rd Street.

PG&E will interconnect the new 230 kV transmission line within Embarcadero Substation (which is currently being upgraded pursuant to the separate Embarcadero Substation 230 kV Bus Upgrade Project) and to a new 230 kV switchyard that will be built adjacent to the existing Potrero Switchyard. The new 230 kV switchyard will be interconnected with the existing 115 kV switchyard, thus integrating PG&E's electric transmission systems in San Francisco.

The precise location of staging and laydown areas will depend on specific encroachment permits and other construction ongoing in the area, and will be coordinated with the City and/or the Port of San Francisco. Barges and other floating equipment necessary for the submarine portion of the Project may be docked or anchored temporarily in the Bay. Construction materials for the Project will be stored at existing PG&E-owned facilities as much as possible or on leased industrial properties.

The estimated Project construction duration is 22 months, starting from CPUC's notice to proceed and ending when the new line is placed in-service.

C. PG&E's Proposed Project

PG&E's Project is discussed below in its component parts, moving from Potrero Switchyard to Embarcadero Substation.

1. Potrero Switchyard

a. General Description

Potrero Switchyard is located in the city of San Francisco on Illinois Street between 23rd and 22nd Streets in what is known as the "Dogpatch" neighborhood. The existing Potrero 115 kV to 12 kV Switchyard contains underground 115 kV connections to the PG&E transmission system and to the TransBay Cable High-Voltage Direct Current facility and associated protection equipment. The 12 kV portion of the switchyard includes several 12 kV feeders serving local PG&E customers and associated protection equipment.

Since there currently is no 230 kV equipment at the existing Potrero Switchyard, the Project includes construction of a new 230 kV switchyard to accommodate the new cable's connection to the PG&E transmission system. The proposed location for the new switchyard is on a parcel owned by NRG Energy Inc. (NRG) (formerly GenOn Energy, Inc.), located on 23rd Street, adjacent to and east of the existing switchyard. PG&E will acquire from NRG approximately 1.523 acres of land for the new switchyard, and a temporary construction easement of approximately 1.40 acres.

b. Structures and Equipment to Be Built

The existing 115 kV Potrero switchyard, built in the 1960s, was designed as an "air insulated switchyard." However, due to present space constraints, the new 230 kV switchyard will be designed with a "gas insulated switchgear" (GIS) design that dramatically reduces the physical electrical clearance of the electrical bus phases by combining them in gas insulated ducts rather than several feet apart in the open air. This very significantly reduces the overall facility's footprint.

The GIS equipment, associated Modular Protection, Automation and Control (MPAC) equipment, and station service systems will be housed in an estimated 8,500 square foot building with an equally large basement. The basement will contain electrical conduits, trays and cables to interconnect the electrical equipment on the main floor. The height of the building will be approximately 40 feet above grade to accommodate the height and maintenance requirements of the electrical equipment.

Outdoor equipment will be partitioned from the GIS building with firewalls. The outdoor equipment includes one new 230/115 kV transformer, one new 230 kV shunt reactor, and their respective cable-to-air bushing connections. The design will include spare bays that allow for the possible future installation of an additional 230 kV transformer and shunt reactor if determined to be needed or appropriate.

The following major equipment will be installed in the new 230 kV switchyard or the existing 115 kV switchyard:

- Two 230 kV GIS break and a half (BAAH) bays, set up in ring bus arrangement with circuit breakers and disconnect switches (two breakers in one bay and one in the second bay for possible future BAAH equipment)
- One 3-phase, 230/115 kV, 420-megavolt ampere transformer bank with Load-Tap Changer and 12 kV station service transformers
- One 230 kV cable termination for the new Embarcadero-Potrero cable
- One spare position for any future 230 kV cable connection
- One 230 kV shunt reactor for the Embarcadero-Potrero cable with a circuit breaker and disconnect switch
- One spare position for any future 230 kV transformer bank, shunt reactor, circuit breakers, and disconnect switches
- Two 115 kV GIS Bus Sectionalizing breakers with associated disconnect switches
- One 115 kV GIS BAAH bay with circuit breakers and disconnect switches for the low-side of the 230/115 kV transformer bank, plus a spare position for any future bank
- Connection to the existing 115 kV substation
- 115 kV and 230 kV capacitance coupled voltage transformers (CCVT) or potential transformers as required
- An MPAC section for the 230 kV and the 115 kV equipment
- A battery to provide direct current power for the MPAC and the switchyard equipment

PG&E has retained ABB to design and construct the new 230 kV switchyard. PG&E's design criteria include the requirement that the significant switchyard equipment must meet the Institute of Electrical and Electronic Engineers Standard 693 (Recommended Practice for Seismic Design of Substations) "High" qualification level. As discussed further in Chapter 8, in general, the "High" qualification level requires the substation equipment and components to withstand a standard input motion anchored to 0.5 grams Peak Ground Acceleration. When subjected to this level of seismic loading, mechanical and structural component stresses are limited to Allowable Strength Design acceptance criteria, which provide a substantial margin against failure. Most 230 kV equipment and components are required to be shake table-tested and their functionality is verified following shaking. Other equipment are qualified by analytical means. Equipment that has been subjected to and passed these seismic qualification protocols also is expected to maintain its structural integrity and continue to function following the 84th percentile 7.8 moment magnitude (M) San Andreas Earthquake that PG&E has defined as the maximum credible earthquake (MCE) for this Project.[1]

The new buildings housing the GIS equipment at Potrero Switchyard (and Embarcadero Substation) will be designed to Occupancy Category III requirements of the California Building Code, which are appropriate for important buildings such as these. In addition, the new buildings will be designed to meet higher performance objectives that is expected to permit occupancy following an 84th percentile 7.8 M San Andreas Earthquake. This performance objective is intended to provide reasonable assurance that personnel can safely enter the building following a large earthquake to perform necessary restoration or repair activities if needed, and is compatible with the performance objectives for substation equipment.

c. Termination for the New 230 kV Cable

The 230 kV ZA-1 solid dielectric cable will be routed into the building basement via concrete duct bank. Once inside the basement, the ZA-1 cable will be trained from the wall penetrations through the basement into the cable end units just below the 230 kV GIS. From there, it will be terminated into single-phase GIS cable end units.

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1 As stated in Chapter 8, a 7.8 M earthquake on the San Andreas Fault, with ground motions at the 84th percentile of potential ground motions (meaning there Is only a 16% chance of greater ground motions), is thought to be equivalent to the 1906 San Francisco earthquake. The ground motions from such an earthquake are similar to the expected ground motions from an earthquake with a 10 percent probability of exceedance in 50-years level (a 475-years return period).

d. Interconnection to PG&E's 115 kV System

The new 230 kV switchyard will connect to PG&E's existing 115 kV switchyard through underground 115-kV cables. Once the cables enter the 115 kV switchyard underground, the cables then come above ground in tubular steel termination poles approximately 10 feet high. Each pole is topped with an overhead "pothead," for the underground cable termination, which in turn is connected to the existing 115 kV buses using flexible conductor. The height of the existing bus is structure approximately 27 feet.

The interconnection of the 115 kV and 230 kV Potrero switchyards will allow electricity to flow between the 115 kV and 230 kV systems within the City as needed thus reinforcing both systems. This interconnection also allows power from the nearby TransBay Cable, which connects into PG&E's 115 kV switchyard, to flow on to ZA-1 Line as needed.

e. Exterior Visual Shielding

As discussed above, most of the new 230 kV switchyard's components will be enclosed in a building. Two large components, the transformer and shunt reactor, will be installed near the building but outside in order to allow the components to be better kept cool. The 23rd Street frontage is expected to include an entry gate and 10-foot-tall screening wall planted with vines that will partially screen the components that will remain outdoors. The wall and new landscaping will improve the streetscape appearance and enhance the pedestrian environment along 23rd Street.

2. Transmission Line from Potrero 230 kV Switchyard to the HDD to the Bay

a. General Description

From the new Potrero switchyard, the cable alignment will run southerly in an underground duct bank configuration in 23rd Street towards the water's edge. The duct bank will be installed just north of the TransBay Cable, which also is underground in 23rd Street. At a point approximately 200 feet from the water's edge, the underground duct bank will split into three single-phase manholes, where the underground cable will be spliced into submarine cable. The submarine cable will then be installed in High Density Polyethylene (HDPE) conduits installed via horizontal directional drilling to a distance of approximately 1,500 feet off-shore.

b. Structural Design

1) Reinforced Duct Bank Design

Because the short on-shore underground segments will be installed in soil that is known to have potential for liquefaction during a major earthquake, the cable will be installed in a reinforced concrete encased duct bank system. Much like a reinforced concrete structure is intended to yield and deform to protect occupants inside a building during and after an earthquake, if earthquake-induced strains are great enough, the reinforced duct bank system is intended to yield to protect the cables inside.

PG&E has specified that the underground cable system must meet PG&E Standard 068192 (Section 7. Seismic Requirement), with a design expected to keep the cable operational following the specified MCE of 7.8 M, 84th percentile, on the San Andreas Fault. A conceptual design for a seismically reinforced concrete duct bank expected to meet this standard was developed by Black & Veatch for this Project’s Certificate of Public Convenience and Necessity (CPCN) filing, and can be seen on Figure 2-9 of the Proponents Environmental Assessment (PEA). The duct bank dimensions are expected to be a minimum of 3′-4″ in height and 3′-7″ in width, and the reinforcement would include engineered longitudinal rebar, hooks and stirrups. The final design may include larger than standard conduits so that greater deformation can be accommodated without pinching the cables inside. Final engineering will occur after Commission approval, and will be subject to the design standard noted above.

The design intent is to prevent abrupt shear failure, but allow plastic hinges to form under bending or rotation to accommodate the deformations caused by the ground movements from the specified design seismic event noted above. While the concrete encasement will likely crack, and the reinforcing steel yield and potentially break due to displacements from the design seismic event, the cable laid inside the embedded conduits is expected to remain operational.

2) Vault and Racking Design

The Project will require seven vaults in total, with three located in 23rd Street. Vaults are also referred to as manholes, and are necessary for the splicing of underground cable segments. The cable racking inside the vault and the vault interface with the duct bank will be designed to meet PG&E's seismic standard noted above.

Two typical cable racking systems are currently used in the cable industry. One is a rigid system and the other is a flexible system:

- The rigid system requires the cable and joint to be installed and clamped straight in the manhole. This configuration will push the thermal expansion and/or elongation of the cables into the cable conduits between manholes.
- The "S" shape or offset splice racking design allows for flexibility so the cable can expand and contract into the manhole from the duct without putting significant forces directly into the splice.

The cable manufacturer will perform a detailed racking design and will submit it to PG&E, which will review the design with respect to PG&E's seismic standards.

The interface between the duct bank and a vault must also be considered as part of the design. The PG&E duct bank system contractor will opt for one of two alternatives when conducting detailed design:

1) Rigidly connect the duct bank to the manhole wall, and detail the reinforcing such that cracking and deformation occurs preferentially in the duct bank over a distance away from the manhole, or preferentially within the vault wall but away from the cable racking structural members within the manhole.

2) Provide a flexible system at this interface, where the void between the cable surface and the inside surfaces of the conduit and vault entrance is increased to allow differential movement to occur between the duct bank and the vault without imposing excessive forces onto the cable itself.

The PG&E duct bank system contractor will submit the detailed design to PG&E, which will review the design with respect to PG&E's seismic standards.

c. Construction Method

1) Trenching/Duct Bank Installation

The duct bank will be installed underground, primarily under City streets.

After the route is marked, the pavement within the trench line will be removed. The typical dimensions of the trench for a single circuit duct bank in a vertical configuration is approximately four feet wide by and eight feet deep, although dimensions may vary depending on soil stability, the presence of existing substructures, and EMF reduction measures. The trench will be widened or shored where needed to meet California Occupational Safety and Health Administration safety requirements. As needed, dewatering of the trench will be conducted using a pump or well points.

An open trench length of 150 to 300 feet will be typical at any one time, depending on the City's encroachment permit requirements. Steel plating will be placed over the trench to maintain vehicular and pedestrian traffic across areas that are not under active construction.

As the trench for the underground 230 kV cable is completed, PG&E will install the cable conduit and reinforcement rebar system then pour the concrete encasement duct bank. The duct bank cover will be 36 inches at a minimum.

Where the duct bank will cross or run parallel to other substructures that generate operating temperatures at earth temperature, a minimum radial clearance of 12 inches will be required. These substructures include gas lines, telephone lines, water mains, storm lines, and sewer lines. In addition, a 5-foot minimum radial clearance will be required where the new duct bank crosses another heat-radiating substructure at right angles. A 15-foot minimum radial clearance will be required between the duct bank and any parallel substructure whose operating temperature significantly exceeds the normal earth temperature. Such heat-radiating facilities may include other underground transmission circuits, primary distribution cables (especially multiple-circuit duct banks), steam lines, or heated oil lines.

PG&E will identify other utilities along the proposed alignments during final design, evaluate their proximity and potential for induced current and/or corrosion, and in coordination with the utility-system owner, determine whether steps are necessary to reduce the potential to induce current or cause corrosion. PG&E will take the necessary steps in coordination with those utility system owners to minimize any potential effects through measures such as increased cathodic protection or utility relocation.

Once the duct bank is installed and ready, thermal-select or controlled backfill will be transported to the site, placed, and compacted. A road base backfill or slurry concrete cap will be installed, and the road surface will be restored in compliance with the locally issued permits. While the completed trench sections are being restored, additional trench lines will be opened farther down the street. This process will continue until the entire conduit system is in place.

Throughout construction of the trench, duct bank, and vaults, the asphalt, concrete, and other excavated material will be hauled to a permanent disposal site. The excavated material will not be used as backfill.

Backfilling material will be engineered material called flowable thermal concrete (FTC), and flowable thermal backfill. Each has unique properties specific to its application, while both are designed to have thermal characteristics for heat displacement: for a typical trench, the Polyvinyl Chloride (PVC) conduit at the bottom two feet of the duct bank will be encased with FTC, while the remainder of the trench will be filled with "diggable" flowable backfill to the roadway sub-base level. From that point, all restoration is based upon matching the street's existing sub-base and surface (i.e., asphalt, concrete, or combination of the two).

Jackhammers will be used when needed to break up sections of concrete that the saw-cutting and pavement-breaking machines cannot reach. Other miscellaneous equipment will include a concrete saw, various paving equipment, and pickup trucks. In general, no equipment will be left at the trench site overnight, with the exception of an excavator.

Jack and bore construction methods will be used if traditional open trenching cannot be used or existing utilities must be avoided. The trenchless construction method expected on this project will be HDD for the submarine to underground transition.

If a jack and bore installation is required, a casing will be advanced into the soil while the soils are removed by an auger rotating inside the casing. A steel casing will be used initially while the hole is being drilled and is then replaced by a final casing. The internal PVC conduits will then be installed in the casing using plastic spacers to keep the conduits separated. The annular space between conduits and casing will then be filled with thermal grout.

2) Vault Installation

Based on preliminary design, PG&E anticipates installing a total of seven vaults, all of which will be located in the on-shore portion of the Project. Three single-phase vaults where the underground cable is to be spliced into the submarine cable will be placed under each of Spear Street and 23rd Street, at the northern and southern landing locations, respectively, and one vault will be placed under Folsom Street between Main and Fremont Street The following generally describes how vaults are installed.

Vault spacing is dependent on several factors including the cable design, allowable cable pulling tensions and sidewall pressure, capacity of the cable reels, and installation and shipping constraints (maximum weights for ground transport). For this project, the determination of vault locations also will consider feasible avoidance of areas with the largest predicted ground movements during the design seismic event. The manhole locations will be determined at the final design stage (after Commission approval).

The typical complete pre-cast vault installation usually takes four to seven days, working 10 hours per day from breaking ground to finishing grade. An approximately 34 feet long, 14 feet wide and up to 15 feet deep excavation is performed using excavators. Since numerous dump trucks are required for the hauling operation, trucks are staged near the construction site for rotating hauling activities. Staging and excavation requires approximately 1,500 square feet of work space. Dust control and wet sweeping best management measures are implemented during excavation.

The large size of the vault excavation requires shoring components such as driven sheet piles, or slide rail steel sheeting. Once the initial excavation and shoring is installed, preparation of the sub base consists of the installation of crushed rock for leveling purposes.

Once the vault preparation steps (excavation, shoring and finish grade leveling) are completed, setting the vault is performed via sectional lifts of the three vault pre-cast sections using either a hydraulic or a lattice type crane. With all sections of the vault set in place, backfilling can start as the shoring is removed.

The major equipment required for this construction phase consists of an excavator, pickup trucks, end dump trucks, stake trucks for material, 75-ton crane, crane riggers truck, tractor trailers for sheet piling delivery, tractor trailers for delivery of precast concrete manhole sections, and possibly water trucks and/or containment water tanks (Baker tanks).

Appropriate traffic control configuration is set up and in place ahead of the work described above and may include, without limitation: typical traffic control cones, candles, electronic signage board and temporary fixed warning signs for workmen prior to work zone in both directions, and Type III barricades for total road closures.

3) Cable Pulling

A cable consists of three individual conductors (one per electrical phase) and a communication fiber-optic cable. Pulling between two vaults typically takes approximately two to three days, working 10 hours per day. To pull each conductor through the duct bank, a cable reel is placed at the end of a duct bank section above a vault, and a pulling rig is placed at the other end of the duct bank section above another vault. With a small rope called a “fish line,” a larger rope is pulled into the duct. The large rope is attached to pulling eyes on a conductor end, and the large rope pulls the conductor into the duct. To ease pulling tensions, a lubricant is applied to the conductor as it enters the duct. The three electric phases and one communication cable are pulled through their individual ducts at the rate of two of the three sections between vaults per day.

4) Cable Splicing and Termination

Racking and splicing the solid-dielectric cross-linked polyethylene (XLPE) copper conductor underground cable is specialized work that is not performed by PG&E. The duct bank contractor will install the approved racking, and the cable manufacturer will be responsible for splicing the cables. The installation of racking and splicing at each single phase vault is expected to take approximately four days (racking and splicing at a 3-phase vault is expected to take approximately seven to nine days because some activities can be performed concurrently).

The vault is first outfitted with steel racks that will ensure the cable splices are securely affixed to the vault’s inner walls. This activity usually is completed within two days. The vaults must be kept dry during all phases of splicing to prevent water or impurities from contaminating the unfinished splices. A water pump will be available to draw water if necessary and keep the vault dry. A splice trailer is positioned adjacent to the vault openings to facilitate the access to material, tools and equipment, and a mobile power generator is located directly behind the trailer to provide temporary power for lighting and tools. Splicing is mostly sequenced one cable splice at a time with two splicers and an assistant in the vault. However, a splicer may elect to perform one splice up to a certain stage, and then start the second splice in the case of a 3-phase vault.

At the southern end of the route, the cable continues underground into the new Potrero 230 kV Switchyard and connects to a transition structure approximately 10 feet in height inside the GIS building. At the northern end of the route, the cable terminates into the Embarcadero transmission bus GIS building in an underground configuration. Terminating the cable involves a similar splicing process and requires roughly the same amount of time per phase as in the vaults.

d. Right-of-Way

The transmission line segment from the new Potrero 230 kV Switchyard to the Bay will be installed in franchise or PG&E will acquire the necessary land rights. The on-shore portions of the Project, including the two HDD termination points, are located primarily in franchise in City streets or on PG&E-owned property, with the exception of a portion of the southern landing area. No Right-of-Way (ROW) acquisition is required in public streets in franchise.

At the southern landing area, the cable alignment will be in franchise (public ROW) along 23rd Street, terminating at the DHL Company private property gate, located approximately 760 feet from the San Francisco Bay shoreline. A permanent easement of approximately 0.53 acres will be acquired for this piece of property for three landings and associated manholes from the private property owner beyond the DHL gate.

3. Potrero HDD to the Bay

a. General Description

As noted above, the new 230 kV underground cable will separate into three single-phase vaults located on private property beyond the DHL gate at the foot of 23rd Street. At those vaults, the underground cable will be spliced to submarine cable, which then will enter an HDPE conduit installed by HDD into the Bay. The HDPE conduit will end on the Bay floor approximately 1,500 feet off shore.

At the southern landing zone, the HDD will begin at an entry point to be determined during final design, likely between 150 to 250 feet from the shoreline in an HDD pit excavated in the continuation of 23rd Street, transitioning to a depth of approximately 30 to 50 feet below ground level and proceeding approximately 700 to 900 feet to the exit point at the bottom of the Bay floor. This path stays above the bedrock layer, and is within soft clays. No seawall or deep pile obstructions are expected along this section of shoreline. Another similar high-voltage cable, the TBC, was recently installed near this same area. The final alignment, and appropriate HDPE conduit, will be determined during detailed final engineering, which will be performed after Commission approval of the Project.

b. HDD Construction Method

1) HDD Drill and Pull Sites

At the Potrero transition, an HDD drilling pit will be excavated for the installation of conduits into which the cable will transition from land to bay.

HDD installations utilize a guided drill head to open the initial hole and use a series of increasingly larger drill bits to bring the opening to the desired final diameter. After the hole is at the specified diameter, the internal conduits are bundled together and pulled at one time through the hole. The detailed design of the HDD installation is done during the final design stage of a project. For purposes of this description, a slick bore installation (meaning without a casing) is assumed.

HDD operations at each landing zone are expected to last for approximately six weeks. In brief, work includes the following steps:

- Excavating the HDD pit and inserting the HDD rig.
- Drilling the HDD bore holes.
- Excavating an adjacent 24 feet by 12 feet long and 7 feet deep at the exit of the bore hole in the Bay to capture mud, which will be pumped up to a barge for disposal per applicable regulations.
- Pulling fused sections of HDPE pipe into the bore holes
- Connecting the ends of HDPE pipes into the transition splice vaults.
- Pulling the submarine cables back through the HDPE pipes and then into the splice vaults.
- Splicing the submarine cable to the underground land cable in the splice vault.
- Restoring the area to pre-construction conditions.

HDD entry pits are up to about 5 feet wide, 8 feet long, and 6 feet deep and will be covered with steel plates during non-working hours. These pits are used only for fluid containment before the fluid is pumped to the solids control equipment for cleaning and re-circulation. Exit (receiving) pits in the Bay will be up to about 24 feet by 12 feet long and 7 feet deep.

Excavation of entry pits will require saw cutting the asphalt and excavating with a backhoe. Receiving pits would be excavated using a clamshell from a work barge anchored above the exit points. Shoring would be used for the entry (containment) pit, but no shoring will be undertaken in the exit (receiving) pits. The sides of the offshore pits will be sloped sufficiently such that shoring will not be necessary.

Pilot-hole drilling is typically discontinued approximately 50 to 75 feet away from the exit point, leaving a “plug” of soil between the drilled hole and the sea floor. At that location, the drill pipe will be tripped-out of the hole and the hole will be forward-reamed to a diameter of about 20 inches (assuming a 14-inch outside diameter

HDPE pipe is used). Reaming will be followed by "swabbing" to test the condition of the hole. Drilling fluids will be pumped into the hole during both of these operations. As a result of leaving the 50-foot to 75-foot plug in the bottom of the hole, all drilling fluids used during these processes will flow back to the entry point through the bore-hole annulus for re-circulating.

After swabbing the hole, the final 50 feet to 75 feet will be exited to the sea floor at which time some fluids will drain into the containment sump. The HDPE pipeline will be floated into place, the front end sunk and hooked up to drill pipe, and the pullback will proceed. As the pipe is pulled into the drilled hole, it will displace its volume of drilling fluids to the containment sump for approximately half the length of the pipeline, at which time the flow will begin to turn around to the entry pit where it will be contained in "frac" (fracturing) tanks for either re-use or disposal. In addition to the displacement volume, additional drilling fluid will be pumped during the pullback and will flow to the exit containment sump.

c. Right-of-Way

The portion of the submarine route in the San Francisco Bay will require acquisition of land rights from the Port of San Francisco. At the southern landing area, the cable alignment will be in franchise (public ROW) along 23rd Street, terminating at the DHL private property gate, located approximately 760 feet from the San Francisco Bay shoreline. A permanent easement of approximately 0.53 acres will be acquired for this piece of property for three landings and associated manholes from the private property owner beyond the DHL gate.

4. Submarine Cable

a. General Description

From the southern HDD Bay termination, the submarine cable will turn north toward Embarcadero Substation while maintaining a minimum horizontal separation of approximately 33 feet. This northerly direction will continue for approximately 2.35 miles before gradually turning back to the west as it approaches the shoreline at Berth 30, between Piers 28 and 30/32. As the route starts to turn north from the southern landing location, the water depth slopes gradually to 40 feet. The water depth in the center section of the route moving northward varies between 40 to 58 feet. Near the northern transition point, the water depth increases to 80 feet approximately 850 feet east of Piers 28 and 30/32.

Based on preliminary engineering by Black & Veatch, the submarine cable will consist of three single-phase, 230 kV rated, double-armored, solid-dielectric, XLPE 1400 square millimeter copper conductors with digital temperature sensor (DTS) fiber optic cables. The three cables will be directly buried using a hydroplow to a depth of approximately 6 to 10 feet below the Bay floor. Submarine cables are typically separated from one another by a distance equal to two or three times the water depth. This decreases the risk of damage to the cable and provides the space necessary for potential maintenance or repair activities. These cables will have a minimum separation of approximately 33 feet in the shallower water areas and a maximum separation of approximately 150 feet in the deeper water areas.

b. Cable Design

1) Submarine Cable Design Specifications

PG&E has specified that the submarine cable be designed in a manner, and with sufficient strength and flexibility, to withstand effects expected to result from 84th percentile motions from a 7.8 M earthquake on the San Andreas Fault. The design features are expected to include measures to provide “slack” in the cable that could move in response to ground deformations and thereby reduce tension on the cable. The cable itself will be designed to withstand the expected strains from ground deformation. To further enhance the submarine cable’s ability to withstand external tension or impact, PG&E has specified that the submarine cable should have double copper armoring at several million dollars additional cost. If need be, PG&E also will consider use of steel armoring. The final design will be determined during detailed final engineering, which will be performed after Commission approval of the Project.

Submarine cables are transported and installed using large turntable spools and require fewer splices than on-shore cables. Because the proposed ZA-1 submarine cable is relatively short, it will not require any splices in the Bay (only at the transition manholes on-shore). However, the contractor is required to provide repair splices so that any future damage to the submarine cable can be repaired expeditiously.

The submarine cable system will also include optical fiber control/communication submarine cable, designed according to the requirements set out in the International Electrotechnical Commission 60794-1-2 recommendations as well as PG&E's specific telecommunication system requirements. Two submarine optical fiber cables will be supplied and installed bundled with the outer two phases of the submarine power cable.

Temperature monitoring over the entire submarine power cable route will be carried out using an optical fiber DTS system. The sensor fibers will be contained in stainless steel tubes placed under or in the armor layer of the submarine cable, unless PG&E approves an alternative design utilizing external fiber optic cable. Two such tubes will be placed in each cable phase. DTS equipment will be installed at one end of the submarine cable route and temperature measurements carried out on a fiber loop (2 x cable length) to achieve a target (typical) performance as specified. The temperature measurements are used by a Real Time Rating (RTR) system to determine the performance of the system.

The RTR system will perform, automatically and periodically, on-line predictions of the steady state and the 4-hour, 24-hour, and 48-hour emergency ratings at least as frequently as once every 15-30 minutes.

2) Conceptual Design of the Submarine Cable Transition Into HDD Conduit

PG&E retained Black & Veatch to develop a conceptual design for the submarine cable's transition into the HDD conduit given concerns about seismically induced ground deformations. In general, there have not been reports of large historical deformations along the waterfront area near the Potrero Substation or Embarcadero Substation. The seawalls at the Embarcadero end appear to have performed well, limiting soil deformations following earthquakes. Nonetheless, these areas are mapped as having high to very high liquefaction susceptibility and the onshore portion of the HDD conduit may pass through soil zones that are subject to displacement during an earthquake. However, the location of the HDD is such that it will extend beneath the seawalls and thus only the upper portion of the HDD transition to the onshore vaults may be within artificial fill identified as having high to very high liquefaction susceptibility.

Preliminary analyses indicate that the HDD onshore entry points can be located in Competent Soil and thus avoid liquifaction risk. If not, however, engineering solutions will be implemented. Black & Veatch identified opportunities during preliminary design to adjust conduit diameter, route geometry, and other parameters to reduce potential of the cable becoming damaged due to soil displacement from a seismic event. Geometry can be adjusted to include "S" curves in the zone just outside of the exit point to provide additional cable length to be pulled into the casing in the event the conduit elongation imparts tensions onto the cable inside. Conduit diameter can be increased to maximize the void space between the cable and the conduit, providing more room for cable movement within the pipe. Depth and location of the drill path can be adjusted to reduce the magnitude of possible ground deformations at the location of the conduit.

Submarine cable armoring provides a significant amount of mechanical protection. In the event a sharp shear is applied to the cable, such as cable being displaced sideways against the conduit, the cable armoring is much more durable than the HDPE conduit, so it is likely the conduit would deform prior to any significant damage to the cable itself could occur. If strain on the cable results in tension on the land side of the transition, the cable can be either rigidly anchored at the manhole, or the cable racking in the manhole can be designed to allow some cable slack to accommodate the elongation. Based on these concepts, Black & Veatch opined that a design solution is feasible to properly address soil displacement issues along these transition zones to the same level of reliability as elsewhere on the proposed submarine route.

c. Submarine Cable Installation Method

The submarine transmission cables will be buried a minimum of six feet, or as specified by permitting agencies, under the surface of the Bay floor to protect the cables from mechanical damage. Cables are expected to be installed by using a hydroplow that is pulled along the Bay floor behind a barge. The barge will typically be pulled into position via two commercial tugboats, and the barge anchors will be positioned to allow the barge to kedge between them along the cable route. Once in position, the moored barge will be propelled via two diesel engines—one for steering, the other for kedging anchor. Kedging is a process by which a ship is moved slowly along the surface of the water towards the fixed point of the anchor.

The barge will tow a water jet that consists of a long blade mounted to either a sled- or tire-mounted submerged vehicle, the hydroplow. The blade contains water nozzles on the leading edge that displace the sediment using high-pressure water. The submarine cable is fed from the barge down to the seabed through the blade and exits at the foot of the blade to be laid directly into the sea bottom sediments. The length and angle of the blade determines the burial depth of the cable. As the blade moves forward and the cable is placed in the momentarily-opened trench, the majority of the fluidized sediments behind the blade fall back into the trench, effectively burying the cable. This cable-laying method causes considerably less environmental disturbance than traditional mechanical trenching methods. The cable laying process is expected to require 24-36 hours of plowing time for each of the three cables, with one day needed before and after the hydroplowing to mobilize and demobilize.

The submarine cable route identified in preliminary design avoids known rocky soil conditions and any existing buried cables so that the proposed three submarine cable phases are expected to be buried by hydroplow for their entire lengths. Nonetheless, either rocky soil conditions or existing (but unknown) cables crossing the route may not physically allow the cables to be buried, or engineering design to provide "slack," may leave some portions unburied. At these locations, the cables would be laid directly on the bottom of the Bay for a short distance until they can again be buried into the sediments. To protect such segments of exposed cable from damage by anchors, fishing gear, etc., concrete "blankets" or steel half-pipe sections would be placed over them. Typically, this might be done for 100 feet to either side of a crossing, at 50 feet in width (200 feet by 50 feet total area). Preliminary engineering indicates that no such blankets or pipe is needed. Final design review prior to construction will include a review of existing conditions. However, to allow flexibility should the need arise in final design evaluations, PG&E is assuming up to 5 percent of the line, or 650 feet in length by 50 feet, may need to be covered.

d. Right-of-Way

The portion of the submarine route in the San Francisco Bay will require acquisition of land rights from the Port of San Francisco. PG&E has negotiated the terms for a license with the Port for the first 40-year term. The license will be renewable for an additional 26 years.

e. Measures to Avoid Interference With Shipping During Construction

For purposes of traffic management, the United States (U.S.) Coast Guard Vessel Traffic Service (VTS) area in the Bay is divided into two Sectors: Offshore and Inshore. The project is located within the In-shore Sector. The Project's marine construction team would contact VTS daily so that information on the construction activities within the established Vessel Safety Zone could be included in navigational advisories, and may be included in a Local Notice to Mariners (USCG, 2005; 2012).

f. Measures to Avoid Future Damage

PG&E is taking various measures to reduce the risk of future damage to the cables from shipping and fishing.

Routing

The Project alignment is designed such that the cable will be located significantly away from the Bay's shore. Furthermore, it is designed to be located west of the established north/south shipping lanes (and designated anchoring areas) used by commercial and naval traffic that travel into and out of the Bay.

Surveying

PG&E intends to conduct marine surveys at regular intervals after cable installation to assess whether potential seabed topography changes have occurred along the cable route. A cable-tracking system may also be deployed as part of the route survey to confirm cable burial depth.

A combination of bathymetry (swathe multi-beam) to characterize the morphology of the route (including areas of seabed change) and side-scan-sonar to image the seabed acoustically will be used for this survey. Side-scan sonar data will indicate, for example, areas where the cable may have become exposed or any objects/debris on the seabed that may pose a risk to the cable system.

Recording on Maritime Maps

Once the submarine cables are installed they will be recorded by the Coast Guard and given to the National Oceanic and Atmospheric Administration (NOAA) for publication. PG&E will publish a Local Notice to Mariners via Coast Guard District 11. This will provide advisory to the San Francisco VTS to allow the management of waterway traffic over VHF-FM Channel 14 requiring transit through the project location. Once the relevant NOAA navigational charts are updated to reflect the location of the cables, the VTS will monitor the subject area and direct vessels to cease operations in violation of NOAA prescriptions for safe navigation. If vessels refuse to comply with a VTS Directive, the Sector Command Center (SCC) is notified and authorized to issue the vessel a Captain of the Port (COTP) Order in accordance with 33 Code of Regulations

(CFR) 6.04-8. If the vessel does not comply with the COTP Order, the SCC can launch response assets to pursue the violators for civil penalty.

Maritime Alert System

Besides promoting the new cable awareness and engaging stakeholders by registering the new cable on navigational maps, PG&E intends to implement an operations and maintenance strategy that will include an automatic identification system vessel monitoring to ensure the new cable security. The system will use live vessel position in conjunction with the cable location information to create automatic warnings if the cable is at risk due to abnormal shipping activities such as off-course or displaying unusual speed.

5. Embarcadero HDD to the Bay

At the north landing zone, the exact location of the HDD entry and exit points will be determined during final design; they are likely to be approximately 400 feet from the shoreline and continuing another approximately 1,000 feet to the exit points on the Bay floor. At the north landing zone, the HDD will transition to a depth of between 40 to 80 feet below ground, and more than 50 feet deep where needed to pass below both the sewer transport/storage box under The Embarcadero and the seawall between Piers 28 and 30/32. This path is above the bedrock layer, below the piles that support the seawall, and within Colma Formation clayey sand deposits and Bay muds. The exit points are a sufficient distance away from the steep off-shore slope, permitting a smooth transition to direct burial of the cable in the Bay sediments. The design and method of HDD construction are the same as will apply to the Potrero HDD to the Bay.

As with the Potrero transition, the three marine cable phases will be spliced into three underground cable phases in three single-phase vaults located in Spear Street. At the northern landing area, the cable alignment will be in franchise (public ROW) along Spear and Folsom Streets. PG&E will seek a right of way for an area under the Bay Bridge owned by Caltrans.

6. Transmission Line From Embarcadero Substation GIS Facility to the Transition to the Bay

From the three single phase vaults in Spear Street to Embarcadero Substation's GIS Facility, the new 230 kV transmission line will be installed underground in a reinforced concrete-encased duct bank system. The design and construction methodology are the same as set forth above with respect to the transmission line from Potrero Switchyard to the transition to the Bay. This alignment is entirely in franchise.

The underground cable will be brought directly into the GIS cable connection point in the upgraded 230 kV bus in the GIS facility at Embarcadero Substation. The new 230 kV cable will then be connected into the substation equipment.

7. Communications Equipment

a. Primary Line Protection and Communications System

As discussed in the Cable Design, Submarine Cable Technical Specifications section (page 4-17) above, the cable will include two submarine control/communication optical fiber cables that will be installed bundled with the outer two phases of the submarine power cable. These will be spliced to an unarmored type fiber optic cable and extended through the duct bank of the land portions to each termination.

b. Secondary Line Protection and Communications Equipment

Secondary or "redundant" line protection will be achieved via existing on-shore communication channels between Embarcadero and Potrero.

D. Construction Duration and Workforce

Based upon preliminary design, discussions with interested agencies, and discussions with contractors and potential contractors, PG&E currently estimates that construction of the Project will take 22 months from the date of Commission issues a Notice to Proceed (NTP). PG&E is taking and has taken steps to reserve submarine cable manufacturing capacity, as this task otherwise could delay the Project schedule.

Based upon the assumption that the CPUC will issue a full NTP in February 2014, which would in turn require the issuance of a CPCN in 2013 and the issuance of all required secondary, resource agency approvals before February 2014, PG&E estimates the construction schedule and duration as set forth below. Changes to the permitting timeline may change the construction schedule.

The off-shore construction activities timeline below conservatively includes hydroplow work only during the San Francisco Central Bay dredging work windows to minimize potential impacts to marine species, if feasible. Off-shore construction will typically occur between 7 a.m. and 8 p.m. No specific anchoring points or locations are known at this time. It is expected that crews will need to board crew boats from an existing commercial marina such as the Yerba Buena Island Marina and be taken to the designated anchoring locations of other project vessels. Because Bay traffic varies daily, project vessels and barges anchoring locations will be directed daily via coordination with the Vessel Traffic Service of San Francisco and the U.S. Coast Guard.

On-shore construction will typically occur between 7 a.m. and 8 p.m., or during times that will be set through coordination with the City and County of San Francisco. If trenching work is expected to cause traffic congestion, nighttime work may be requested via the City permit to avoid traffic disruption.

<u>Transmission Line Construction</u>	
Onshore Installation	Sep 2014 – Apr 2015
Offshore to Onshore Transition	Oct 2014 – May 2015
Offshore Construction Moratorium	Oct 2014 – Dec 2014
Offshore Installation	Jun 2015 – Nov 2015
Testing and Commissioning	Dec 2015

<u>Potrero Switchyard Construction</u>	
Soil Removal/Replacement and Site Preparations	Feb 2014 – Jun 2014
Building Construction	Jun 2014 – Feb 2015
Substation Interconnection	Oct 2014 – Mar 2015
Substation Installation	Dec 2014 – Nov 2015
Testing and Commissioning	Dec 2015

It is expected that the project will employ on average of approximately 30 construction personnel and approximately eight truck drivers for excavation and conduit installation using two excavation crews. Approximately 20 construction personnel will be employed during cable installation, 15 construction personnel during the HDD installations, and 25 construction personnel during the submarine cable installation. The number of employees will peak at approximately 75 construction personnel and will include switchyard workers, supervisors, and inspectors. PG&E expects to hire approximately 20 percent of its construction workforce locally (roughly 10 to 15 employees). PG&E contractors will be required to make a good faith effort to establish a local hiring plan in collaboration with PG&E and City Build, a City of San Francisco agency created to develop local jobs and hiring in the City.

E. PG&E's Compliance With CPUC EMF Policies (Sponsoring Witness Michael Herz)

EMFs are a natural consequence of the electrical circuits associated with electrical appliances, electrical wiring in the home and workplace as well as power lines. Though many studies have examined the health effects of exposure to EMF, no scientific consensus exists on whether exposure to EMF has harmful health effects and EMF has not been established as causing harmful health effects. Neither the U.S. nor the state of California has adopted any regulation setting any limit on exposure to EMF from power lines. Recognizing the lack of scientific consensus that EMF from power lines has adverse health effects, the Commission has adhered to a precautionary approach to EMF issues by requiring public utilities to incorporate "low cost" and "no cost" mitigation measures into transmission projects. PG&E outlines below the Commission's approach to EMF and describes steps taken by PG&E in compliance with these requirements.

1. Background on Electric and Magnetic Fields

EMF is an expression used to refer to the power frequency or 60 cycle per second (60 Hertz) electric and magnetic fields emanating from sources such as electric power facilities, wiring, and electrical appliances in the home and the workplace. Electric fields are present whenever voltage exists on a conductor, and are not dependent on current. For power lines, the magnitude of the electric field is primarily a function of the operating voltage of the line and decreases with the distance from the source (i.e., the line). The electric field can be shielded (i.e., the strength can be reduced) by any conducting surface, such as trees, fences, walls, buildings, and most types of structures. The strength of an electric field is measured in volts (or kilovolts, i.e., a kilovolt is 1,000 volts) per meter.

Magnetic fields are present whenever current flows in a conductor, and are not dependent on the voltage present on the conductor. The strength of magnetic fields also decreases with distance from the source. However, unlike electric fields, many materials have little shielding effect on magnetic fields. The magnetic field strength is a function of both the current flowing on the conductor and the design of the system. Magnetic fields are measured in units called Gauss. However, for the levels normally encountered in power systems and everyday life, the field strength is measured with a smaller unit, the milligauss (mG) (i.e., a milligauss is 0.001 gauss). While both electric and magnetic fields exist near electric transmission facilities, magnetic fields have been the subject of most recent public debate and scientific research.

2. CPUC EMF Requirements

On January 15, 1991, the CPUC initiated an investigation to consider its role in mitigating the health effects, if any, of electric and magnetic fields from utility facilities and power lines. A working group of interested parties, called the California EMF Consensus Group, was created by the CPUC to advise it on this issue. It consisted of 17 stakeholders representing citizens groups, consumer groups, environmental groups, state agencies, unions, and utilities. The Consensus Group's fact-finding process was open to the public, and its report incorporated concerns expressed by the public. Its recommendations were filed with the Commission in March 1992.

In August 2004, the CPUC began a proceeding known as a “rulemaking” (R.04-08-020) to explore whether changes should be made to existing CPUC policies and rules concerning EMF from electric transmission lines and other utility facilities. Through a series of hearings and conferences, the Commission evaluated the results of its existing EMF mitigation policies and addressed possible improvements in implementation of these policies. The CPUC also explored whether new policies are warranted in light of recent scientific findings on the possible health effects of EMF exposure.

The CPUC completed the EMF rulemaking in January 2006 and presented these conclusions in Decision 06-01-042:

- The CPUC affirmed its existing policy of requiring no-cost and low-cost mitigation measures to reduce EMF levels from new utility transmission lines and substation projects.
- The CPUC adopted rules and policies to improve utility design guidelines for reducing EMF, and provides for a utility workshop to implement these policies and standardize design guidelines.
- Despite numerous studies, including one ordered by the Commission and conducted by the California Department of Health Services, the CPUC stated "we are unable to determine whether there is a significant scientifically verifiable relationship between EMF exposure and negative health consequences."
- The CPUC said it will "remain vigilant" regarding new scientific studies on EMF, and if these studies indicate negative EMF health impacts, the Commission will reconsider its EMF policies and open a new rulemaking if necessary.

In response to a situation of scientific uncertainty and public concern, the Decision specifically requires PG&E to consider "no-cost" and "low-cost" measures, where feasible, to reduce exposure from new or upgraded utility facilities. It directs that no-cost mitigation measures be undertaken, and that low-cost options, when they meet certain guidelines for field reduction and cost, be adopted through the project certification process. PG&E was directed to develop, submit and follow EMF guidelines to implement the CPUC decision. Four percent of total project budgeted cost is the benchmark in implementing EMF mitigation, and mitigation measures should achieve incremental magnetic field reductions of at least 15 percent.

3. PG&E's Implementation of CPUC Requirements

In compliance with CPUC Decision 06-01-042, PG&E takes steps to reduce EMF exposure in the design of new and upgraded facilities. In the context of the Embarcadero-Potrero Project, PG&E will comply with these requirements by adhering to its "EMF Design Guidelines for Electrical Facilities," filed with the CPUC, for implementation of no cost/low cost mitigation. These Guidelines are attached. (See Attachment 4-A.)

"No cost" measures are those steps taken in the design stage, which will not increase the project cost but will reduce the magnetic field strength. Low-cost measures are those steps that will cost about 4 percent or less of the total project cost and will reduce the magnetic field strength in an area (for example, by a school, near residences, etc.) by approximately 15 percent or more at the edge of the ROW.

Specifically, PG&E will comprehensively evaluate the final transmission line route approved by the Commission in order to make the most effective use of the 4 percent low cost mitigation funds. PG&E will then prioritize the use of those funds consistent with its "EMF Design Guidelines for Electrical Facilities." Under PG&E's "EMF Design Guidelines for Electrical Facilities," these funds are prioritized in the following manner: (1) Schools and licensed day care; (2) Residential; (3) Commercial/Industrial; (4) Recreational; (5) Agricultural, Rural; (6) Undeveloped Land.

In general, there are four techniques which may be available to reduce the magnetic field strength levels from electric power transmission facilities. They are: (1) to increase distance from conductors; (2) to reduce conductor spacing; (3) to minimize current on the line; and (4) to optimize phase configuration.

With its CPCN Application, PG&E submitted a Preliminary Transmission EMF Management Plan for the Embarcadero-Potrero 230 kV Transmission Project. Based upon the proposed Project, the Preliminary Plan proposes, as a "low cost" EMF reduction measure, to have a 5-foot lower trench, that achieves at least a 15 percent magnetic field reduction, for the underground transmission line near daycare and residential land uses adjacent to the segment from the Bay Bridge to the Embarcadero Substation (along Spear and Folsom Streets). The mitigation plan ultimately implemented for the Embarcadero-Potrero Project will be tailored to the final route and configuration approved by the Commission.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

ATTACHMENT A

EMF DESIGN GUIDELINES FOR ELECTRICAL FACILITIES

EMF Design Guidelines for Electrical Facilities

1 California EMF Policy

1.1 Historical Background of California EMF Policy

In 1993, the California Public Utilities Commission (CPUC) issued Decision 93-11-013, establishing EMF policy for California's regulated electric utilities.

The Decision acknowledged that scientific research had not demonstrated that exposures to EMF cause health hazards and that it was inappropriate to set numeric standards that would limit exposure. In recognizing the scientific uncertainty, the CPUC addressed public concern over EMF by establishing a no-cost and low-cost EMF reduction policy that utilities would follow for proposed electrical facilities.

In workshops ordered by the CPUC, the utilities developed the initial EMF Design Guidelines based upon the no-cost and low-cost EMF policy. Fundamental elements of the policy and the Design Guidelines included the following:

A) No-cost and low-cost magnetic field reduction measures would be considered on new and upgraded projects.

B) Low-cost measures, in aggregate, would:

   a. Cost in the range of 4% of the total project cost.

   b. Achieve a noticeable magnetic field reduction.

   The CPUC stated,

   > "We direct the utilities to use 4 percent as a benchmark in developing their EMF mitigation guidelines. We will not establish 4 percent as an absolute cap at this time because we do not want to arbitrarily eliminate a potential measure that might be available but costs more than the 4 percent figure. Conversely, the utilities are encouraged to use effective measures that cost less than 4 percent."[1]

C) For distribution facilities, utilities would apply no-cost and low-cost measures by integrating reduction measures into construction and design standards, rather than evaluating no-cost and low-cost measures for each project.

1.2 Current California EMF Policy

In 2006, the CPUC updated its EMF Policy in Decision 06-01-042. The decision re-affirmed that health hazards from exposures to EMF have not been established and that state and federal public health regulatory agencies have determined that setting numeric exposure limits is not appropriate. The CPUC also re-affirmed that the existing no-cost and low-cost precautionary-

[1] CPUC Decision 93-11-013, Section 3.3.2, p.10

based EMF policy should be continued. In the decision, the CPUC required the utilities to update their EMF Design Guidelines to reflect the following key elements of the updated EMF Policy:

A) "The Commission [CPUC] has exclusive jurisdiction over issues related to EMF exposure from regulated utility facilities."[2]

B) "…while we continue our current policy of low-cost and no cost EMF mitigation, as defined by a 4% benchmark of total project cost, we would consider minor increases above the 4% benchmark if justified under unique circumstances, but not as a routine application in utility design guidelines. We add the additional distinction that any EMF mitigation cost increases above the 4% benchmark should result in significant EMF mitigation to be justified, and the total costs should be relatively low."[3]

C) For low cost mitigation, the "EMF reductions will be 15% or greater at the utility ROW [right-of-way]…"[4]

D) "Parties generally agree on the following group prioritization for land use categories in determining how mitigation costs will be applied:

1. Schools and licensed day care[5]
2. Residential
3. Commercial/industrial
4. Recreational
5. Agricultural
6. Undeveloped land"

E) "Low-cost EMF mitigation is not necessary in agricultural and undeveloped land except for permanently occupied residences, schools or hospitals located on these lands."[6]

F) "Although equal mitigation for an entire class is a desirable goal, we will not limit the spending of EMF mitigation to zero on the basis that not all class members can benefit."[7]

G) "…. We [CPUC] do not request that utilities include non-routine mitigation measures, or other mitigation measures that are based on numeric values of EMF exposure, in revised design guidelines…"[8]

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[2] CPUC Decision 06-01-042, p. 21
[3] Ibid., p. 7
[4] Ibid., p. 10
[5] "As an additional fixed location of young children, we will add hospitals to this category." Ibid., p. 7
[6] Ibid., p. 20
[7] Ibid., p. 10
[8] Ibid., p. 17

The CPUC also clarified utilities' roles on EMF during the CPCN (Certificate of Public Convenience and Necessity) and PTC (Permit to Construct). The CPUC stated,

> "EMF concerns in future CPCN [Certificate of Public Convenience and Necessity] and PTC [Permit to Construct] proceedings for electric transmission and substation facilities should be limited to the utility's compliance with the Commission's [CPUC] low-cost and no-cost policies."[9]

Furthermore, the CPUC directed "the Commission's Energy Division to monitor and report on new EMF related scientific data as it becomes available."[10] These EMF Design Guidelines, therefore, will be revised as more information or direction from the CPUC becomes available.

1.2.1 Standardized EMF Design Guidelines

Decision 06-01-042 directed the utilities to hold a workshop to develop standard approaches for their EMF Design Guidelines. This workshop was held in spring of 2006, and this document represents the standardized design guidelines produced as a result of that workshop. The guidelines describe the routine magnetic field reduction measures that all regulated California electric utilities will consider for new and upgraded transmission line and transmission substation projects.

These guidelines are not applied to changes made in connection with routine maintenance, emergency repairs, or minor changes to existing facilities. See §3.4 for a list of exemptions.

1.2.2 Standardized Table of Magnetic Field Reduction Measures

As directed by Decision 06-01-042, these guidelines include a standardized table that utilities will use to summarize "the estimated costs and reasons for adoption or rejection"[11] of reduction measures considered for any particular project. Table 1-1 shows the information to be displayed in the standardized table. Utilities may choose to add columns for additional information as necessary for any particular project. Typical format is shown below.

Table 1-1 Low-Cost Reduction Measures Adopted or Rejected

Project Segment	Location (Street, Area)	Adjacent Land Use	Reduction Measure Considered	Measure Adopted? (Yes/No)	Reason(s) if not adopted	Estimated Cost to Adopt
		Per §1.2-D	Per § 2			

[9] Ibid., p. 21
[10] Ibid., p. 16
[11] Ibid., p. 13.

1.2.3 Additional Considerations Used in the Design Guidelines

These additional elements of policy resulting from Decisions 93-11-013 and 06-01-042 are fundamental to application of the guidelines:

- Any proposed changes in guidelines should be consistent with the EMF policy established in this decision [D.06-01-042] and in D.93-11-013.[12]
- The guidelines "should not compromise safety, reliability, or the requirements of [CPUC] General Orders (GO) 95 and 128."[13]
- Without exception, design and construction of electric power system facilities must comply with all applicable federal and state regulations, applicable safety codes, and each electric utility's construction standards.
- Non-routine field reduction measures are not necessary except in unique circumstances, and are not included in the guidelines.
- The guidelines do not include reduction measures "that are based on numeric values of EMF exposure."[14]
- Modeling is done for magnetic fields only.
- Modeling of magnetic fields is for comparison of reduction techniques, and "does not measure actual environmental magnetic fields."[15]
- "[P]ost-construction measurement of EMF in the field cannot indicate the effectiveness of mitigation measures"[16] and is not required.
- "The appropriate location for measuring EMF mitigation is the utility ROW as this is the location at which utilities may maintain access control."[17]
- Reduction measures are not applicable to reconfigurations or relocations of up to 2,000 feet, the distance under which certain exemptions apply under GO 131-D.[18]
- "Utility design guidelines should consider EMF mitigation at the time the FMP [(Magnetic) Field Management Plan] is prepared…" The CPUC does "not require utility design guidelines to include low-cost EMF mitigation for undeveloped land."[19]
- Distribution facilities are not considered in magnetic field modeling or in FMPs for transmission line or substation projects rated 50 kV and above.

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[12] Ibid., p. 20.
[13] Ibid., p. 21.
[14] Ibid., p. 17.
[15] Ibid., p. 11.
[16] Ibid., p. 11.
[17] Ibid., p. 20.
[18] The CPUC's General Order 131-D establishes rules and specifications for permitting and construction of electric generation, transmission and distribution facilities and substations located in California.

[19] Ibid., p. 9.

2 Methods for Reducing Magnetic Fields

The following magnetic field reduction methods may be considered for new and upgraded electrical facilities:

A) Increasing the distance from electrical facilities by:

   a. Increasing structure height or trench depth.

   b. Locating power lines closer to the centerline of the corridor.

B) Reducing conductor (phase) spacing.

C) Phasing circuits to reduce magnetic fields.

2.1 Increasing the Distance from Electrical Facilities

Reducing magnetic field strength by increasing the distance from the source can be accomplished either by increasing the height or depth of the conductor from ground level. Furthermore, locating the power lines as far away from the edge of the right-of-way or as close to centerline as possible will result in lower field levels at the edge of the right-of-way. For substations, placing major electrical equipment, such as switch-racks and power transformers, near the center of the substation can reduce the magnetic field levels at the property line.

2.2 Reducing Conductor (Phase) Spacing

The magnetic field produced by overhead and underground power lines is approximately inversely proportional to the distance between the phase conductors. Thus, reducing the spacing between conductors by 50 percent generally reduces the magnetic field at ground level by approximately 50 percent. The minimum distance between overhead conductors for power lines built in California is established by CPUC General Order (GO) 95. Utilities may establish minimum clearances greater than those allowed in GO 95 if required for safe working conditions or to prevent flash over. In most cases, insulation levels will be established based on lightning, switching surge, or insulator contamination considerations.

Because underground conductors are insulated, they may be placed within inches of each other. This means that there generally can be greater magnetic field cancellation in an underground circuit than an overhead circuit. Therefore, the magnetic field levels from an underground circuit will generally be lower than a comparably loaded overhead circuit at most locations other than directly above the underground line, where the cancellation effect of the underground conductors is offset by their proximity to the surface. In contrast, overhead conductors will be much farther away and will generally create a lower magnetic field directly under the line than a comparably loaded underground circuit.

2.3 Phasing Circuits to Reduce Magnetic Fields

When two or more circuits share a pole or tower, the resultant magnetic field will be the vector sum of the individual conductor fields on the structure. By using proper phasing techniques, the field from one circuit can reduce the field from another circuit, thereby reducing the level of magnetic field at ground level.

3 The Field Management Plan Process

3.1 The Field Management Plan

The Field Management Plan (FMP) documents the consideration of no-cost and low-cost magnetic field reduction measures for new or significantly reconstructed transmission lines and substations rated 50 kV and above (refer to § 3.4 for exceptions).

FMPs will be prepared for relevant transmission projects and will be retained with the work order. For any project requiring a permit under GO 131-D, the FMP will be incorporated as a part of the GO 131-D filing.

Utilities have incorporated magnetic field reduction measures into their distribution construction and design standards. Therefore, FMPs are not prepared for any distribution projects.

Basic elements of the FMP include a project description, an evaluation of no-cost and low-cost magnetic field reduction measures, and specific recommendations regarding magnetic field reduction measures to be incorporated into the transmission line and substation design (see §§ 4 and 5 of these guidelines for additional information concerning the contents of transmission line and substation FMPs).

3.2 Types of FMP

There are two types of FMP for transmission line projects, a "Basic FMP" and a "Detailed FMP," and a "Checklist FMP" for substation projects.

For transmission line projects with limited work scope, as described in Table 3-1 below, a Basic FMP is sufficient to document no-cost and low-cost magnetic field reduction measures. The Basic FMP consists of a transmission line project description, applicable no-cost and low-cost magnetic field reduction measures without magnetic field model(s), and recommendations.

The Detailed FMP consists of a transmission line project description, evaluation of no-cost and low-cost magnetic field reduction measures, magnetic field models, and recommendations (refer to § 3.3 to determine what types of transmission line projects require a Detailed FMP).

For substation projects, a checklist FMP, showing an evaluation of magnetic field reduction measures adopted or rejected, will be used. An example of the Checklist FMP is shown on Table 5-1.

3.3 Determining If an FMP is Required, and If so, What Type

The CPUC in Decision 93-11-013 (§ 3.4.2, p. 15) states, "Utility management should have reasonable latitude to deviate and modify their guidelines as conditions warrant and as new magnetic fields information is received." Table 3-1 provides criteria to determine if the project requires a Detailed FMP, a Basic FMP, a Checklist FMP, or no FMP.

Table 3-1 Criteria to Determine Whether an FMP is Required		
FMP Type Required	**Type of Work**	**FMP Criteria**
Transmission Line (rated 50 kV and above)		
Detailed FMP Note: A Detailed FMP will be used for transmission line projects requiring permitting under GO 131-D.	**New Transmission Line**: The construction of a new transmission line, if the construction requires permitting under GO 131-D. **Major Upgrade**: Major upgrade (including replacement of a significant number of existing structures) on an existing transmission line, if the upgrade requires permitting under GO 131-D.	The construction of a new transmission line will incorporate no-cost and low-cost magnetic field reduction measures. Magnetic field model is required. All major upgrades of existing transmission lines will require no-cost and low-cost magnetic field reduction measures unless otherwise exempted under § 3.4. If permitting under GO 131-D is not required, a Basic FMP may be used, and magnetic field modeling is not required.
Basic FMP Note: A Basic FMP will be used unless the transmission line project requires permitting under GO 131-D.	**Rule 20 Conversions**: Direct replacement of overhead transmission lines with underground transmission lines under Rule 20. **Relocation more than 2000 ft**: Relocation of poles and/or towers involving more than 2000 feet of transmission line. **Pole-head Reconfiguration more than 2000 ft**: Pole-head reconfiguration involving more than 2000 feet of transmission line. The complete replacement of an existing pole-head configuration with a new design.	The transmission line route generally is pre-established for Rule 20 conversions. Phase spacing and depth are set by utility construction standards. Thus, phase arrangement is the only magnetic field reduction measure available to the designer. Therefore, the Basic FMP will be restricted to an evaluation of phase arrangement. Magnetic field modeling is not required. Relocation of existing transmission lines generally does not provide for alternative transmission line routes. Available options are typically limited to minor changes in pole and/or tower height, minor changes in pole-head[20] configuration, or phase arrangement. The Basic FMP will normally cover these options only. Magnetic field modeling is not required. Pole-head replacement is limited in scope; thus, field management options are generally restricted to selecting the pole-head configuration and phase arrangement. In most cases, the new pole-head configuration must be consistent with the remainder of the line. The Basic FMP will be limited to an

[20] It can also be referred to as "pole-top"

Table 3-1 Criteria to Determine Whether an FMP is Required		
FMP Type Required	**Type of Work**	**FMP Criteria**
Basic FMP Note: A Basic FMP will be used unless the transmission line project requires permitting under GO 131-D	 **<u>Reconductoring more than 2000 ft.</u>**: Replacement only of existing conductors and/or insulators with new conductors and/or insulators.	assessment of alternative pole-head configurations and will not require magnetic field modeling. In most cases, replacement of existing transmission conductors is limited in scope; therefore, the Basic FMP will be limited to an assessment of phase arrangement for reconductor activity involving more than 2000 transmission circuit feet. Magnetic field modeling is not required.
None (see exemptions § 3.4)	**<u>Relocation less than 2000 ft</u>**: Relocation of poles and/or towers involving less than 2000 feet of transmission line(s). **<u>Reconductoring less than 2000 ft.</u>**: Replacement only of existing conductors and/or insulators with new conductors and/or insulators. **<u>Pole-head Re-Configuration less than 2000 ft.:</u>** Pole-head reconfiguration involving 2000 feet or less of a transmission line(s) will not require a FMP. **<u>Maintenance</u>:** All maintenance work that does not materially change the design or overall capacity of the transmission line, including the one-for-one replacement of hardware, equipment, poles or towers. **<u>Safety and Protective Devices:</u>** The addition of current transformers, potential transformers, switches, power factor correction, fuses, etc. to existing overhead, pad-mount, or underground circuits. **<u>Emergency Repairs</u>:** All emergency work required to restore service or prevent danger to life and property.	Minor relocation of facilities is limited in scope and does not provide significant opportunity to implement magnetic field reduction measures. Replacement of existing transmission line conductors is limited in scope and does not provide significant opportunity to implement magnetic field reduction measures. Pole-head reconfiguration involving 2000 feet or less of a transmission line(s) will not require a FMP. Maintenance work is limited in scope and does not provide significant opportunity to implement magnetic field reduction measures. The addition of protective equipment or power factor correction to existing transmission circuits is limited in scope and does not provide significant opportunity to implement magnetic field reduction measures. This work is performed on existing facilities under emergency conditions and does not involve redesign.

Table 3-1 Criteria to Determine Whether an FMP is Required		
FMP Type Required	**Type of Work**	**FMP Criteria**
Substation (Rated 50 kV and above)		
Checklist FMP	**New Substations:** The construction of a new substation having a rated high side voltage of 50kV or above.	The construction of a new substation will incorporate no-cost and low-cost magnetic field reduction measures as outlined in §5. A no-cost and low-cost checklist[21] will be used as a part of the FMP.
	Major Upgrade with GO 131-D: Major reconstruction of an existing substation that involves the installation of additional transformers to achieve an increased rated capacity and that requires permitting under GO 131-D.	All major upgrade of existing substations will require evaluations of no-cost and low-cost magnetic field reduction measures as outlined in §5, unless otherwise exempted under § 3.4. A no-cost and low-cost check list may be used.
	Major Upgrade without GO 131-D: Major upgrade of an existing substation that involves the installation of additional transformers to achieve an increased rated capacity and that does not require permitting under GO 131-D.	Major substation upgrade projects involving the addition of new transformers but not requiring GO 131-D permitting may use a no-cost and low-cost check list only. The 'no-cost and low-cost' will be limited to an evaluation of magnetic field reduction measures applicable to the transmission get-away[22] and to the location of the new transformers so as to maximize the distance from the transformers to the substation fence.

[21] See Section 5 for more information about no-cost and low-cost check lists for substation projects.
[22] This can be a part of Transmission FMP.

Table 3-1 Criteria to Determine Whether an FMP is Required

FMP Type Required	Type of Work	FMP Criteria
None (see exemptions § 3.4)	**<u>Reconstruction without installation of additional transformers</u>**: This includes, for example, the installation of additional switchgear, line or bank positions, power factor correction capacitors, underground circuits and overhead circuits.	The addition of switchgear or other apparatus is limited in scope and does not provide significant opportunity to implement magnetic field reduction measures.
	<u>Direct Replacement</u>: The direct replacement of substation equipment, even if the new equipment has a different capacity rating.	The direct replacement of substation equipment is limited in scope and does not provide significant opportunity to implement magnetic field reduction measures.
	<u>Maintenance:</u> All maintenance work that does not materially change the design of the substation.	Maintenance work is limited in scope and does not provide significant opportunity to implement magnetic field reduction measures.
	<u>Emergency Repairs</u>: All emergency work required to restore service or prevent danger to life and property.	This work is performed on existing facilities under emergency conditions and does not involve redesign.
Distribution Project (Rated less than 50 kV)		
None	Construction or reconstruction of distribution lines with voltages less than 50 kV.	Each electric utility's distribution construction and design standards incorporates magnetic field reduction measures for distribution lines.

3.4 Projects Exempt from the FMP Requirement

The CPUC, in Decision 93-11-013, recognized that some flexibility was required in the EMF Design Guidelines. In section 3.4.2 of the Decision, the CPUC stated: "Electric utility management should have flexibility to modify the guidelines and to incorporate additional concepts and criteria as new EMF information becomes available. However, if the EMF Design Guidelines are to be truly used as guidelines, the utilities should incorporate criteria which justify exempting specific types of projects from the guidelines."

The following criteria to determine those transmission and substation projects exempted from the requirement for consideration of no-cost and low-cost magnetic field reduction measures:

1. Emergency
   - All work required to restore service or remove an unsafe condition.
2. Operation & Maintenance
   - Washing and switching operations.
   - Replacing cross-arms, insulators, or line hardware.
   - Replacing deteriorated poles.
   - Maintaining underground cable and vaults.
   - Replacing line and substation equipment with equipment serving the same purpose and with similar ratings.
   - Repairing line and substation equipment.
3. Relocations
   - Line relocation of up to 2000 feet.
   - Installation of guy poles or trenching poles only.
4. Minor Improvements
   - Addition of safety devices.
   - Reconductoring up to 2000 feet, where changing pole-head configuration is not required.
   - Installation of overhead switches.
   - Insulator replacement.
   - Modification of protective equipment and monitoring equipment.
   - Intersetting of additional structures between existing support structures.
5. Projects located exclusively adjacent to undeveloped land—including land under the jurisdiction of the National Park Service, the State Department of Parks and Recreation, U.S. Forest Service, or Bureau of Land Management (BLM).

3.5 Prioritizing Within and Between Land Use Classes

The CPUC stated in Decision 06-01-042, "[a]lthough equal mitigation for an entire class is a desirable goal, we will not limit the spending of EMF mitigation to zero on the basis that not all class members can benefit."[23]

While Decision 06-01-042 directs the utilities to favor schools, day-care facilities and hospitals over residential areas when applying low-cost magnetic field reduction measures, prioritization within a class can be difficult on a project case-by-case basis because schools, day-care facilities, and hospitals are often integrated into residential areas, and many licensed day-care facilities are housed in private homes that can be easily moved from one location to another. Therefore, utilities may group public schools, licensed day-care centers, hospitals, and residential together to receive highest prioritization for low-cost magnetic field reduction measures. Commercial and industrial areas may be grouped as a second priority group, followed by recreational and agricultural areas as the third group. Low-cost magnetic field reduction measures will not be considered for undeveloped land such as open space, state and national parks, Bureau of Land Management and National Forest Service Land.

When spending for low-cost measures would otherwise disallow equitable magnetic field reduction for all areas within a single land-use class, prioritization can be achieved by considering location and/or density of permanently occupied structures on lands adjacent to the projects, as appropriate.

[23] Ibid., p. 10

4 Field Management Plans for Transmission Lines

Construction of a new transmission line or the major upgrade of an existing transmission line, if they require GO-131D permitting, or the relocation of 2000 feet or more of an existing transmission line will require the preparation of a FMP; refer to § 3.3 to determine if a Detailed FMP (or Basic FMP) is needed; refer to § 3.4 for exemption criteria.

Transmission FMPs should include the following sections:

- Project Description;
- Evaluation of No-Cost Magnetic Field Reduction Measures;
- Evaluation of Low-Cost Magnetic Field Reduction Measures; and
- Recommendations including a table showing magnetic field reduction measures.

In addition to these requirements, a two-dimensional (2D) magnetic field model is required for a Detailed FMP.

4.1 Project Description

The project description portion of the transmission line FMP will include the following:

- For a Detailed FMP, the proposed line route should be shown on an attached project map illustrating the transmission line route, alternative line route (if applicable), and major streets and highways. A Basic FMP should briefly describe the scope of work including the line route;
- Description of land use adjacent to the line route for both Basic and Detailed FMPs;
- Circuit name and rated voltage, and circuit phasing if more than one circuit is present in the same corridor for both Basic and Detailed FMPs (rated 50 kV and above);
- Description of proposed design. For a Detailed FMP, include circuit configuration, and minimum ground clearance for overhead design. For a Basic FMP, include circuit configuration. For underground facilities (for both Detailed FMP or Basic FMP), show the depth and configuration of duct bank;
- Include estimated total project costs for proposed design.(for a Detailed FMP).

4.2 Two-Dimensional Magnetic Field Modeling for Transmission Line

The purpose of magnetic field modeling is to evaluate relative effectiveness of various magnetic field reduction measures, not to predict magnetic field levels, as the CPUC recognized in Decision 06-01-042:

> "Utility modeling methodology is intended to compare differences between alternative EMF mitigation measures and not determine actual EMF amounts."[24]

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[24] Ibid., p. 20

> "… the modeling indicates relative differences in magnetic field reductions between different transmission line construction methods, but does not measure actual environmental magnetic fields. In the same way, these relative differences in mitigation measures will be evident regardless of whether a maximum peak or a projected peak is used for the comparisons… It is also true that post construction measurement of EMF in the field cannot indicate the effectiveness of mitigation measures used as it would be extremely difficult to eliminate all other EMF sources."[25]

Two-dimensional magnetic field software can be used to evaluate the magnetic field characteristics of the proposed construction and various magnetic field reduction alternatives. Estimates of magnetic field levels are calculated based on a specific set of conditions. Therefore, it is important to make logical assumptions as to what these conditions will be and to keep these calculation conditions consistent when comparing two or more different cases.

Typical two-dimensional magnetic field modeling assumptions include:

- The line will be considered operating at forecasted design load;
- Magnetic field strength is calculated at a height of three feet above ground (assuming flat terrain);
- Resultant magnetic fields are being used;
- All line loadings are considered as balanced (i.e. neutral or ground currents are not considered);
- The line is considered working under normal operating conditions (emergency conditions are not modeled);
- Terrain is flat;
- Dominant power flow directions are being used; and
- Contribution of shield wire currents is not included.

[25] Ibid., p. 11

5 Field Management Plan for Substations

Construction of a new substation rated 50 kV and above or the major upgrade of an existing substation rated 50 kV and above will require the preparation of a substation FMP in a form of a check list (see example in Table 5-1). Magnetic field modeling for the substation project is not required.

A major upgrade for purposes of these Guidelines means the expansion of an existing substation through the addition of transformer bank(s) or new transmission line(s). "One-for-one" replacement of substation transformers, circuit breakers, or other apparatus does not constitute an major upgrade for purposes of these Guidelines, even if that replacement results in an increase in rated capacity. The addition of instrumentation, control, or protection equipment does not constitute a major upgrade. Refer to § 3.3 to determine if a substation FMP is needed, and to § 3.4 for exemption criteria.

Generally, magnetic field values along the substation perimeter are low compared to the substation interior because of the distance to the energized equipment. Normally, the highest values of magnetic fields around the perimeter of a substation are caused by overhead power lines and underground duct banks entering and leaving the substation, and not by substation equipment. Therefore, the magnetic field reduction measures generally applicable to a substation project are as follows:

- Site selection for a new substation;
- Setback of substation structures and major substation equipment (such as bus, transformers, and underground cable duct banks, etc.) from perimeter;
- Lines entering and exiting the substation (this will be a part of a transmission line FMP).

The Substation Checklist FMP evaluates the no-cost and low-cost measures considered for the substation project, the measures adopted, and reasons that certain measures were not adopted. An example Substation check list is shown below:

Table 5-1 Example of Substation Checklist for a FMP

No.	No-Cost and Low-Cost Magnetic Field Reduction Measures Evaluated for a Substation Project	Measures Adopted? (Yes/No)	Reason(s) if not Adopted
1	Keep high-current devices, transformers, capacitors, and reactors away from the substation property lines.	☐	
2	For underground duct banks, the minimum distance should be 12 feet from the adjacent property lines or as close to 12 feet as practical.	☐	
3	Locate new substations close to existing power lines to the extent practical.	☐	
4	Increase the substation property boundary to the extent practical.	☐	
5	Other:	☐	

6 California Department of Education's (CDE) Criteria for Siting New Schools Adjacent to Electric Power Lines Rated 50 kV and Above

The California Department of Education evaluates potential school sites under a range of criteria, including environmental and safety issues. Proximity to high-voltage power transmission lines[26] is one of the criteria. As the CPUC directed in Decision 06-01-042, the California investor-owned utilities worked with the CDE to align EMF Design Guidelines with the CDE's policies to the extent those policies were consistent with the CPUC's EMF Policy as stated in its Decision 06-01-042. As a result, the updated power line setback exemption guidelines were issued in May 2006. In revising its precautionary EMF approach, the CDE stated:

> "The proposed guidance acknowledges the scientific uncertainty of the health effects of EMFs, the lack of any state or nationally established standard for EMF exposure, and the PUC's recently reconfirmed reliance upon no/low-cost measures targeted to only reduce fields from new power transmission lines." [27]

CDE has established the following "setback" limits for locating any part of a school site property line near the edge of easements for any overhead power lines rated 50 kV and above:

- 100 Feet for 50 – 133 kV Power Lines (interpreted by CDE up to 200 kV)
- 150 Feet for 220 – 230 kV Power Lines
- 350 Feet for 500 – 550 kV Power Lines

For underground power lines rated 50 kV and above, the CDE's setback distances are as follows:

- 25 feet for 50-133 kV line (interpreted by CDE up to 200 kV)
- 37.5 feet for 220-230 kV line
- 87.5 feet for 500-550 kV line

School districts that have sites which do not meet the CDE's setbacks may still obtain construction approval from the state by submitting an exemption application. Generally, school districts hire independent consultants who are familiar with the process to complete CDE's application requirements.

[26] *School Site Selection and Approval Guide*, California Department of Education
[27] "Power Line Setback Exemption Guidance - May 2006" by the California Department of Education

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

COST ESTIMATE FOR PG&E'S PROPOSED PROJECT

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COST ESTIMATE FOR PG&E'S PROPOSED PROJECT

A. Introduction

1. Purpose and Scope

The purpose of this chapter is to provide an overview of the estimated construction and operation costs of the proposed Project.

2. Organization of the Remainder of This Chapter

- Section B – Cost Estimate for Pacific Gas and Electric Company's (PG&E) Proposed Project
- Section C – Methodology for Calculating Cost Estimates

B. Cost Estimate for PG&E's Proposed Project

Based upon preliminary design and cost estimates provided by consultants, PG&E estimates that the total construction cost for the Project will be approximately $171 million before contingencies. Project construction costs are broken down in the following preliminary estimates:

Line No.	Estimated Construction Costs	Cost ($2013)
1	Transmission Line and Embarcadero Interconnection	$101.0M
2	Potrero 230 kilovolt (kV) Gas Insulated Switchgear (GIS)	69.8M
3	Total Construction Costs	$171M

PG&E also has included $26 million in contingency on the Project. As discussed below, as PG&E obtains actual pricing on various Project components, this contingency may be further reduced. This contingency is not intended to include any costs associated with future project-related regulatory/licensing requirements that are too remote and speculative to be estimated at this time.

These cost estimates are lower than the cost estimates included in Exhibit H to PG&E's application for the Project filed on December 11, 2012 in the California Public Utilities Commission (CPUC or Commission) proceeding Application 12-12-004. Specifically, the total Project cost, without contingencies, has decreased from $191 million in the application to $171 million, as described in this chapter. The decision-quality cost estimate attached to the application was prepared on November 9, 2012, and is superseded by this testimony. The reductions in the cost estimate result from the reduction in cost uncertainty due to PG&E's contracting progress in the intervening period. The new information obtained from suppliers allowed PG&E to both update its earlier estimates and to reduce the contingencies it reserved to account for remaining cost uncertainty.

PG&E's detailed cost estimates, based on preliminary design and the cost estimates provided by consultants are attached hereto as Attachment 5-1. As noted above, these detailed cost estimates supersede and replace the detailed cost estimates provided in Exhibit H to the application.

PG&E also has estimated its future annual operation and maintenance costs. Operations and Maintenance (O&M) costs will also include transmission line monitoring, surveying and reporting. To determine whether the submarine cable remains buried and identify any potential impacts on the Bay floor, PG&E intends to monitor the location of the cables annually through a contract with a marine surveyor. PG&E also will use a marine monitoring system that will automatically notify PG&E should a vessel remain in place over the cables for a particular length of time.

Line No.	Estimated Operation and Maintenance Costs	Average Annual Cost ($2012)
1	Transmission Line (monitoring, surveying, reporting)	$59,825
2	Potrero 230 kV GIS Switchyard	17,680
3	Total Annual O&M Costs	$77,505

C. Methodology for Calculating Cost Estimates

Attachment 5-1 hereto contains a detailed breakdown of the estimated costs of engineering, procurement and construction of the proposed Project. The cost estimates are based on a combination of preliminary costs estimates and bids that PG&E obtained from independent engineering and construction firms, Black & Veatch Construction Inc. (Black & Veatch or B&V), ABB Inc. (ABB), and Sumitomo Electric USA (SEUSA) as well as PG&E's estimates of its costs.

Black & Veatch prepared preliminary cost estimates for components of the Project that relate to the engineering, procurement and construction of the new 230 kV transmission line. These components include the estimated cost of the on-shore and off-shore project design, materials, construction, construction management, surveying, soil boring, and permitting.

ABB prepared preliminary cost estimates for components of the Project that relate to the engineering, procurement and construction of the new 230 kV Potrero Switchyard and connection to the Embarcadero Substation. These components include the estimated cost of design, materials, construction, construction management, surveying, soil boring, and permitting.

PG&E prepared cost estimates for transmission planning, preliminary engineering and feasibility analysis, project management, permitting, and land costs.

Each set of cost estimates is discussed below.

1. Black & Veatch and SEUSA 230 kV Transmission Line Cost Estimates

Black & Veatch's preliminary Cost Estimate includes the engineering, material procurement and construction for both submarine cable and land cable installation with labor breakdown per unit where possible and covers the cable alignment as proposed by PG&E in its application:

- On-Shore Cable System:
  - Potrero to land to Bay transition
  - Embarcadero to land to Bay transition
- Off-Shore Cable System
  - Submarine portion from Potrero Bay/land transition to Embarcadero Bay/land transition

As discussed in Chapter 4, the on-shore cable system includes Horizontal Directional Drilling (HDD) and installation of a High Density Polyethylene (HDPE) duct system to facilitate the transition from land to Bay. The off-shore cable system includes the installation of a submarine cable through the HDPE ducts and splicing at the Bay to land cable joints in transition manholes.

The land-based cable system estimate is a "bottoms-up" estimate based on unit quantities of materials and labor required. Quantities were determined based on conceptual engineering design, which involved site visits, field data gathering, general engineering design, selection of materials, preliminary structure designs, and conversations with PG&E and other consultants to define the scope of work required to construct the

Project in accordance with PG&E requirements. The quantities are arranged into "functional units," such as linear feet of cable, linear feet of Polyvinyl Chloride (PVC) duct bank in lump sum basis, square feet of asphalt, and others. A unit material/equipment cost is assigned to each unit, as well as a unit labor-hour to assemble and install the functional unit or a subcontracted unit cost to install the functional unit. The unit material/equipment cost is the cost of the material(s), including delivery to the site. Most of the unit costs in this estimate were based on statistics from previous projects of similar complexity. The unit labor hour used for this estimate is $130.00 per hour. This "loaded" unit cost represents underground transmission line construction in the area, including all levels of craftsmen and laborers, construction equipment and tools, per diem or subsistence, overhead costs, et cetera. This rate has as its basis the labor rates in the 2012 International Brotherhood of Electrical Workers agreement.

The second component is the cost estimate for the cable system and is based on (1) a proposal received from cable supplier SEUSA as a result of competitive bidding; and (2) an adjusted budgetary Black & Veatch cost estimate. The SEUSA proposal covers the manufacturing, shipping and installation of the cable from termination to termination at the Potrero Switchyard and Embarcadero Substation. While the contract terms are still currently under review, the final estimated amount is not expected to change in excess of several thousand dollars which would be covered by the contingency pool. The Black & Veatch budgetary base cost estimate, which covers the installation of the vaults, the duct bank system and the HDD transition from land to Bay, was adjusted downward to account for reduction in scope and associated contract and construction management costs—in summary, the electric and fiber optic cable pulling, splicing and terminating, and the land portion of the distributed temperature sensing system was reassigned to the SEUSA scope of work. Further, a method was developed to connect the submarine cable to the HDD conduits that will not require installing cofferdams. The BV cost estimate remains at the budgetary estimate stage because Black & Veatch has not completed its duct bank system and HDD transition to bay construction competitive bidding process.

Engineering and Construction Management estimates are based on the recent historical performance of several underground transmission projects completed in the Bay Area.

The estimate is based on 0.6 miles of on-shore alignment, 0.4 miles of HDDs for the two submarine landings, and 2.5 miles of off-shore alignment.

a. On-Shore Alignment

On-Shore Cable Detailed Design – The design cost estimate includes developing a project design memorandum, cable size design, a geotechnical and geothermal analysis, underground land survey, developing plan and profile drawings, duct bank and vault and cable racking design, a construction detail design and traffic control for local construction permitting submittals.

Duct Bank – The duct bank cost estimate is based on a 4' wide trench which includes four 8" ducts to house the three electrical phases of the cable plus one spare, and two - 4" ducts for the fiber optic communications cable. The cost estimate assumes the duct bank will be concrete encased with steel reinforcement to meet the seismic design, and will be backfilled with Fluidized Thermal Backfill.

Soil Management – The soil management cost estimate includes disposing of all trenched soils as the native material does not have the requisite thermal properties to allow its use as backfill. It accounts for disposing of non-contaminated excavated soils for 100 percent of the land cable route at a Class 3 landfill site. The estimate does not include disposing of contaminated Class 2 soils, hazardous Class 1 soil and dewatering contaminated discharge in the excavation areas, because it is not possible to estimate the amount of contaminated spoil material and any hazardous materials that may be unearthed during excavation, if any. However, there is adequate funding in the estimate contingency to cover the eventuality that hazardous materials or contaminated soils are found.

Vaults – The vaults cost estimate is based on six vaults conceptually located at the bay/land transitions and one additional vault in Folsom Street to the cable terminations at the substations. The size of the vaults was selected based on the anticipated size of cable to be used and historical data of allowable pulling lengths for similar cable in similar environments.

Restoration – The restoration cost estimate includes a 2” deep × 11’ wide asphalt pavement restoration for the entire land route per City requirement.

Substation Work – Riser & Termination Structures – This cost estimate includes one low profile H-frame termination structure at each substation.

b. Transition HDD HDPE Conduits

HDD – The estimate includes six HDD bores, approximately 1,000 feet each, to transition the cable from bay to land. The cost estimate assumes utilizing 1-10” HDPE, DR11 conduit directly pulled in the HDD bore hole without casing.

c. Off-Shore Cable

Design – The cost estimate includes engineering tasks for submarine cable installation, including hydrographic survey, cable route engineering, utility locates and cable engineering.

Land and Submarine Cables – The estimate includes cable lengths equal to the horizontal distance of the route plus 3 percent to account for additional length due to changes in elevation, splicing and other waste. Material pricing, of the cable and cable accessories, was based on a proposal received from cable supplier SEUSA as a result of competitive bidding. Also included in the off-shore cable cost estimate is a Distributed Temperature System. The cost estimate is based on joint PG&E and Black & Veatch specifications calling for a 2,500 thousand circular mil cable for the on-shore alignment and 1,400 mm^2 CU cable for the off-shore alignment, and on a proposal received from cable supplier SEUSA as a result of competitive bidding. The estimate also includes the following spare material: 2,000 feet of cross-linked polyethylene (XLPE) land cable, 2 XLPE cable terminations, 5,000 feet of submarine cable, 2 Bay/land cable transition joints and 4 submarine cable repair joints.

Fiber Optics – The estimate includes 2 circuits of 48-strands communication fiber cables installed the full length of the circuit. The submarine fiber cables will be lashed with the submarine power cables during installation, and installed in the 4” PVC conduits with Maxcell inner ducts.

d. B&V Contingencies

Project Risk Assessment – Potential risks were identified and 10 percent of their total material and labor cost was included in the estimate. These potential risks include: Curb to curb pavement restoration per City request due to pavement disturbance; HDD cost increase detail design resulting in a longer length than conceptually anticipated; the management and disposal of contaminated and/or hazardous soil and water; greater duct bank reinforcement and utility relocations.

Contingency – Additional unknown risks will be covered by the overall PG&E controlled contingency pool.

2. ABB’s Cost Estimate for Potrero Switchyard

ABB’s cost estimate for the Potrero Switchyard includes all costs typically included in an engineering, procurement and construction (EPC) scope. ABB enlisted the assistance of professionals local to the San Francisco area including an architect firm and a professional estimating firm. The architect was added to ABB’s Study team to provide expertise with the building aesthetics. The estimator provided ABB with expert local costing information for the GIS building. For all other pricing, ABB divided the Project into phases that can be fairly accurately compared to similar installations ABB has completed in the past so as to eliminate unknowns and reduce the estimate tolerance and risk contingencies.

Engineering and Construction Management – Estimates were based on the recent historical performance of similar GIS switchyard projects.

GIS Building – The Potrero GIS building engineering, procure and construct phase, was isolated and costing developed by a professional estimating service.

Equipment – Major equipment and material (as discussed in Chapter 4) were estimated using either quotations from suppliers or recent historical data.

Ancillary Systems and Minor Equipment – This equipment is essentially standard for most stations in the PG&E system and was estimated from recent historical costing data.

Recent local historical data was used to estimate construction permitting and sub-contractor mobilization and demobilization. Construction labor costs were estimated using the recent historical unit cost data of similar projects.

a. ABB Contingencies

Project Risk Assessment – Potential risks were identified and 8.5 percent of their total material and labor cost was included in the estimate. These potential risks include: management and disposal of contaminated and/or hazardous soil and water, seismic reinforcements, cultural resources management, utility relocations and cable termination delays, and building design Certificate of Public Convenience and Necessity (CPCN) imposed mitigation measures. The ABB proposal which was received on August 30, 2013, is currently under review and is expected to be reduced by as much as 3 percent to account for reduced scope and contract negotiation.

Contingency – No further contingency is included, in the ABB current cost proposal or expected to be included in the PG&E agreed upon version.

3. PG&E Cost Estimates

a. Land Costs

In estimating land costs, PG&E calculated: (a) the cost of acquiring fee title to the proposed Potrero Switchyard site; (b) the cost of acquiring rights of way easements for the portion of the proposed duct bank alignment that is not in franchise in City streets (public right of way); and (c) the cost of acquiring a Port of San Francisco license for portions of the project that will be located on Port property, including a portion of the new 230 kV Potrero Switchyard area, a portion of the underground cable near the waterfront and the submarine cable.

a) The Potrero Switchyard site will be acquired in fee simple from landowner NRG Energy, Inc. (NRG) (formerly GenOn Energy, Inc.). A fee purchase amount of $1.8M was determined by an appraiser using a market sales approach where comparative sales data in the area were used to develop an estimated cost.

b) The on-shore portions of the project, including the two HDD termination points, are located primarily in franchise in City streets or PG&E-owned property. No right-of-way acquisition is required in public streets in franchise; however, PG&E will acquire rights of way for a portion of the southern landing area owned by NRG and stretching approximately 760 feet from the San Francisco Bay shoreline along 23rd Street. This permanent easement is estimated to cost $730,000. A temporary construction easement consisting of a total of one acre located in two areas, one just north of the future Potrero switchyard site and another along the duct bank alignment in 23rd Street will also be acquired from NRG. This is estimated to cost $155,000.

c) The Port of San Francisco has jurisdiction over the Bay and waterfront lands in the vicinity of Piers 28 and 30, near the northern landing, and Pier 70 and 23rd Street near the southern landing. PG&E and the Port of San Francisco have agreed to terms governing the issuance of a license for the Project with an estimated lump sum, net present value of approximately $15.0 million for the first 40-year term. PG&E also has agreed, if requested by the City, to screen the existing Potrero switchyard equipment (such potential cost is not included in PG&E's cost estimate), and to provide the Port with an option to purchase PG&E's Hoedown Yard based upon appraisals of fair market value if such a transaction is approved by the California Public Utilities Commission (CPUC or Commission). PG&E and the Port further have agreed that the license may be renewed for an additional 26 years at a cost to be determined and paid after 40 years according to an agreed-upon methodology (which cost is not included in PG&E's current cost estimate because it is too remote and will be accounted for separately by PG&E at that time).

b. PG&E Internal Services and Permitting Costs

The supervision and inspection costs were estimated based on input from the PG&E project engineers and the inspection's department supervisor. For supervision, these costs include support in project planning in general and the development of the Proponents Environmental Assessment, material and standards specifications; support in the development of the project EPC contract specification, contract competitive bid evaluation and award and construction field engineering support. For inspection, they include part time on-site inspection and monitoring of the contractor and sub-contractors work, inspectors and third party testing contractors (i.e., for soil compaction), coordination with PG&E's project management and engineering, local jurisdiction, other utilities, communities, and the CPUC environmental monitors.

The project management costs were calculated based on input from the senior project manager assigned to the Project. They include overall responsibility and accountability of the Project from inception to completion and consist of initiating internal project approval and funding, assembling teams and developing schedules, costs and cost monitoring, assisting in leading the project CPCN filing and California Environmental Quality Act review, sponsor testimony, lead the Project EPC contracting process and executing detail design and construction.

These cost estimates include the acquisition of licenses and/or permits from various jurisdictional agencies such as: Port of San Francisco; United States (U.S.) Army Corps of Engineers; San Francisco Bay Area Regional Water Quality Control Board; National Marine Fisheries Service; U.S. Fish and Wildlife Service; California Department of Fish and Wildlife and the U.S. Coast Guard.

They also include biological assessments, surveys, agency consultations, support work for preparation of incidental take permits (if required) and project environmental monitoring, and provision for any required mitigation as a result of construction of the Project.

c. Estimated Cost of Mitigation Measures

Best management practices will be employed throughout the project execution. Additional mitigations measures may be imposed as part of CPUC granting the CPCN and or state or federal resource agencies permits. It is not possible to estimate their costs before they are known; however, $3.9 million is included in the project contingency to cover potential environmental mitigation measures.

d. Electric and Magnetic Fields Reduction Costs

PG&E's cost estimates also include the four percent budget benchmark amount for Electric and Magnetic Fields reduction measures for the Project, as required by CPUC Decision 06-01-042.

e. Sales Tax, Overhead, Material Burden, Allowance for Funds Used During Construction and Escalation

PG&E's cost estimate has applied the City and County of San Francisco's 9.50 percent 2013 sales and use tax to the purchase of all equipment. This tax has been excluded in the B&V cost estimates for material purchases due to the unknown time frame of construction. For purposes of its cost estimates, PG&E has assumed the 2013 rate will apply.

PG&E's standard 2013 rate of 15 percent for overhead has been applied to the total direct cost, plus taxes, to cover the distribution of Administrative and General (A&G) expenses to the capital program. The percentage used is in accordance with PG&E Capital Accounting Guidelines, Instruction 7, Exhibit B (rates for calculating overhead costs).

PG&E's standard 18 percent material burden is intended to distribute warehousing costs to the material and equipment that PG&E procures, receives, inspects and otherwise handles. The percentage used is in accordance with PG&E Capital Accounting Guidelines, Instruction 7, Exhibit B (rates for calculating overhead costs). However, there is no cost involving material burden as all material is handled by contractors.

PG&E's Allowance for Funds Used During Construction (AFUDC) is an estimate of PG&E's cost of capital invested in the Project during construction and is applied to all capital orders or projects that have a construction period of greater than 30 days. The percentage used is in accordance with PG&E Capital Accounting Guidelines, Instruction 7, Exhibit B (rates for calculating AFUDC costs). AFUDC is applied to the Project's total direct cost, applicable taxes, capital A&G, and any escalation. AFUDC is accrued from the first month that costs are first charged to the Project and continues until the month the Project is declared operational. For estimating purposes, the actual first month that costs were first charged to the Project which was February 2008 and the anticipated operational date of December 2015 were used to determine a project duration of 7 years and 11 months, resulting in an AFUDC rate of 8 percent.

PG&E adds escalation to the estimate of any long-term project (i.e., greater than one year in duration) as a provision for increases in costs resulting from inflation. The percentage used is in accordance with PG&E Capital Accounting Guidelines, Instruction 7, Exhibit B (rates for calculating escalation). For estimating purposes, the actual first month that costs were first charged to the Project which was February 2008 and the anticipated operational date of December 2015 were used to determine this project duration of 7 years and 11 months, resulting in an overall escalation factor of 6 percent.

f. Contingencies

The following contingency amounts were added to the project cost estimate:

Line No.		
1	Duct bank, vaults and transition to bay	$5,200,000
2	Cable installation	10,400,000
3	Potrero switchyard construction	2,600,000
4	Environmental Mitigation	3,900,000
5	Land and right of way acquisition	3,900,000
6	Total Contingency(a)	$26,000,000

(a) Contingency is $26 million due to lower cost estimates and more advanced contracting information.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

ATTACHMENT A

PROJECT COST ESTIMATE

Pacific Gas and Electric Company

Job Estimate - Face Sheet

62-6251 (Rev. 02/09)
Capital Accounting

Date: September 03, 2013

Business Area: Utility Operations - Energy Delivery
Receiver Cost Center: TSM&C Martin UG
Receiver Cost Center No.: 10934

Applicant: Pacific Gas & Electric Company
Job Title: **Embarcadero-Potrero 230kV Transmission Line**
Location: **San Francisco**
County: 038 - San Francisco County
Regulatory Cat.: 1001 - Capital Electric
Major Work Cat.: 60 - Electric Transmission T-Line Capacity
Person in Charge: Alain Billot, Sr. Consulting Project Manager
Job Preparer: Alain Billot, Sr. Consulting Project Manager

Start Date: 03/01/2008
Operative Date: 12/31/2015
Completion Date: 06/30/2016
Accident Rpt. No. (AR): N/A
Planning Order No.: 5731444
Planned Amount: $101,010,226
Project No.: P.02693

Job Summary and Necessity

This job estimate is an updated version of the job estimate attached to the Dec. 2012 CPCN Application filing and is prepared as an exhibit to the project CPUC CPCN Testimony filing. It is based on 1) an updated cost estimate to install the on-shore duct bank system and HDDs provided by PG&E consultant Black & Veatch and a competitive proposal from Sumitomo Electric USA and sub-contractor Durocher Marine to supply and install the submarine cable and is subject to the limitations described therein, and 2) a cost estimate prepared internally that documents costs to-date and forecasts internal PG&E labor, miscellaneous contracts, land acquisition and indirect and overhead costs at the current stage of project development and current labor and overhead rates. As with the cost estimate attached to the Application filing, this remains a budgetary, "decision quality" job estimate. whereas a "construction quality" job estimate will be developed after CPUC has issued its final cable alignment decision and the project implementation

Work Breakdown and Cost Summary (See Supplemental Page for Cost and Accounting Detail)

Removal Order No. or Asset No.	Resp. Cost Center	Description	Hours	Total Cost
	Various	Actual Costs since inception through July 2013	8,190	4,522,774
	Various	Summary Forecast PG&E costs post July 2013 to completion	8,437	22,761,838
	Various	Cable installation (prepared by Black & Veatch and Sumitomo US		69,856,419
		Electro Magnetic Field (EMF)		3,869,195

Expenditure by Year (excludes contingency)

Year	Prior Years	2012	2013	2014	2015-2016	Total
Capital	$3,249,621	$2,500,000	$6,500,000	$18,000,000	$70,760,605	$101,010,226
Expense						

Total Costs	
Cap Install'n	87,874,807
Cap Removal	
Expense	
Mat'l Burden	
Cap A&G	380,692
AFUDC	7,482,239
Escalation	5,272,488
Contingency	
Gross Amount Authorized	101,010,226
Scrap/Re. Mat'l.	
Credits	
Net Amount Authorized	101,010,226

Project Sponsor
Geisha Williams
Sr. VP - Energy Delivery

Sponsor's Representative
Alain Billot
Sr. Consulting Project Manager

Job completion information:
Start Date: ______
Operative Date: ______
Completion Date: ______

Foreman's Signature:

Job Authorization

Recommend	**Recommend**
Concur	**Concur**
Authorize	**Date Authorized**
Order Number	**30605686**

Pacific Gas and Electric Company

Job Estimate - Summary Sheet

62-6251 (Rev. 02/09)
Capital Accounting

Job Title: Embarcadero-Potrero 230kV Transmission Line
Location: San Francisco

Current Burden Rate for Material < $75,000: 18.00%

Order Number: 30605686

Removal Order or Asset No.	Resp. Cost Center	Description	Hrs	Internal Services	Material	Contract	Other	Material Burden	Capital A&G	AFUDC	Escal'n	Conting.	Conting. % by Line Item	Scrap	Credits	Total Cost
		Applied Percentage Rate:							15.00%	8.00%	6.000%					
	Various	Actual Costs since inception through Ju	8,190	1,179,360		2,594,448			187,518	335,020	226,428					4,522,774
	Various	Summary Forecast PG&E costs post Jul	8,437	1,214,928		1,768,000	16,717,640		193,174	1,686,062	1,182,034					22,761,838
	Various	Cable installation (prepared by Black &			4,558,282	56,462,349				5,174,550	3,661,238					69,856,419
		Electro Magnetic Field (EMF)					3,379,800			286,607	202,788					3,869,195
		Escalated Amounts		2,537,945	4,831,779	64,474,285	21,303,286									
		Total Cost	16,627	2,394,288	4,558,282	60,824,797	20,097,440		380,692	7,482,239	5,272,488					101,010,226

Pacific Gas and Electric Company

Job Estimate - Detail Sheet: Plant to be Installed

Order Number: 30605686

Embarcadero-Potrero 230kV Transmission Line
San Francisco

Removal Order or Asset No.	Description	Quantity	Provider Cost Center	Activity	Standard Rate	Hours	Internal Services	Material	Contract	Other	TOTAL ($ only)
							SUB-TOTAL AMOUNT (dollars only)				
	Actual Costs since inception through July 2013										
	PG&E Internal Labor (Engr, Prj Mgmt, Environmental, Planning, etc..)						-				
	Permits, land and ROW acquisition		Various	Various	144.00	8190.00	1,179,360				1,179,360
	Misc. contracts						-		2,594,448		2,594,448
	Subtotal Actual Costs since inception through July 2013					8,190	1,179,360		2,594,448		3,773,808
	Summary Forecast PG&E costs post July 2013 to completion										
	PG&E Internal Labor		Various	Various	144.00	8,437	1,214,928				1,214,928
	Inspection (Civil & Electrical)								500,000		500,000
	Mapping Overhead									717,640	717,640
	External Legal & Experts								668,000		668,000
	CH2M Hill (PEA)								200,000		200,000
	Black & Veatch Feasibility CPCN Support								50,000		50,000
	Right-of-Way Acquisitions									16,000,000	16,000,000
	Environmental Monitoring								350,000		350,000
	Subtotal Summary Forecast PG&E costs post July 2013 to completion					8,437	1,214,928		1,768,000	16,717,640	19,700,568
	Cable installation (prepared by Black & Veatch and Sumitomo USA)										
	Cable manufacturing, shipping, laying, pulling through transitions to land and terminating (proposed by Sumitomo USA)										
	Cable Offshore								14,459,657		14,459,657
	Bay to land transition joints								1,196,288		1,196,288
	Supporting structures								224,792		224,792
	Control/Communication fiber optic cable								405,000		405,000
	Fiber optic cable transition joints								16,328		16,328
	Supporting structures								27,684		27,684
	Submarine cable testing								1,039,976		1,039,976
	Submarine cable installation								20,412,254		20,412,254
	Contingency (5%, Cable matting where minmum 3 foot burial cannot be achieved)								1,890,000		1,890,000
	Onshore Cable System Materials & Installation (Prepared by Black & Veatch, pending proposal by SE USA)										
	Engineering & Design										
	Engineering & Technical Support during construction								500,000		500,000
	230kV, 2500 kcmil Seg. Cu Cable	11,532 FT						1,775,928	172,980		1,948,908
	Spare 230kV, 2500 kcmil Seg. Cu Cable	2,000 FT						308,000			308,000
	230kV Cable Terminations - GIS	6						66,000	180,000		246,000
	Spare Cable Term-GIS	2						22,000	75,000		97,000
	Cable Joints	3						19,800			19,800
	Spare Cable Joints	2						13,200			13,200
	Surge Arresters	6						30,212	36,657		66,869
	3Ph Link Box w/SVL's	3						9,900	4,281		14,181
	3Ph Link Box w/o SVL's	3						6,600	4,275		10,875
	1Ph Link Box w/SVL's	3						6,199	3,288		9,487
	1Ph Link Box w/o SVL's	3						3,630	3,288		6,918
	Ground Continuity Conductor (250 kcmil)	3,820 FT						57,300	11,460		68,760
	Field Testing							5,000	30,000		35,000
	Mobilization/Demobilize (Cable)								100,000		100,000
	On-shore duct bank system and transition to bay										
	(Prepared by Black & Veatch)										
	Actual cost since inception (Feasibility study & preliminary design)								2,538,322		2,538,322
	Onshore Civil Work										
	General										
	Mobilization/Demobilize (Prime)								350,000		350,000
	Construction Surveying & Staking								8,830		8,830
	Ductbank Installation										
	Utilility Locates 200/Mile								91,650		91,650
	Traffic Control								110,000		110,000
	Soil Erosion and Sediment Control							1,766	8,830		10,596
	Excavation (50ft/day)	6217 Cu Yd						155,417	1,865,000		2,020,417
	Concrete Encasement	1647 Cu Yd						242,097	247,038		489,135
	Concrete Reinforcement, Rebar (18 Long+Cross@ 5')	160,017 FT						200,021	960,102		1,160,123
	Backfill, FTB	2433 Cu Yd						287,955	182,496		470,451
	Road Bed Restoration, 1'-6" Crushed Rock	3108 Cu Yd						62,167	124,333		186,500
	Pavement Saw Cutting, Concrete	7460 LFT							113,765		113,765
	Pavement Removal, 11 feet wide	41,030 SQFT						86,163	410,300		496,463
	Pavement Restoration, Concrete, 11 feet wide	41,030 SQFT						315,521	310,187		625,708
	8" SCH. 40 PVC Conduit	14,920 LFT						111,900	223,800		335,700
	2" SCH. 40 PVC Conduit	3730 LFT						4,924	22,380		27,304
	4" SCH. 40 PVC Conduit	7460 LFT						23,126	74,600		97,726
	1.25" HDPE Conduit	22,380 LFT						24,842	67,140		91,982
	8" Conduit Spacers	2984 each						44,760	35,808		80,568
	4" Conduit Spacers	1492 each						17,904	17,904		35,808
	Dewater (100%)	3730 LFT							74,600		74,600
	Shoring (100%)	111,900 sqft						55,950	223,800		279,750
	HDD Installation										
	Horiz. Directional Drill	6000 LFT						360,000	2,500,000		2,860,000
	Conduit for Cables, 10" DR 11 HDPE	6000 LFT						240,000	180,000		420,000
	Cofferdam Construction (not used)	6									
	Traffic Control	2							424,000		424,000
	Construction Management								2,500,000		2,500,000
	Contingency (10%)								2,004,256		2,004,256
	Subtotal Cable installation (prepared by Black & Veatch and Sumitomo USA)							4,558,282	56,462,349		61,020,631
	Electro Magnetic Field (EMF)										

Pacific Gas and Electric Company

Job Estimate - Detail Sheet: Plant to be Installed

Order Number: 30605686

Embarcadero-Potrero 230kV Transmission Line
San Francisco

Removal Order or Asset No.	Description	Quantity	Provider Cost Center	Activity	Standard Rate	Hours	SUB-TOTAL AMOUNT (dollars only) Internal Services	Material	Contract	Other	TOTAL ($ only)
	(4% of this estimate total)									3,379,800	3,379,800
	Subtotal Electro Magnetic Field (EMF)									**3,379,800**	**3,379,800**
Total Order Cost (Excl ESCAL, CONTINGENCY, AFUDC, & OVERHEADS)						**16,627**	**2,394,288**	**4,558,282**	**60,824,797**	**20,097,440**	**87,874,807**

Pacific Gas and Electric Company

Job Estimate - Face Sheet

62-6251 (Rev. 02/09)
Capital Accounting

Date: September 03, 2013

Business Area: Utility Operations - Energy Delivery
Receiver Cost Center: TSM&C Martin Sub
Receiver Cost Center No.: 10904

Applicant:	Pacific Gas & Electric Company	Start Date:	03/01/2008
Job Title:	**Embarcadero-Potrero 230 kV Line: Potrero Substation**	Operative Date:	12/31/2015
Location:	**San Francisco**	Completion Date:	06/30/2016
County:	038-San Francisco County	Accident Rpt. No. (AR):	N/A
Regulatory Cat.:	1001-Capital Electric	Planning Order No.:	5731443
Major Work Cat.:	61: Electric Transmission Line Capacity	Planned Amount:	$69,754,063
Person in Charge:	Alain Billot, Sr. Consulting Project Manager	Project No.:	P.02693
Job Preparer:	Alain Billot, Sr. Consulting Project Manager		

Job Summary and Necessity

This job estimate is an updated version of the job estimate attached to the Dec. 2-12 CPCN Application filing prepared as an exhibit to the project CPUC CPCN Testimony filing. It is based on 1) an updated cost estimate to engineer, procure and construct this project provided by PG&E consultant ABB Inc. at the 30% design stage and is subject to the limitations described therein, and 2) a cost estimate prepared internally that documents costs to-date and forecast internal PG&E labor, miscellaneous contracts, land acquisition, indirect and overhead costs at the current stage of project development and current labor and overhead rates. As with the cost estimate attached to the Application filing, this remains a budgetary, "decision quality" job estimate. whereas a "construction quality" job estimate will be developed after CPUC has issued its final switchyard sitting decision and the project implementation competitive bidding is complete, forecast early 2014.

Work Breakdown and Cost Summary (See Supplemental Page for Cost and Accounting Detail)

Removal Order No. or Asset No.	Resp. Cost Center	Description	Hours	Total Cost
	12579	Actual Costs thru July 2013	2,856	779,498
	12809	Summary Forecast PG&E costs post July 2013 to completion	6,057	5,973,226
	11842	Summary Estimated Potrero Cost (propoded by ABB)		60,326,967
		Electro Magnetic Field (EMF)		2,674,372

Expenditure by Year (excludes contingency)

Year	Prior Years	2012	2013	2014	2015-2016	Total
Capital	$253,422	$150,000	$5,000,000	$35,000,000	$28,741,945	$69,145,367
Expense						

Total Costs	
Cap Install'n	60,738,701
Cap Removal	
Expense	
Mat'l Burden	
Cap A&G	204,072
AFUDC	5,166,968
Escalation	3,644,322
Contingency	
Gross Amount Authorized	69,754,063
Scrap/Re. Mat'l.	
Credits	
Net Amount Authorized	69,754,063

Project Sponsor
Geisha Williams
Executive VP Electric Operations

Sponsor's Representative
Alain Billot
Sr. Consulting PM

Start Date:
Operative Date:
Completion Date:

Foreman's Signature:

Job Authorization

Recommend	**Recommend**
Concur	**Concur**
Authorize	**Date Authorized**
Order Number	**30605684**

Pacific Gas and Electric Company
Job Estimate - Summary Sheet

62-6251 (Rev. 07/08)
Capital Accounting

Job Title: Embarcadero-Potrero 230 kV Line: Potrero Substation
Location: San Francisco
Order Number: 30605684

Current Burden Rate for Material < $75,000: 18.00%

Applied Percentage Rate: Capital A&G 15.00% · AFUDC 8.00% · Escal'n 6.000%

Removal Order or Asset No.	Resp. Cost Center	Description	Hrs	Internal Services	Material	Contract	Other	Material Burden	Capital A&G	AFUDC	Escal'n	Conting.	Conting. % by Line Item	Scrap	Credits	Total Cost
	12579	Actual Costs thru July 2013	2,856	411,264		207,949			65,391	57,741	37,153					779,498
	12809	Summary Forecast PG&E costs post July 2013 to completio	6,057	872,208		1,200,000	3,014,664		138,681	442,461	305,212					5,973,226
	11842	Summary Estimated Potrero Cost (propoded by ABB)				52,696,512				4,468,664	3,161,791					60,326,967
		Electro Magnetic Field (EMF)					2,336,104			198,102	140,166					2,674,372
		Escalated Amounts		1,360,480		57,350,729	5,671,814									
		Total Cost	8,913	1,283,472		54,104,461	5,350,768		204,072	5,166,968	3,644,322					69,754,063

Job Estimate - Detail Sheet: Plant to be Installed

Order Number: 30605684

Embarcadero-Potrero 230 kV Line: Potrero Substation
San Francisco

Removal Order or Asset No.	Description	Quantity	Provider Cost Center	Activity	Standard Rate	Hours	SUB-TOTAL AMOUNT (dollars only) Internal Services	Material	Contract	Other	TOTAL ($ only)
	Actual Costs thru July 2013										
	PG&E Internal Labor (Engr, Prj Mgmt, Environmental, Planning, etc.)		Various	Various	144.00	2856.00	411,264				411,264
	Permits, land and ROW acquisition										
	Misc. contracts								207,949		207,949
	Subtotal Actual Costs thru July 2013					2,856	411,264		207,949		619,213
	Summary Forecast PG&E costs post July 2013 to completion										
	Summary PG&E Internal Labor with average standard rate		Various	Various	144.00	6057.00	872,208				872,208
	Inspection (Civil & Electrical - Reassigned to ABB and reduced to oversight only		13545	INSPSV					100,000		100,000
	NRG (ex-GenOn) Property Acquisition									1,900,000	1,900,000
	Environmental Monitoring & Remediation								750,000		750,000
	External Legal and Experts								350,000		350,000
	Sales tax									1,114,664	1,114,664
	Subtotal Summary Forecast PG&E costs post July 2013 to completion					6,057	872,208		1,200,000	3,014,664	5,086,872
	Summary Estimated Potrero Cost (propoded by ABB)										
	Substation Installation								5,924,064		5,924,064
	Subcontract/Installation								13,305,020		13,305,020
	Material								574,000		574,000
	Logistics/Support								7,881		7,881
	Mob and demob, jobsite facilities, temp power								112,146		112,146
	Engineering								3,382,739		3,382,739
	Management - Project, Safety								1,780,243		1,780,243
	Management & facilities - Site								2,380,548		2,380,548
	Scheduling								88,576		88,576
	Ministerial permits								99,616		99,616
	Insurance								335,792		335,792
	Warranty								419,740		419,740
	EPC Markup								4,094,511		4,094,511
	GIS building construction								17,749,533		17,749,533
	Green initiative								83,787		83,787
	ABB's proposed risk assessment								4,358,316		4,358,316
	Adjustment to account for expected reduced scope and contract negotiation								-2,000,000		-2,000,000
	Subtotal Summary Estimated Potrero Cost (propoded by ABB)								52,696,512		52,696,512
	Electro Magnetic Field (EMF)										
	(4% of this job estimate total)									2,336,104	2,336,104
	Subtotal Electro Magnetic Field (EMF)									2,336,104	2,336,104
Total Order Cost (Excl ESCAL, CONTINGENCY, AFUDC, & OVERHEADS)						8,913	1,283,472		54,104,461	5,350,768	60,738,701

Pacific Gas and Electric Company

Job Estimate - Property / Settlement Sheet

62-6251 (Rev. 07/08)
Capital Accounting

Job Title: Embarcadero-Potrero 230 kV Line: Potrero Substation **Order Number:** 30605684

Location: San Francisco

Units of Property Installed

Description of Unit of Property	Quantity	Asset No.	Cost	Percent of Cost
		Total Installed		

Removal Costs

Description of Removal Costs	Removal Order	Cost	Percent of Cost
	Total Removal		
	Total for Settlement		

Activities Not Used in Settlement Computation

#REF!		
	Grand Total	

Units of Property Retired

Description of Property Retired	Quantity	Asset No.	Acq. or Rlpc. Cost	Year Installed

Pacific Gas and Electric Company

Job Estimate - WBS Order List

Job Title: Embarcadero-Potrero 230 kV Line: Potrero Substation

Project No: P.02693

Location: San Francisco

WBS No.	Order No.	MWC	Description	Gross Amount Authorized ($)	Credits/ Scrap/ Ret Mat'l ($)	Net Amount Authorized ($)	Comment
P.02693	30605684	61		$69,754,063			
			JE Total	$69,754,063	$0	$0	
			PA Total				

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

SEISMIC RISK TO PG&E'S EXISTING SAN FRANCISCO 230 KV TRANSMISSION SYSTEM

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
SEISMIC RISK TO PG&E'S EXISTING SAN FRANCISCO 230 KV TRANSMISSION SYSTEM

A. Introduction

1. Purpose and Scope

The purpose of this chapter is to provide an overview of the various seismic risks to the two existing Martin-Embarcadero 230 kilovolt (kV) transmission (HZ) cables serving downtown San Francisco.

2. Organization of the Remainder of This Chapter

- Section B – Overview and Summary of Seismic Risk to HZ Cables
- Section C – Methodology of Study

B. Overview and Summary of Seismic Risk to HZ Cables

InfraTerra, Inc. (InfraTerra) was retained by Pacific Gas and Electric Company (PG&E) to assess the seismic reliability of PG&E's two HZ transmission lines serving downtown San Francisco. InfraTerra's report, entitled "Seismic Reliability Assessment: HZ-1 and HZ-2 230 kV Electric Transmission Lines" (HZ Seismic Risk Report) is attached hereto as Confidential Attachment 6A.[1] This chapter provides an overview of InfraTerra's findings, which are set forth in detail in the HZ Seismic Risk Report. In addition, this chapter provides the results of InfraTerra's analysis of the probability of overlapping outages of both HZ lines as a result of a major earthquake.

The United States Geological Survey (USGS) has estimated a 63 percent probability of a major earthquake in the Bay Area in the next 30 years. The San Andreas Fault and the Hayward Fault, with 21 percent and 31 percent probability of a major earthquake in the next 30 years, are the two most significant contributors to this probability. Both of these faults are located less than 16 kilometers from the HZ lines. Ground shaking from a major earthquake

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[1] The HZ Seismic Risk Report contains confidential critical infrastructure information and therefore is submitted pursuant to Public Utilities Act § 583. The only protestant, Division of Ratepayer Advocates, has a copy of the report. If any other person or entity that is or becomes a party to the proceeding wishes to review the report, PG&E is willing to enter a Non-Disclosure Agreement and/or to redact the report.

in the Bay Area has a potential for causing significant ground deformations that would damage the HZ lines. Unless a third transmission line is constructed to Embarcadero Substation, damage to both HZ lines would result in a loss of power to Embarcadero Substation.

The HZ lines cross several areas of high liquefaction hazard. Sections of the two HZ lines that cross the former Sullivan Marsh and the infilled former channel of Mission Creek were considered most at risk based on the presence of liquefiable deposits and documented occurrence of large liquefaction-induced lateral displacement and settlement in past earthquakes. Liquefaction analyses performed for a Peak Ground Acceleration (PGA) of 0.3g, representing the median ground motion expected from a repeat of the 1906 earthquake on the San Andreas Fault, show high predicted amounts of ground settlement and lateral spread for the former Mission Creek and Sullivan Marsh areas, consistent with ground deformation observed in the 1906 earthquake. Similarly, a Magnitude 7.0 earthquake on the Hayward Fault can also generate ground shaking that is strong enough to produce large lateral spread deformations in the former Mission Creek and Sullivan Marsh areas that would damage the HZ lines.

Due to variation in subsurface conditions in both the vertical and horizontal direction, the HZ lines are subject to abrupt changes in lateral displacement and ground settlement as the lines cross between areas of high liquefaction hazard and competent soil. The changes in the imposed ground deformation introduce large strains in the pipelines as they transition from non-liquefiable to liquefiable zones. The HZ lines are also vulnerable to damage at the interface with manhole vaults and at utility crossings in areas of high liquefaction hazard. Differential settlements between the manhole vault and HZ lines and between the HZ lines and other utilities, such as concrete or brick sewers, including pile supported sewers, would result in large strain concentrations in the pipelines within the areas of concentrated ground deformation.

Nonlinear finite element analyses of the buried HZ lines were performed to assess their response to anticipated permanent ground deformations in the identified areas of high liquefaction hazard. The expected damage from the high strains in the pipelines computed in InfraTerra's analyses would require de-energizing the HZ lines for repair. The expected type of damage would include local buckling of the pipe wall from excessive bending deformations, which would result in crimping of the cables inside the pipeline, and rupture at the pipeline joint or in the pipe body, resulting in loss of pressure integrity of the pipeline. The latter would result in loss of the positive pressure in the insulating fluid, thus providing an opportunity for groundwater or other contaminants to enter the pipeline. According to PG&E, contact with water or contaminants will cause ionization of the oil impregnated paper causing a short and immediate failure of the line.

InfraTerra also computed the probability of failure of the HZ lines from a seismic event in the Bay area over the next 30 and 50 years. Based on analyses of the two segments considered most vulnerable for each HZ line,[2] InfraTerra concludes that there is a 33 percent probability of at least one earthquake induced failure in the HZ-1 line and a 30.8 percent probability of at least one earthquake induced failure in the HZ-2 line in the next 30 years. The failure probabilities for the next 50 years for the HZ-1 and HZ-2 lines are 48.7 percent and 45.8 percent, respectively.

InfraTerra also considered the risk to the HZ lines from two specific earthquake scenarios; a Magnitude 7.8 earthquake on the San Andreas Fault and a Magnitude 7.0 earthquake on the Hayward Fault. InfraTerra's analyses of two segments of each HZ line show multiple locations where the computed strains exceed the failure criteria by a significant margin for an earthquake similar in size to the 1906 Magnitude 7.8 San Francisco earthquake. For such an event, there is a 96 percent probability of at least one failure in the HZ-1 line and a 92.2 percent probability of at least one failure in the HZ-2 line. For a Magnitude 7.0 earthquake on the Hayward Fault, InfraTerra's analyses also show high strain levels in the two HZ lines, with a 56.1 percent probability of at least one failure in the HZ-1 and a 58.9 percent probability of at least one failure in the HZ-2 line.

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2 In the HZ Seismic Risk Report, Infra Terra reported the risk of failure in only the single segment considered most vulnerable for each of the two HZ lines. More recently, in the report attached to Chapter 7, Infra Terra updated the failure probabilities of the HZ lines by studying the two segments considered most vulnerable on each HZ line, which increased the likelihood of failure in each seismic event studied. These probabilities likely still understate the true probability of failure given there is some probability that other segments of each HZ line may fail in a given seismic event even if the studied segments do not fail. The failure probabilities reported in this chapter are based on the analysis of two segments of each HZ line.

InfraTerra focused its analysis on four HZ line segments (two for each line) considered to be at most risk in a seismic event. Given the high probability of failure at multiple locations within these four segments, additional analyses for other potentially vulnerable sections were not performed. Analyses performed to assess the potential for failure at manhole vaults and utility crossings show that the HZ-1 and HZ-2 lines are each potentially vulnerable at three manhole vault locations and multiple utility crossing locations. Given the high probability of failure based on the other calculated strains on the pipeline, the additional risk from vaults and utility crossing was not quantified.

Embarcadero Substation is served by both HZ-1 and HZ-2, and InfraTerra understands from PG&E that, at present, either cable can provide sufficient power to Embarcadero to serve customer demand. Therefore, since completing the HZ Seismic Risk Report, InfraTerra has conducted further analyses to predict the risk of a major earthquake causing overlapping outages of both HZ cables, i.e., if a Magnitude 7.8 earthquake on the San Andreas Fault poses a 96 percent chance of causing failure of HZ-1 and an 92.2 percent chance of causing failure of HZ-2, what is the chance that the same earthquake will cause failure of both lines. InfraTerra ran 100,000 Monte Carlo simulations to compute joint failure probabilities for HZ-1 and HZ-2. The results for concurrent outages for both HZ-1 and HZ-2 are:

- Magnitude 7.8 on San Andreas Fault: 91.1 percent probability of concurrent failure of HZ-1 and HZ-2.
- Magnitude 7.0 on Hayward Fault: 48.2 percent probability of concurrent failure of HZ-1 and HZ-2.
- The 30 year and 50 year probabilities for joint failure of both HZ lines are 26 percent and 39.4 percent, respectively

Based on this analysis, InfraTerra concludes that both HZ-1 and HZ-2 lines have a high risk of failure at multiple locations from liquefaction-induced permanent ground deformations resulting from a major earthquake in the Bay Area. Such an earthquake has a high probability of occurring within the next 30 years.

C. Methodology of Study

InfraTerra's methodology for analyzing the seismic vulnerability of the HZ lines is discussed in detail in the HZ Seismic Risk Report (see Confidential

Attachment 6-1). In brief, InfraTerra first gathered information about the design of the HZ cable system, including its location and construction. InfraTerra then identified the seismic hazard along the transmission line routes using maps and reports published by the USGS and California Geological Survey, and other available information regarding geology and liquefaction hazard. Based on this preliminary geotechnical and geological assessment, two segments of each of the HZ lines considered to be at the highest risk of failure were identified for more detailed assessment. For these segments, specific geological information was collected and the likely liquefaction induced lateral spread and vertical settlement calculated.

InfraTerra then calculated strains in the HZ pipelines at the selected segments resulting from the imposed earthquake induced ground deformations. InfraTerra evaluated the seismic performance of the HZ lines by comparing the calculated strains with the strains that would likely cause damage to the pipelines. Nonlinear finite element analyses of the buried HZ lines were performed to assess their response to liquefaction-induced ground deformations predicted by the geologic and geotechnical assessment. The analyses were performed using ANSYS general purpose finite element software, which is used frequently for complex pipeline deformation analysis. The buried sections of the HZ pipelines were modeled with special pipe elements in ANSYS. The three-dimensional soil reaction to pipeline movement was represented by a series of discrete springs that simulate the nonlinear load deformation behavior of soils in the axial, lateral, and vertical directions. Analyses were performed for each of the four pipeline segments to compute the maximum tensile and compressive strains in each segment for the imposed ground deformations. Sensitivity studies using different water depths and force displacement relationships for the surrounding soil were also performed. InfraTerra also performed finite element analyses to assess strains in the pipeline at the pipeline-vault interface and where the pipeline might interact with other buried utilities in close proximity.

InfraTerra's analysis methodology to assess the seismic risk to the HZ lines consists of the following steps:

1. Estimation of ground shaking hazard: Ground shaking hazard in terms of median, 84th percentile and 98th percentile PGA values were computed for Magnitude 7.8 and Magnitude 7.0 earthquakes on the San Andreas and the

Hayward faults, respectively. In addition to the scenario ground motions, probabilistic estimates of PGA were also computed.

2. Estimation of liquefaction induced lateral displacements: Estimates of lateral displacements for the selected segments were computed using the semi-empirical approach described in Section 6.2 of the HZ Seismic Risk Report for the anticipated levels of ground shaking. The computed lateral displacements depend on a range of factors that include surface ground slope, duration of shaking (represented in terms of earthquake magnitude), depth of ground water and subsurface soil conditions.
3. Soil structure interaction analysis: Nonlinear finite element analyses of the most vulnerable sections of the HZ lines were performed to compute tensile, compressive and bending strains in the HZ lines when subjected to the estimated lateral spread displacements. Peak strain values as a function of increasing amplitude of imposed lateral displacements were computed.

Monte Carlo simulations were performed to compute the probability of failure by treating the pipeline strains as a function of lateral displacement and lateral displacements as a function of PGA. The failure probabilities were then integrated over the range of PGA estimates for Magnitude 7.0 and Magnitude 7.8 scenario earthquakes to compute failure probabilities for the two lines for each such scenario earthquake. In addition to probabilities of failure for the two scenario earthquakes, the overall risk of failure in the next 30 and 50 years for the two lines was also computed by integrating the failure probabilities as functions of PGA and earthquake magnitude with the ground shaking hazard curves. As noted above, additional analysis was performed later to estimate the number of overlapping outages.

The vulnerability assessment was performed by InfraTerra with support from A3GEO, Inc. InfraTerra specializes in seismic response of infrastructure systems. The project team included individuals with expertise in earthquake engineering, structural engineering, geology and geotechnical engineering. An independent technical review panel consisting of Dr. Thomas O'Rourke of Cornell University and Dr. Steve Kramer of the University of Washington were involved throughout the course of this work. The technical review panel helped develop the overall technical approach for the project and provided technical oversight of the work. Dr. O'Rourke is an internationally recognized expert in seismic response of large geographically distributed systems such as water supplies, gas and liquid fuel systems, electric power, and transportation facilities, and has an intimate knowledge of earthquake related geotechnical hazards in downtown San Francisco. He is an elected member of the U.S. National Academy of Engineering (1993) and a Fellow of the American Association for the Advancement of Science (2000). Dr. Kramer is a recognized expert in soil liquefaction, site response analysis, seismic slope stability, and earthquake hazard analyses. He is the author of the book “Geotechnical Earthquake Engineering,” which is taught at graduate and undergraduate levels in many universities.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

ATTACHMENT A

SEISMIC RELIABILITY ASSESSMENT HZ-1 AND HZ-2

230 kV ELECTRIC TRANSMISSION LINES

CONFIDENTIAL

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PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

SEISMIC RISK TO NEW EMBARCADERO-POTRERO

230 KV TRANSMISSION LINE

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
SEISMIC RISK TO NEW EMBARCADERO-POTRERO
230 KV TRANSMISSION LINE

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
SEISMIC RISK TO NEW EMBARCADERO-POTRERO 230 KV TRANSMISSION LINE

A. Introduction

1. Purpose and Scope

The purpose of this chapter is to provide an overview of the seismic risks to the new Embarcadero-Potrero 230 kV Transmission Line (also known as ZA-1).

2. Organization of the Remainder of This Chapter

- Section B – Overview and Summary of Seismic Risk to Proposed ZA-1 Cable
- Section C – Methodology

B. Overview and Summary of Seismic Risk to Proposed ZA-1 Cable

InfraTerra, Inc. was retained by Pacific Gas and Electric Company (PG&E) to assess the seismic reliability of PG&E's proposed ZA-1 230 kV transmission line, which is proposed to provide additional electric transmission service to downtown San Francisco. InfraTerra's report, entitled "Seismic Reliability Assessment ZA-1 230 kV Electric Transmission Line" (ZA-1 Seismic Risk Report) is attached hereto as Confidential Attachment 7-1.[1] This chapter provides an overview of InfraTerra's findings, which are set forth in detail in the ZA-1 Seismic Risk Report. In addition, this chapter provides the results of InfraTerra's analysis of the probability of overlapping outages of both HZ lines and the proposed ZA-1 line as a result of a major earthquake.

1. Seismic Risk to the ZA-1 Line

As noted in Chapter 6, the United States Geological Survey has estimated a 63 percent probability of a major earthquake in the Bay Area in the next 30 years. The San Andreas Fault and the Hayward Fault, with

[1] The ZA-1 Seismic Risk Report contains confidential critical infrastructure information and therefore is submitted pursuant to Public Utilities Act § 583. The only protestant, Division of Ratepayer Advocates, has a copy of the report. If any other person or entity that is or becomes a party to the proceeding wishes to review the report, PG&E is willing to enter a Non-Disclosure Agreement and/or to redact the report.

21 percent and 31 percent probability of a major earthquake in the next 30 years, respectively, are the two most significant contributors to this probability. Both of these faults are located less than 16 kilometers from the proposed ZA-1 line as well as the existing HZ lines.

Recognizing the liquefaction and lateral spread hazard in the fill areas of San Francisco, which the HZ lines cross, the alignment of ZA-1 line was selected to avoid as much of this hazard as reasonably practical by placing a significant portion of the ZA-1 line offshore. The offshore cable would be embedded in relatively homogenous soft, highly plastic, marine clay and silt within San Francisco Bay known as Young Bay Mud. The approximately 2.5 mile long offshore cable would be connected to short onshore segments (approximately 0.6 miles) through approximately 0.4 miles of horizontal directional drilling (HDD) sections.

To assess the seismic reliability of the ZA-1 line, InfraTerra analyzed the onshore, offshore, and onshore to offshore transitions of the proposed ZA-1 line based on currently available geotechnical data and a reasonable understanding of likely design as the final design has not yet been completed. (There likely are other potential design options that could be used to provide the same, or enhance, the line's seismic resiliency). Seismic assessment of the offshore marine cable and the onshore ductbank was performed using non-linear soil-structure interaction analysis. The assessment considered the range of probable earthquakes in the Bay Area as well as scenario earthquakes of 7.8 moment magnitude (M) on the San Andreas Fault and 7.0 M on the Hayward Fault.

Our assessment of various design options indicate that the overall seismic risk of damage to the power cables is small; however, the risk of damage to the onshore reinforced concrete ductbanks is high. Short segments of the proposed onshore ZA-1 alignment cross zones of liquefaction hazard along the northern and southern ends. A major earthquake has a significant probability of damaging the steel-reinforced, concrete ductbanks that encase the ZA-1 cable in the onshore segments, with the extent of damage depending on the ultimate design and geotechnical conditions. However, the ductbanks are designed to be sacrificial elements to protect the cable inside.

PG&E conducted full-scale load tests on reinforced concrete ductbanks at Pacific Earthquake Engineering Research Center (PEER). At failure, the cross-sectional deformation of the embedded conduits was minimal and the staff performing the tests could pull a mandrel, of the same diameter as an XLPE cable, through the conduits without difficulty; thereby concluding no adverse effects on the embedded XLPE cable under this level of deformation. Protection of the ZA-1 cable will require that the ductbanks are designed and detailed to achieve high ductility so that they can deform to a relatively large and smooth curvature. Based upon InfraTerra's analysis, for both the north and south onshore segments, the failure probability of the cable is judged to be negligible as the curvatures in the ductbank resulting from all evaluated earthquakes are substantially below the 0.004 rad/in criteria based on PEER tests.

Based on geologic cross sections that incorporate available geotechnical borings, InfraTerra's assessment shows that the marine to onshore transition can be designed such that the cable is placed within competent material beneath liquefiable material using HDD. Similarly, it appears feasible to locate the transition manhole vaults in competent ground, and thus avoid significant ground deformation.

InfraTerra evaluated a number of scenarios for the performance of the submarine cable in a seismic event. The failure probabilities are sensitive to the assumed values of stiffness and strength of the cable. The lower stiffness value provided by the cable supplier, J-Power Systems (JPS), results in failure probability of approximately 2 percent whereas it is close to 17 percent if the cable stiffness is based on values for solid copper. However, because the cable is not solid copper, it is not expected to have the stiffness of solid copper even if it is somewhat greater than estimated by JPS. Moreover, the estimate of the allowable tension capacity of 68 kips for the double armor submarine cable provided by JPS is conservative, but the safety margin has not been quantified by testing at this time. Using a conservative estimate of the shear strength for the Bay sediment, InfraTerra calculated probabilities of failure based on: (a) JPS's estimates of flexibility and (b) the flexibility of solid copper with a 1.5 safety margin for tensile strength.

Under those two scenarios, InfraTerra calculates the failure probability for the ZA-1 cable, depending upon the ultimate strength and flexibility of the submarine cable, to be between 4.6 percent and 8.1 percent in the San Andreas 7.8 M earthquake, between 0.8 percent and 1.6 percent in the Hayward 7.0 M earthquake, between 0.6 percent and 1.2 percent over the next 30 years, and between 0.9 percent and 1.9 percent over the next 50 years.

2. Seismic Risk to Embarcadero Substation With Addition of ZA-1

Seismic assessment of the existing HZ-1 and HZ-2 lines and the proposed new ZA-1 line serving the Embarcadero Substation in downtown San Francisco shows that the ZA-1 adds additional reliability to power supply to San Francisco both by virtue of additional redundancy and by overall improvement in seismic performance of the line.

As discussed in Chapter 6, based upon analysis of only two segments of each HZ line and Monte Carlo analysis of the chance that an earthquake would damage both lines, the results for concurrent outages for both HZ-1 and HZ-2 are:

- Magnitude 7.8 on San Andreas Fault: 91.1 percent probability of concurrent failure of HZ-1 and HZ-2;
- Magnitude 7.0 on Hayward Fault: 48.2 percent probability of concurrent failure of HZ-1 and HZ-2;
- The 30-year probability for joint failure of both HZ lines is 26 percent; and
- The 50-year probability for joint failure of both HZ lines is 39.4 percent.

By contrast, the proposed ZA-1 line will consist of more robust XLPE cable that does not rely on maintaining fluid pressure around the cable. Further, the proposed alignment of the ZA-1 line bypasses, to the extent possible, most of the onshore areas of high liquefaction hazard. InfraTerra calculates that, when Embarcadero Substation is served by three lines (HZ-1, HZ-2 and ZA-1), and depending upon the ultimate strength and flexibility of the submarine cable, the combined probability of a concurrent outage of all three lines is:

- Magnitude 7.8 on San Andreas Fault: between 4.6 percent and 8 percent probability of concurrent failure of ZA-1, HZ-1 and HZ-2;

- Magnitude 7.0 on Hayward Fault: 0.8 percent and 1.6 percent probability of concurrent failure of ZA-1, HZ-1 and HZ-2;
- The 30-year probability for concurrent failure of ZA-1, HZ-1 and HZ-2 lines is between 0.6 percent and 1.1 percent; and
- The 50-year probability for concurrent failure of ZA-1, HZ-1 and HZ-2 lines is between 0.9 percent and 1.9 percent.

C. Methodology

Although the alignment of ZA-1 line is selected to avoid, as much as practical, zones of liquefaction and lateral spread hazard, it is still subject to earthquake hazards. Both quantitative and qualitative methods were employed to evaluate the potential earthquake hazards to the ZA-1 line and to assess the potential failure modes associated with these hazards.

As discussed in Section 8.0 of the ZA Seismic Risk Assessment, the analysis methodology adopted for the seismic assessment of the ZA line consists of the following steps:

1. Estimation of ground shaking hazard: The design criterion for the ZA-1 line is established as the 84th percentile ground motions from an megawatt 7.8 earthquake on the San Andreas Fault. A probability distribution of PGA estimates was developed by computing median, median ± one standard deviation and median ± two standard deviations for Magnitude 7.8 and Magnitude 7.0 earthquakes on the San Andreas and the Hayward faults, respectively. In addition to the scenario ground motions, probabilistic estimates of PGA were also computed. The annual probability of exceedance of PGA in downtown San Francisco for dense soil conditions from all potential earthquakes in the region is shown in Figure 50 of the Report. The figure also shows the contribution of different magnitude ranges to the total hazard.
2. Estimation of permanent ground deformation (PGD) for the offshore segment: The offshore cable is buried in Young Bay Mud. Due to the highly non-linear response of Young Bay Mud, nonlinear geotechnical analyses were performed to estimate earthquake induced PGD using two different analysis programs (FLAC and PSNL). Details of the methodology used are provided in Section 6.1.1 of InfraTerra's report. The nonlinear analyses were performed using seven spectrum compatible earthquake acceleration

time histories that were selected from 17 sets of strong motion records from past earthquakes and modified using the program RSPMatch to represent characteristics of the design earthquake. The estimated PGD values along the offshore segment of the ZA-1 line are presented in Table 5 of InfraTerra's report. Statistical analyses were performed to compute median values of PGD and its standard deviation. More than 800 analyses were also performed to relate the PGD as a function PGA.

3. Estimation of liquefaction induced lateral displacements for the onshore segments: Liquefaction induced lateral displacements were estimated using the semi-empirical approach described in Section 6.2.1 of InfraTerra's report for the anticipated levels of ground shaking. The computed lateral displacements depend on a range of factors that include surface ground slope, duration of shaking (represented in terms of earthquake magnitude), depth of ground water and subsurface soil conditions. The computed lateral displacements and settlements along the onshore segments of the ZA-1 line are presented in Table 7 and Table 8, respectively, in InfraTerra's report. Analyses were also performed to relate lateral displacements as a function of PGA.

4. Soil structure interaction analysis: Nonlinear finite element analyses of the offshore marine cable and the onshore ductbanks was performed to compute their seismic response. The analyses included modeling of the surrounding soil through discrete springs with nonlinear force deformation response. The analyses were performed using ANSYS, a general purpose finite element software frequently used for complex nonlinear analyses of buried structures. Multiple ANSYS analyses were performed to study several design options from a range of possible design considerations to compute stresses and strains in the offshore cable and the ductbanks. For each design option, force and/or deformation demands in the ZA-1 structural components (offshore cable and ductbanks) were computed as a function of imposed ground deformations ranging from a fraction of the value for the design ground motions to multiple times that value.

The reliability assessment of the proposed ZA-1 line was performed by InfraTerra. InfraTerra specializes in seismic response of infrastructure systems.

The project team included individuals with expertise in earthquake engineering, structural engineering, geology and geotechnical engineering.

An independent technical review panel consisting of Dr. Thomas O'Rourke of Cornell University and Dr. Steve Kramer of the University of Washington were involved throughout the course of this work. The technical review panel helped develop the overall technical approach for the project and provided technical oversight of the work. Dr. O'Rourke is an internationally recognized expert in seismic response of large geographically distributed systems such as water supplies, gas and liquid fuel systems, electric power, and transportation facilities, and has an intimate knowledge of earthquake related geotechnical hazards in downtown San Francisco. Dr. Kramer is a recognized expert in soil liquefaction, site response analysis, seismic slope stability, and earthquake hazard analyses. He is the author of the book "Geotechnical Earthquake Engineering," which is taught at graduate and undergraduate levels in many universities.

In addition to Dr. O'Rourke and Dr. Kramer, the project team consulted with Professor Armen Der Kiureghian of the University of California at Berkeley. Professor Der Kiureghian is an expert in the development and application of probabilistic methods to solve civil engineering problems. He specializes in the safety and reliability assessment of structures, risk analysis and decision-making for infrastructure systems, stochastic dynamic analysis of linear and nonlinear structures, and systems modeling and performance assessment. He has more than 380 publications, including more than 110 in archival journals.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

ATTACHMENT A

SEISMIC RELIABILITY ASSESSMENT ZA-1

230 kV ELECTRIC TRANSMISSION LINE

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PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

SEISMIC RISK TO OTHER SYSTEM COMPONENTS SERVING EMBARCADERO SUBSTATION

PACIFIC GAS AND ELECTRIC COMPANY
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SEISMIC RISK TO OTHER SYSTEM COMPONENTS SERVING EMBARCADERO SUBSTATION

A. Introduction

1. Purpose and Scope

The purpose of this chapter is to provide an overview of the seismic resiliency of components of the electric system serving Embarcadero Substation, other than seismic risks to the Martin-Embarcadero (HZ) 230 kilovolt (kV) lines described in Chapter 6.

2. Organization of the Remainder of This Chapter

- Section B – The New Embarcadero-Potrero Transmission Line Is Expected to Have Power to Transmit to Embarcadero Substation Even After a Major Earthquake

B. The New Embarcadero-Potrero Transmission Line Is Expected to Have Power to Transmit to Embarcadero Substation Even After a Major Earthquake

The Project will strengthen a critical link in Pacific Gas and Electric Company's (PG&E) San Francisco 230 kV transmission system by adding a third transmission line to Embarcadero Substation, constructed along a route less subject to seismic hazards and designed to meet PG&E's performance objective of withstanding the Project-specific Maximum Credible Earthquake (MCE). PG&E has set the MCE for this Project at a 7.8 moment magnitude (M) earthquake on the San Andreas Fault, with ground motions at the 84th percentile of potential ground motions (meaning there Is only a 16 percent chance of greater ground motions). Such an earthquake is thought to be equivalent to the 1906 San Francisco earthquake. The ground motions from such an earthquake are similar to the expected ground motions from an earthquake with a 10 percent probability of exceedance in 50 years level (a 475-year return period).

PG&E expects the ZA-1 line to be able to deliver power from Potrero Switchyard to Embarcadero Substation after an earthquake that has a high probability of damaging both HZ cables. For the ZA-1 line to provide that benefit, both the Embarcadero Substation and Potrero Switchyard must be operational, and have a source of power, post-earthquake. There are two sources of power to Potrero Switchyard: PG&E's San Francisco 115 kV transmission system, originating at PG&E's Martin Substation, and the Trans Bay Cable (TBC). PG&E has assessed the likely impact of a major seismic event on each element in this system, as discussed below.

PG&E notes that some of the threats to the existing HZ cables do not pose a concurrent threat to the other elements of the system, e.g., planned HZ outages for maintenance or infrastructure development, or forced outages caused by dig-ins, water/sewer breaks, or internal failure of a cable. Therefore, this chapter focuses on the impact of a major earthquake.

1. PG&E's Substation Design

PG&E and most utilities located in areas of high seismic hazard seek to meet Institute of Electrical and Electronic Engineers (IEEE) Standard 693, "Recommended Practice for Seismic Design of Substations." IEEE 693 was adopted by PG&E starting in 1997 for application to certain types of equipment. Over time, PG&E has sought to implement IEEE 693 to the extent practicable and has transitioned to nearly full implementation when procuring substation equipment. IEEE 693 addresses performance objectives for electric substation equipment and their supports, as well as the permissible methods of qualification for different types and classes of equipment.

IEEE 693's performance objective for substation equipment is functionality after the design earthquake. The IEEE 693 standards are based on an earthquake that generates ground motions with a 10 percent probability of exceedance in 50 years level (475 years return period). As noted above, this is approximately equivalent to the MCE (a 7.8 M, 84th percentile, San Andreas Fault earthquake) for this Project. IEEE 693 uses three standard levels of qualification (Low, Moderate and High), which are assigned by the utility based upon substation site hazard. In the San Francisco Bay Area, substation sites are assigned the High level of qualification.

PG&E has specified that the significant new substation equipment at both Embarcadero and Potrero must meet the IEEE 693 High qualification level, which imposes a required response spectrum with 0.5g Peak Ground Acceleration (PGA). The margin built into the acceptance criteria of IEEE 693 is intended to cover ground motions substantially in excess of this value. When equipment is specified for a given site, the equipment is required to meet IEEE 693 qualification of the level appropriate for that site. Catalog type items, or those equipment that are commonly used by different utilities, such as circuit breakers, air switches, surge arresters and instrument transformers, are often pre-qualified by the manufacturer. Other equipment such as large power transformers, capacitor banks, or air core reactors are frequently custom-designed for a particular application and are qualified at the time the equipment is ordered by the utility. PG&E procures equipment that fall into both of these categories.

PG&E procures most new and replacement substation equipment to meet IEEE 693 standards. Many of PG&E's substations were constructed and equipped long before IEEE 693 was adopted. Starting around 1997, PG&E began installing IEEE 693-qualified equipment in substations for capacity improvement, substation reconfiguration or as older equipment reached the end of their life cycle and needed replacement. In general, PG&E has not replaced existing, non-qualified equipment with new IEEE 693-qualified equipment solely due to seismic concerns for a variety of reasons, including cost, differences in site-specific seismic risk, redundant equipment, and the expected time to repair or replace equipment that might be damaged in an earthquake. However, seismic capability is an important consideration in replacing and adding substation equipment.

Where substations include buildings, current PG&E practice is to design new buildings to meet California Building Code (CBC) requirements for Occupancy Category III. Substation buildings are generally unoccupied. PG&E's intent is to prevent unacceptable damage at the 10 percent in 50 years level. As a prescriptive standard, the CBC does not explicitly define performance objectives for the various Occupancy Categories. Conformance to the CBC for Occupancy Category III however, implies a higher level of performance than life safety protection which is the minimum building code objective for ordinary buildings which fall into Occupancy Category II.

The new Gas Insulated Switchgear (GIS) buildings for both Embarcadero Substation and Potrero Switchyard will be designed to meet both the CBC Occupancy Category III requirements as well as higher performance objectives that will permit occupancy of the buildings following an earthquake generating ground motions with only a 10 percent probability of exceedance in 50 years (i.e., ground motions approximately equivalent to a 7.8 M 84th percentile San Andreas Earthquake). This requirement is intended to provide reasonable assurance that personnel can safely occupy the building following the design earthquake to perform necessary restoration or repair activities if needed. This level of performance is intended to be compatible with the performance objectives for substation equipment.

2. Embarcadero Substation

The Embarcadero Substation, located at the corner of Folsom and Fremont Streets in San Francisco, is expected to remain operational following a major earthquake. Although some transmission and/or distribution equipment may suffer some damage, PG&E expects that such equipment could be restored to service or replaced relatively quickly. PG&E notes that, generally, there are uncertainties associated with the performance of substation equipment in the event of major earthquake-induced ground shaking.

Embarcadero Substation lies near the northwestern flank of the Rincon Hill, just above the historical shoreline. No Young Bay mud or soft clay deposits were mapped on any geological maps issued by the United States Geological Survey (USGS) nor was it encountered in any geotechnical borings conducted at this site. The subsurface soil can be generally characterized by the following four layers from top down: 10-feet (ft) of loose undocumented fill, 10-ft of dense native clayey sand, 60-ft of dense to very dense sand, 10-ft of stiff clays overlying Franciscan sandstone bedrock at a depth of about 90 ft. The site was investigated by 12 borings in 1971 and 8 borings for the annex building in 1979. The undocumented fill, generally 6 to 12-ft thick comprises of loose sands, silty and clayey sands and occasionally intermixed with brick and rubble. The native original deposit is characterized by a thin and continuous layer (about 10-ft) of medium dense to dense to very dense clayey sand that overlies a thick deposits (50-ft to 60-ft) of sand and silty sand with dense to very dense consistency. Below this sand layer lies a 5- to 15-ft-thick stiff silty clay to sandy clay layer that overlies the bedrock.

Groundwater was encountered at 35- to 45-ft deep during the 1971 investigation. The loose undocumented fill generally lies above the groundwater table. During the 1906 earthquake and the 1989 Loma Prieta earthquake, no liquefaction was reported in the vicinity of the site. The closest reported liquefaction from the 1906 earthquake was near Market Street and First Street or three blocks northwest of the substation. The historical liquefaction observation is consistent with the geotechnical investigation that showed the consistencies of the saturated sandy deposits are generally dense to very dense and are not susceptible to liquefaction under strong ground shaking.

The site is classified as Site Class D, and is expected to experience ground motion with about 0.47g PGA in the 7.8 M 84th percentile San Andreas Earthquake.

Pursuant to PG&E's Embarcadero Substation Bus Upgrade Project, PG&E is constructing a new 230 kV transmission bus adjacent to the existing Embarcadero Substation building. The new 230 kV transformers and GIS to be installed during this project will be seismically qualified to the IEEE 693 "High" qualification level (if ABB's new GIS design has not been IEEE 693 qualified before the time of installation, ABB will demonstrate that it can survive the expected MCE through shake table testing). As a result, this equipment is expected to remain functional following a large earthquake.

The new 230 kV GIS is to be housed in a new building located adjacent to the existing substation building. As discussed previously, the new GIS building will be designed to the current CBC Occupancy Category III requirements as well as performance-based engineering principles to provide reasonable assurance that personnel can safely occupy the building following the design earthquake to perform necessary restoration or repair activities if needed. This level of performance is intended to be compatible with the performance objectives for substation equipment.

Inside the existing Embarcadero Substation building, equipment consists of a mix of recently installed and older vintage equipment. The older transmission equipment will be replaced as part of the Embarcadero Substation Bus Upgrade Project.

Distribution equipment are housed in the upper floors of the substation building and are expected to experience amplified input motions. In general, low voltage distribution equipment have performed well in earthquakes however, there is some possibility of damage due to high levels of shaking on the upper floors.

Principal seismic vulnerabilities include the existing 230 kV cable terminations (HZ-1, HZ-2), older transformer bushings and surge arresters on 230 kV transformer banks pre-dating IEEE 693. As part of the Embarcadero Substation Bus Upgrade Project, the HZ-1 and HZ-2 lines, as well as the proposed ZA-1 cable, will be directly terminated in the new GIS, which eliminates the vulnerability associated with the old terminations.

The existing Embarcadero Substation building is a reinforced concrete shear wall and steel frame building that was designed and constructed in the early 1970s. PG&E has not performed a detailed evaluation of this building. Structural steel code-designed buildings of this vintage are expected to experience some damage from a large earthquake. Typical damage may include yielding, deformation, or other damage to structural steel members and connections, and detachment of exterior cladding. However, steel framed buildings are unlikely to collapse, based on California earthquake experience.

3. Potrero Switchyard

The Potrero Switchyard is located at the intersection of Illinois and Humboldt Streets in San Francisco. Currently, the Potrero Switchyard includes a 115 kV switchyard. The Potrero 115 kV switchyard is fed by three buried transmission cables (AHW-1, AHW-2 and AP-1) and the TBC. This Project would add a new 230 kV switchyard along with a connection to the existing 115 kV switchyard. Potrero Switchyard, both the 230 kV and 115 kV switchyards, is expected to remain operational following a major earthquake. Although some transmission and/or distribution equipment may suffer some damage, PG&E expects that such equipment could be restored to service or replaced relatively quickly. PG&E notes that, generally, there are uncertainties associated with the performance of substation equipment in the event of major earthquake-induced ground shaking.

The switchyard is located along the western margins of the old Potrero power plant along Illinois Street between 22nd and 23rd Streets near Potrero Point, south of San Francisco along the Bayshore. The old power plant is bounded in the north-south direction by 22nd and 23rd Streets and extended from Illinois Street on the west to the San Francisco Bay toward the east. The power plant was investigated in 1991, 1999 and 2004 with borings. The western half of the power plant footprint is underlain by serpentine bedrock and the eastern half of the power plant and a small portion of the southwestern corner of the power plant were extended into the Bay by placing fill beyond the historical shoreline. Most of the substation is located on the western margin of the power plant footprint and is underlain by serpentine bedrock of the Franciscan Formation which is confirmed by borings excavated near the northern and eastern limits of the substation. The subsurface soil near the southern end of the south substation or close to 23rd Street is mapped as artificial fill based on published USGS geologic maps. Nearby geotechnical borings within the fill in the vicinity of the southern end of the south substation show possible liquefaction hazard exists, depending on the depth of groundwater. If the potentially loose fill in the south part of the south switchyard should liquefy, there is insufficient slope on the flat switchyard site or nearby free face to facilitate lateral spreading. In addition, borings for the warehouse located southeast of the switchyard, south of 23rd Street, shows shallow bedrock which precludes liquefaction-induced spreading towards San Francisco Bay. Structure foundations in this area may be subjected to differential settlements of about 4 inches based on the best available data.

The site, generally characterized as Site Class D with the southern portion of the switchyard classified as Site Class F given the possible presence of liquefiable deposits, is approximately 13 kilometers (km) from the San Andreas Fault and is expected to experience about 0.5g PGA in a 7.8 M 84th percentile San Andreas Earthquake.

The Project includes construction of a new 230 kV switchyard adjacent to the existing 115 kV switchyard. The new 230 kV transformers and GIS to be installed during this Project will be seismically qualified to the IEEE 693 "High" qualification standard (if ABB's new GIS design has not been IEEE 693 qualified before the time of installation, ABB will demonstrate that it can survive the expected MCE through shake table testing). As a result, this equipment is expected to remain functional following a large earthquake.

Similar to Embarcadero Substation, the new 230 kV GIS at Potrero Switchyard is to be housed in a new building located adjacent to the existing substation building. As discussed previously, the new GIS building will be designed to the current CBC using Occupancy Category III requirements as well as performance-based engineering principles to provide reasonable assurance that personnel can safely occupy the building following the design earthquake to perform necessary restoration or repair activities if needed. This level of performance is intended to be compatible with the performance objectives for substation equipment.

The existing 115 kV switchyard consists of a mix of recently installed and older vintage equipment. Existing 115 kV substation equipment is generally expected to perform well during a major earthquake. Principal seismic concerns include the older 115 kV existing cable terminations, rigid bus work, disconnect switches mounted on tall structures. Old equipment will gradually be replaced as it reaches the end of its life cycle with new, IEEE 693 "High" qualified equipment. In general, such above ground equipment can be repaired, replaced or bypassed within a relatively short time following a large earthquake as evidenced by post-earthquake utility experience in California and developed nations. The cable terminations for AHW-1 and -2 were recently replaced with seismically qualified units as part of re-cabling projects; these terminations are expected to survive the design earthquake. The AP-1 cable termination is a composite cross-linked polyethylene type cable termination which is expected to survive the design earthquake.

PG&E has also reviewed the risk of damage from a 7.8 M 84th percentile San Andreas Earthquake scenario to the buried PG&E cables (AHW-1, AHW-2 and AP-1) supplying Potrero Switchyard. PG&E concluded that the AHW-1 and -2 cables have a low chance of failure due to the more favorable type of fill (likely to contain sand, silt, clay and bedrock materials excavated from the surrounding hills as opposed to dune sand used to fill areas south of Market that are highly susceptible to liquefaction) and depth of liquefiable fill in areas traversed by these cables. The AP-1 cable has a moderate chance of damage due to the possibility of lateral spread near the Islais channel. From these studies, PG&E believes it is likely that at least two of PG&E's 115 kV cables to Potrero will survive the design earthquake.

4. Martin Substation

Martin Substation is located at the intersection of Geneva Avenue and Bayshore Boulevard in Daly City. Martin Substation includes 230 kV and 115 kV yards, which provide power to San Francisco. The 230 kV bus at Martin provides power to Embarcadero Substation via two underground cables (the HZ cables). The 115 kV bus at Martin provides power to Potrero Switchyard as well as other San Francisco substations via several underground transmission cables. To serve load in San Francisco, Martin receives power via two 230 kV underground cables, one each from San Mateo and Jefferson Substations, and six overhead 115 kV transmission lines from San Mateo Substation.

Martin Substation (other than a small portion that does not contain substation equipment) is not thought to be subject to significant liquefaction risk. A portion of the 230 kV yard is also underlain by a relatively thin (about 5 ft) layer of potentially liquefiable material below the water table. Settlement of up to 2 inches may be expected. The site is approximately 7.7 km from the San Andreas Fault and is expected to experience about 0.62g PGA in a 7.8 M 84th percentile San Andreas Earthquake.

The 230 kV and 115 kV yards at Martin are expected to remain operational following a major earthquake. Although some transmission and/or distribution equipment may suffer some damage, PG&E expects that such equipment could be restored to service or replaced relatively quickly. PG&E notes that, generally, there are uncertainties associated with the performance of substation equipment in the event of major earthquake-induced ground shaking.

The 115 kV system at Martin was recently re-built with new equipment and structures that are expected to continue to function following a large seismic event. New equipment is generally qualified to the IEEE 693 standard, and new structures and supports have been designed to modern seismic design criteria. These equipment and structures are expected to respond acceptably in a large earthquake. The risk assessment study did identify older style surge arresters for the HY-1 and HP-4 cable terminations as vulnerable. In general, such above ground equipment can be repaired, replaced, or bypassed within a relatively short time following a large earthquake as evidenced by post-earthquake utility experience in California and developed nations.

The 230 kV section of Martin Substation consists of a mix of new and old equipment and structures, some of which were constructed or installed before modern seismic design criteria were developed and implemented. A consultant evaluation did not identify significant issues at Martin other than generic weaknesses (e.g., cable terminations that have no seismic qualification, rigid bus connectors for bypass switches, older wave traps and instrument transformers that have not been qualified). In general, such above ground equipment can be repaired, replaced, or bypassed within a relatively short time following a large earthquake.

The 115 kV system is fed by six 115 kV overhead transmission lines from San Mateo Substation which are expected to continue to function, or be restored to service relatively quickly should damage occur.

The 230 kV section of Martin is fed by two buried cables from San Mateo and Jefferson Substations. PG&E believes that the 230 kV cable terminations for the HZ-1, HZ-2, and San Mateo-Martin buried cables may be vulnerable to earthquake motions. These terminations were installed before the development of modern seismic design standards, and we are aware of no earthquake experience data for these items. During its design, the 230 kV Jefferson-Martin cable termination was evaluated for seismic loading, from which we conclude that it will likely survive a 7.8 M 84th percentile San Andreas Earthquake.

A consultant evaluation concluded that there is a moderate chance of failure of the buried San Mateo-Martin cable, and a low chance of failure of the Jefferson-Martin cable under the 7.8 M 84th percentile San Andreas Earthquake scenario. From these studies, we conclude that one 230 kV cable supplying Martin will likely be available following a 7.8M 84th percentile San Andreas Earthquake.

In summary, we expect the 115 kV section of Martin Substation to be functional or restored relatively quickly following a 7.8M 84th percentile San Andreas Earthquake. The 230 kV section of the substation is also expected to be functional or restored relatively quickly, although possibly one of the two 230 kV buried cables supplying Martin will be out of service. Because of the interconnection of the 230 kV and 115 kV systems at Martin, the 115 kV buses can also be supplied by the 230 kV section.

5. Assessment of Other 115 kV and 230 kV Transmission Cables

PG&E has performed engineering studies to assess the vulnerability of 115 kV cables to permanent ground deformation. As discussed above, at least two of the 115 kV lines serving Potrero Switchyard from Martin Substation are expected to remain operational following a major earthquake, and Martin Substation is expected to receive power to transmit to Potrero Switchyard from other transmission lines that remain operational following a major earthquake. These 115 kV lines are expected to provide sufficient Alternating Current (AC) power for TBC to deliver Direct Current (DC) power to Potrero and, if TBC is not operational, to provide power that the new ZA-1 line could deliver to Embarcadero Substation. Alternatively, if an HZ cable survives such an earthquake, the new ZA-1 line may deliver power to Potrero Switchyard to reinforce the 115 kV system. Outages of other transmission lines serving San Francisco may impact the ability of the remaining systems to meet all of the electric demand in San Francisco, but would not negate the benefit of the Project.

6. Trans Bay Cable

The Potrero Switchyard has a separate source of energy, the TBC, which can provide power so long as it is in operation and a sufficient amount of power reaches Potrero Switchyard through PG&E’s 115 kV network to feed the TBC converter station adjacent to the Potrero Switchyard. Based on information from TBC, PG&E has calculated that, to re-start and maintain DC energy delivery from TBC, it is necessary to have a relatively strong AC power system at Potrero Switchyard, which requires that two of PG&E's 115 kV cables into Potrero be in service. Based upon its existing review of seismic threats to its 115 kV system, PG&E expects that at least two 115 kV cables will remain in service following a major seismic event. Based upon available information, PG&E believes that AHW-1 and AHW-2, running from Martin to Bayshore to Potrero, are likely to survive a 7.8 M earthquake, with 84th percentile ground acceleration, because they are located in areas that are expected to have little ground movement even in such an event. If, in the future, TBC adds "blackstart" capability, it could provide electricity to the PG&E system even if no 115 kV cables provided power to the Potrero Switchyard.

PG&E did not design or construct, and does not own or operate the TBC. However, TBC informed PG&E that the converter stations at both ends of the TBC were designed in accordance with IEEE 693. In the case of equipment that is not explicitly addressed by IEEE 693, TBC indicated that they used the CBC as their guiding standard. PG&E did not review any TBC documentation nor inspect the equipment installation at the converter stations. Based upon information provided by TBC, PG&E expects that the converter station would remain functional following a 7.8 M 84th percentile San Andreas Earthquake. However, the actual performance would greatly depend upon details of the engineering design and their implementation.

TBC stated that no special seismic design was applied to the submarine cable except for additional cable slack provided at the Hayward-Rodgers Creek Fault crossing where ground displacement is expected to occur. PG&E did not review any TBC engineering documents and has not independently assessed the likelihood of availability of the TBC following a large seismic event.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

POTENTIAL NON-SEISMIC OUTAGES OF EXISTING

SAN FRANCISCO 230 KV TRANSMISSION LINES

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A. Introduction

1. Purpose and Scope

In addition to an outage caused by a seismic event, as discussed in Chapter 6, Pacific Gas and Electric Company's (PG&E) existing Martin-Embarcadero (HZ) transmission lines may undergo outages caused by non-seismic events. This chapter provides testimony regarding those potential events.

2. Organization of the Remainder of This Chapter

- Section B – PG&E's San Francisco 230 kilovolt (kV) Cables May Undergo Planned Outages
- Section C – PG&E's Underground HZ Cables May Suffer Unplanned Outages

B. PG&E's San Francisco 230 kV Cables May Undergo Planned Outages

1. Maintenance Outages

PG&E conducts detailed inspections of its pipe-type cable circuits, including HZ-1 and HZ-2, once every calendar year, and routine inspections every month. A routine inspection is a visual inspection of above ground components only, which include terminations, connectors, wire drops from substation bus, support structures, etc. Operational parameters such as cable circuit pressure and pipe-to-soil cathodic protection levels are recorded. During the annual detailed inspection, a PG&E cableman visually inspects both the above ground components and exposed underground components. Standing water, if present, is pumped from the vaults and all exposed circuit components such as containment pipe, splice casing, etc. within the vault are inspected.

If an inspection identifies a problem that cannot be repaired at the time of the inspection, the maintenance is scheduled for a later date. Most planned maintenance does not require a circuit clearance to complete.

Planned maintenance requiring a clearance (de-energization of the line) at a later date can usually be completed within a one day period. Activity such as cleaning of terminations would be typical of planned maintenance requiring a clearance to complete. A circuit clearance request is submitted to PG&E Operations by maintenance personnel. This request must be submitted a minimum of 45 days prior to the work to enable Operations to review the request and either approve the scheduled date for the circuit clearance or propose an alternative date. Approval is granted only if the circuit clearance will not jeopardize system stability and reliability criteria. System Operations issues a switching log which describes the procedure, step-by-step, to clear the desired circuit and will arrange for a switchman to complete the tasks listed on the log.

On the day of the scheduled clearance, a qualified switchman will begin opening and closing required disconnect switches and circuit breakers (switching) to clear the circuit for maintenance. Once the circuit is de-energized and maintenance personnel are notified by Operations that the circuit is de-energized, protective grounds are placed at the correct position to safeguard the work site from inadvertent energization during the repair or cleaning. When the repair work or maintenance activity is completed, the protective grounds are removed and switching to re-energize the circuit is completed.

Routine maintenance work requiring a clearance usually would be completed in an 8- to 12-hour day.

2. Outages to Accommodate Infrastructure Construction

Much of San Francisco's utility infrastructure is located below the City streets, including PG&E facilities, City water and sewer, telecommunications, etc. As a result, infrastructure construction requires careful coordination among the construction contractor and all owners of infrastructure in the affected streets.

So long as PG&E's underground transmission lines in the affected areas do not need to be relocated, infrastructure work near a line, including the HZ lines, usually does not require a planned outage of the line. PG&E's underground circuit may be excavated without a circuit clearance if safe to do so. PG&E personnel ensure that third-party contractor is supporting and protecting the HZ pipeline during construction, and PG&E cablemen are on standby as needed.

However, the nature of the construction work may, and any need to relocate an HZ line will, require that the affected HZ line be de-energized. In such a case, the nature and scope of the work to be performed to install the new infrastructure will dictate the length of time the HZ circuit would be out of service. The City of San Francisco recently requested that HZ-2 be de-energized for four months, and relocated, to allow reconstruction of a sewer segment that is part of the City's Sewer Replacement Project. Even more recently, the City requested that a segment of HZ-1 be de-energized and relocated to allow reconstruction of another sewer segment. Because of the period of time that these requested outages would put the City at risk of a failure of the sole remaining HZ cable, the projects have been deferred pending construction of the Embarcadero-Potrero 230 kV Transmission Project (Project or proposed Project).

The steps required to clear the cable circuit to allow infrastructure construction work would consist of switching to clear the circuit and installation of grounds to safeguard the worksite from inadvertent energization during the construction work. Often, on critical circuits such as the HZ-1 and HZ-2 230 kilovolt (kV) lines, when feasible, PG&E Operations will require that grounds be removed at the end of the work day and switching performed to return the circuit to service each night for system reliability. Such a requirement would require switching to clear the circuit and re-installation of grounds to perform work each day. At the end of the day's construction, removal of the protective grounds and switching to re-energize the cable would be performed again to permit operation of the cable circuit when crews are not working on the infrastructure project. The ability to re-energize the HZ circuits nightly assumes that no work has been performed on the circuits and that the circuits were only de-energized to permit the third-party construction to be performed safely without threat of electrocution.

If PG&E only needs to de-energize its circuit to allow others to safely construct their infrastructure, then, after their work is complete, PG&E will inspect the pipeline to ensure it is not damaged. This requires inspection of the pipe and the protective coating around the pipe as scratches in the protective coating left un-repaired can lead to corrosion of the steel metal pipe beneath. Once the pipeline system is determined to be in proper condition, then the low strength thermal concrete is poured around the pipe. After sufficient curing time for the thermal concrete to support the weight of backfill (approximately 24 hours), the excavation is backfilled.

If the infrastructure work requires relocation of the PG&E pipeline, then the task is akin to the original construction of the pipeline. In brief, PG&E must re-align and install its pipe-type cable where space is available—which may or may not be in the same street. A trench must be excavated and possibly shored, one or more new vaults may be necessary, and a new pipeline constructed. When the new pipeline is ready to receive cable, the portion of the pipeline to be relocated must be isolated by freezing the dielectric fluid at each end of pipeline to be removed, the splices at the manhole at each end cut, and the old cable pulled out for scrap. The new pipeline is then finished to those manholes, and new cable pulled and spliced. Some of these tasks are discussed in more detail in Chapter 11. After testing of the splices, the dielectric fluid freeze “plugs” at each side of the relocated line are thawed, dielectric fluid restored to the entire pipeline and re-pressurized. If further testing shows the relocation is successful, then the line can be re-energized. Thereafter, the old pipeline must be demolished, removed and the trench backfilled, and the new pipeline must be encased in low strength thermal concrete, the trench filled with backfill, the location of the line marked, and the surface street or sidewalk restored.

The length of outage time for the HZ circuit will be dictated by the nature and scope of the infrastructure work.

C. PG&E’s Underground HZ Cables May Suffer Unplanned Outages

The HZ transmission lines may suffer forced, unplanned outages as a result of various events, in addition to the seismic events discussed in Chapter 6. Replacement or repair of damaged components require taking the circuit out of service to perform the required work. Below is an explanation of the relevant HZ transmission line facilities, and then discussion of the potential causes of forced outages.

1. Facilities Description

The HZ-1 and HZ-2 230 kV circuits are high pressure fluid filled, pipe-type, underground electrical circuits which begin and terminate at Martin and Embarcadero Substations. Each of these pipe-type cable systems consist of a single steel containment pipe housing three phase conductors which are insulated with a high-quality taped insulation. The free area in the pipe is pressurized with a dielectric fluid to a nominal pressure of 200 per square inch (psi).

Each circuit is located in separate corridors between the two substations.

Major system components of the underground transmission circuits are:

- Containment Pipe – Each containment pipe is a 10-inch in diameter and 1/4-inch thick steel pipe with an external protective, factory installed corrosion barrier. Each pipe segment is welded together during construction to form a continuous containment housing for the conductor and insulating fluid. The containment pipe is cathodically protected to maintain the integrity of the steel pipe and protect the pipe from corrosion. Failure to provide and maintain cathodic protection can result in serious corrosion and ultimately in fluid leaks.
- Pressurization Fluid – The pressurizing fluid (mineral oil) which fills free space within the containment pipe increases dielectric strength and suppresses ionization in the conductor insulation. The fluid also retards moisture ingress if there is a leak in the pipe. If water reaches the conductor insulation, the affected conductor must be replaced as the water will cause ionization of the oil impregnated paper causing a short and immediate failure of the line.
- Conductor – The conductor design uses copper conductors that are insulated with helically wrapped Kraft paper impregnated with high-viscosity synthetic dielectric fluid. The paper insulation requires complete and constant impregnation of high-viscosity synthetic insulation fluid pressurized to function.
- Vaults – Below ground vaults are situated at varying distances along the circuit route to permit splicing of the conductors during installation and to

provide access to the pipe system for repairs and maintenance. The vaults are constructed of pre-cast or cast-in-place concrete.

- Pressurization Units – A pressurization unit is provided at both ends of each circuit to maintain the required liquid pressure for the cables under all loading conditions. The pressurization plants includes pumps, relief valves, and controls to maintain fluid pressure, recorders and alarms, and an insulating oil reservoir tank to accommodate fluid expansion and contraction resulting from changes in electrical loading. The plant also provides for slow or rapid fluid circulation to dissipate generated heat if required.
- Conductor Splices – Conductor splices are located in each vault with distance between splices and vaults limited by permissible pulling tensions during conductor installation, and manufacturing/delivery limitations. Conductor splices are situated within the containment pipe.
- Terminations – Each phase conductor is terminated at the transition from the cable circuit to the substation bus or switch. The termination must be able to withstand both cable pressure and voltage stresses.

2. Physical Damage to Cable System

a. Damage to Containment Pipe

Damage to the HZ cable containment pipes may occur during construction activities by other entities installing or repairing other underground facilities or by events such as breaks in a nearby water or sewer line.

In addition to seismic activity, the main threat to the HZ-1 and HZ-2 underground cables is from underground construction activity including:

- Excavators
- Horizontal Drilling
- Vertical Drilling

The HZ cable circuits are in a trench backfilled with limestone screenings, cement, and water slurry having a 28-day compressive strength of 200 psi. The slurry may alert a construction crew to the presence of a utility, but is weaker than structural concrete, can be readily removed to allow work on the pipe or pipe protective coating, and is not protection against mechanized digging or drilling equipment.

One of the most effective means of preventing damage to PG&E's underground cable circuits is good communication by PG&E with contractors planning work in the vicinity of PG&E's underground utilities. If contacted, PG&E is able to provide basic information about underground cables and accurately identify their location, allowing contractors to avoid making contact. Code of Federal Regulation No. 49, Section 192.614 requires that every operator of an underground, buried pipeline must carry out a written program to prevent damage to that pipeline from excavation activities. The cable operator may comply with these provisions by participating in a qualified one-call system such as Underground Service Alert (USA). PG&E participates in the USA Central/Northern California and Nevada and the USA of Southern California. PG&E also marks its underground transmission circuits with paint.

Notwithstanding its precautions, PG&E has experienced accidental "dig-ins" to its underground circuits. For example, during excavation to repair a broken water main in 2006, a San Francisco maintenance crew penetrated the cable containment pipe of the PG&E PX-1 115-kV High-Pressure Gas-Filled line with a back-hoe ram, punching a 4-inch diameter hole in the circuit pipe. PG&E was alerted to the damage by a low pressure alarm, and dispatched teams to electrically isolate and clear that section of line, excavate the area of the dig-in, and repair the damage. Because it appeared that contamination did not enter the pipeline, PG&E installed a temporary repair sleeve. Line pressure was then brought up to approximately 20 psi to verify the soundness of the temporary sleeve. Following engineering inspection of the damage at a later date, a permanent welded patch was installed by PG&E gas crews. Repair of the damaged section took 18 days from start to finish.

PG&E has experienced other hot spot and dig-in failures on several underground cables:

- The Hunters Point-Mission No. 1 (PX-1) 115-kV Cable had an insulation failure and fault in 1997 due to a localized hot spot. Over

200 feet of cable and pipe was replaced. It took seven weeks to complete the repair.

- A 230 kV cable to Vineyard Substation in the Tri-Valley area was dug into on July 9, 2004. Repair took about 30 days.
- The 115-kV cables supplying Wolfe and Stelling Substations in Cupertino were bored into on October 1, 2004. The cables were repaired and returned to service in mid-2005.

During the PG&E San Francisco 115-kV Recable Project, in which existing cable was removed from service and replaced with a cable of higher ampacity capability placed into the existing containment pipe, unreported damage to the containment pipe, suspected to occur during construction activities by other entities, would not permit installation of the new conductor without replacing segments of the original pipe. The pipe had been crushed to a point that new cable could not be pulled through that section of pipe without pipe replacement. The Recable Project was completed in 2010.

Such unreported damage, if left unrepaired, can lead to future corrosion failure because of damage to the protective pipe coating, eventually resulting in leaks of the insulating fluid.

In CIGRÉ Publication 398, "Third-Party Damage to Underground and Submarine Cables," produced by Working Group B1.21 in December 2009, it was found that "failure statistics show that the risk of third-party mechanical damage is three to five times higher than the risk of internal failures." For underground cables, "failure caused by external agents is the most frequent type of failure. About 70 percent of the failures are caused by mechanical work."

Although PG&E tries its best to prevent third-party dig-ins by its participation in the USA mark and locate program, which provides positive identification and location marking of its underground facilities, and by providing construction stand-by inspection during excavations and drilling in close proximity to underground cable circuits, damage is possible and has occurred on other circuits.

If the damage does not penetrate the pipe, such as scratching the exterior pipe corrosion protection coating, then the circuit probably would not need to be taken out of service. The containment pipe and pipe coating are most susceptible to unreported damage. Major damage resulting in loss of insulating fluid will be detected by the pressurization unit. Minor damage to only the pipe protective coating may go undetected for months or years. This poses a risk of undetected corrosion that eventually could cause a leak in the pipe.

If the damage penetrates the containment pipe and a substantial fluid leak is initiated, the fluid loss and resulting drop in fluid pressure will trigger an alarm at the pressurization unit when the fluid pressure reaches a predetermined level. A general alarm is received by the grid control center, who in turn will notify the underground transmission supervisor that an alarm has been received indicating that a problem may exist on the circuit. The supervisor then will dispatch a transmission cableman to verify that the alarm is legitimate and to determine the reason for the alarm. If the alarm is legitimate and the cause for alarm is determined, the maintenance supervisor will dispatch additional maintenance personnel to make the necessary repair. The extent of damage and fluid loss rate will dictate the type of repair and will determine whether or not the circuit can remain in service during repair activities. Should the fluid pressure continue to drop and cannot be controlled, the circuit must be taken out of service for repair before the fluid pressure reaches a minimum level and ionization begins. At this level of pressure, permanent damage to the conductor and cable system components occurs. To remove the circuit from service, switching must take place to transfer electrical loading to other circuits before repairs can begin.

PG&E attempts to maintain a positive fluid pressure within the containment pipe during the fluid leak regardless of whether the circuit remains in service or not. If a positive insulating fluid pressure is not maintained in the containment pipe after penetration, water and contaminant infiltration into the pipe may occur. Incoming water intrusion into the pipe system may be wicked into the electrical cable which may cause electrical breakdown (faulting) of the cable.

Cable failure by electrical fault may require removal and replacement of the damaged containment pipe and cable. If the electrical fault is substantial in magnitude, the containment pipe may experience damage that is not repairable and replacement of that pipe section may be required. Not all cable electrical faults will penetrate the containment pipe. The steps to repair a pipe segment, and the time it likely will take to do so, is discussed in Chapter 11.

b. Damage to Cable and/or Cable Insulation

The HZ circuits will be forced out of service if there is damage to either the cable or the cable insulation. Damage to the cables or insulation requires replacement of the damaged cable. Such damage can occur from dig-ins, overheating, thermo-mechanical bending, or a failure of the pressurization units.

- <u>Dig-Ins</u>

  As discussed above, construction near PG&E's underground transmission lines, including the HZ circuits, can result in mechanical penetration of the containment pipe. Such penetration can damage the copper conductor or its insulation directly, or indirectly damage the insulation by allowing water or particle contamination into the insulation. In either case, the damaged cable will have to be replaced. Such replacement is a lengthy process, as discussed in Chapter 11.

- <u>Overheating/"Hot Spots"</u>

  Pipe-type cable insulation on the HZ cable circuits consists of many individual layers of impregnated kraft paper. The insulation must be free of intrusive particles or voids to function as designed. For an underground electrical cable to continue functioning, its insulation must remain functional. If the insulation fails, the cable will suffer a fault and be forced out of service.

  Underground pipe-type cables operating at elevated temperatures experience a more rapid deterioration of the cable paper insulation and thus can fail before the end of its expected lifetime. The HZ circuits were constructed in 1973 and energized in 1974 and thus are at the end of their 40-year expected lifetime.

Pipe-type cables have had good operating experience and are expected to last beyond their originally-expected lifetimes if not operated at elevated temperatures. However, potential advanced deterioration of their paper insulation from unknown elevated heating remains a concern.

The maximum steady-state temperature difference between the cable conductor and the remote ambient temperature by PG&E standards is 85 degrees C in accordance with the Association of Edison Illuminating Companies specification. Above this temperature, the cable insulation begins to age (aging rate for impregnated paper doubles for every 8-10 degrees C increase in temperature.) This temperature is the maximum steady-state temperature the cable insulation can tolerate within a 40-year life span without incurring significant thermal aging, deterioration and eventual failure. In an underground cable such as the HZ circuits, the electrical insulation acts as a thermal insulation and impedes the transfer of heat away from the conductor. The surrounding soil can also act as a significant thermal barrier, particularly if it is dry.

PG&E generally avoids the thermal deterioration of the cable insulation by limiting the normal operating temperature at which the cable conductor may operate, considering existing and known future environmental sources of heat such as other buried cables, sewers, etc. and their effect on the cable temperature, encasing the pipe in select thermal backfill, and burying the cable pipe system as shallow as possible while still avoiding interference with existing utilities and buried infrastructure and providing sufficient cover for protection of the cable system.

In addition, on High-Pressure Fluid-Filled systems, during periods of elevated temperature operation, the insulating fluid can be circulated through the pressurization unit and the pipe system to increase thermal transfer from the cable. Temperature measurement by a direct sensor, such as thermocouples installed during construction, can occur at spot locations along the circuit route. Thermocouples are attached to the pipe and lead wires used to connect monitoring devices to the thermocouples are installed away from the pipe location where temperature recording can occur in a safe area away from the street where the circuit is located. Over the life of the circuit, new construction excavation can destroy the lead wires, leaving no means to monitor cable temperature in that area. Localized overheating of the cable conductor may result and not be noticed by PG&E until the cable fails.

- Thermo-Mechanical Bending

  Cables expand and contract with load cycling. This motion is usually accommodated by cable snaking in the pipe. Cable expansion is normally controlled by flexing or bird-caging rather than axial movement along the pipe. However, where circuits are installed on inclines, the cable will tend to move down the incline due to load cycle ratcheting unless proper restraining methods are implemented to anchor the cable.

  At joint locations, excessive cable slack may develop which is free to bend and twist. This uncontrolled thermo mechanical bending (TMB) results in soft spots being developed within the insulation structure adjacent to the splice. If left uncorrected, this can lead to cable failure. Similar cable movement and resulting TMB can be experienced on cable circuits installed under roadways or along railroads as a result of traveling ground vibrations caused by traffic in conjunction with load cycling.

  Thermal expansion and contraction of the cable cannot be stopped but it can be limited and contained as to not cause damage. Control measures such as cable anchorage on hillsides are installed during construction.

  Repair procedures are based on the degree of total movement and the amount of damage to the cable or splice. Where excessive movement without cable damage is encountered, the joint reducer is moved back to provide clearance. Joint restrictors can be installed to limit future flexing. Where cable damage is present, additional work will be necessary, the extent of which will depend on the nature of the damage.

- <u>Damage to Pressurization Units</u>

  Pipe-type cable systems are designed to operate under positive fluid pressure at all times. On pipe-type circuits, pumping plants are used to maintain the fluid pressure within a preset operating range. When the system pressure drops below or rises above the preset range, fluid is introduced into or withdrawn from the circuit. The pressurization unit is designed for automatic operation.

  The HZ-1 and HZ-2 230-kV circuits each have two pumping plants connected to maintain fluid pressure; one on each end of the circuit to maintain circuit reliability should one of the units fail during service. In addition, each of the pressurization units contains a nitrogen supplied pump which operates upon failure of the main pump, increasing pumping plant reliability. The pressurization units are inspected and tested annually.

  There is low probability of complete failure of the pressurization system on the HZ cables. Separate ladders (pump systems) on each of the cables, redundant pumps on each end of the circuit and back-up nitrogen driven pumps on the pumping plant units make complete failure of the pressure system highly improbable.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 10

POTENTIAL NON-SEISMIC OUTAGES OF NEW EMBARCADERO-POTRERO 230 KV TRANSMISSION LINES

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POTENTIAL NON-SEISMIC OUTAGES OF NEW EMBARCADERO-POTRERO 230 KV TRANSMISSION LINES

A. Introduction

1. Purpose and Scope

This chapter describes the potential non-seismic risks to the proposed Embarcadero-Potrero 230 kilovolt (kV) Transmission Project (the Project) that may lead to an outage of the Project.

2. Organization of the Remainder of This Chapter

- Section B – Non-Seismic Outages of the Submarine Portion of ZA 1 (In Bay and Horizontal Directional Drilling (HDD))
- Section C – Potential Non-Seismic Outages of Underground Portion of ZA 1

B. Non-Seismic Outages of the Submarine Portion of ZA-1 (In Bay and HDD)

1. Overview of Reliability of Submarine Cables

As discussed in Chapter 4, the Project includes a submarine cable from the transition manholes at the southern Potrero end, through the HDD High Density Polyethylene (HDPE) conduits into the Bay, under the Bay floor for approximately 2.4 miles, through the HDD HDPE conduits out of the Bay and into the transition manholes at the northern Embarcadero end. The submarine cable consists of three single-phase, 230 kV rated, double-armored, solid-dielectric, cross-linked polyethylene (XLPE) 1,400 square millimeter (mm2) copper conductors with optical fiber distributed temperature sensor (DTS) system. For most or all of the way, the three conductors will be directly buried using a hydroplow to a depth of approximately 6 to 10 feet below the Bay floor. The seismic risk to the ZA-1 submarine cable is discussed in Chapter 7. This chapter discusses potential non-seismic causes of outage of the submarine cable.

Submarine electric transmission cables have been installed and are in use around the world. Over the years, several types of submarine cables have been used, including, for Alternating Current (AC) systems, self-contained fluid filled cables (SCFF), high pressure fluid filled, polypropylene laminated paper (PPLP) and XLPE, and, for direct current systems, SCFF, mass impregnated cables, PPLP and XLPE. Different installation methods also have been used, including laying the cable on the sea floor without protection, covering the cable as it lies on the sea floor, and burial of the cable.

In recent years, more high-voltage XLPE submarine cables have been installed. The International Council on Large Electric Systems (CIGRÉ) has collected information on both underground land and submarine cables. Below are two tables regarding the numbers of installed submarine cable that have used extruded XLPE insulation.[1] Table 10-1 lists existing installations for XLPE insulated submarine cables for voltage levels greater than 170 kV from 2006-2013, and Table 10-2 provides a list of XLPE insulated cables for voltages less than 170 kV from 1973-2013. The route length, maximum water depth and application of each installation are provided in each table.

TABLE 10-1
PACIFIC GAS AND ELECTRIC COMPANY
INSTALLED AND PLANNED HVAC SUBMARINE EXTRUDED CABLE PROJECTS > 170 kV

Line No.	Year	Country, Project	Voltage (kV Um)	Area (mm^2)	Route (km)	Depth (m)	Application
1	2006	Brazil, Santa Catarina	245	1 x 500 Cu	4.5	10	Interconnection
2	2006	Norway, Ormen Lange	420	1 x 1,200 Cu	2.7	210	Interconnection
3	2008	Canada, Wolf Island	245	3 x 500 Cu	8.4	30	Wind farm
4	2008	Norway, Oslo Fjord	420	1 x 1,200 Cu	3.2	300	Interconnection
5	2010	Qatar, Doha Bay	245	1 x 1,600 Cu	7.3	20	Interconnection
6	2010	Ireland, Cork Harbour 1	245	1 x 1,600 Cu	3.3	10	Interconnection
7	2011	Ireland, Cork Harbour 2	245	1 x 1,600 Cu	4.3	30	Interconnection
8	2011	Sweden, Nacka Sjö	245	1 x 1,200 Cu	6.5	45	City ring
9	2011	USA, NJ-Brooklyn	362	1 x 1,750 kcmil Cu	11.0	20	Interconnection
10	2012	Russia, Russky Island	245	3 x 500 Cu	2.2	43	Interconnection
11	2012	Denmark, Anholt	245	3 x 1,600 Cu	24.5	20	Wind farm
12	2012	Norway, Oslo Fjord	420	1 x 1,200 Cu	13.0	300	Interconnection
13	2013	Saudi Arabia	245	3 x 500 Cu	45.0	60	Oil platform
14	2013	Malta-Sicily, Italy	245	3 x 630 Cu	100.0	150	Interconnection

1 This information is extracted from “Recommendations for Testing of Long AC Submarine Cables with Extruded Insulation for System Voltage above 30 (36) kV to 500 (550) kV,” CIGRÉ TB490, February 2012.

TABLE 10-2
PACIFIC GAS AND ELECTRIC COMPANY
EXAMPLES OF INSTALLED AND PLANNED EHV/HVAC SUBMARINE EXTRUDED CABLE PROJECTS ≤ 170 kV

Line No.	Year	Country, Project	Voltage (kV Um)	Area (mm^2)	Route (km)	Depth (m)	Application
1	1973	Sweden-Aland	84	1 x 185 Cu	55	50	Interconnection
2	1979	Sweden – Bornholm	72	1 x 240 Cu	43	55	Interconnection
3	2000	UK (Isle of Man)	90	3 x 300 Cu	104	100	Interconnection
4	2002	Denmark (Horns Rev 1)	170	3 x 630 Cu	20	20	Wind farm
5	2003	Denmark (Nysted)	170	3 x 760 Cu	21	10	Wind farm
6	2005	Japan (Matsushima-Narao)	66	3 x 325 Cu	53	75	Interconnection
7	2006	UAE (Delma Island)	145	3 x 300 Cu	42	30	Interconnection
8	2007	Italy (Sardinia-Corsica)	170	3 x 400 Cu	15	75	Interconnection
9	2008	Belgium (Thornton Banks)	170	3 x 1,000 Cu	38	24	Wind farm
10	2009	Denmark (Horns Rev 2)	170	3 x 630 Cu	42	20	Wind farm
11	2010	Denmark (Redsand 2)	170	3 x 800 Cu	9	10	Wind farm
12	2010	Norway (Gjöa)	115	3 x 240 Cu	100	500	Oil/gas rig
13	2011	Australia (Sydney)	132	1 x 1,600 Cu	3	21	Bay crossing
14	2012	Tanzania (Zanzibar 2)	145	3 x 300 Cu	37	55	Interconnection
15	2012	Norway (Goliat)	115	3 x 240 Cu	106	500	Oil/gas rig
16	2013	Spain (Mallorca-Ibiza)	145	3 x 300 Cu	117	700	Interconnection

CIGRÉ also has collected data on failures of submarine cables and their causes.[2] Based on the data, CIGRÉ noted: "External damage is the most common reason for submarine cable failures." (CIGRÉ 2009b at 5.) For this reason, CIGRÉ concluded: "Installation is an extremely important element in submarine cable systems. The importance of cost effective cable protection from external Damage is well understood. More focus on surveys and routing to find more suitable routes to facilitate protection of the cables by burial and to ensure a more controlled installation has certainly led to a reduction in external damage." (CIGRÉ 2009a at 4.) CIGRÉ also noted the importance of making information about the cable location available to mariners and fisherman. (CIGRÉ 2009b at 6.)

Overall, submarine cables have been very reliable. Forty-nine faults worldwide were reported to CIGRÉ for the 15-year period ending December 2005 for 7,000 kilometers (km) of installed submarine cables. The faults were for all submarine cable designs, not just those with extruded XLPE insulation. (CIGRÉ 2009a at 5, 61.) Of the 49 failures, only 4 were on XLPE insulated cables, with the causes identified as 2 external

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2 The most recent data on this issue, from 1990 to 2005, is found in "Update of Service Experience of HV Underground and Submarine Cable Systems," CIGRÉ TB 379, April 2009 (CIGRÉ 2009a). The issue is further discussed in "Third Party Damage to Underground and Submarine Cables," CIGRÉ TB 398, December 2009 (CIGRÉ 2009b).

(anchors), 1 “other,” and 1 “unknown.” Two of the failed XLPE cables were between 21 and 25 years old. (CIGRÉ 2009a at 64.) Considering all of the failures, CIGRÉ’s analysis found that 50 percent of all failures occurred on unprotected cables. (CIGRÉ 2009a at 5.) CIGRÉ noted: “Much emphasis has been placed on installation and protection, including burial of submarine cables in recent years in order to reduce the risk of damage” (*Id.*)

Potential causes of outage for the ZA-1 submarine cable are discussed below.

2. Maintenance Outages

Submarine cables are not taken out of service for routine maintenance. Annual or bi-annual survey of the cable route is recommended to ensure the cable route is clear of debris and that the cable has not become unburied due to shifting sea bed conditions. If mattress protection has been used where burial was not feasible, the survey should check that the mattresses are still in position. The survey also should check for shoreline erosion, marine growth on the cable if not buried and corrosion of the cable armor and metallic sheath. The survey does not require taking the cable out of service.

The frequency of the maintenance survey very much depends upon the cable location and age. For example, if the cable is in a high current or tidal area, then maintenance inspections should be carried out at least once a year. The frequency of further inspections will be based upon the findings of each inspection.

Because of the dynamic nature of the Bay sea floor, Pacific Gas and Electric Company (PG&E) will monitor the location of the cables annually through a contract with a marine surveyor. PG&E will also use a marine monitoring system that will automatically notify PG&E should a vessel remain in place over the cables for a particular length of time.

3. Forced Outage Caused by Physical Damage to Submarine Cable

CIGRÉ found that “[m]ost of the failures in submarine cables are caused by external causes,” which it broke into failures caused by natural causes and failures caused by human activities. (CIGRÉ 2009b at 41.)

Other than seismic events, CIGRÉ identified the natural causes as erosion due to tide and waves, abrasion because of moving materials on the seabed, and free-hanging cable sections that may vibrate under certain conditions. CIGRÉ advised that the best way to control these types of risk is to protect the cables. (CIGRÉ 2009b at 41.) The ZA-1 submarine cable will be buried in the Bay floor and will transition from Bay to land in HDPE conduits installed by HDD. As a result, these potential causes of outages are not likely to impact the ZA-1 cable.

The risks from human activities include: "anchors; ocean dumping of dredged material or garbage; other installations including pipes, telecommunication cables, etc.; and influence of other existing cables." (CIGRÉ 2009b at 41-42.) Fishing trawling also poses a risk. (*Id.* at 47.)

Anchors can penetrate into the sea bottom, with the depth of penetration determined by the weight of the anchor and the hardness of the soil. A heavy (30 ton) anchor can penetrate up to 5 meters into soft soil. (*Id.* at 42.) By contrast, an anchor weighing less than a ton cannot penetrate much more than 1 meter into soft soil, and even "heavy fishing gear penetrates less than 0.5 meters into soft soil." (*Id.* at 43.) "If an anchor snags a cable, it will normally cause mechanical damage to the cable and lead to an electrical failure (breakdown). If the anchor only rubs against the cable, it may only destroy the armoring wires and make (invisible) damage to the insulation which later could lead to breakdown." (*Id.* at 44.)

As discussed in Chapter 4, the ZA-1 submarine cable is protected against the identified risks by the following:

- The cable will be buried approximately 6 to 10 feet below the Bay floor with alternative protection provided if burial is not possible in some areas.
- The cable route is designed to be located west of the established north/south shipping lanes (and designated anchoring areas) used by commercial and naval traffic into and out of the Bay.
- At the transition points from Bay to land, the submarine cable will be inside an HDPE conduit installed by HDD.
- PG&E's expected license with the Port of San Francisco will include a prohibition on other uses that could impact the three phases of the cable,

and further includes a “compatible use zone” around the path of the cable that limits the installation of other electrical cables.

- PG&E has agreed to take all necessary measures within its control to ensure that the License Area is depicted on all official navigation maps as a “no anchoring” area.
- PG&E intends to conduct marine surveys at regular intervals after cable installation to assess whether potential seabed topography changes have occurred along the cable route.
- Once the submarine cables are installed they will be recorded by the Coast Guard and given to National Oceanic and Atmospheric Administration for publication. PG&E will publish a Local Notice to Mariners via Coast Guard District 11.
- Besides promoting the new cable awareness and engaging stakeholders by registering the new cable on navigation maps, PG&E intends to implement an operation and maintenance strategy that will include the new cable security. The system will use live vessel position in conjunction with the cable location information to create automatic warnings.
- Other than dredging routinely performed by or on behalf of the U.S. Army Corps of Engineers (USACE) or dredging otherwise planned by the USACE, the Port shall not enter into any written agreements permitting any dredging in the Submarine Section of the License Area.
- The cable route was selected to avoid any crossing of the existing TransBay Cable.

These measures should provide very good protection against external risks. In the unlikely event that an anchor has penetrated to the cable depth and damage has occurred to the cable, then a repair may be necessary. Whether an outage is required will depend on the level of damage to the cable and whether the layers below the armor have been compromised. Minor damage to the outer serving and armor may not require any outage repair.

4. Potential Failure Due to Overheating

The ZA-1 submarine cable will have a maximum conductor continuous operating temperature of 90˚C and an emergency temperature of 105˚C.

Furthermore, the cable has been designed to carry a specific power load in normal operation and emergency conditions with respect to its maximum conductor operating temperature of 90˚C. If the cable is loaded to exceed its maximum conductor operating temperature, damage may occur that could lead to cable failure.

To protect the cable from third party damage, the ZA-1 cable will be buried in the Bay floor, thus reducing the cooling provided by the sea water if the cable were not buried. Burial thus reduces the rating, or load capacity, of the cable. PG&E will have control over the power load that the cable can carry as the conductor temperature along the cable is continually monitored by a DTS that will be installed along with the cable.

As a result of the DTS monitoring, PG&E should be able to avoid overheating of the ZA-1 cable.

C. Potential Non-Seismic Outages of Underground Portion of ZA-1

1. Overview of Reliability of Underground Cables

The Project's new ZA-1 transmission line includes two short underground sections, running from Embarcadero Substation and Potrero Switchyard to the transition manholes at the northern and southern ends, where the underground cable is spliced into the submarine cable. The underground transmission line will consist of 230 kV solid-dielectric, XLPE copper conductor underground land cables installed in a buried concrete-encased duct bank system.

Underground cables of this type have been very reliable, suffering very few failures. The seismic risk to the new ZA-1 transmission line is discussed in Chapter 7. This section addresses potential non-seismic outages to the underground portions of the new ZA-1 transmission line, including both planned and forced outages.

2. Potential Maintenance Outages for Underground Cables

In general, maintenance repair of solid dielectric, XLPE underground cables is not often required. The cable system in manholes and at terminations is inspected on a regularly set schedule to identify whether any of the equipment needs to be serviced or replaced, potentially due to malfunction or corrosion. A planned outage of the transmission line will be required if any of the grounding or bonding equipment, or the cable racking system, needs servicing or replacement. If necessary, such work usually takes approximately one day per manhole.

3. Potential Outages to Accommodate Infrastructure Construction

As discussed in Chapter 9, San Francisco's sewer replacement projects have resulted in requests to relocate a segment of each of the HZ-1 and HZ-2 transmission lines. No similar projects currently are known to cross the locations of the two short underground sections of the new ZA-1 transmission line. So long as the transmission line does not need to be relocated, infrastructure work near the underground duct bank usually does not require a planned outage of the line. PG&E personnel ensure that third-party contractor is supporting and protecting the cable duct bank during construction, and PG&E cablemen are on standby as needed.

4. Potential Outages Caused by Physical Damage to Duct Bank/Cable Inside

Based upon an industry survey, the most common cause of forced outages of underground cable systems is mechanical damage caused by third party construction work.[3] Excavators, vertical drilling, and horizontal directional bore equipment can damage a duct bank and the cable within, causing a fault and relay of the circuit. Such "dig-ins" are a known risk to underground electric cable systems.

However, cable systems installed in concrete duct bank have significant protection against dig-ins. "[I]nstallation of cables in concrete ducts or tunnels gives very good protection against external third party damage."[4] Here, as discussed in Chapter 4, the concrete duct bank in the underground sections of the ZA-1 transmission line will be reinforced with rebar to increase its strength in a seismic event. The rebar reinforcement also will provide further protection for the ducts and cables.

Damage to the concrete encasement alone will not force an outage of a solid dielectric XLPE transmission line because, unlike a high pressure, fluid

3 CIGRÉ Report 398, Third Party Damage to Underground and Submarine Cables (December 2009), page 5.

4 CIGRÉ Report 398, Third Party Damage to Underground and Submarine Cables (December 2009), page 5.

filled type transmission line, the cable does not require a pressurized fluid to operate safely. Depending upon the extent of damage to the duct bank, repair may not require an outage of the transmission line. Moreover, depending upon the extent of damage, even if an outage is required to repair it, the outage can be planned for a time when other transmission lines are not out of service.

If a dig-in penetrates a cable duct, usually an outage is necessary to closely inspect the cable to determine the extent of the damage. If the cable jacket is only nicked, then it need not be replaced; the duct can be patched and the cable can be placed back in service. Depending upon how quickly access to the damage location is attained, e.g., is the damage in an excavation or caused by a drill where excavation is still required, an outage to inspect the cable to assess damage may take from 12 hours to 48 hours.

If the dig-in penetrates the cable sheath, then the cable will remain out of service while the damaged segment is replaced. In the event of damage to an underground XLPE cable, the damaged cable section between the manholes (or, in the case of ZA-1, which has very few manholes, a termination) on either side of the dig-in location would be replaced. PG&E stocks spare cable lengths on reels and splice kits to replace the damaged length. Underground AC cable systems include three phases, i.e., three single conductor cables. Each conductor cable is in an individual duct within the duct bank. If only one conductor cable is damaged, then only that conductor cable must be replaced. However, if multiple conductor cables are damaged, then each must be replaced. The process for pulling each conductor into a duct, and splicing the conductor segments together, is discussed in Chapter 4. The extent of damage to the duct bank will impact restoration time; PG&E's standard duct bank includes one spare duct. Restoration steps and timeframe are further discussed in Chapter 11.

The most important preventive measure is providing information to government agencies and contractors so that the location of the cables is known to third parties engaged in construction in the vicinity of the cables. PG&E participates in the Underground Service Alert Central/northern California and Nevada and the Underground Service Alert of southern California. In addition, PG&E marks duct bank locations by placing red paint showing the width of duct bank and “230 kV” colored plastic markers in fill above duct bank. PG&E also patrols the routes of certain underground cables on a set routine basis or more often in case of a “do not touch” alert from CAISO. Notwithstanding these efforts, mistakes still occur that result in dig-ins.

PG&E has experienced dig-ins on occasion. As discussed in Chapter 9, in 2004, PG&E suffered two separate dig-ins on underground XLPE cables that required replacement of the cable segments and repair of the concrete duct bank. In each case, the circuits were properly marked or identified, and the contractor should have avoided the damage.

Because the underground sections of the new ZA-1 line will be quite short (totaling 0.6 mile), there will be relatively little underground cable exposed to the risk of dig-ins. The rebar-reinforced, concrete duct bank also will provide significant protection. PG&E will provide information about the underground segments to relevant government agencies and to Underground Service Alert, as well as in response to third-party engineering planning requests. PG&E will mark the duct bank as noted above.

5. Potential Outage Due to Overheating

Underground electric cables can fail early as a result of overheating. “Hot spots” can exist along circuits from poor surrounding soils, adjacent heat generating utilities, and faulty cross-bonding components. These hot spots effectively can shorten the life of a cable at the location of overheating by eventually causing a breakdown and fault of the cable insulation. The impact of a hot spot occurs over time. For example, if the cable is operated in a manner where it would be expected to have a 40-50 year life, a hot spot could cause a failure in about 20-30 years.

PG&E uses the following measures to reduce the risk of overheating.

- Pre-testing soils and using engineered backfills for more homogeneous thermal conductivity.
- Built-in DTS fiber optic for monitoring cable temperature which can locate hot spots and elevated temperature of sections with faulty cross-bonding.
- Locating the circuit at a reasonable distance from other heat generating utilities to avoid mutual heating.

- When a hot spot is identified, engineer a thermal mitigation of the location to remove the risk.

The risk of a hot spot causing overheating effectively is eliminated by implementation of the above measures.

However, post-installation construction work by third parties can impact the thermal fill and result in a hot spot. Heat damage to a cable cannot be repaired. Once discovered, the location would be mitigated to remove risk of further overheating. But, if the cable fails, that cable section must be replaced.

With respect to the underground segments of the ZA-1 line, the duct bank will be installed in engineered backfill called flowable thermal concrete and flowable thermal backfill, which are designed to allow heat displacement. The cable system will have built in DTS fibers to monitor the cable temperature. The cables will be located an appropriate distance from other heat generating utilities. As a result, overheating is not expected to be a threat to the underground sections of the new ZA-1 transmission line.

6. Other Failure Mechanisms Are Not Likely

Other potential failure mechanisms are not likely for a solid-dielectric XLPE underground cable. There are no known thermo mechanical bending risks to XLPE cable since it is a solid dielectric material. Corrosion of the cable is highly unlikely because an XLPE cable has a metallic moisture barrier covered with a polyethylene jacket to keep water out. If water got into the cable insulation, the cable would fail quite rapidly, but such intrusion is not likely. The XLPE cable has a metallic sheath and polyethylene jacket around the cable and its insulation. The cable splices inside the manhole are in a metallic can and waterproofed with tape and heat-shrink. Defects in the cable jackets should be avoided and detected by quality control/quality assurance testing before installation. Absent vandalism, or third party mechanical damage (e.g., dig-ins), water intrusion is not likely.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 11

RESTORATION TIME FOR TRANSMISSION LINE OUTAGES

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A. Introduction

1. Purpose and Scope

This chapter discusses the duration of outages that may be expected due to events that may damage the existing Martin-Embarcadero (HZ) transmission lines or the proposed Embarcadero-Potrero 230 kilovolt (kV) Transmission Project (the Project or proposed Project).

2. Organization of the Remainder of This Chapter

- Section B – Overview
- Section C – Potential Outages and Restoration Times for Existing HZ Cables
- Section D – Potential Outages and Restoration Times for Proposed ZA-1 Cable

B. Overview

Potential outages of the existing HZ and new ZA-1 transmission lines to Embarcadero Substation, caused by seismic and non-seismic events, are addressed in Chapters 6, 7, 9 and 10. This chapter addresses the estimated time it would take to restore these transmission lines to service, depending upon the nature of the outage. It is important, however, to recognize that the impact of an outage on Pacific Gas and Electric Company's (PG&E) transmission system, and on electrical service to downtown San Francisco, differs significantly if the Project is constructed.

Currently, with only the two HZ lines serving Embarcadero Substation, loss of both lines forces Embarcadero Substation out of service and a planned or forced outage of one HZ line puts Embarcadero Substation at risk should there be an outage of the remaining HZ line. In the future, when both HZ cables are needed to serve Embarcadero Substation load, loss of either cable will cause a partial loss of service.

If the Project is constructed, ZA-1 would be the third line serving Embarcadero Substation. As a result, a planned or forced outage of any two transmission lines serving Embarcadero Substation will not impact electric service at current loads. Even in the future, when two cables are necessary to serve load, a planned or forced outage of a single transmission line will not impact electric service so long as the other two lines are in operation.

Likely restoration times for the HZ lines and the ZA-1 line, based on various potential outage scenarios, are discussed below. Actual restoration time in the event of an outage, however, will vary depending upon the specific circumstances of the outage.

C. Potential Outages and Restoration Times for Existing HZ Cables

1. Planned Maintenance Outage

As discussed in Chapter 9, the HZ cables do not require a planned outage (also referred to as a "clearance") for routine inspection and maintenance. However, some work does require a clearance to safely perform that work; activity such as cleaning of terminations or minor repairs to the pipe requires a clearance to complete and normally takes about a day. Absent an urgent need for such work, the planned maintenance outage would not be scheduled to overlap with a planned outage of other equipment serving the same load (e.g., a planned maintenance outage for an HZ line would not be taken during a planned outage of the other HZ line or, after it is built, the ZA-1 line).

Currently, if there were a forced outage of the other HZ line during a planned maintenance outage of one HZ line, the HZ line on maintenance would be restored to service as quickly as safely possible. The restoration time would depend upon the status of the maintenance work at the time PG&E learned of the forced outage of the other HZ line. There is no way to restore operation to a circuit that is not electrically operable or partially repaired. Normally, even if the maintenance work is done (or not started), it requires 2-3 hours to safely button up and secure facilities, unground the cable, and inspect for safe release. In an emergency situation, the time will depend upon what is necessary to ensure that the line can be returned to service safely.

2. Planned Outage to Accommodate Infrastructure Construction Work

As discussed in Chapter 9, construction work by third parties or PG&E near the HZ lines will not necessarily require a planned outage. However, depending upon the nature and proximity of the work, de-energizing an HZ line may be necessary. If an HZ line must be relocated to accommodate other underground infrastructure, then a planned outage will be required.

The nature and scope of the work to be performed to install the new infrastructure, and any relocation of the HZ line, will dictate the length of time the HZ line would be out of service.

The steps required to clear the cable circuit to allow infrastructure construction work would consist of switching to clear the circuit and installation of grounds to safeguard the worksite from inadvertent energization during the construction work. If the infrastructure work did not otherwise impact the HZ cable, and relocation of the HZ cable was not required, then the duration of the outage would be determined by the duration of the other construction work. Often, on critical circuits such as the HZ-1 and HZ-2 lines, and when feasible, PG&E Operations will require that grounds be removed at the end of the work day and switching performed to return the circuit to service each night for system reliability. Such a requirement would require switching to clear the circuit and re-installation of grounds to perform work each day. At the end of the day's construction, removal of the protective grounds and switching to re-energize the cable would be performed again to permit operation of the cable circuit when crews are not working on the infrastructure project.

When the infrastructure work is completed, PG&E would inspect the pipeline to ensure it is not damaged. This requires inspection of the pipe and the protective coating around the pipe. The HZ line then can be safely returned to operation. Either before or after the line is returned to service, low strength thermal concrete is poured around the pipe and, after it dries, the excavation is backfilled. If a forced outage of the other HZ cable required restoring the HZ cable on planned outage to service as quickly as possible, the surrounding construction work would have to stop and the area made safe for re-energizing the HZ cable. Then PG&E would inspect the circuit to make sure that the line can be re-energized electrically, remove the installed personal grounds and report off the clearance to Operations. Operations would contact a switchman to restore the system to normal, and safely return the HZ cable to operation.

If the other infrastructure work required relocation of the HZ cable, however, the steps to restore the cable to service would be quite different. PG&E must re-align and install its pipe-type cable. The task is similar to the original construction of a pipe-type cable system except that, because the existing pipeline already is filled with pressurized dielectic fluid, specialized equipment must be used to create and maintain “plugs” of frozen dielectric fluid in the pipeline on each side of the pipeline and cable segment to be relocated. The extent of pipeline and cable to be relocated will depend upon the availability of underground space in the street or sidewalk. Both the existing pipeline to be relocated, and the path for the relocated pipeline, must be excavated, either in total or on a rolling basis as the new pipeline is laid. The steps and time necessary to replace a segment of High Pressure Fluid Filled Pipe Type (HPFF) cable, like the HZ cables, is discussed below with respect to forced outages caused by mechanical damage. The estimated time to replace an HZ segment is 8-16 weeks, and the need to prepare a new pipeline path could significantly extend that time.

If there were a forced outage of the other HZ transmission lines during a planned relocation outage of one HZ line, the HZ line on the planned outage would be restored to service as quickly as safely possible. The restoration time would depend upon the status of the relocation work at the time PG&E learned of the forced outage of the other HZ line. There is no way to restore operation to a circuit that is not electrically operable and may not even be physically connected. If the HZ section being relocated is still physically intact and could be restored to service due to an emergency, all work around the HZ circuit would need to cease, the circuit be ungrounded and released to operations. Although it normally takes 2-3 hours to safely button up and secure facilities, unground, and inspect for safe release, it could take longer if other construction personnel and equipment are in the area. However, if the HZ line was in the process of relocation, it could not be restored to service without completing the steps discussed above. Depending on the status of the relocation process when the forced outage occurred, restoration of that HZ cable to service could easily take 8-16 weeks.

3. Forced Outage Caused by Physical Damage to Cable System

As discussed in Chapters 6 and 9, a seismic event, dig-in, or undetected corrosion could cause physical damage to an HZ pipeline, cable or both. The type and length of repair to fix a damaged cable and/or pipeline will depend on the type and extent of the damage. Three potential damage scenarios are: (a) damage to the exterior of the pipeline that does not breach the integrity of the pipe; (b) damage to the pipeline that creates a small leak of dielectric fluid, but PG&E is able to maintain positive pressure in the dielectric fluid to prevent entry of contamination until the leak is sealed; and (c) damage to the cable or insulation directly, or damage to the pipeline where positive pressure of the dielectric fluid cannot be maintained. Each is discussed below.

a. Damage to Containment Pipe Without Breach of Integrity

The HZ pipeline could suffer damage that does not breach its integrity, such as construction work that hits the exterior of the pipe without breaking it or a seismic event that bends the pipe without breaking it. If PG&E learned of such an event, PG&E would excavate, uncover and inspect the pipeline at the affected location.

If there were only damage to the pipe coating, such as a scratch or a nick, the damage would be repaired by exposing the damaged coating, cleaning and wire brushing to bare metal, and then applying new protective material. The polymeric coatings on the HZ cable pipelines would be repaired using self-bonding, polyethylene tape. The pipeline then would be encased in low strength thermal concrete, the excavation trench filled in, and the surface (usually roadway) restored. This work would not require that the affected cable be taken out of service. Other physical damage to the pipe, but which does not breach its integrity, may be repaired with a welded steel patch or a welded steel split sleeve over the damaged area, followed by re-construction of the pipe coating. The pipeline then would be encased in low strength thermal concrete, the excavation trench filled in, and the surface (usually roadway) restored.

If there were more significant damage, such as bending in the pipe, but its integrity had not been breached, an assessment would be made of the remaining strength of the pipe. In an emergency situation, where no other transmission line to Embarcadero Substation was operating, PG&E would continue to operate the line if it could be done so safely. If replacement was necessary, but not urgent, replacement would be deferred until a planned outage could be taken without a loss of service. If, however, immediate replacement was necessary to ensure safe operation, then the steps discussed below would be necessary.

b. Damage to the HZ Pipeline, but Positive Pressure of Dielectric Fluid Maintained

As discussed in Chapter 9, if physical damage breaches the integrity of the pipeline, but the cable is undamaged and positive pressure of the dielectric fluid can be maintained until the leak is clamped shut, then the cable system may be repaired without replacing the cable segment. Roughly, the steps in this process include:

1) PG&E likely would be alerted to the rupture or leak in the HZ pipeline by the loss of pressure in the dielectric fluid, which is monitored by the pressurization units at each end. The system provides an alert to the operators when pressure drops below 180 per square inch (psi). If the pressure drops below 80 psi, the system automatically de-energizes the affected HZ circuit. The system is then manually configured to maintain positive pressure of 5 psi to prevent groundwater or other contaminants from entering the system. The extent of time during which positive pressure can be maintained will be determined by the size of the leak or rupture, the amount of reserve oil in the reservoir tanks, and how many leaks there are.
2) PG&E must locate the leak or rupture in the HZ pipeline. If the damage is located in a third-party excavation or seismic surface disruption and released mineral oil is evident, locating the problem may be relatively quick. If the damage is entirely underground, it

may not be easily found. The process may take less than a day or up to a week. Moreover, following a major earthquake, there may be multiple ruptures in the pipeline, some of which may be evident and some of which may not be found until the first ruptures found are fixed.

3) Because excavation, inspection and potential replacement of damaged cable requires more manpower and expertise than is currently available within PG&E, PG&E would seek to mobilize specialized contractors to assist. There are a limited number of contractors with the expertise to splice pipe-type cables and their availability is uncertain. Where replacement of cable appears likely, such as following a major earthquake, PG&E would alert contractors quickly.

4) Once the rupture is located, the site must be excavated (if the fault occurred outside a manhole) to assess the extent of the damage, develop a repair or replacement procedure, and determine the required materials. Excavation requires care to avoid further damage to the pipeline (all excavation within 5 feet of the circuit containment pipe must be performed by hand); the low strength thermal concrete is removed by hand digging.

5) If feasible, the fluid leak must be stopped to prevent groundwater or other contaminants from entering the pipeline and to prevent further releases of mineral oil. This is usually accomplished by installing a temporary split repair clamp around the pipe.

6) The dielectric fluid in the damaged area must be isolated from the remainder of the circuit by freezing the fluid on both sides of the faulted area (unless the damage is between the termination and the first vault, in which case only one side needs to be frozen). The dielectric fluid temperature must be reduced to a point that a “plug” forms which will withstand a pressure differential between that of the remaining circuit pressure and atmospheric pressure at the fault site. This requires excavation of the pipeline on both sides of the damaged area and wrapping the pipeline in liquid nitrogen “blankets” supported by specialized equipment. Nitrogen blankets

are wrapped around the pipe and liquid nitrogen is pumped through the blanket to begin the freeze plug. A large reservoir of nitrogen is required and is supplied by a contracted tanker truck. Special kits with plumbing and pump must be connected to the nitrogen blanket to permit circulation of the liquid nitrogen. Personnel remain on site to monitor the progress of the freeze plug. The process of creating a freeze plug takes approximately two days; the nitrogen blankets and equipment must be kept in place until the repair is completed.

7) Once the plug is in place, the dielectric fluid can be drained from the work section and an inspection hole cut into the pipe to assess the internal damage. This inspection will determine the plan of action for repair or replacement.

8) If the inspection determines that the cable and its insulation is undamaged, and that no contamination entered the pipe, then a pipe patch is welded over the inspection window and the pipes protective coating is repaired.

9) After the pipeline is repaired, and the pipe and casings placed on support members, then the nitrogen blankets are removed to thaw the freeze plugs. Thawing the plugs takes approximately 1-2 days.

10) The dielectric fluid must be restored and pressurized to at least 220-230 psi throughout the HZ pipeline. Prior to placing the cable circuit into service, a 24-hour soak test is performed. The soak test energizes the circuit without load to ensure that the new repair is electrically sound. If the cable passes the final tests, it will be re-energized and returned to service.

11) The repaired and excavated pipeline will be encased in low strength thermal concrete, the excavation trench filled in, and the surface (usually roadway) restored.

The full time to repair the HZ cable system under this scenario (a breach of the pipeline without damage to the cable or its insulation, and positive pressure of the dielectric fluid maintained) will be dictated by the amount of time required to locate the cable fault, the type and extent of damage, the repair or replacement scenario selected, the availability of skilled contractor labor force, the availability of specialized equipment, the amount of emergency materials on hand, the ability to locate additional repair materials if required, and the physical location of the damage and surrounding infrastructure. Within San Francisco, the amount of installed infrastructure around the HZ pipelines, which has been in the ground for several decades, will be extensive.

The estimated repair time for this scenario can range from 8-16 weeks.

c. Damage to Cable or Insulation, or Positive Pressure of Dielectric Fluid Not Maintained

As discussed in Chapter 9, damage to the HZ cable or its insulation, whether caused by a seismic event, a dig-in, overheating or thermo mechanical bending, or by contamination in the dielectric fluid, will cause a fault in the cable system and take the line out of service. Roughly, the steps to fix a single point of damage, and restore the system to service, include the following. If there are multiple damage points, this process would have to be repeated at each damage point.

1) PG&E would be alerted to a fault by loss of the line (fault would cause opening of the protective circuit breakers). If there also was a rupture or leak in the HZ pipeline, PG&E also would be alerted by the loss of pressure in the dielectric fluid, as discussed above.
2) PG&E must locate the fault or damage point. As noted above, this may take less than a day or up to a week. If there are multiple failures in the line, some may not be found until faults found early are fixed.
3) Because replacement of damaged cable requires more manpower and expertise than is currently available within PG&E, PG&E would seek to mobilize specialized contractors to assist. There are a limited number of contractors with the expertise to splice pipe-type cables and their availability is uncertain.
4) Once a fault or rupture is located, the site must be excavated (if the fault occurred outside a manhole) to assess the extent of the damage, develop a repair or replacement procedure, and determine the required materials.

5) If feasible, the fluid leak must be stopped to prevent groundwater or other contaminants from entering the pipeline and to prevent further releases of mineral oil.

6) Freeze plugs must be created to isolate the damage area from the dielectric fluid in the remainder of the circuit. As discussed above, creating the freeze plugs requires liquid nitrogen “blankets” supported by specialized equipment for the duration of the repair work.

7) Once the freeze plug is in place, the dielectric fluid is drained from the work section and an inspection hole cut into the pipe to assess the internal damage. This inspection will determine the plan of action for repair or replacement.

8) If the inspection determines that the cable and its insulation is damaged, or that contamination entered the pipe, then the cable must be replaced. All repairs require access to the damaged conductor, necessitating removal of the pipe section. As a result, the pipeline must be repaired, usually requiring installation of new pipe segments. The necessary pipe segments must be obtained and prepared, brought to the site, and welded into place. Some additional excavation may be needed. Special care must be taken to ensure that all contamination (dirt, water, etc.) is removed from the interior of the pipeline as it otherwise can cause a fault in the repaired or new cable. All new pipe sections must be swabbed several times to ensure removal of contaminants prior to cable installation.

9) The length of cable that must be replaced will depend upon the extent of the damage. Damage to a small section may be repaired using connectors, after which a larger diameter pipe section with flanges will be installed to accommodate the larger diameter of the repaired conductor. If the damage cannot be repaired using a standard or elongated connector, replacement conductor must be installed. One or all three conductors may need to be replaced. In most cases, this will be done by replacing the segment of damaged cable between the two nearest manholes.

The damaged cable must be pulled out of the pipeline from one or both manholes using a cable puller or winch line. New cable must be pulled from one manhole (from a reel mounted on a cable tensioning rig to the other manhole using a cable pulling rig). Special care must be taken to avoid damaging the cable insulation. If all three conductors in the cable are damaged, this process must be repeated three times.

10) Once the new conductors have been pulled, they must be racked and spliced to the rest of the cable system in the manhole on each end. Splicing pipe-type cable is highly specialized work, performed only by a limited number of contractors. The manhole within which the splicing occurs must be climate controlled (free from dirt, debris, inclement weather, kept dry, low humidity, temperature controlled between 68 and 72 degrees Fahrenheit). In order to control the climate with the splice area, a portable work housing is placed over the top of the manhole entrances. Roughly, the splicing process involves welding the two butted conductors, building up the splice insulation with kraft paper, and securing the splice casing around the splice to connect the completed splice with the containment pipe. Each splice takes from 2-3 days; three conductors in each of two manholes can take from 6-7 days, assuming some tasks can be performed concurrently. Once the splice is completed, it is encased in a pipe casing.

11) After the pipeline is repaired, and new cable is installed, the pipe and casings placed on support members and spliced, then the nitrogen blankets are removed to thaw the freeze plugs. Thawing the plugs takes approximately 1-2 days.

12) The dielectric fluid must be restored and pressurized to at least 220-230 psi throughout the HZ pipeline. Prior to placing the cable circuit into service, a 24-hour soak test is performed. The soak test energizes the circuit without load to ensure that the new repair is electrically sound. If the cable passes the final tests, it will be re-energized and returned to service.

13) The repaired and excavated pipeline will be encased in low strength thermal concrete, the excavation trench filled in, and the surface (usually roadway) restored.

The full time to repair the HZ cable system under this scenario (damage to the cable or insulation, or contamination of the dielectric fluid) will be dictated by the amount of time required to locate the cable fault, the type and extent of damage, the repair or replacement scenario selected, the availability of skilled contractor labor force, the availability of specialized equipment, the amount of emergency materials on hand, the ability to locate additional repair materials if required, and the physical location of the damage and surrounding infrastructure. Within San Francisco, the amount of installed infrastructure around the HZ pipelines, which has been in the ground for several decades, will be extensive.

The estimated repair time for this scenario can range from 8-16 weeks for one point of damage. PG&E recently suffered a forced outage of its PX-1 115-kV transmission line, which is a high pressure gas-filled line. The outage was caused by water that entered the pipeline during a previous dig-in, and which had escaped detection then because it flowed down the pipeline to a lower elevation. The repair work, including replacing the affected cable, took 7.5 weeks. Repair of a damaged HZ cable would be expected to take longer because the HZ pipelines are oil-filled and 230 kV. If there are multiple points of damage, the restoration time will be significantly longer, depending upon how quickly each damage point is found and whether sufficient skilled labor, specialized equipment, and spare material and labor is available to work on multiple repairs concurrently.

4. Forced Outage Caused by Damage to Splices Within a Vault

If the damage to the cable system occurs within a vault, most of the same repair steps must be followed, but less excavation may be required. Before opening the pipe, the fluid in the vault area must be isolated using the freeze plugs discussed above; depending upon the location of the damage, there may be sufficient room for the nitrogen blankets inside the manhole or it may be necessary to excavate outside the manhole to access the pipeline.

Depending on the extent of the damage, damage to splices within a vault can be repaired with an elongated connector or two standard connectors and a section of conductor. The insulation is re-constructed with paper tape. If the damage is extensive, adjacent, direct buried splices are installed and replacement cables inserted between the direct bury splices. The completed repair is closed using either split reducers and split repair sleeves and couplings.

The estimated time to repair a damaged splice inside a vault is 6-8 weeks, subject to the time required to locate the cable fault, the type and extent of damage, the repair or replacement scenario selected, the availability of skilled contractor labor force, the availability of specialized equipment, the amount of emergency materials on hand, and the ability to locate additional repair materials if required.

D. Potential Outages and Restoration Times for Proposed ZA-1 Cable

The proposed ZA-1 transmission line consists of submarine cable and underground cable. Because the restoration activities and times differ, each is discussed separately.

1. Restoration Times for Potential Outages of ZA-1 Underground Sections

If the ZA-1 line were out of service, due to a planned or forced outage, PG&E would take steps to restore the line to service. However, because ZA-1 would be the third line serving Embarcadero Substation, such an outage is less likely to have any effect on PG&E customers and San Francisco. Currently, with only the two HZ lines serving Embarcadero Substation, loss of both lines forces Embarcadero Substation out of service and a planned or forced outage of on HZ line puts Embarcadero Substation at risk of a forced outage of the remaining HZ line. In the future, when both HZ cables are needed to serve Embarcadero Substation load, loss of either cable will cause a partial loss of service. If the ZA-1 line is constructed, a planned or forced outage of any two transmission lines serving Embarcadero Substation will not impact electric service at current loads. Even in the future, a planned or forced outage of a single transmission line will not impact electric service so long as the other two lines are in operation.

As a result of ZA-1 being a third cable to Embarcadero Substation, a planned or forced outage of the line is not likely to create an emergency situation. Nonetheless, if an HZ cable were forced out of service while ZA-1 was out of service, PG&E would attempt to restore one or both lines to service as quickly as is safely possible. Likely restoration times are discussed below.

a. Planned Maintenance Outage

As discussed in Chapter 10, solid-dielectric cross-linked polyethylene (XLPE) cables do not require a planned outage (also referred to as a "clearance") for routine inspection and maintenance. However, if work is required on the racking, bonding or grounding equipment in a manhole, then a clearance is required to safely perform that work, which takes approximately one day. Absent an urgent need for such work, the planned maintenance outage would not be scheduled to overlap with a planned outage of other equipment serving the same load (e.g., a planned maintenance outage for the ZA-1 line would not be taken during a planned outage of either HZ line).

If there were a forced outage of either HZ transmission lines during a planned maintenance outage of the ZA-1 line, the ZA-1 line would be restored to service as quickly as safely possible. The restoration time would depend upon the status of the maintenance work at the time PG&E learned of the forced outage of an HZ line. In an emergency situation, all work around the ZA-1 circuit would need to cease, the circuit be ungrounded and released to operations. There is no way to restore operation to a circuit that is not electrically operable or partially repaired. Normally, it requires 2-3 hours to safely button up and secure facilities, unground, and inspect for safe release. In an emergency situation, the time will depend upon what is necessary to ensure that the line can be returned to service safely.

b. Planned Outage to Accommodate Infrastructure Construction Work

As discussed in Chapter 10, construction work near the ZA-1 underground sections will not necessarily require a planned outage. However, if the ZA-1 line must be relocated, then a planned outage will be required. If there were a forced outage of either HZ transmission lines during a planned relocation outage of the ZA-1 line, the ZA-1 line would be restored to service as quickly as safely possible. The restoration time would depend upon the status of the relocation work at the time PG&E learned of the forced outage of an HZ line. There is no way to restore operation to a circuit that is not electrically operable and may not even be physically connected.

If the ZA-1 section being relocated is still physically intact and could be restored to service due to an emergency, all work around the ZA-1 circuit would need to cease, the circuit be ungrounded and released to operations. Although it normally takes 2-3 hours to safely button up and secure facilities, unground, and inspect for safe release, it could take longer if other construction personnel and equipment are in the area. If the ZA-1 section has been physically disconnected to be re-located, then the work discussed with respect to physical damage to the cable would have to be completed.

c. Forced Outage Caused by Physical Damage to Duct Bank/Cable Inside

As discussed in Chapters 7 and 10, there is a low probability that a major earthquake or third party construction work could cause physical damage to the ZA-1 underground cables despite PG&E's protective measures. If the cable is still operable, there would be no reason to replace the cable immediately. Unlike the HPFF HZ pipe-type cables, where damage to the surrounding pipe can result in water intrusion that can spread to and harm greater lengths of the cable, operating a damaged, but operable, solid-dielectric XLPE cable will not harm other segments of the cable. As a result, if Operations need the ZA-1 cable to assure power to Embarcadero Substation, and the underground segment was damaged but operable, it could be kept in service. Later inspection may determine that the duct bank needs repair or a cable needs to be replaced.

If a seismic event or dig-in resulted in physical damage to the underground ZA-1 able that forced the line out of service, PG&E would take the following steps to restore it to service.

First, the location of the damage causing the fault would have to be found. PG&E would travel the cable route looking for surface disruption that might identify the location of damaged to the buried cable. PG&E would also inspect all terminations and manholes for the failure point. If not evident, PG&E would use fault locating equipment or scan the DTS fiber optic to locate an unseen fault. If the fault was caused by an earthquake, multiple failure points might exist. The ZA-1 underground sections are quite short (totally 0.6 miles), so the damage point(s) likely could be found relatively quickly.

Second, the damaged area would have to be excavated to allow visual inspection of the duct bank, the ducts and the cables for damage.

Third, if the damaged cable is inoperable, it must be removed from its duct in the duct bank. The splices at each of the segment (manhole to manhole, or manhole to termination, depending on location) will be cut so that the damaged segment can be removed.

Fourth, once the cable is removed, the duct will be videoed and mandreled to determine if it is usable, or whether some or all must be replaced. To repair or replace a duct, the necessary length of line must be excavated (personnel will dig a trench and go in from the side of the duct bank unless the damage is extensive), the concrete around the duct bank chipped away, the duct repaired or replaced, and concrete poured again around the duct bank. If multiple ducts and cables have been damaged, each damaged duct must be repaired or replaced.

Fifth, the new cable segment must be pulled into the duct. Once the necessary equipment and material is available, a new cable segment can be pulled between two vaults in about a day. To pull each conductor through the duct bank, a cable reel is placed at the end of a duct bank section above a vault, and a pulling rig is placed at the other end of the duct bank section above another vault.

Sixth, as described in Chapter 4, the new cable segment must be racked inside the vault, old splices blown and removed, and the new segment spliced to the other transmission line segment(s). If a termination is on end of replaced length, the new cable end is prepared for new termination. Racking and splicing the solid-dielectric XLPE copper conductor underground cable is specialized work that is not performed by PG&E, and specialized contractors must be utilized. The installation of racking and splicing for a single conductor cable is expected to take approximately 4 days at each end (racking and splicing multiple conductor cables in one manhole is expected to take a bit less time because some activities can be performed concurrently). The vaults must be kept dry during all phases of splicing 24 hours per day to prevent water or impurities from contaminating the unfinished splices. A water pump must be available to draw water if necessary and keep the vault dry. A splice trailer is positioned adjacent to the vault openings to facilitate the access to material, tools and equipment, and a mobile power generator is located directly behind the trailer to provide temporary power for lighting and tools.

Seventh, the cables inside the vault must be undergo final inspection and testing before the line can be placed safely back into service.

The time to complete these restoration steps is estimated to take approximately 45 days or more, depending upon the extent of damage. This estimate assumes that skilled labor and equipment is readily available to repair all damage to duct bank, excavate, cut and remove damaged cable, and pull in spare cable length. It also assumes that sufficient spare cable is readily available. The critical timing would be to arrange for skilled splicers to be present as soon as the new cable segments are pulled.

Additional restoration time could be needed depending on such variables as: (a) difficulties in finding fault; (b) damage to third-party infrastructure near the damaged cable; (c) difficulty of access; (d) heavy traffic control; (e) more severe duct bank damage; (f) skilled splicers' availability; (g) damage to multiple conductors; or (h) changes in ground conditions caused by an earthquake.

2. Restoration Times for Potential Outages of ZA-1 Submarine Section

a. Planned Maintenance Outage

As discussed in Chapter 10, the ZA-1 submarine cable will not be taken out of service for routine maintenance. If an outage is necessary for maintenance, the time to restore the cable to service will depend on the type of maintenance or repair being performed. If any repair or operations have been carried out directly on the cable, some tests after repair may be necessary before connecting to the system. Once the maintenance or repair has been completed, and any necessary testing performed, the cable can be brought back on line simply by connecting the ZA-1 cable to the system.

b. Forced Outage Caused by Damage to Submarine Cable

In the event of external damage to the ZA-1 submarine cable, whether an outage is required will depend on the level of damage and whether the layers below the armor have been compromised. Minor damage to the outer serving and armor would not require any outage repair.

The time to restore a damaged submarine cable to service will depend on the nature of the damage. Complete severance of a submarine cable is very rare. Normally, the extent of damage is a small puncture hole in the cable at the failure site or bending of the cable due to an anchor drag. On the other hand, if the damage is not quickly detected, corrosion can be extensive if pinholes or cracks occur in the protective polymer sheath, allowing intrusion of sea water into the cable. Depending upon the time before the damage is detected, complete disappearance of the metallic sheath can occur for long sections of the cable.

In the event that cable must be replaced, the length of cable to be replaced will depend upon the water depth and the extent of water penetration along the cable. The ZA-1 design includes water blocking, which would reduce the extent of any water penetration. The most common cable repair method is to grapple the cable, cut it, bring one end to the surface on a barge or vessel, cut out the damaged portion of cable, splice on a new piece of cable, partially lower the new cable and splice, pick up the other end of the old cable, splice it to the remaining end of the new cable, and overboard the splice without getting a twist in the cable.

In the event of a cable repair, it would be necessary to install a new length of cable into the circuit and making two joints (one at each end of the replacement cable). This would require the availability of spare length of cable, repair joints, jointing personnel and a moored barge or cable vessel. To facilitate any required repair of the submarine cable, PG&E's contract with the submarine cable supplier will include provision of a length of spare cable and repair joints, which PG&E will store nearby. The long lead time task tends to be the mobilization of the repair barge or vessel and jointers, which typically could be in the range of 4-6 weeks. PG&E intends to establish a stand-by agreement with a marine contractor to provide transportation and technical support on an as-needed basis, but availability of skilled jointers may remain an issue. Once the barge and jointers have been mobilized, then the repair would take approximately 7-10 days depending on the level of post jointing remedial protection to be performed.

For submarine cables of all types, the estimated outage time following a fault is 60 days. The outage time from any particular event is affected by many factors, including the availability of spare cable and accessories, availability of the cable repair vessel, availability of skilled labor, weather conditions and any regulatory restriction on operations.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 12

ECONOMIC AND SOCIAL IMPACTS OF AN EMBARCADERO SUBSTATION OUTAGE

PACIFIC GAS AND ELECTRIC COMPANY
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ECONOMIC AND SOCIAL IMPACTS OF AN EMBARCADERO SUBSTATION OUTAGE

A. Introduction

1. Scope and Purpose

The purpose of this chapter is to provide an overview of the economic and social impacts associated with an outage at Embarcadero Substation.

2. Organization of the Remainder of This Chapter

- Section B – Estimated Total Outage Business Cost of Embarcadero Substation Outage
- Section C – Displaced Residents Resulting From an Embarcadero Substation Outage
- Section D – Potential Social Disruption Resulting From an Embarcadero Substation Outage
- Section E – Lost Businesses and Employment Resulting From an Embarcadero Substation Outage

B. Estimated Total Outage Business Cost of Embarcadero Substation Outage

1. Overview of Outage Cost Study

Pacific Gas and Electric Company (PG&E) retained Freeman, Sullivan & Co. (FSC) to estimate the costs associated with power outages lasting between 24 hours and seven weeks in downtown San Francisco—specifically PG&E's business customers (and their tenants) served by PG&E's Embarcadero Substation (also referred to as the *target population*). Nearly 3,000 direct business customers are served by this substation, and FSC estimates that there are in addition roughly 2,500 businesses that are tenants of master metered buildings in the target population. The final report of this research effort, entitled "Downtown San Francisco Long Duration Outage Cost Study" (Outage Cost Study) is Attachment 12A hereto. This testimony provides a brief summary of key points and results discussed in detail in the Outage Cost Study.

Table 12-1 summarizes the estimated economic costs to businesses of an outage of Embarcadero Substation by cost category and outage duration. The estimated outage costs are divided into two components: (1) direct outage costs experienced by businesses in the target population; and (2) indirect outage costs experienced by businesses in California as a whole (also known as spillover costs). The direct costs were estimated by business customers in the target population in response to an outage cost survey. The indirect outage costs were obtained from a careful review of the literature on hazard losses. Indirect outage costs are reported as a range because a relatively wide range of indirect cost ratios were reported in the hazard loss literature.

TABLE 12-1
PACIFIC GAS AND ELECTRIC COMPANY
TOTAL OUTAGE COST ESTIMATES BY COST CATEGORY AND OUTAGE DURATION
($ MILLIONS)

Line No.	Outage Duration	Direct Cost ($ Millions)	Indirect Cost ($ Millions)	Total Outage Cost ($ Millions)
1	24 hours	$125.7	$62.9 to $251.4	$188.6 to $377.1
2	4 days	$407.4	$203.7 to $814.8	$611.1 to $1,222.2
3	3 weeks	$1,417.0	$708.5 to $2,833.9	$2,125.5 to $4,250.9
4	7 weeks	$2,922.6	$1,461.3 to $5,845.2	$4,383.9 to $8,767.8

Combining both the direct and indirect cost estimates from the study, a 24-hour outage among business customers in the target population is projected to result in an outage cost between $190 million and nearly $380 million. As outage duration increases, the projected impact on the California economy becomes more severe. At three weeks, the total projected outage cost ranges from $2.1 billion to over $4.2 billion. If PG&E’s Embarcadero Substation lost power for seven weeks, the total projected outage cost ranges from $4.4 billion to nearly $8.8 billion. Although FSC did not study cost impacts of longer outages, it is reasonable to expect that outages extending beyond seven weeks would have higher costs than those reported in the Outage Cost Study.

Embarcadero Substation also serves over 24,000 residential accounts (and each person residing at those residences). Lost income and wages resulting from the outage are counted in the direct cost to businesses in the lost revenue category. However, residential customers were not surveyed and other residential customer direct costs (e.g., relocation) were not included in the quantitative total outage cost estimate. These costs were not included because they are small relative to those experienced by businesses and because the costs of additional surveys of residential customers to document these low costs are relatively high (i.e., survey costs). However, a long duration outage would require many residential customers to evacuate their homes until electrical service was restored. The inconvenience and economic impact on affected residents cannot be ignored. FSC also considered, and discusses below, other impacts of a long duration outage, including social disruption and associated costs, loss of employment and displacement of residents.

2. Methodological Context

To develop the direct outage cost estimates for businesses, FSC surveyed a stratified random sample of businesses in the target population. The survey methodology, including sample and survey instrument design, are set forth in the Outage Cost Study. Indirect outage costs were estimated using a range of cost multipliers that were obtained through a careful review of the hazard loss estimation literature, which is included in Appendix B of the Outage Cost Study.

FSC has conducted numerous outage cost studies (also known as *value of service* studies) over the past 25 years for various utilities around the United States, including PG&E. These previous studies have focused primarily on short duration outages (i.e., outages of 24 hours or less) and the procedures used to collect information about such outages are well established in the utility industry. However, the impacts of a long duration outage on customers are very different than those experienced as a result of a short duration outage because, when feasible, most customers significantly alter their operations in response to a long duration outage in an effort to reduce the outage's impact. To account for these significant changes in customer operations, FSC modified its survey instruments and procedures to focus more heavily on measuring the economic costs of these operational changes.

The California Public Utilities Commission (CPUC or Commission) has directed PG&E and other California utilities to conduct outage cost surveys on multiple occasions. Prior to PG&E's 2005 outage cost study, the CPUC, PG&E and other stakeholders compared various methodologies and the CPUC ultimately directed PG&E to use a survey-based approach in conducting its 2005 outage cost study.[1] The CPUC again directed PG&E to use survey-based methods in its 2012 outage cost study.[2] Both the 2005 and 2012 outage cost studies were carried out successfully by FSC, and we have applied the same high standard for estimating direct outage costs in this study.

3. Outage Cost Survey Response

Table 12-2 summarizes survey response rates obtained by segment and usage category. Overall, the survey had an 18.8 percent response rate among listed small and medium business (SMB) customers and this SMB response rate was roughly consistent across usage categories. At 20.4 percent, master metered tenants had a similar response rate. In the listed large business (LB) segment, the response rate increased as usage increased, which is expected considering that larger customers generally have a close relationship with their account managers who helped with recruitment efforts. To ensure that the survey results were representative of the target population, FSC conducted a detailed non-response bias assessment. Results of this assessment are described in Section 4 of the Outage Cost Study. There was no evidence for non-response bias in the study.

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[1] CPUC Res. E-3922.

[2] CPUC D.10-06-048.

TABLE 12-2
PACIFIC GAS AND ELECTRIC COMPANY
CUSTOMER SURVEY RESPONSE SUMMARY BY SEGMENT AND USAGE CATEGORY

Line No.	Segment	Usage Category (Average kW)	Population	Sample Design Target	Records Released	Survey Responses	Response Rate
1	Listed SMB Customers	0.5 to 1.8	656	36	192	34	17.7%
2		1.8 to 6.4	691	37	200	39	19.5%
3		6.4 to 30.5	587	37	200	38	19.0%
4		30.5 to 600	306	40	208	39	18.8%
5		*SMB Overall*	*2,240*	*150*	*800*	*150*	*18.8%*
6	Listed LB Customers	600 to 855	21	5	21	6	28.6%
7		855 to 1,353	13	5	13	6	46.2%
8		1,353 to 8,900	11	10	11	7	63.6%
9		*LB Overall*	*45*	*20*	*45*	*19*	*42.2%*
10	Master Metered Tenants		2,444	50	269	55	20.4%
11	Overall		4,729	220	1,114	224	20.1%

C. Displaced Residents Resulting From an Embarcadero Substation Outage

Most of the residential customers in the target population live in residential hotels, low rise and high rise buildings that would need to be evacuated as a result of a long duration outage. In the survey, some property managers of residential buildings reported that their residents would have to be evacuated in the event of an outage because elevator, heating, cooling and ventilation systems would not be able to operate, which would lead to health and safety hazards for residents. In addition to the inconvenience of being displaced, these residential customers (or their property managers) would likely be required to bear the cost of living elsewhere for the duration of the outage.

Assuming a worst case scenario in which living and accommodation costs $200 per day and 90 percent of the more than 24,000 residential accounts are required to evacuate, the cost as a result of displaced residents would be about $17 million for a 4-day outage, about $91 million for a 3-week outage and about $212 million for a 7-week outage. Considering that these direct costs for residential customers would result in a proportionately small increase in the quantifiable total cost even in the worst case scenario, these costs have been omitted from the total cost estimate. Nonetheless, the inconvenience and economic impact that these residential customers would experience should not be ignored. The resulting costs could be quite significant for individuals or families, and all would suffer significant inconvenience. In addition, imagine how difficult it would be to find temporary housing for even 2,000 families, not to mention more than 24,000.

D. Potential Social Disruption Resulting From an Embarcadero Substation Outage

Another important consideration specifically for downtown San Francisco is the potential social disruption, and resulting costs, that could occur as a result of a long duration power outage. As discussed in the Outage Cost Study, a long duration outage in downtown San Francisco would cause social disruption and resulting costs from, among other things, government response to security and traffic control needs, private security, potential looting or vandalism, and disruption of transportation (Bay Area Rapid Transit (BART), Muni, TransBay Terminal and Cruise Terminal). Additionally, as noted in Corwin and Miles (1978), there are many other non-quantified costs associated with social impacts, such as the cancellation of planned activities, changes in normal work and leisure routines, and the inconvenience of everyday life functions. As a result, the indirect outage costs are likely to be toward the higher end of the range of estimates that is provided in the Outage Cost Study.

The costs of government response and assistance, and damage from looting and rioting, have been quite significant in the aftermath of some major outages and disasters, particularly in urban areas. For example, due to the costs of property damage and additional emergency services as a result of looting and rioting during a 25-hour blackout in New York City in 1977, indirect costs were estimated to be more than five times the direct cost, which is well outside the range of multipliers included to estimate indirect costs in the Outage Cost Study (0.5x to 2x). In present day downtown San Francisco, it is reasonable to expect that the costs from looting and rioting would be less than in New York City in 1977. Nonetheless, it is impossible to predict the potential level of damages from criminal conduct impacting unoccupied buildings, and the costs of government action to respond to or prevent such conduct.

Another source of social disruption is the interruption in transportation flows. The BART and the San Francisco Municipal Railway (MUNI) could experience substantial impacts from a long duration outage of power to the Embarcadero Substation. This station is roughly at the center of the four major BART lines running through the Bay Area. Although traction power for both BART and MUNI comes from different sources, Embarcadero Station power is from Embarcadero Substation. Loss of Embarcadero Station during the outage would disrupt BART and MUNI commuting; if BART and/or MUNI are unable or unwilling to send trains through the Embarcadero Station during a long duration outage, the resulting costs to BART/MUNI and impacts on Bay Area commuters and businesses would be considerable.

E. Lost Businesses and Employment Resulting From an Embarcadero Substation Outage

Another important impact of a long duration outage in downtown San Francisco is the likely increase in business failures and unemployment. Among the SMBs surveyed, the average reported likelihood of complete business failure (i.e., going out of business) as a result of an extended outage ranged from around 20 percent to slightly over 28 percent for the 3-week and 7-week outage scenarios. More than one out of 10 SMBs report that they have a 70 percent or greater likelihood of going out of business as a result of an outage lasting three to seven weeks. In contrast, the average reported likelihood among LBs is 1.5 percent for a 3-week outage and 4.1 percent for a 7-week outage. Only one LB respondent indicated that they had a greater than 10 percent likelihood of going out of business. Clearly, smaller businesses would be disproportionately impacted by a long duration outage.

Survey respondents were also asked to report the percentage of employees by labor category that they would forego paying during the 4-day, 3-week and 7-week power outages. As expected, contract/temporary employees would be most seriously affected by a long duration outage. For an outage lasting three to seven weeks, businesses in each segment would stop paying around 35 percent of their contract/temporary employees on average. Part-time employees working for SMBs would be similarly affected by a long duration outage, with those businesses reporting that over 40 percent of part-time employees would not be paid throughout a 7-week outage. Among full-time employees, lost pay is relatively low, but it would still have substantial secondary impacts on the businesses that serve this population. For a 7-week outage, businesses would stop paying an average of 16.4 percent to 27 percent of their full-time employees (depending on segment), which would be a substantial loss of income to the service businesses in the region.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 12

ATTACHMENT A

DOWNTOWN SAN FRANCISCO LONG DURATION

OUTAGE COST STUDY

FSC FREEMAN, SULLIVAN & CO.

A MEMBER OF THE FSC GROUP

Downtown San Francisco Long Duration Outage Cost Study

Prepared for:
Pacific Gas & Electric Company

March 27, 2013

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1 Executive Summary

Pacific Gas & Electric Company (PG&E) retained Freeman, Sullivan & Co. (FSC) to estimate the costs associated with power outages lasting from 24 hours to 7 weeks in downtown San Francisco, specifically for customers (and tenants of customers) served by PG&E's Embarcadero substation (also referred to as the *target population*). Nearly 3,000 direct business customers and over 24,000 residential accounts (and each person residing at that residence) are served by this substation. In addition, FSC estimates that there are roughly 2,500 businesses that are tenants of master metered buildings in the target population.[1] This report summarizes the study methodology and results for estimating the costs that these customers would experience as a result of such long duration power outages.

The study estimated outage costs for four outage scenarios – 24 hours, 4 days, 3 weeks and 7 weeks. The estimated outage costs are divided into two components:

- Direct outage costs experienced by businesses in the target population; and
- Indirect outage costs experienced by businesses in California as a whole (also known as *spillover* costs).

To develop the direct outage cost estimates for businesses, FSC carried out a survey of a stratified random sample of businesses in the target population. Indirect outage costs were estimated using a range of cost multipliers that were obtained through a careful review of the hazard loss estimation literature. Residential direct costs have been omitted from the quantitative total cost estimate. Nonetheless, the inconvenience and economic impact on each affected resident should not be understated. FSC also considered, and discusses below, other impacts of a long duration outage, including social disruption and associated costs, loss of employment and displacement of residents.

1.1 Outage Cost Estimates

Table 1-1 summarizes the total outage cost estimates obtained in the study by cost category and outage duration. Indirect outage costs are reported as a range because a relatively wide range of indirect cost ratios were reported in the hazard loss literature. In total, a 24-hour outage among customers in the target population would result in an outage cost ranging from about $190 million to nearly $380 million. As outage duration increases, the impact on the California economy becomes more severe. At 3 weeks, the total outage cost ranges from $2.1 billion to over $4.2 billion. If PG&E's Embarcadero substation lost power for 7 weeks, the total outage cost would range from $4.4 billion to nearly $8.8 billion. Although FSC did not study cost impacts of longer outages, it is reasonable to expect that outages extending beyond 7 weeks would have higher costs than those reported in this report.

[1] Due to the removal of inactive PG&E accounts from the analysis population and aggregation procedures that were required for unbiased sampling and surveying of representative businesses in the target population, the customer counts in this report do not directly correspond to the number of PG&E service agreements or customer accounts. Section 3 provides more details on these aggregation procedures and why they were required.

Table 1-1: Total Outage Cost Estimates by Cost Category and Outage Duration ($ Millions)

Outage Duration	Direct Cost ($ Millions)	Indirect Cost ($ Millions)	Total Outage Cost ($ Millions)
24 hours	$125.7	$62.9 to $251.4	$188.6 to $377.1
4 days	$407.4	$203.7 to $814.8	$611.1 to $1,222.2
3 weeks	$1,417.0	$708.5 to $2,833.9	$2,125.5 to $4,250.9
7 weeks	$2,922.6	$1,461.3 to $5,845.2	$4,383.9 to $8,767.8

1.2 Potential Social Disruption

The costs of government response and assistance, damage from looting and rioting have been quite significant in the aftermath of some major outages and disasters, particularly in urban areas. Due to the costs of property damage and additional emergency services as a result of looting and rioting during a 25-hour blackout in New York City in 1977, researchers found that the indirect cost estimate was more than five times the direct cost estimate, which is well outside the range of multipliers used in this study (0.5x to 2x). In present day downtown San Francisco, it is reasonable to expect that the costs from looting and rioting would be relatively less than in New York City in 1977, but given that it is impossible to predict the potential level of damages from looting and rioting and the costs of government response, the indirect cost estimate is likely to be toward the higher end of the range of estimates that is provided in this study.

Another source of social disruption reported during the 1977 New York City blackout is the interruption in transportation flows. The Bay Area Rapid Transit (BART) and the San Francisco Municipal Railway (MUNI) could experience substantial impacts from a long duration outage of power to the Embarcadero Substation. This station is roughly at the center of the four major BART lines running through the Bay Area. Although traction power for both BART and MUNI comes from different sources, Embarcadero Station power is from Embarcadero Substation. Loss of Embarcadero Station during the outage would disrupt BART and MUNI commuting; if BART and/or MUNI are unable or unwilling to send trains through the Embarcadero Station during a long duration outage, the resulting costs to BART/MUNI and impacts on Bay Area commuters and businesses would be considerable.

1.3 Lost Businesses and Employment

Another important impact of a long duration outage that the survey measured was the likely magnitude of lost business and employment as a result of a long duration outage. Among small and medium businesses, the average reported likelihood of complete business failure (i.e., going out of business) as a result of an extended outage ranged from around 20% to slightly over 28% for the 3-week and 7-week outage scenarios. More than one out of 10 small and medium businesses report that they have a 70% or greater likelihood of going out of business as a result of an outage lasting 3 to 7 weeks. In contrast, the average reported likelihood among large businesses is 1.5% for a 3-week outage and 4.1% for a 7-week outage. Only one large business respondent indicated that they had a greater than 10% likelihood of going out of business. Perhaps, not surprisingly, smaller businesses would be disproportionately impacted by a long duration outage.

Survey respondents were also asked to report the percentage of employees by labor category that they would forego paying during the 4-day, 3-week and 7-week power outages. As expected, contract/temporary employees would be most impacted by a long duration outage. For an outage lasting 3 to 7 weeks, businesses in each segment would stop paying around 35% or more of their contract/temporary employees on average. Part-time employees working for small and medium businesses would be similarly impacted by a long duration outage, with those businesses reporting that over 40% of part-time employees would not be paid throughout a 7-week outage. Among full-time employees, lost pay is relatively low, but it would still be substantial. For a 7-week outage, businesses would stop paying an average of 16.4% to 27% of their full-time employees (depending on segment), which would be a substantial loss of income to the region.

1.4 Displaced Residents

Most of the residential customers in the target population live in residential hotels, low rise and high rise buildings that would need to be evacuated as a result of a long duration outage. In the survey, some property managers of residential buildings reported that their residents would have to be evacuated in the event of an outage because elevator, heating, cooling and ventilation systems would not be able to operate, which would lead to health and safety hazards for residents. In addition to the inconvenience of being displaced, these residential customers (or their property managers) would likely be required to bear the cost of living elsewhere for the duration of the outage. However, because residential relocation costs are so small relative to business interruption costs, even in the worst case scenario, direct costs for residential customers would only lead to a slight increase in the quantifiable total cost. Therefore, residential direct costs have been omitted from the total cost estimate. Nonetheless, the inconvenience and economic impact on each affected resident should not be understated. Although the aggregate direct financial impact would not be substantial in comparison to that of business customers, the economic impact to the affected resident might be significant. In addition, imagine how difficult it would be to find temporary housing for even 2,000 families, not to mention 25,000.

2 Introduction

FSC has conducted many outage cost studies (also known as *value of service* studies) over the past 25 years for various utilities around the U.S., including PG&E. However, these previous studies focused primarily on short duration outages (i.e., outages of 24 hours or less). The procedures used to collect information about such outages are well established. However, because customers inevitably must alter their operations in response to long duration outages in important ways, the impacts of long duration outages are very different from those of short duration outages. Therefore, FSC modified its survey instruments in order to account for issues specific to estimating the costs associated with a 24-hour to 7-week outage. To begin this project, FSC reviewed the literature associated with estimating costs from long duration power outages. While there is a substantial body of literature on shorter duration power outages, the literature on long duration, widespread power outages is fairly thin and more journalistic than scientific – if only because such outages are highly uncommon. When long duration outages do occur, it is often in the aftermath of a natural disaster. FSC therefore turned to the literature on hazard loss estimation to review methods applicable to a long duration outage scenario in downtown San Francisco. This literature focuses on two types of costs that result from business interruptions – direct costs and indirect costs. FSC's summary of the literature on hazard loss estimation is attached as Appendix B.

2.1 Estimating Direct Costs

Direct costs of outages include the net revenue losses, equipment damage and response costs for customers that lose power. These costs are primarily attributed to commercial and industrial customers. There are three methods for direct cost estimation, including:

- Scaling of macroeconomic indicators;
- Extrapolation from prior case studies; and
- Primary data collection through surveys.

Although uncommon in the hazard loss estimation literature due to their relatively high data collection cost, survey methods provide the most reliable evidence of direct costs. Simpler and less expensive methods that rely on scaling output losses from macroeconomic variables (such as annual gross output), while easy to undertake, rely on fundamentally unrealistic assumptions (i.e., scalar adjustments for resiliency). Similarly, methods that use estimates from prior case studies rely on conditions and assumptions that may have little bearing on the situation under study (i.e., a long duration outage in San Francisco). Approaches based on primary data collection, on the other hand, take into account assumptions and heterogeneity of customers. Surveys derive estimates directly from representatives of the firms that will experience the outage – the agents in the best position to understand their firms and assess the likely costs of disruption. Surveys rely on scientific sampling techniques to ensure that answers obtained from surveys are representative of the customer population of interest, thereby enabling survey results to be scaled to the affected population. Although surveys ask respondents about hypothetical scenarios, and thus obtain estimates of likely costs, alternatives are much less accurate.

In the hazard loss estimation field, most experts use scaled macroeconomic variables as the basis for direct cost estimates, including Dr. Adam Rose who is one of the premier hazard loss estimation experts and wrote a seminal methodological comparison of the different cost estimation techniques in

2004.[2] While most hazard loss estimation experts, including Dr. Rose, agree that surveys are the preferred approach for estimating direct costs, this method is relatively uncommon because of cost concerns. Because this study focuses on a few thousand businesses served by PG&E's Embarcadero substation, survey methods are feasible because the cost to complete a statistically valid survey of these business is not very high for such a small, relatively homogeneous population. More importantly, there is good reason to believe that macroeconomic indicators, such as Gross Domestic Product (GDP), are simply unavailable for such a small geographical area, so a macroeconomic estimate would rely on tenuous assumptions to estimate revenue specifically for the target population.

We know this is the case because we developed an estimate of the direct outage cost that would occur as a result of an interruption of electric service using GDP. To do this, FSC identified the smallest geographical area containing downtown San Francisco for which GDP is published. The U.S. Department of Commerce Bureau of Economic Analysis provides GDP information down to the level of metropolitan statistical area (MSA). The entire target population is located within the San Francisco-Oakland-Fremont MSA. Within this MSA, FSC estimated that the target population accounts for roughly 2% of PG&E non-residential accounts and 12.6% of non-residential electrical usage. Considering that the target population comprises a relatively small portion of the MSA as a whole (that is known to have a very high concentration of high value added businesses), it is problematic to accurately interpolate a localized GDP estimate. With an MSA annual GDP of $335,563 million and 12.6% allocated towards the target population, FSC estimated an annual GDP of $42,355 million within the target population, but this estimate was developed by a highly oversimplified scalar. To develop a GDP-based estimate of outage costs, we assumed that annual GDP is evenly distributed among the hours of the year. Therefore, we divide $42,355 million by 8,760 hours in the year to develop an hourly GDP-based outage cost estimate of $4.8 million per hour. On a daily basis, the GDP-based outage cost estimate is $116 million; $464 million for a 4-day outage; $2.4 billion over 3 weeks; and $5.7 billion for a 7-week business interruption.

Although the GDP-based estimate serves as an interesting comparison to the survey-based results in this study, there are many drawbacks for this GDP-based outage cost estimate, including:

- GDP is a proxy for outage costs as opposed to a direct measurement provided by a survey;
- GDP-generating activities are not evenly distributed throughout the year or the day; and
- Given that GDP is not available at a local level, we rely on the assumption that GDP is evenly distributed (by annual GWh usage) throughout businesses in the MSA. However, it is unknown if the target population produces more or less GDP per GWh relative to the remaining population in the MSA.

These drawbacks highlight many of the reasons why survey-based estimates have become the more commonly accepted practice in the direct outage cost estimation literature, as well as the hazard loss estimation literature (particularly if accurate, localized GDP information for the population of interest is unavailable). Indeed, the California Public Utilities Commission (CPUC) has also found survey-based outage cost estimates to be most appropriate on multiple occasions. Prior to PG&E's 2005 outage cost study, the CPUC, PG&E and other stakeholders compared various methodologies and the CPUC

[2] Rose, Adam. "Economic Principles, Issues, and Research Priorities in Natural Hazard Loss Estimation," in Y. Okuyama and S. Chang (eds.) Modeling the Spatial Economic Impacts of Natural Hazards, Heidelberg: Springer, 2004, pp.13-36.

ultimately directed PG&E to use a survey-based approach in conducting its 2005 outage cost study.[3] The CPUC again directed PG&E to use survey-based methods in its 2012 outage cost study.[4] Both the 2005 and 2012 outage cost studies were carried out successfully by FSC, and we have applied the same high standard for estimating direct costs in this study.

2.2 Estimating Indirect Costs

Indirect costs to commercial and industrial customers result from the chain reaction of economic losses stemming from direct costs: interactions between businesses (e.g., changes in quantities of inputs bought or outputs sold, changes in relative prices) and interactions between consumers and businesses (e.g., lost wages and reduced spending). Indirect costs are thus incurred not only by people and firms subject to an outage, but also to people and firms outside of the affected area. Additionally, outage costs associated with public expenditures (e.g., assistance programs, emergency services, loss of taxes), public goods (e.g., water treatment) and injury or loss of life can be considered a part of indirect costs.

Measuring indirect costs is challenging for several reasons. Indirect losses cannot be readily verified through a survey like direct losses. Moreover, indirect effects are spatially dispersed; if a firm in San Francisco suspends operations, it may affect businesses elsewhere in the Bay Area, the United States, or the world. Finally, indirect losses vary *substantially* with the resiliency – the adaptive behaviors – of affected firms, which in turn varies substantially with specific market conditions that cannot be anticipated or modeled a priori. For example, in the fall of 2012, an Exxon refinery in Torrance experienced a momentary power outage that caused the refinery to shut down for approximately 5 days. This caused wholesale gasoline supplies to tighten significantly in the California market, which in turn caused the retail price of gasoline to spike dramatically over a period of about 10 days. Under normal conditions, removal of the productive output of that refinery would not have materially changed the wholesale price of gasoline because other suppliers would take up the slack. Unfortunately, these were not normal conditions because producers were drawing down their summer gasoline formulation stocks and the Chevron Richmond refinery was off line because of a fire in the preceding month. While we are not aware of any efforts to calculate the indirect cost to gasoline consumers of this outage, there is no doubt that this cost was dramatically higher than it would have been if it occurred either one month earlier or one month later in the annual production cycle

This outage also illustrates another very perplexing issue with estimating indirect costs. As with direct costs, indirect costs represent a net value, since some California businesses stand to benefit in the case of an outage – whether by substituting for adversely-affected competitors or responding to new demand.

Given the above problems, any calculation of indirect costs must necessarily be understood as simply an order-of-magnitude approximation. Indirect costs cannot be captured directly by surveys. It is our view that indirect costs should be estimated from a simple multiplier based on the literature or a regional economic model, and estimates can vary substantially based on the approach used to model them and the scope of costs under consideration. One thing, however, is clear: accounting for indirect

[3] CPUC Resolution E-3922

[4] D.10-06-048

costs always leads to an increase in the total cost estimate. A wide range of indirect costs have been calculated for real and hypothetical electricity outages in the hazard loss literature. These cost estimates and the methods and procedures that were used to calculate them are discussed in detail in Appendix B. Based on our review of this literature, we believe it is reasonable to expect indirect costs to be between one-half and two times direct costs for this study. In this report, we employ these multipliers to develop a range of indirect cost estimates in Section 6.

2.3 Potential Social Disruption

Another important consideration specifically for downtown San Francisco is the potential social disruption, and resulting costs, that could occur as a result of a long duration power outage.

In July 1977, New York City experienced a 25-hour blackout that affected 9 million people and resulted in widespread criminal activity. Corwin and Miles' 1978 study of the New York blackout continues to be widely cited in the literature on the costs of major power outages.[5] They constructed a summary of economic impacts by bringing together separate and independent reports of costs from businesses and business associations, governments, public service agencies, non-profit service organizations, insurers and health institutions. While Corwin and Miles disclaimed that their list was not comprehensive, the summation of reports resulted in an estimated indirect outage cost of $290 million in nominal dollars, which is about $1 billion in 2012 dollars and more than 5 times their direct cost estimate, which is well outside the range of multipliers used in this study (0.5x to 2x). Additionally, Corwin and Miles discussed non-quantified costs associated with social impacts, such as the cancellation of planned activities, the alteration of transportation flows and the inconvenience of everyday life functions.

While it seems unlikely that a long duration outage in San Francisco would result in similar levels of chaos and security response as that 1977 New York City outage, Corwin and Miles' study demonstrates that damage from looting and rioting, and the costs of government response and assistance, can be quite significant in the aftermath of a major outage or disaster, particularly in urban areas. Because business and residential buildings would not be occupied during the outage, there would be costs to secure such buildings, either through a police presence, private security or both. The loss of traffic signals would result in traffic control costs. For a unique area like downtown San Francisco, it is impossible to predict the potential level of damages from looting and rioting and the costs of government response.

Loss of Embarcadero Substation also would disrupt transportation flows in the directly impacted area and beyond. The Bay Area Rapid Transit (BART) and the San Francisco Municipal Railway (MUNI) could experience substantial impacts from a long duration outage of the Embarcadero Substation. The outage would impact the BART/Muni Embarcadero Station (station power), the Temporary TransBay Terminal (currently in operation), and the future TransBay Terminal. Although BART trains run on power that would not be affected by an Embarcadero Substation outage, the BART/Muni Embarcadero Station is roughly at the center of the four major BART lines running through the Bay Area. Similarly, the MUNI system also other sources of track power, but many important MUNI bus and light rail lines run through the Embarcadero Station, so the impact on those key transportation lines could also be

[5] Corwin, J. & Miles, W., 1978. *Impact Assessment of the 1977 New York City Blackout*, Palo Alto, CA: Systems Control, Inc.

considerable. San Francisco's Cruise Terminal also would lose power. The costs to these transportation systems, and additional costs to consumers who might need them, are bound to be substantial. However, these public transportation providers may not be willing to provide detailed impact estimates for security reasons.

As a result of these costs, the indirect cost estimate is likely to be toward the higher end of the range of estimates that is provided in this study.

2.4 Report Organization

The remainder of this report proceeds as follows. Section 3 summarizes the survey methodology that FSC implemented among a stratified random sample of businesses in the target population. Section 4 describes survey response and assesses any potential sources of non-response bias in the survey results. In Section 5, the survey results are presented. Section 6 summarizes the estimated indirect costs that would result from a long duration outage. The full survey instrument is included in Appendix A. Appendix B provides the review of literature focused on direct and indirect cost estimation.

3 Survey Methodology

FSC conducted the survey among a stratified random sample of PG&E business customers in the target population. These business customers were split into three main customer segments:

- Listed small and medium business (SMB) customers;
- Listed large business customers (LB); and
- Master metered tenants.

Listed customers are those that are represented in PG&E's customer database. Throughout the data collection process, FSC had to develop the information for a separate segment of master metered tenants because there are a number of high rise, master metered office buildings in the Embarcadero area. Tenants in these master metered buildings are not represented in PG&E's customer database and if costs for this segment were not including the study, the cost estimates would be drastically underestimated. The process for identifying a master metered building and surveying its tenants is described at the end of this section.

3.1 Survey Implementation Approach

Table 3-1 provides an overview of the survey implementation approach by segment. All customer segments were recruited by telephone. After a respondent verbally committed to participating in the survey, listed SMB customers and master metered tenants were emailed a link to the online survey and a unique access code. For LB customers, FSC scheduled in-person interviews because their business operations are generally more complex and require a trained survey interviewer to properly guide respondents through the survey. The incentive for completing the survey or in-person interview varied by segment and, for listed SMB customers and master metered tenants, the incentive varied over time as the data collection efforts proceeded. FSC initially tested a $75 incentive for completion of the survey by listed SMB customers and master metered tenants, but we quickly determined that a larger incentive was required to achieve reasonable response rates among busy downtown San Francisco businesses. Therefore, FSC first increased the incentive for completing the online survey to $100, which was sufficient to achieve the target of 150 completed surveys among listed SMB customers. For master metered tenants, FSC ultimately had to increase the incentive to $200 in order to achieve an acceptable response rate in that segment. The incentive for listed LB customers was held at $200 throughout the data collection process.

Table 3-1: Survey Implementation Approach by Segment

Segment	Sample Design Target	Recruitment Method	Data Collection Approach	Incentive Provided
Listed SMB Customers	150	Telephone	Online Survey	$75 to $100
Listed LB Customers	20	Telephone	In-person Interview	$200
Master Metered Tenants	50	Telephone	Online Survey	$75 to $200

3.2 Survey Instrument Design

The survey instrument included 6 main sections:

- Description of business, including employment and revenue;
- Case 1: Costs of a 24-hour outage;
- General issues associated with responding to long duration outages;
- Case 2: Costs of a 4-day outage;
- Case 3: Costs of a 3-week outage; and
- Case 4: Costs of a 7-week outage.

Considering that most customers have never experienced an outage that lasts multiple days or weeks, the survey instrument included a section between Case 1 and Case 2 that addresses general issues associated with responding to long duration outages, such as the use of backup generation, telecommuting capabilities and temporary/permanent relocation possibilities. After respondents think about these issues, they are able to more accurately answer more specific questions associated with how their business would respond to a long duration outage and how much it would cost their business. FSC identified these issues by pre-testing the survey instrument among 40 businesses in the New Orleans area that experienced a long duration business interruption after Hurricane Katrina. This pre-testing, as well as pre-testing among customers in the target population, greatly improved the validity of the survey instrument and ensured that the survey covered key issues and cost categories to consider when a long duration business interruption occurs.

For each case, the total outage cost is calculated by the following equation:

$$Total\ Outage\ Cost = Net\ Revenue\ Loss + Total\ Out{-}of{-}Pocket\ Cost$$

In the above equation, *Net Revenue Loss* is the revenue loss during the outage minus the revenue loss recovered after the outage, which are measured through two questions in the survey and only apply to the affected business in the target population. *Total Out-of-Pocket Cost* is the sum of all costs associated with responding to the outage, including:

- Temporary/permanent relocation cost;
- Salaries/wages to staff unable to work;
- Extra shifts/overtime pay;
- Damage to equipment;
- Damage to materials;
- Restart costs;
- Backup generation cost;
- Telecommuting costs; and
- Other out-of-pocket costs.

The temporary/permanent relocation cost was a key factor that FSC identified while pre-testing the survey among business affected by Hurricane Katrina. Therefore, questions regarding relocation are included at various points in the survey instrument. For more details on the survey instrument, refer to Appendix A, which includes the full survey instrument.

3.3 Sample Design

Before detailing the sample design methodology and how these sample points were distributed among usage categories, it is important to note that a *customer* refers to each individual business at each address, not an individual account at each address. When business customers complete an outage cost survey, they provide answers associated with all of their accounts at a certain address. Many of these businesses only have one account at that address, in which case the customer-level estimates and account-level estimates are identical. However, there are some businesses that have multiple accounts at the same address, especially in downtown San Francisco, in which case the respondent is rarely able to provide the cost estimates for an individual account within a building. Therefore, usage and customer contact information were aggregated across all of the accounts associated with each business at each address before sampling customers.

Listed SMB customers were split into four usage categories and listed LB customers were split into three usage categories. The optimal stratum boundaries were determined using the Delanius-Hodges technique, with the natural logarithm of customer usage as the indicator variable. The same variable was used in a Neyman allocation to determine the optimal number of targeted sample points within each stratum. The natural logarithm of customer usage was used as the indicator variable because it is the observable variable that is most highly correlated with customer outage costs, as shown in many prior outage cost studies, including the PG&E's 2012 systemwide value of service study. This sampling approach is necessary because the distribution of usage per customer is highly skewed. As shown in Figure 3-1, a vast majority of customers is clustered towards the lower end of the usage distribution for each segment and there is a *long tail* of high usage customers towards the upper end of the distribution. Considering that usage is a proxy for outage costs, a key objective of the sample design methodology was to ensure that the sample included a sufficient amount of high usage customers. A simple random sample would not accomplish this objective because high usage customers would have a very low probability of being selected for the sample considering that they account for a small percentage of each segment.

Figure 3-1: Distribution of Average Hourly Usage by Segment (Top 5th Percentile for Each Customer Class Omitted)

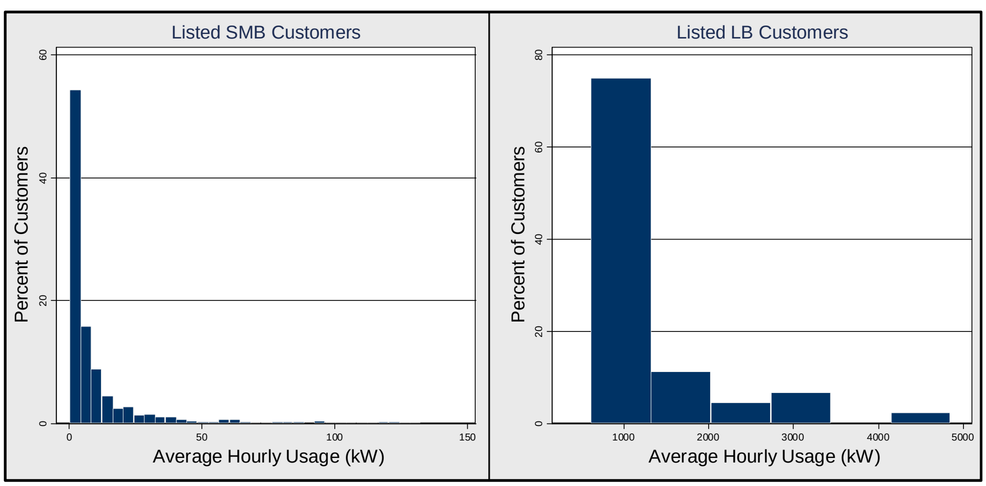


Table 3-2 summarizes the sample design for listed SMB and LB customers. Aggregate average hourly usage is 56.2 MW among all listed SMB customers in PG&E's database and 63.4 MW among all listed LB customers. The target population is defined as the customers served by the Embarcadero substation in San Francisco. Customers with less than 0.5 kW average hourly electricity usage are excluded from the survey because many of these facilities are unmanned (i.e., signals, signs and communications transponders) and collectively they account for a tiny fraction of electricity consumption in the target market. It is simply not cost-effective to expend survey resources on facilities that make up a very small percentage of the aggregate electricity consumption (and presumably outage cost) and are extremely difficult to recruit because they are unmanned. As shown in Table 3-2, these small customers comprise 0.2% of aggregate usage among listed SMB customers, so their impact on the final results is negligible even though they comprise 23.6% of customers in the SMB target population. The 150 sample points for listed SMB customers are divided roughly evenly between the 4 usage categories above 0.5 average kW. Half of the sample points for listed LB customers are allocated toward the largest usage category even though it only accounts for 24.4% of customers in the LB target population. This sample design ensured that the study included a sufficient amount of high usage customers that were likely to have higher and more variable outage costs, which improves the precision of the results but does not introduce bias because population weights are employed to ensure that estimates are representative of the target population.

Table 3-2: Sample Design Summary by Segment

Segment	Usage Category (Average kW)	Target Population				Sample	
		Total MW	% of Total MW	Number of Obs.	% of Population	Target	% of Sample
Listed SMB Customers	0 to 0.5	0.1	0.2%	692	23.6%	0	0.0%
	0.5 to 1.8	0.7	1.2%	656	22.4%	36	24.0%
	1.8 to 6.4	2.5	4.5%	691	23.6%	37	24.7%
	6.4 to 30.5	7.9	14.0%	587	20.0%	37	24.7%
	30.5 to 600	45.0	80.1%	306	10.4%	40	26.7%
	SMB Overall	*56.2*	*100%*	*2,932*	*100%*	*150*	*100%*
Listed LB Customers	600 to 855	15.4	24.3%	21	46.7%	5	25.0%
	855 to 1,353	14.5	22.9%	13	28.9%	5	25.0%
	1,353 to 8,900	33.5	52.8%	11	24.4%	10	50.0%
	LB Overall	*63.4*	*100%*	*45*	*100%*	*20*	*100%*

A stratified random sample for master metered tenants could not be developed a priori because the identity and number of these customers was not known at the time of the sample design. In fact, FSC did not have information on exactly which buildings had master metered tenants until after a directly served customer completed the survey. During the phone recruitment process, FSC filtered out customers that were clearly not property managers with master metered tenants. However, if respondents were unsure or may have been a property manager with master metered tenants, FSC waited until they finished the survey and then called back to verify that the customer was a property manager with master metered tenants. If so, FSC also asked how many tenants were at the address and attempted to obtain their identities. Using this verified information for listed SMB and LB customers that completed the survey, FSC focused its efforts on recruiting a representative sample of tenants in those master metered buildings.

FSC employed several options to develop a sampling frame within each of these master metered buildings. The options, in order of priority, included:

- Working with the property manager to identify all master metered tenants in the building;
- Visiting the building and gathering tenant information from the building directory;
- Standing outside the building and asking people leaving and entering which business they are visiting; and
- Searching online for businesses that are located at the building address.

If a building had 25 or fewer master metered tenants, FSC released[6] all of the records and attempted to recruit all tenants for the survey. If a building had more than 25 master metered tenants, FSC released a random sample of 25 tenants for survey recruitment. In total, FSC released 269 records that were associated with identified business tenants in master metered buildings.

[6] A released record represents a customer that FSC tried to recruit for the survey.

4 Survey Response and Non-response Bias Assessment

Table 4-1 summarizes survey response by segment and usage category. With 224 total completed surveys, customer response was above the overall sample design target of 220. Overall, the survey had a 18.8% response rate among listed SMB customers and this SMB response rate was roughly consistent across usage categories. At 20.4%, master metered tenants had a similar response rate. In the listed LB segment, the response rate increased as usage increased, which is expected considering that larger customers generally have a close relationship with their account managers who helped with recruitment efforts. Nonetheless, non-response bias among high usage LB customers is not a significant concern for the outage cost estimates because usage category is factored into the population weights in the analysis.

Table 4-1: Customer Survey Response Summary by Segment and Usage Category

Segment	Usage Category (Average kW)	Population	Sample Design Target	Records Released	Survey Responses	Response Rate
Listed SMB Customers	0.5 to 1.8	656	36	192	34	17.7%
	1.8 to 6.4	691	37	200	39	19.5%
	6.4 to 30.5	587	37	200	38	19.0%
	30.5 to 600	306	40	208	39	18.8%
	SMB Overall	*2,240*	*150*	*800*	*150*	*18.8%*
Listed LB Customers	600 to 855	21	5	21	6	28.6%
	855 to 1,353	13	5	13	6	46.2%
	1,353 to 8,900	11	10	11	7	63.6%
	LB Overall	*45*	*20*	*45*	*19*	*42.2%*
Master Metered Tenants		2,444	50	269	55	20.4%
Overall		**4,729**	**220**	**1,114**	**224**	**20.1%**

The remainder of this section analyzes survey response for listed customers. This analysis was not conducted for master metered tenants because we only have information for tenants that ultimately completed the survey. Without information for tenants who did not complete the survey, it is not possible to analyze response by usage and industry category and assess the potential sources of non-response. Nonetheless, master metered tenants have a comparable response rate and a similar magnitude of outage costs relative to listed SMB customers (see Section 5), which ensures that the tenant estimates are reasonable.

4.1 Survey Response by Industry Category

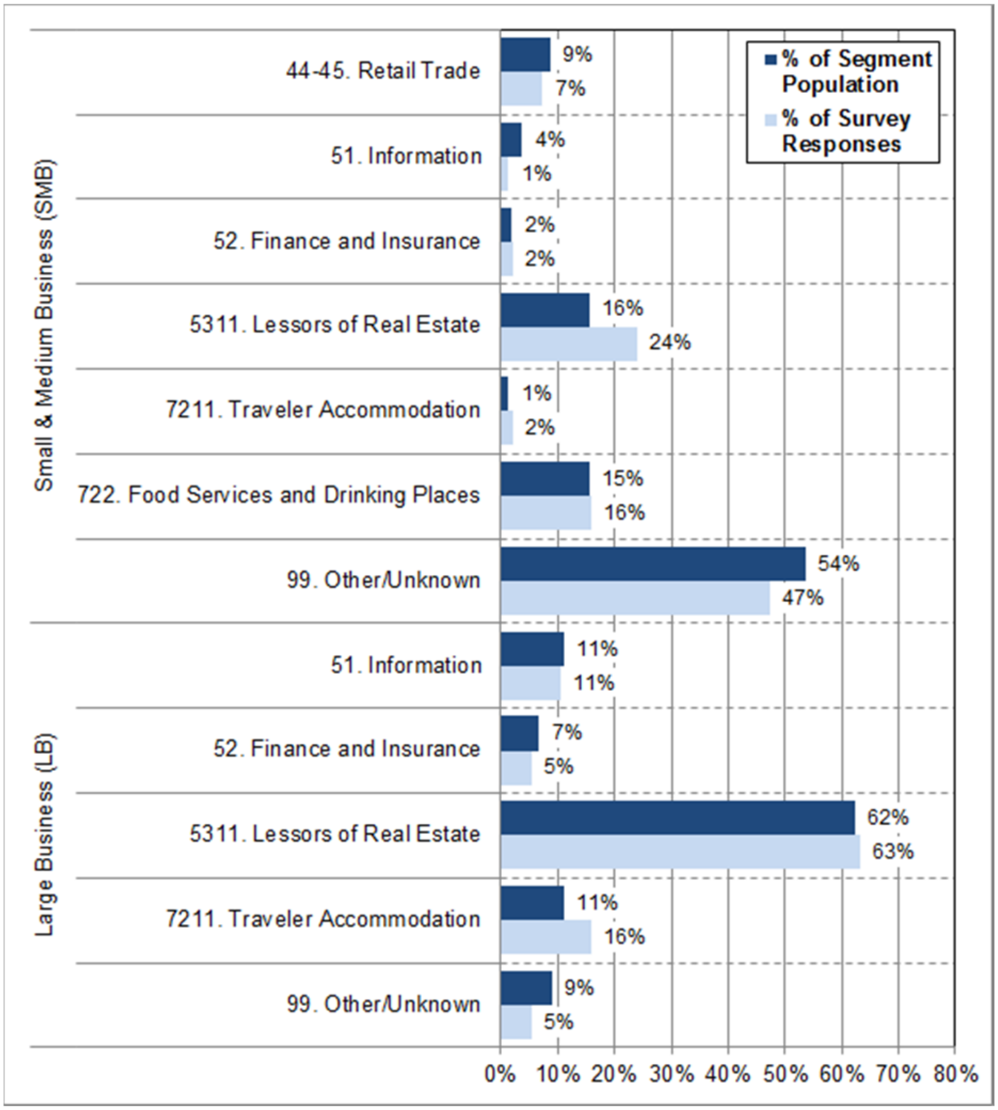
Table 4-2 provides the response rates by segment and industry category. Sample design targets are not included in this table because the survey implementation did not have specific quotas of survey responses by industry category. Stratifying the sample by usage category and industry category would have added substantial costs to the survey implementation and the benefit of doing so is not certain. Nonetheless, it is important to analyze survey response by industry category to ensure that key industry categories are represented in the survey data and that response rates are roughly consistent across business types. Other than customers in the information sector, response rates for listed SMB customers are relatively consistent across industry categories. Response rates for listed LB customers are more variable, but given the relatively small number of customers in each industry category, more variation is expected. This section concludes with a more rigorous non-response bias assessment to determine if these differences are statistically significant.

Table 4-2: Customer Survey Response Summary by Segment and Industry Category

Segment	Industry Category	Population	Records Released	Survey Responses	Response Rate
Listed SMB Customers	44-45. Retail Trade	192	74	11	14.9%
	51. Information	80	28	2	7.1%
	52. Finance and Insurance	41	15	3	20.0%
	5311. Lessors of Real Estate	352	170	36	21.2%
	7211. Traveler Accommodation	27	12	3	25.0%
	722. Food Services and Drinking Places	347	114	24	21.1%
	99. Other/Unknown	1,201	387	71	18.3%
	SMB Overall	*2,240*	*800*	*150*	*18.8%*
Listed LB Customers	51. Information	5	5	2	40.0%
	52. Finance and Insurance	3	3	1	33.3%
	5311. Lessors of Real Estate	28	28	12	42.9%
	7211. Traveler Accommodation	5	5	3	60.0%
	99. Other/Unknown	4	4	1	25.0%
	LB Overall	*45*	*45*	*19*	*42.2%*

Figure 4-1 compares the distribution of the population and survey respondents by segment and industry category. Even though response rates do not vary substantially by industry category, there can still be differences between the population mix and respondent mix if the sampled records were not representative of the population. As shown in the figure, the percentage of the population and respondents that fall into each industry category are highly correlated. In each segment, the other/unknown industry category is underrepresented in the sample, but this trend is expected because those customers generally have lower usage and the sample design targets a relatively low percentage of these smaller customers. Conversely, as a result of targeting relatively large customers more intensively, lessors of real estate in the SMB segment comprise a relatively high percentage of survey respondents. After weighting the results to the population by usage category, these differences are reduced.

Figure 4-1: Distribution of Population and Survey Respondents by Segment and Industry Category



4.2 Detailed Non-response Bias Assessment

Although a 20% overall response rate is reasonable considering that the target population is comprised of busy downtown San Francisco establishments, it is important to conduct a detailed assessment of the potential sources of non-response bias. If the 80% of customers in the released sample who did not respond to the survey are significantly different from the 20% who completed the survey, the outage cost estimates will be biased and adjustments to the population weights may be necessary. To assess potential sources of non-response bias, FSC conducted an analysis of the response trends in the survey. For listed SMB and LB customers, a Probit econometric regression model was run at the individual customer level among all of the released records throughout the data collection process.

Each Probit regression model was run using all of the released records for each segment, with records that completed the survey assigned with a one in the analysis dataset and records that did not complete the survey assigned with a zero in the dataset. Therefore, the Probit regression models summarized in this section show the factors that contributed to the likelihood that a customer completed the survey. A positive regression coefficient is interpreted as an increase in the likelihood of survey response and a negative regression coefficient is interpreted as a decrease in the likelihood of survey response. Any factors that significantly affect the likelihood that a customer completed the survey that were not accounted for in the population weights may lead to non-response bias in the results. As in any survey, there may be unobservable factors that contribute to non-response bias as well, but data is not available for those variables, so those factors are not considered in this analysis.

The variables in the models are usage and industry category (based on the North American Industry Classification System codes). Within each segment, four Probit models with different specifications of the usage variable were run:

- **Model 1:** Usage specified as a linear relationship (average kW variable included in the model)
- **Model 2:** Usage specified as a second order polynomial relationship (average kW and average kW squared variables included in the model)
- **Model 3:** Usage specified as a logarithmic relationship (log of average kW variable included in the model)
- **Model 4:** Usage specified as a categorical relationship (each usage category included in the model as binary variables)

Results for all four models are provided for each segment so that the analysis tests whether or not a finding is robust to the model specification. If a coefficient is statistically significant across all four models, we can conclude that its underlying variable has an effect on response likelihood.

Table 4-3 provides the Probit regression results for the SMB segment. The information sector variable produces the only statistically significant coefficient in all four models, suggesting that customers in the information sector were less likely to respond to the survey. Considering that the information sector in downtown San Francisco consists of many lightly staffed data centers, relatively lower response rates in this industry category would not be surprising. However, even though this coefficient is statistically significant in all four models, there is no evidence for non-response bias because the models as a whole are jointly insignificant, as indicated by the high Chi-square statistics and very low R-squared values. Therefore, we conclude that there may be relatively lower response among customers in the information sector, but given that the models are jointly insignificant, it is not a concern for the final results and adjustments to the population weights are not necessary. Even if adjustments were made, customers in the information sector comprise only 4% of the listed SMB population, so the impact of such adjustments on the overall results would be negligible.

Table 4-3: Probit Regression for Assessment of Non-Response Bias – Listed SMB Customers (Legend: * 10% Significance Level, ** 5% Significance Level, * 1% Significance Level)**

Variable Category	Variable	Model 1	Model 2	Model 3	Model 4
Usage	Average kW	-0.0007	0.0016	—	—
	Average kW Squared	—	0.0000	—	—
	Log of Average kW	—	—	-0.0205	—
	Usage Category 1 (0.5 to 1.8 kW)	—	—	—	(Base)
	Usage Category 2 (1.8 to 6.4 kW)	—	—	—	0.0347
	Usage Category 3 (6.4 to 30.5 kW)	—	—	—	0.0017
	Usage Category 4 (30.5 to 600 kW)	—	—	—	-0.0439
Industry	44-45. Retail Trade	-0.2953	-0.2502	-0.2836	-0.2689
	51. Information	-0.7033*	-0.6751*	-0.6933*	-0.6785*
	52. Finance and Insurance	-0.0725	-0.0126	-0.0657	-0.0664
	5311. Lessors of Real Estate	(Base Industry Category)			
	7211. Traveler Accommodation	0.1430	0.1386	0.1349	0.1303
	722. Food Services and Drinking Places	-0.0636	-0.0302	-0.0315	-0.0289
	99. Other/Unknown	-0.1533	-0.1221	-0.1381	-0.1258
Number of Observations		800	800	800	800
Chi Squared Statistic		0.52	0.28	0.63	0.84
R-Squared		0.0084	0.0106	0.0073	0.0071

Table 4-3 provides the Probit regression results for the LB segment. The only statistically significant variables in all four models are the log of average kW in model 3 and the largest usage category in model 4. As discussed above, this result is expected considering that larger customers generally have a close relationship with their account managers who helped with recruitment efforts. Considering that usage category is factored into the population weights in the analysis, non-response bias among high usage LB customers is not a significant concern for the outage cost estimates. In addition, as in the SMB segment, even though there are statistically significant coefficients, there is no evidence for non-response bias because the models as a whole are jointly insignificant, as indicated by the high Chi-square statistics and low R-squared values.

Table 4-4: Probit Regression for Assessment of Non-Response Bias – Listed LB Customers (Legend: * 10% Significance Level, ** 5% Significance Level, * 1% Significance Level)**

Variable Category	Variable	Model 1	Model 2	Model 3	Model 4
Usage	Average kW	0.0003	0.0004	—	—
	Average kW Squared	—	0.0000	—	—
	Log of Average kW	—	—	0.7479*	—
	Usage Category 1 (600 to 855 kW)	—	—	—	(Base)
	Usage Category 2 (855 to 1,353 kW)	—	—	—	0.5408
	Usage Category 3 (1,353 to 8,900 kW)	—	—	—	0.9931**
Industry Category	51. Information	-0.5009	-0.4488	-0.4733	-0.2106
	52. Finance and Insurance	-0.1865	-0.1797	-0.2142	-0.2266
	5311. Lessors of Real Estate	(Base Industry Category)			
	7211. Traveler Accommodation	0.5086	0.5257	0.5605	0.5686
	99. Other/Unknown	-0.5349	-0.5605	-0.6188	-0.5679
Number of Observations		45	45	45	45
Chi Squared Statistic		0.57	0.65	0.41	0.42
R-Squared		0.0671	0.0700	0.0937	0.0910

5 Survey Results

This section provides two sets of survey results. The direct outage cost estimates summarize the direct costs that businesses in the target population would experience as a result of a long duration outage. The second set of survey results focuses on the likelihood of lost businesses and employment in the target population.

5.1 Direct Outage Cost Estimates

Table 5-1 provides the average cost per outage event estimates by customer segment and outage duration. For a 24-hour outage, listed SMB customers experience an average cost of $20,536 per customer. As outage duration increases, the average cost increases to nearly $300,000 per customer at 3 weeks and over $600,000 per customer at 7 weeks. The incremental cost per day decreases slightly as outage duration increases for listed SMB customers. Between 24 hours and 4 days, the incremental cost per additional outage day is around $15,000. For the 45 additional outage days between 4 days and 7 weeks, the incremental cost per day is slightly lower at roughly $12,000. Although listed SMB customers are able to mitigate some daily costs as outage duration increases, there are still substantial costs for each additional outage day, even after 3 weeks to 7 weeks without power.

Master metered tenants have a similar magnitude of outage costs relative to listed SMB customers. For a 24-hour outage, master metered tenants experience an average cost of $29,086 per customer, which is 42% higher than that of listed SMB customers. As outage duration increases, the average cost for master metered tenants increases to around $250,000 per customer at 3 weeks and over $526,000 per customer at 7 weeks, estimates that are roughly 15% lower relative to those of listed SMB customers. As such, the incremental cost per day decreases relatively more quickly as outage duration increases for master metered tenants, perhaps because they stop paying rent or because they are relatively more capable of adapting by relocating or telecommuting. Between 24 hours and 4 days, the incremental cost per additional outage day is around $22,000. For the 45 additional outage days between 4 days and 7 weeks, the incremental cost per day is slightly lower at roughly $9,500, which is still a significant cost for each additional outage day. Even though average cost per outage event among master metered tenants is estimated from relatively few observations (55), the similar magnitude relative to the estimates for listed SMB customers (which are based on 150 observations) ensures that the tenant estimates are reasonable.

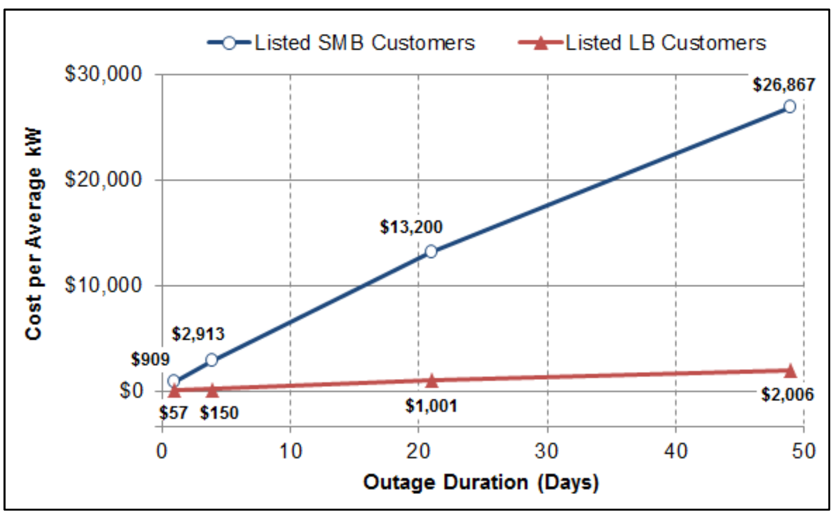
Table 5-1: Average Cost per Outage Event Estimates by Segment and Outage Duration

Segment	Outage Duration	Number of Obs.	Average Cost per Outage Event	95% Confidence Interval	
				Lower Bound	Upper Bound
Listed SMB Customers	24 hours	150	$20,536	$9,226	$31,845
	4 days	150	$65,848	$35,408	$96,287
	3 weeks	150	$298,359	$177,931	$418,787
	7 weeks	150	$607,265	$339,206	$875,323
Listed LB Customers	24 hours	19	$82,104	$8,427	$155,781
	4 days	19	$218,041	$11,890	$424,192
	3 weeks	19	$1,452,069	$3,445	$2,900,693
	7 weeks	19	$2,911,383	$583,527	$5,239,240

Segment	Outage Duration	Number of Obs.	Average Cost per Outage Event	95% Confidence Interval	
				Lower Bound	Upper Bound
Master Metered Tenants	24 hours	55	$29,086	$12,225	$45,948
	4 days	55	$95,836	$40,803	$150,868
	3 weeks	55	$250,477	$123,341	$377,614
	7 weeks	55	$526,370	$263,740	$789,000

Across outage durations, listed LB customers experience average costs per outage event that are roughly 3.3 to 5 times greater than those of listed SMB customers. However, considering that average demand is 1,451 kW among listed LB respondents and 22.6 kW among listed SMB respondents (98.4% less than LB average demand), the percentage difference in outage cost between segments is substantially lower than the percentage difference in average demand. As a result, outage costs for listed SMB customers are significantly higher when normalized by average kW. As shown in Figure 5-1, the outage cost per average kW estimates among listed SMB customers are more than an order of magnitude higher than those of listed LB customers at each outage duration. Considering that most listed LB customers are property managers that have master metered tenants in their buildings, this finding is expected given that those incremental tenant costs are separate from the cost per average kW estimates. Therefore, the outage cost estimates for listed LB customers are relatively low when normalized by average kW, even though the per event estimates are as high as around $2.9 million per customer for 7-week outage. Between 4 days and 7 weeks, the incremental cost per day is nearly $60,000 for listed LB customers, which is substantial cost for each additional outage day.

Figure 5-1: Cost per Average kW Estimates by Segment and Outage Duration[7]



With these cost per average kW estimates, it is relatively straightforward to develop the aggregate cost estimate for all listed customers in the target population. As discussed in Section 3, aggregate

[7] Cost per average kW estimates for mastered metered tenants are not included in this figure because usage information specifically for these customers is not available. Therefore, the cost per outage event estimates for master metered tenants cannot be normalized by average kW.

hourly usage is 56.2 MW among listed SMB customers and 63.4 MW among listed LB customers. These values are multiplied by the cost per average kW estimates in Figure 5-1 to develop the aggregate cost estimate for each outage duration.

For master metered tenants, calculating the aggregate cost is not as straightforward because we must estimate the total amount of these unlisted businesses in the target population. Table 5-2 summarizes this calculation. The estimated number of master metered tenants is 0.62 tenants per listed customer in the SMB segment and 23.2 tenants per listed customer in the LB segment. These averages are calculated and weighted to the population in the same manner that the average cost per outage event estimates are calculated in Table 5-1. The estimated number of mastered metered tenants is simply another result from the data collection efforts, except these responses were collected during the recruitment phase and then verified over the phone after a listed customer completed the survey. The total number of listed customers by segment is multiplied by the average number of master metered tenants per listed customer to develop the estimated total number by segment. Overall, we estimate that there are 2,444 total master metered tenants in the target population. This value is multiplied by the average cost per outage event estimates in Table 5-1 to develop the aggregate cost estimate among master metered tenants for each outage duration.

Table 5-2: Summary Calculation of the Estimated Total Number of Master Metered Tenants in the Target Population

Variable / Estimate	SMB	LB	Overall
Estimated Number of Master Metered Tenants per Listed Customer	0.62	23.2	1.07
Total Number of Listed Customers	2,240	45	2,285
Estimated Total Number of Master Metered Tenants	**1,399**	**1,045**	**2,444**

Table 5-3 provides the aggregate outage cost estimates by segment and outage duration. If the entire target population lost electric power for 7 weeks, businesses would experience a total direct outage cost of over $2.9 billion. A 3-week outage would lead to an aggregate outage cost of around $1.4 billion among businesses in the target population. For outages lasting 24 hours to 4 days, master metered tenants comprise around 57% of the aggregate outage cost, listed SMB customers account for roughly 40% of the total and the remaining 2% to 3% is in the listed LB segment. For a 3-week to 7-week outage, listed SMB customers account for the majority of the aggregate cost (around 52%), master metered tenants comprise over 43% of the total and the remaining 4% to 4.5% is in the listed LB segment.

Table 5-3: Aggregate Outage Cost Estimates by Segment and Outage Duration ($ Millions)

Outage Duration	Listed Customers		Master Metered Tenants	Total
	SMB	LB		
24 hours	$51.0	$3.6	$71.1	**$125.7**
4 days	$163.6	$9.5	$234.3	**$407.4**
3 weeks	$741.3	$63.4	$612.3	**$1,417.0**
7 weeks	$1,508.8	$127.1	$1,286.7	**$2,922.6**

5.2 Lost Businesses and Employment

Another important impact of a long duration outage that the survey measured was the likely magnitude of lost business and employment as a result of a long duration outage. At the end of the 3-week and 7-week outage scenarios, the survey instrument included an additional question, "How likely is it that this outage would cause you to go out of business?" Table 5-3 provides the results to this question by outage duration and segment. Among listed SMB customers and master metered tenants, the average reported likelihood of going out of business as a result of the outage ranged from around 20% to slightly over 28%. More than one out of 10 customers in these two segments report that they have a 70% or greater likelihood of going out of business as a result of an outage lasting 3 to 7 weeks. In contrast, the average reported likelihood among listed LB customers is 1.5% for a 3-week outage and 4.1% for a 7-week outage. Only one listed LB respondent indicated that they had a greater than 10% likelihood of going out of business. As such, smaller businesses (listed SMB customers and master metered tenant) would be disproportionately impacted by a long duration outage.

Table 5-3: Reported Likelihood of Going Out of Business as a Result of 3-week and 7-week Outages

Segment	Outage Duration	Number of Obs.	Average Reported Likelihood	Distribution of Responses				
				0%	10% to 30%	40% to 60%	70% to 90%	100%
Listed SMB Customers	3 weeks	150	23.1%	44%	31%	14%	7%	4%
	7 weeks	150	28.2%	39%	28%	18%	8%	8%
Listed LB Customers	3 weeks	19	1.5%	89%	11%	0%	0%	0%
	7 weeks	19	4.1%	80%	16%	0%	3%	0%
Master Metered Tenants	3 weeks	55	19.6%	49%	33%	5%	7%	5%
	7 weeks	55	20.7%	51%	27%	9%	7%	5%

Survey respondents were also asked to report the percentage of employees by labor category that they would forego paying during the 4-day, 3-week and 7-week power outages. As shown in Table 5-4, contract/temporary employees would be most impacted by a long duration outage. For an outage lasting 3 to 7 weeks, businesses in each segment would forgo paying around 35% or more of their contract/temporary employees on average. Part-time employees working for listed SMB businesses would be similarly impacted by a long duration outage, with those businesses reporting that over 40% of part-time employees would not receive pay throughout a 7-week outage. Among full-time employees, lost pay is relatively low, but it would still be substantial. For a 7-week outage, listed SMB customers would forgo paying an average of 27% of their full-time employees, which would be a substantial loss of income to the region. This lost income would not only result less commercial activity by the affected employees, but reduce income tax revenues for government and increase unemployment insurance payouts.

Table 5-4: Average Reported Percentage of Unpaid Employees by Segment and Labor Category

Segment	Outage Duration	Full-time	Part-time	Contract/ Temporary
Listed SMB Customers	4 days	19.1%	35.9%	35.4%
	3 weeks	22.0%	38.4%	35.7%
	7 weeks	27.0%	40.4%	40.4%
Listed LB Customers	4 days	9.9%	10.5%	17.2%
	3 weeks	18.4%	10.5%	38.9%
	7 weeks	19.5%	10.5%	38.9%
Master Metered Tenants	4 days	9.2%	15.5%	34.5%
	3 weeks	14.8%	21.8%	35.9%
	7 weeks	16.4%	22.2%	36.8%

5.3 Direct Outage Costs for Residential Customers

Although the Embarcadero area is primarily a business district, it is important to remember that many people live there as well. In fact, there are over 24,000 PG&E residential accounts that are served by the Embarcadero substation. Most of these residential customers live in high and low rise buildings that would need to be evacuated as a result of a long duration outage. In the survey, some property managers of residential buildings reported that their residents would have to be evacuated in the event of an outage because elevator, heating, cooling and ventilation systems would not be able to operate, which would lead to health and safety hazards for residents. In addition to the inconvenience of being displaced, these residential customers (or their property managers) would likely be required to bear the cost of living in a hotel, motel or short-term apartment (at considerable distance from the city) for the duration of the outage. Residential customers that do not live in high rise buildings may not be required to evacuate, but they would still experience substantial inconvenience costs as a result of a long duration outage.

Considering that we did not survey residential customers, it is difficult to determine what percentage would be required to evacuate and the extent of the inconvenience costs they would experience. As discussed in Section 2.1, direct costs of outages are primarily attributed to commercial and industrial customers. If we assume a worst case scenario in which living and accommodation costs $200 per day and 90% of the 24,000 residential accounts must evacuate, the cost as a result of displaced residents would be $17.3 million for a 4-day outage, $90.7 million for a 3-week outage and $212 million for a 7-week outage. Considering that these direct costs for residential customers would result in a proportionately small increase in the quantifiable total cost even in the worst case scenario, these costs have been omitted from the total cost estimate. Nonetheless, the inconvenience and economic impact that these residential customers would experience should not be ignored. The resulting costs could be quite significant for individuals or families, and all would suffer significant inconvenience.

6 Indirect Outage Cost Estimates

As a result of lost revenue and increased costs to businesses in the target population, there would be significant indirect spillover effects in the greater California economy as a result of a long duration outage. These indirect costs to commercial and industrial customers represent the chain reaction of economic losses stemming from direct costs: interactions between businesses (e.g., changes in quantities of inputs bought or outputs sold, changes in relative prices) and interactions between consumers and businesses (e.g., lost wages and reduced spending). Indirect costs are thus incurred not only by people and firms subject to an outage, but also to people and firms outside of the affected area. For example, when a business forgoes paying an employee in downtown San Francisco, that employee will reduce household consumption and investment, which will adversely affect businesses in the greater Bay Area and California as a whole. The same logic applies to affected businesses, which will also reduce consumption and investments that benefit other businesses, including neighboring businesses in the target population. Additionally, outage costs associated with public expenditures (e.g., assistance programs, emergency services, loss of taxes), public goods (e.g., water treatment), and injury or loss of life can be considered a part of indirect costs. Considering the complexity of indirect cost estimation, these costs were not measured through the survey. We instead use a range of multipliers that is informed by the hazard loss estimation literature.

As discussed in Section 2, a reasonable multiplier that can be used in this study to estimate indirect costs for California businesses is between one half and two. Using these multipliers, Table 5-3 provides the aggregate indirect outage cost estimates by outage duration. The estimated indirect outage costs range from $62.9 million to $251.4 million for a 24-hour outage to between nearly $1.5 billion and over $5.8 billion for a 7-week outage.

Table 5-3: Aggregate Indirect Outage Cost Estimates by Outage Duration ($ Millions)

Outage Duration	Total Direct Outage Cost	Range of Total Indirect Outage Costs	
		Low (Direct Cost x 0.5)	High (Direct Cost x 2.0)
24 hours	$125.7	$62.9	$251.4
4 days	$407.4	$203.7	$814.8
3 weeks	$1,417.0	$708.5	$2,833.9
7 weeks	$2,922.6	$1,461.3	$5,845.2

6.1 Potential Social Disruption

As discussed in Section 2, a long duration outage in downtown San Francisco would cause social disruption and resulting costs from, among other things, government response to security and traffic control needs, private security, potential looting or vandalism, and disruption of transportation (BART, Muni, TransBay Terminal and Cruise Terminal). Additionally, as noted in Corwin and Miles (1978), there are many other non-quantified costs associated with social impacts, such as the cancellation of planned activities, changes in normal work and leisure routines, and the inconvenience of everyday life functions. As a result, the indirect cost estimate is likely to be toward the higher end of the range of estimates that is provided in this study.

Appendix A Survey Instrument

PG&E San Francisco Business Outage Study

Dear PG&E Customer,

Thank you for agreeing to participate in this important study. Please be assured that all your answers will be kept confidential. Your name and address will not be associated with the answers you provide.

When answering the questions, please think **only about your business location at the address below.** If your business shares a building with other businesses, please answer the questions **only about the space your business occupies at:**

1234 Main Street
City, CA 12345

If you have technical questions about the survey, please call FSC Group at 415.948.2307.

Click the "right arrow" to continue.

Remember that your responses only apply to your business at 1234 Main Street.

Some background information about your business will help us understand how power outages affect your type of business.

Please describe your core business in a few words.

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Which of the following categories best describes your core business?

- Assembly/Light Industry/Heavy Equipment
- Restaurant/Food Service
- Lodging (hotel, health care facility, dormitory, etc.)
- Information Technology/Other High Tech
- Office (legal, finance, consulting, etc.)
- Retail
- Transportation
- Real Estate/Property Management
- Entertainment/Museum/Sports/Tour operations
- Other (please specify):

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Is your business part of a larger parent company?

- ○ Yes
- ○ No

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

What is your business' approximate total annual revenue at this location? $ [ ] per year

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

How many of each type of employee is currently employed by your business **at this location?**

Type of Employee	How many total?
Full-time, year-round - with ANNUAL SALARY	
Full-time, year-round - with HOURLY WAGE	
Part-time, year-round	
Contractor/project-based/temporary	

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

What is your business' approximate <u>total</u> annual payroll **<u>at this location</u>**?
$ [ ] per year

How many square feet does your business occupy **<u>at this location</u>**? [ ] square feet

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Approximately what percentage of your business' annual operating budget is spent on electricity? %

Do not pay directly for electricity (i.e., included in lease)

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

The next section describes a hypothetical power outage. We would like to know the **costs to your business** of adjusting to this power outage.

For many businesses, the costs of a power outage depend upon the particular situation, and **may vary** from day to day depending upon business conditions. You will be given the opportunity to report the **range of outage costs** that your business might face (from low to high), as well as to estimate **the cost that you would be most likely to have** under typical circumstances.

It is important to try to answer all of the questions. If a question is difficult for you to answer, **please give us an estimate** and feel free to **enter any comments about your answers** at the end of the survey.

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 1

On a hot summer weekday, a complete power outage occurs at 10:00 AM without any warning, affecting your business. At first, you do not know how long it will last. After a few hours, PG&E announces that the outage will last 24 hours. At 10:00 AM the next morning, your business' electricity is fully restored.

The next several questions will be about this case.

Case 1 Summary

Conditions:	Hot summer weekday
Start time:	10:00 AM
Duration:	24 hours
End time:	10:00 AM the next morning

How disruptive would this power outage be to your business?

Not disruptive at all 1	2	3	4	5	6	Very disruptive 7
○	○	○	○	○	○	○

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 1 Summary

Conditions:	Hot summer weekday
Start time:	10:00 AM
Duration:	24 hours
End time:	10:00 AM the next morning

How many hours would your operations stop or slow down? (include both time during and time after the power outage)

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 1 Summary

Conditions:	Hot summer weekday
Start time:	10:00 AM
Duration:	24 hours
End time:	10:00 AM the next morning

The following questions will ask you about loss of revenues from this interruption—that is, the loss of sales or other income to your business.

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 1 Summary

Conditions:	Hot summer weekday
Start time:	10:00 AM
Duration:	24 hours
End time:	10:00 AM the next morning

Considering all of the actions you might take to respond to this 24-hour power outage, please estimate the total loss of revenue that your business would most likely experience. Please enter zero if there is no lost revenue.

Scenario	Est. Revenue Loss
Most Likely Total Revenue Loss	$

In addition, please provide your lowest and highest total loss of revenue estimates for this hypothetical outage.

Lowest Total Revenue Loss	$
Highest Total Revenue Loss	$

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 1 Summary

Conditions:	Hot summer weekday
Start time:	10:00 AM
Duration:	24 hours
End time:	10:00 AM the next morning

What percent of this revenue loss typically would be made up after the power outage?

0% 10% 20% 30% 40% 50% 60% 70% 80% 90% 100%

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 1 Summary

Conditions:	Hot summer weekday
Start time:	10:00 AM
Duration:	24 hours
End time:	10:00 AM the next morning

The next questions will ask you about out-of-pocket costs from this outage — that is, the expenditures this outage would cause your business to incur beyond normal operations.

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 1 Summary

Conditions:	Hot summer weekday
Start time:	10:00 AM
Duration:	24 hours
End time:	10:00 AM the next morning

Which of the following out-of-pocket costs would your business experience as a result of this outage?

Select all that apply.

- ☐ Salaries and wages to staff unable to work
- ☐ Extra shifts/overtime pay to make up for lost work
- ☐ Damage to equipment
- ☐ Damage/spoilage to materials
- ☐ Extra costs to restart business after outage
- ☐ Costs to run backup generation
- ☐ Telecommuting costs
- ☐ Other out-of-pocket costs

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 1 Summary

Conditions:	Hot summer weekday
Start time:	10:00 AM
Duration:	24 hours
End time:	10:00 AM the next morning

Please estimate the most likely cost of these out-of-pocket expenses.

	Estimated Cost
Salaries and wages to staff unable to work	$
Extra shifts/overtime pay to make up for lost work	$
Damage to equipment	$
Damage/spoilage to materials	$
Extra costs to restart business after outage	$
Costs to run backup generation	$
Telecommuting costs	$
Other out-of-pocket costs	$
Most Likely Total Out-of-Pocket Cost:	$ 0

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

RESPONDING TO LONG DURATION OUTAGES

Under extremely rare circumstances, it is possible for an outage to last multiple days or weeks. Although it is unlikely that your business has experienced such a long duration outage, we would like to know about various aspects of your business that would affect your company's response to an outage that lasts multiple days or weeks.

Please remember, all of your answers are *confidential*. Your name and address will be kept anonymous and will not be associated with the information you provide.

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Has your business ever experienced an outage lasting several days, such as during the 1989 Loma Prieta Earthquake?

- Yes
- No

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

What year?

For how many days?

What did your business do during that time to handle the interruption of power?

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Do you have onsite back-up electrical generation?

- ◯ Yes
- ◯ No

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

What extent of your operations would it support?

- Full/nearly full operations
- Partial operations
- Minimal operations

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Do you have offsite servers or use "cloud" systems for your servers?

- Yes
- No

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

What percent of your employees are currently able to work remotely? [ ] %

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

During an outage that lasts multiple days or weeks, could you physically relocate your equipment or infrastructure to ensure continuity of your business operations?

- Yes
- No

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

If YES to previous question:

How long would it take to do so? [ ] days

How much would it cost to do so? $ [ ]

If NO to previous question:

Why not?

[ ]

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Do you have other offices or facilities similar to this location outside of the downtown San Francisco area or in other nearby cities?

- Yes
- No

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Where are they?

If your current location were suddenly inoperable, what percent of employees could relocate to your other locations?

%

What expenses could you foresee in relocating operations temporarily, i.e. more than one day?

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

What percent of your revenue is generated from sales to customers that physically enter your premises, i.e. walk-up customers?

[   ] %

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

If business is RETAIL, RESTAURANT/FOOD SERVICE, or LODGING:

What percent of your annual sales comes from tourist visitors? [ ] %

If business is ENTERTAINMENT, MUSEUM, SPORTS, or TOUR OPERATOR:

If a power outage forces you to cancel or postpone an event or daily admissions, what is the average number of patrons that would have attended? [ ] patrons

If business is REAL ESTATE/PROPERTY MANAGEMENT:

If a power outage occurs, would lack of elevator services and/or HVAC systems require tenants to vacate the premises until restoration of power?

- Yes
- No

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

The next section describes hypothetical power outages that last multiple days or weeks. These long duration outages are extremely unlikely, and it may be difficult to estimate the costs that your business would experience under these conditions. Please make your best effort to think through how your business would respond.

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 2

On a Monday, a complete power outage occurs at 10:00 AM without any warning, affecting your business. At first, you do not know how long it will last. After a few hours, PG&E announces that the outage will last several days. The power is finally restored 4 days following the initial blackout.

Case 2 Summary:
Outage Duration: 4 days

Which of the following best describes your business' ability to adapt to an outage of this duration?

- ◯ The business would experience a full interruption of work during most or all of the outage.
- ◯ The business would resume partial operations, with little or no revenue-generating activity during the outage.
- ◯ The business would resume partial operations, with partial revenue-generating activity during the outage.
- ◯ The business would maintain almost full or full operations during the outage.

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 2 Summary
Outage Duration: 4 days

During this interruption, would you continue to pay ...

Full-time employees?

○ Yes, all ○ Yes, some (what %?) [ ] ○ No ○ Not applicable

Part-time employees?

○ Yes, all ○ Yes, some (what %?) [ ] ○ No ○ Not applicable

Contractors/project-based/temporary employees?

○ Yes, all ○ Yes, some (what %?) [ ] ○ No ○ Not applicable

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 2 Summary
Outage Duration: 4 days

Considering all of the actions you might take to respond to this 4-day power outage, please estimate the total loss of revenue that your business would most likely experience. Please enter zero if there is no lost revenue.

For your reference, we have included the loss of revenue you reported for the 24-hr outage case.

Scenario	Est. revenue loss for 4-day outage in dollars	For the 24-hour (case 1) loss of revenue, you responded:
Most Likely Total Revenue Loss $		$ 234

In addition, please provide your lowest and highest total loss of revenue estimates for this hypothetical outage.

Lowest Total Revenue Loss $		$ 234
Highest Total Revenue Loss $		$ 234

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 2 Summary
Outage Duration: 4 days

What percent of this revenue loss typically would be made up after the power outage?

0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
○	○	○	○	○	○	○	○	○	○	○

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 2 Summary
Outage Duration: 4 days

Which of the following out-of-pocket costs would your business experience as a result of this outage?

(Your business's out-of-pocket costs from the 24-hour outage case have been pre-selected here for you.)

Select all that apply.

- [x] Salaries and wages to staff unable to work
- [x] Extra shifts/overtime pay to make up for lost work
- [x] Damage to equipment
- [x] Damage/spoilage to materials
- [x] Extra costs to restart business after outage
- [x] Costs to run backup generation
- [x] Telecommuting costs
- [x] Other out-of-pocket costs

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 2 Summary
Outage Duration: 4 days

Please estimate the most likely cost of these out-of-pocket expenses.

	Estimated Cost	For the 24-hour case, you responded:
Salaries and wages to staff unable to work	$	$ 234
Extra shifts/overtime pay to make up for lost work	$	$ 234
Damage to equipment	$	$ 234
Damage/spoilage to materials	$	$ 234
Extra costs to restart business after outage	$	$ 234
Costs to run backup generation	$	$ 234
Telecommuting costs	$	$ 234
Other out-of-pocket costs	$	$ 234
Most Likely Total Out-of-Pocket Cost:	$ 0	

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 2 Summary
Outage Duration: 4 days

Do you have business interruption insurance?

- ◯ Yes
- ◯ No

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 2 Summary
Outage Duration: 4 days

What percent of your costs and loss of revenues would you expect your business interruption insurance to cover? ______ %

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 3

On a Monday, a complete power outage occurs at 10:00 AM without any warning, as a result of a natural disaster such as an earthquake. Your business and employees do not experience any damages from the natural disaster, but the power outage persists and you do not know how long it will last. After a few hours, PG&E announces that the outage will last several weeks. One week passes, then another. The power is finally restored 3 weeks following the initial blackout.

Case 3 Summary
Outage Duration: 3 weeks

Which of the following best describes your business' ability to adapt to an outage of this duration?

- ○ The business would experience a full interruption of work during most or all of the outage.
- ○ The business would resume partial operations, with little or no revenue-generating activity during the outage.
- ○ The business would resume partial operations, with partial revenue-generating activity during the outage.
- ○ The business would maintain almost full or full operations during the outage.

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 3 Summary
Outage Duration: 3 weeks

Would this duration of outage prompt your business to undertake a permanent relocation—i.e. without intent to return to your current location?

- Yes
- No

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 3 Summary
Outage Duration: 3 weeks

Would this duration of outage prompt your business to undertake a temporary relocation—i.e. with intent to return to your current location?

- Yes
- No

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 3 Summary
Outage Duration: 3 weeks

Where would you likely temporarily relocate to?

Estimate the total expenses of temporary relocation:

$

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 3 Summary
Outage Duration: 3 weeks

During this interruption, would you continue to pay ...

Full-time employees?

- Yes, all
- Yes, some (what %?) [ ]
- No
- Not applicable

Part-time employees?

- Yes, all
- Yes, some (what %?) [ ]
- No
- Not applicable

Contractors/project-based/temporary employees?

- Yes, all
- Yes, some (what %?) [ ]
- No
- Not applicable

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 3 Summary
Outage Duration: 3 weeks

Considering all of the actions you might take to respond to this 3-week power outage, please estimate the total loss of revenue that your business would most likely experience. Please enter zero if there is no lost revenue.

For your reference, we have included the loss of revenue you reported for the 4-day outage case.

Scenario	Est. revenue loss for 3-week outage in dollars	For the 4-day (case 2) loss of revenue, you responded:
Most Likely Total Revenue Loss $		$ 500

In addition, please provide your lowest and highest total loss of revenue estimates for this hypothetical outage.

Lowest Total Revenue Loss $		$ 500
Highest Total Revenue Loss $		$ 500

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 3 Summary
Outage Duration: 3 weeks

What percent of this revenue loss typically would be made up **within a year** after the power outage?

0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
○	○	○	○	○	○	○	○	○	○	○

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 3 Summary
Outage Duration: 3 weeks

Which of the following out-of-pocket costs would your business experience as a result of this outage?

(Your business's out-of-pocket costs from the 4-day outage case have been pre-selected here for you.)

Select all that apply.

- [x] Salaries and wages to staff unable to work
- [x] Extra shifts/overtime pay to make up for lost work
- [x] Damage to equipment
- [x] Damage/spoilage to materials
- [x] Extra costs to restart business after outage
- [x] Costs to run backup generation
- [x] Telecommuting costs
- [x] Other out-of-pocket costs

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 3 Summary
Outage Duration: 3 weeks

Please estimate the most likely cost of these out-of-pocket expenses.

The temporary/permanent relocation costs you previously listed for this outage will be included in your out-of-pocket expense estimates.

	Estimated Cost	For the 4-day case, you responded:
Temporary/permanent relocation cost	$ 23423	$ n/a
Salaries and wages to staff unable to work	$	$ 444
Extra shifts/overtime pay to make up for lost work	$	$ 444
Damage to equipment	$	$ 444
Damage/spoilage to materials	$	$ 444
Extra costs to restart business after outage	$	$ 444
Costs to run backup generation	$	$ 444
Telecommuting costs	$	$ 444
Other out-of-pocket costs	$	$ 444
Most Likely Total Out-of-Pocket Cost:	$ 23423	

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 3 Summary
Outage Duration: 3 weeks

What percent of your costs and loss of revenues would you expect your business interruption insurance to cover? ____ %

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 3 Summary
Outage Duration: 3 weeks

How likely is it that this outage would cause you to go out of business?

0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
○	○	○	○	○	○	○	○	○	○	○

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 4

On a Monday, a complete power outage occurs at 10:00 AM without any warning, as a result of a natural disaster such as an earthquake. Your business and employees do not experience any damages from the natural disaster, but the power outage persists and you do not know how long it will last. After a few hours, PG&E announces that the outage will last several weeks. One week passes, then another. The power is finally restored 7 weeks following the initial blackout.

Case 4 Summary
Outage Duration: 7 weeks

Which of the following best describes your business' ability to adapt to an outage of this duration?

- ○ The business would experience a full interruption of work during most or all of the outage.
- ○ The business would resume partial operations, with little or no revenue-generating activity during the outage.
- ○ The business would resume partial operations, with partial revenue-generating activity during the outage.
- ○ The business would maintain almost full or full operations during the outage.

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 4 Summary
Outage Duration: 7 weeks

Would this duration of outage prompt your business to undertake a permanent relocation—i.e. without intent to return to your current location?

- Yes
- No

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 4 Summary
Outage Duration: 7 weeks

Where would you likely permanently relocate to?

Estimate the total expenses of permanent relocation:

$

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 4 Summary
Outage Duration: 7 weeks

During this interruption, would you continue to pay ...

Full-time employees?

- Yes, all
- Yes, some (what %?) [ ]
- No
- Not applicable

Part-time employees?

- Yes, all
- Yes, some (what %?) [ ]
- No
- Not applicable

Contractors/project-based/temporary employees?

- Yes, all
- Yes, some (what %?) [ ]
- No
- Not applicable

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 4 Summary
Outage Duration: 7 weeks

Considering all of the actions you might take to respond to this 7-week power outage, please estimate the total loss of revenue that your business would most likely experience. Please enter zero if there is no lost revenue.

For your reference, we have included the loss of revenue you reported for the 3-week outage case.

Scenario	Est. revenue loss for 7-week outage in dollars	For the 3-week (case 3) loss of revenue, you responded:
Most Likely Total Revenue Loss $		$ 1,000

In addition, please provide your lowest and highest total loss of revenue estimates for this hypothetical outage.

Lowest Total Revenue Loss $		$ 1000
Highest Total Revenue Loss $		$ 1,000

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 4 Summary
Outage Duration: 7 weeks

What percent of this revenue loss typically would be made up **within a year** after the power outage?

0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
○	○	○	○	○	○	○	○	○	○	○

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 4 Summary
Outage Duration: 7 weeks

Which of the following out-of-pocket costs would your business experience as a result of this outage?

(Your business's out-of-pocket costs from the 3-week outage case have been pre-selected here for you.)

Select all that apply.

- [x] Salaries and wages to staff unable to work
- [x] Extra shifts/overtime pay to make up for lost work
- [x] Damage to equipment
- [x] Damage/spoilage to materials
- [x] Extra costs to restart business after outage
- [x] Costs to run backup generation
- [x] Telecommuting costs
- [x] Other out-of-pocket costs

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 4 Summary
Outage Duration: 7 weeks

Please estimate the most likely cost of these out-of-pocket expenses.

The temporary/permanent relocation costs you previously listed for this outage will be included in your out-of-pocket expense estimates.

	Estimated Cost	For the 3-week case, you responded:
Temporary/permanent relocation cost	$ 234444	$ 23423
Salaries and wages to staff unable to work	$	$ 500
Extra shifts/overtime pay to make up for lost work	$	$ 500
Damage to equipment	$	$ 500
Damage/spoilage to materials	$	$ 500
Extra costs to restart business after outage	$	$ 500
Costs to run backup generation	$	$ 500
Telecommuting costs	$	$ 500
Other out-of-pocket costs	$	$ 500
Most Likely Total Out-of-Pocket Cost:	$ 234444	

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 4 Summary
Outage Duration: 7 weeks

What percent of your costs and loss of revenues would you expect your business interruption insurance to cover? %

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Case 4 Summary
Outage Duration: 7 weeks

How likely is it that this outage would cause you to go out of business?

0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
○	○	○	○	○	○	○	○	○	○	○

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Comments

Please share any additional comments about how the outages described in this survey would affect your business at this location:

1234 Main Street
City, CA 12345

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

Thank you for your participation. The survey has been fully completed!

To receive your $75 thank-you check, please fill in the information below.

This information will be used solely for mailing you the thank-you check and will not be associated with any of your survey responses.

The incentive check can be made out to any individual or charitable organization (in the U.S.) as designated by you.

If you choose not to accept any incentive, please type "decline" in the first line.

Check payble to (name):	
Name on envelope:	
Address (line 1):	
Address (line 2):	
City:	
State:	
Zip code:	

Click the "right arrow" to continue.

0% 100%

Remember that your responses only apply to your business at 1234 Main Street .

THANK YOU FOR YOUR HELP!

You can close the browser.

Appendix B Literature Review

Calculating the losses from a long-term power outage involves estimating costs that are the immediate consequence of the outage, called *direct costs*, and costs provoked by the consequences of the outage, called *indirect costs*. In this appendix, we summarize basic conceptual and methodological aspects of estimating costs from long-duration outages. Section B.1 and Section B.2 compare the various methodologies for estimating direct and indirect costs, much of which draws from Adam Rose's 2004 article entitled, "Economic Principles, Issues, and Research Priorities in Hazard Loss Estimation," and Hallegatte and Przyluski's 2010 article entitled, "The Economics of Natural Disasters: Concepts and Methods." Then, Section B.3 reviews studies that estimate the cost of long duration power outages and Section B.4 reviews relevant studies on the estimated cost of natural disasters. Finally, this appendix concludes with Section B.5, which provides a list of referenced literature.

B.1 Estimating Direct Costs

Direct costs of outages are primarily attributed to commercial and industrial customers and consist of several components: lost output (business interruption costs), losses from damage to equipment and materials, payments to labor associated with making up lost output and costs associated with back-up generation. Additionally, direct costs are a net measure; savings to firms (for example, for unpaid wages) are subtracted from costs to arrive at a final value.

Survey methods are optimal for direct cost estimation. Methods that rely on scaling output losses from macreconomic variables (such as annual gross output), while simple to undertake, rely on fundamentally unrealistic assumptions. Similarly, methods that use estimates from prior case studies rely on conditions and assumptions that may have little bearing on the scenario and population under study. Approaches based on primary data collection, on the other hand, take into account assumptions and heterogeneity of customers. Surveys derive estimates directly from the firms—the agents in the best position to understand their firms and assess the likely costs of disruption. Surveys rely on scientific sampling techniques to ensure that answers obtained from surveys are representative of the customer population of interest, thereby enabling survey results to be scaled to the affected population. Although surveys ask respondents about hypothetical scenarios, and thus may be approximations at best, alternatives are much less accurate. Surveys of direct costs primarily focus on businesses and do not include the costs associated with government response or transportation disruption. In addition, residential direct costs may not be considered in a survey because these costs are so low relative to business direct costs that it is not cost-effective to conduct a formal survey of impacted households.

B.2 Estimating Indirect Costs

Indirect costs to commercial and industrial customers represent the chain reaction of economic losses stemming from direct costs: interactions between businesses (e.g., changes in quantities of inputs bought or outputs sold, changes in relative prices) and interactions between consumers and businesses (e.g., lost wages and reduced spending). Indirect costs are thus incurred not only by people and firms subject to an outage, but also to people and firms outside of the affected area. Additionally, outage costs associated with public expenditures (e.g., assistance programs, emergency services, loss of taxes), public goods (e.g., water treatment), injury or loss of life, and inconvenience to residents can be considered a part of indirect costs.

Measuring indirect costs is challenging for several reasons. Indirect losses cannot be readily ascertained through surveys like direct losses. Moreover, indirect effects are spatially dispersed; if a firm in San Francisco suspends operations, it may affect businesses elsewhere in the Bay Area, the United States, or the world. Also, indirect losses will vary substantially with the resiliency—the adaptive behaviors—of affected firms. As with direct costs, indirect costs should represent a net value, since some businesses stand to benefit in the case of an outage—whether by substituting adversely-affected competitors or responding to new demand. Any calculation of indirect costs, therefore, represents simply an order-of-magnitude approximation.

Because surveys may not be feasible with indirect costs, estimation of indirect costs has typically used one of several methods: input-output models, computational general equilibrium models, or macroeconometric models. In each approach, direct losses from business interruption are the negative shock input into the model. These direct losses can be estimated from surveys, but are more often derived from scaled macroeconomic indicators. Direct losses from physical damage are not included in the input to these models, since the models rely on flow measures of economic activity (e.g., output, income) rather than stock measures of asset values (e.g., replacement costs of capital).[8]

B.2.1 Input-output Models

Input-output (I/O) models are static, linear models of all purchases and sales between sectors of an economy, based on historical correlations between quantities of inputs and outputs from each sector used by every other sector. If outputs of particular sectors in particular areas experience a negative shock, such as from a power outage, the level of purchases and sales between sectors adjusts accordingly, rippling through all sectors in the economy. An I/O model therefore uses direct costs as an input, such as a net loss of revenue to firms, and calculates indirect losses relative to direct losses; the result is a multiplier that can be applied to direct loss estimates. The sum of direct costs and indirect costs is the total cost estimate. The advantage to I/O models is that they are fairly transparent and can be used relatively easily, given the simplifying assumptions involved. However, they remain allocative in the sense that they cannot represent strategic behavior—sectors simply reallocate quantities of inputs and outputs to adjust. The main disadvantages of I/O models include their inability to incorporate behavioral responses of firms, interdependencies between quantities and prices, and resource constraints.[9] As such, I/O models are better suited for short-duration disruptions.

B.2.2 Computational General Equilibrium Models

[8] In regional economic modeling, indirect costs are always caused by business interruption, not asset damage. For example, it is not the damage to a factory that matters to other businesses that supply its inputs or purchase its outputs, but rather the interruption of that factory's production. Therefore, damage to capital should generally not be used as an input to regional economic models. However, businesses must still make outlays to repair or replace damaged assets following an outage, representing a forced investment and thus a loss of welfare. The value of an asset is the discounted flow of net future returns from its operation; since the replacement cost of an asset is not likely to equal the lost output from that asset being out of service for a short duration, replacement costs may overstate the amount of output sacrificed through this forced investment. Nevertheless, it stands to reason that some amount of physical damages (perhaps amortized) could be included in the direct cost input to regional economic models. This possibility is beyond the scope of our review.

[9] Extensions and adaptation of I/O models exist to account for more realistic economy-wide interactions. However, a review of the various adjustments to and extensions of I/O models is beyond the scope of this review.

Computational general equilibrium (CGE) models are multi-market simulations that optimize behavior between consumers and firms in response to price signals, subject to economic account balances and resource constraints. If outputs of particular firms in particular areas experience a negative shock, such as from a power outage, prices adjust and stimulate behavioral responses in an iterative fashion until equilibrium is restored; indirect losses are calculated by the difference in overall output after the shock. By incorporating production and consumption functions and price and import elasticities, CGE models are fundamentally *adaptive*; they incorporate behavioral responses of firms, input substitution, increasing or decreasing-returns-to-scale, non-infinite supply elasticities and other assumptions. The main disadvantages of CGE models include their assumption that economies return to equilibrium, that all agents optimize under full information and that substitution occurs instantaneously. In addition, without incorporating the costs associated with these adaptive behaviors (i.e., the fuel cost of using a backup generator), the net cost reduction is not properly estimated. As such, CGE models are likely to represent an underestimate or lower-bound of indirect losses from a long-duration outage.

Note that CGE models do not yield an indirect cost multiplier like I/O models since they model non-linear relationships. Whereas indirect effects are a constant multiple of direct effects in an I/O model, indirect effects vary non-linearly with direct effects in a CGE model. Therefore, the effective indirect cost multiplier in a CGE model will depend on the actual value of direct costs.

B.2.3 Macroeconometric Models

Macroeconometric models are a set of statistically estimated simultaneous equations that represent the aggregate workings of an economy, with parameters based on (long) time series data. Indirect costs are predicted by running the simultaneous equations with and without an adjustment for direct costs in a future time period. The main advantage of macroeconometric models is that they can effectively separate out changes in an economy due to a negative shock from other secular changes in an economy. However, their main disadvantages are that the historical experience upon which these models are based is unlikely to be representative of future activity, particularly following a major disruption, and that data are often not available at sub-regional levels.

B.2.4 Further Considerations

Exogenous policy responses, such as government assistance and security programs, cannot be captured by these models. A long-duration outage, insofar as it resembles a major disruption of urban activity, is likely to include some amount of public expenditure as determined on an ad hoc, emergency basis. Also, non-market costs, such as inconvenience, injury or death, and pollution, often remain unaccounted for since they cannot easily be measured.

Finally, a difficulty in power outage cost assessment lies in the definition of the baseline scenario. This baseline may not be easy to define. Moreover, in cases where recovery does not lead to a return to the baseline scenario, there are permanent effects that are difficult to compare with a baseline scenario. For instance, a long-duration outage can lead to a permanent extinction of vulnerable economic activities in a region, whether because these activities are already threatened and cannot recover or because they can relocate. In that case, the disaster is not a temporary event, but a permanent negative shock for a region and it is more difficult to define the disaster cost. Also, recovery may increase productivity in the event that capital stock is replaced; this can lead to a final situation considered more desirable than the baseline scenario.

B.3 Studies of Long Duration Power Outages

FSC reviewed the literature on costs associated with major power outages.[10] We primarily focused on studies that estimated overall economic losses from outages in urban areas lasting a half day or longer. Furthermore, only studies of outages in the United States were examined. Most of the studies deal with actual outages; however, this literature review includes studies of hypothetical outages lasting longer than two weeks. In addition to information on the outage that each study examines and the method employed in each study, FSC has included an inflation-adjusted estimate of the economic losses overall and per capita in each study.

Estimates of outage costs vary substantially. Variation is due, in part, to the timing and duration of a given outage and the economic output of the affected area. Also, some studies attempt to estimate the costs from outages that occur in the course of natural disasters, whereas others focus on system disturbances alone. Ultimately, though, different methods of cost estimation reach significantly different results. The studies included in Table B-1 employ a variety of methods, ranging from back-of-the-envelope style estimates to surveys to regional economic modeling, often in combination. Moreover, the studies vary in the extent to which they capture direct, indirect or induced losses.

The ratio between direct and indirect costs (commonly known as the multiplier) ranges substantially. Early studies suggested indirect costs from power outages were substantial, perhaps more than five times direct costs. More recent studies have suggested indirect costs to be much lower, with some suggesting indirect costs as small as one quarter of direct costs, but these studies rely on theoretical models that have not been validated through primary data collection (i.e., a survey). For the purposes of understanding a long-duration outage in downtown San Francisco, it is reasonable to expect an indirect cost estimate between one-half and two times direct costs. However, for an important economic hub and urban area like downtown San Francisco, which has not been considered in prior studies, the indirect costs could be more than two times direct costs.

10 There are two major bodies of literature on outage costs that we chose to exclude from the present review. First, there is a substantial literature on the cost of unserved kWh (alternately called the value of lost load); these studies measure customers' valuation of power disruptions for the purposes of reliability planning for short-duration outages. Second, there is a literature on the annual cost of all power system disturbances; these studies estimate macroeconomic costs for the purposes of reliability planning and high-level policymaking.

Table B-1: Summary of Studies on Long Duration Power Outages

Study	Population Studied	Region Affected	Outage Duration	Outage Date	Hypothetical / Actual	Method	Population Affected	Total Cost Estimate (2011 $)*	Cost per Capita (2011 $)*		Notes
									Total	Per Day	
Corwin and Miles 1978	Non-residential	New York City	Up to 25 hours	Thursday, January 13, 1977	Actual	Reports from businesses and agencies	9 million	$1.3 billion	$144	$144	Much of cost from looting and arson, not representative of most outages
Rose and Lim 2002	Non-residential	Los Angeles (LADWP territory)	Up to 36 hours	Monday, January 17, 1994	Actual	I/O model with ex post resiliency adjustments	3.5 million	$8 - 158 million	$2 - 45	$1 - 30	Resiliency adjustments: electricity importance (-16%), production rescheduling (-84%) (may not be possible for a long duration outage), and time of day of usage (-94%); method is biased underestimate; population number from LADWP
Gordon et al 1998	Non-residential and commuters	Los Angeles County	Up to 36 hours	Monday, January 17, 1994	Actual	Survey and I/O model	9.1 million	$4.4 billion	$484	$323	Impacts: 51% impact zone, 20% rest of LA county, 29% region and world; population affected is LA County, so total impacts ($6.5 billion) have been scaled to it; additionally, 63% of cost is attributed to loss of utilities, so estimate is further scaled; method is biased overestimate; population number from Census
AUS Consultants 2001	Private sector	California	20 effective hours	June to September 2001	Hypothetical	Survey, macroeconomic measures, and I/O model	34.6 million	$31.2 billion	$900	$69	Rolling blackouts, so 20 hours is in 60-90 minute blocks over several months; method is biased overestimate; population number from Census

Study	Population Studied	Region Affected	Outage Duration	Outage Date	Hypothetical / Actual	Method	Population Affected	Total Cost Estimate (2011 $)*	Cost per Capita (2011 $)*		Notes
									Total	Per Day	
Rose et al 2005	Non-residential	Los Angeles County	4x 1 hour	March 19-20 and May 7-8, 2001	Actual	PE and CGE model with ex post resiliency adjustments	9.6 million	$0.6 – 40.7 million	$0.06 - 4	$0.02 - 1	Short rolling blackouts with advance notice;* lost sales is the primary figure; range of estimates reflects no resilience versus full resilience options; CGE modeling of regional impact has ambiguities, difficult to know actual impact; population number from Census
Anderson Consulting 2003	Non-residential	Northeastern U.S.	Between 16 and 72 hours	Thursday, August 14, 2003	Actual	Macroeconomic measures and indirect effects multiplier	45 million	$5.5 - 10.1 billion	$122 - 224	$61 - 112	Population number from Wikipedia
ICF 2003	Non-residential	Northeastern U.S.	Between 16 and 72 hours	Thursday, August 14, 2003	Actual	Unserved kWh cost from prior studies	45 million	$8.3 - 12.6 billion	$184 - 280	$92 - 140	Population number from Wikipedia
Brattle Group 2003	Non-residential	Northeastern U.S.	Between 16 and 72 hours	Thursday, August 14, 2003	Actual	Unserved kWh cost from prior studies	45 million	$7.3 billion	$162	$81	Estimate is considered a lower bound; population number from Wikipedia
Ohio Manufacturers' Association (ref in ELCON 2004)	Manufacturing sector	Ohio	Between 16 and 72 hours	Thursday, August 14, 2003	Actual	Survey	11.4 million	$1.3 billion	$114	$57	Limited to impact on Ohio; Represents double the Anderson estimate for the state; population number from Census
Anderson et al 2007	General	Northeastern U.S.	Between 16 and 72 hours	Thursday, August 14, 2003	Actual	I/O model with inoperability	45 million	$8 billion	$178	$89	Population number from Wikipedia
National University System 2011	General	San Diego	Up to 13 hours	Thursday, September 08, 2011	Actual	Extrapolation from prior outages	2 million	$97 - 118 million	$49 - 59	$49 - 59	Estimation is considered a lower bound
Moore II et al 2005	General	Los Angeles & Orange Counties	One month	Summer mid-2000s	Hypothetical	Spatial I/O model	11.8 million	$14.4 billion	$1,220	$41	Relies on data from 1990s; population data from Census
Rose et al 2007	General	Los Angeles County	2 weeks	Summer mid-2000s	Hypothetical	CGE model with ex post resiliency adjustments	9.8 million	$3 - 14.2 billion	$306 - 1449	$22 - 104	Resiliency primarily from production rescheduling; population data from Census

* Values adjusted to 2011 dollars using CPI-U.

B.3.1 1977 New York City Outage

In July 1977, New York City experienced a 25-hour blackout that affected 9 million people and resulted in widespread criminal activity. Corwin and Miles' 1978 study of the blackout continues to be widely cited in the literature on the costs of major power outages. They constructed a summary of economic impacts by bringing together separate and independent reports of costs from businesses and business associations, governments, public service agencies, non-profit service organizations, insurers, and health institutions. Table B-2 presents the tabulation of these reports in nominal dollars. While Corwin and Miles disclaimed that their list was not comprehensive, the summation of reports resulted in an estimated outage cost of $345 million in nominal dollars. Additionally, Corwin and Miles discussed non-quantified costs associated with social impacts, such as the cancellation of planned activities, the alteration of traffic flows and the inconvenience of everyday life functions.

Table B-2: Corwin and Miles (1978) Tabulation of Costs for the 1977 NYC Blackout

Impacted Entities	Direct Costs (1977 $M)		Indirect Costs (1977 $M)	
Business	Food Spoilage	$1.0	Small Businesses	$155.4
	Wages Lost	$5.0	Emergency Aid (private)	$5.0
	Securities Industry	$15.0		
	Banking Industry	$13.0		
Government			Federal Assistance Programs	$11.5
			NY State Assistance Program	$1.0
Electric Utility	Restoration Costs	$10.0	New Capital Equipment	$65.0
	Overtime Payments	$2.0		
Insurance			Federal Crime Insurance	$3.5
			Fire Insurance	$19.5
			Private Property Insurance	$10.5
Public Health			Hospitals–overtime & emergency room	$1.5
Public Services	Transportation Authority Revenue Losses	$2.6	Vandalism	$0.2
	Overtime and Unearned Wages	$6.5	New Capital Equipment	$11.0
			Red Cross	$0.0
			Fire Department overtime	$0.5
			Police Department overtime	$4.4
			State Courts overtime	$0.1
			Prosecution and Correction	$1.1
Westchester County	Food Spoilage	$0.3		
	Public services overtime and damage	$0.2		
Total	**All Direct**	**$55.5**	**All Indirect**	**$290.2**

Corwin and Miles' primary methodological contribution was to study both impacts directly caused by an outage (e.g., business losses, lost wages) and costs incurred indirectly as a response to an outage (e.g., emergency services, assistance programs). Applying this method to downtown San Francisco would require, for example, interviewing government agencies and public service providers (e.g., SFMTA, SFPD) on the costs they would expect to incur from a long-duration outage. These entities may already have cost estimates associated with disaster planning.

B.3.2 1994 Northridge Earthquake Outage

On January 17, 1994, a magnitude 6.7 earthquake struck 20 miles northwest of downtown Los Angeles, causing a power outage in the LA Department of Water and Power service territory that was gradually restored over the course of 36 hours. Gordon et al. (1998) surveyed large businesses in the impact zone of the earthquake to solicit estimates of business interruption costs and understand what proportion experienced business interruption losses due to power outage. The estimates derived from the survey were then used as inputs into the Southern California Planning Model, an input-output regional economic model that adjusts the inputs and outputs of all sectors in response to a shock. In the paper, Gordon et al. elucidate the cost due to transportation problems by scaling the results of the I/O model according to the proportion of businesses reporting losses due to transportation problems. While the authors do not explicitly do this calculation in their own paper, we scaled the I/O model results similarly by the proportion of businesses reporting losses due to disruption of utility services (63%). The results are presented in Table B-3. In this approach, only 51% of losses are attributed to businesses within the impact zone; moreover, 29% of losses are attributed to businesses outside of LA County.

Table B-3: Gordon et al. (1998) Estimate of 1994 Losses Due to Outage

Area	Direct Losses (1994 $B)	Indirect and Induced Losses (1994 $B)	Total Losses (1994 $B)
Impact zone total	$1.97	$0.13	$2.10
Rest of Los Angeles City		$0.15	$0.15
Rest of Los Angeles County		$0.67	$0.67
Rest of region		$0.55	$0.55
Rest of world	$0.65		$0.65
Total	$2.62	$1.51	$4.12

Rose and Lim (2002) take a related approach to the outage following the Northridge earthquake. Like Gordon et al., Rose and Lim also use an I/O model, the Input–Output (I-O) Transactions Table for Los Angeles County, CA, to compute business losses in all sectors resulting from the outage. To compute the shock, Rose and Lim scaled annual gross output for each sector down to a single day and computed losses by the fraction of a day that a given sector's businesses had no power; this results in estimated losses of $88 million nominal dollars, which is substantially lower than the survey-based measurement of direct costs in Gordon et al. Rose and Lim then applied three adjustments cumulatively according to models of sector resiliency: adjustment according to the importance of electricity to operations, adjustment by production rescheduling and adjustment according to typical time of electricity use by each sector. The results of the initial I/O model results and adjustments are presented in Table B-4.

Table B-4: Rose and Lim (2002) Estimate of 1994 Losses Due to Outage

Sector	Base case	Electricity importance adjustment		Production shifting adjustment		Time of use adjustment	
	Output reduction (1994 $M)	Importance (%)	Output reduction (1994 $M)	Rate (%)	Output reduction (1994 $M)	Night/Day /Evening (%)	Output reduction (1994 $M)
Agriculture	0.4	50	0.2	75	0.1	20/60/20	0.0
Mining	0.7	90	0.6	99	n	30/40/30	0.0
Construction	5.6	40	2.2	95	0.1	10/80/10	0.0
Food processing	2.0	90	1.8	95	0.1	30/40/30	0.0
Nondurable manufacturing	5.6	98	5.5	95	0.3	30/40/30	0.1
Durable manufacturing	12.0	100	12.0	99	0.1	25/50/25	0.0
Petroleum refining	1.2	100	1.2	99	0.0	30/40/30	0.0
Transportation	2.4	30	0.7	30	0.5	25/50/25	0.2
Communication	1.9	90	1.7	40	1.0	25/50/25	0.3
Private Electric Utilities	0.0	80	0.0	75	0.0	30/40/30	0.0
Gas Utilities	1.7	80	1.4	75	0.4	30/40/30	0.1
Water Utilities	0.7	80	0.5	90	0.0	30/40/30	0.0
Wholesale Trade	4.0	90	3.6	99	0.0	30/80/30	0.0
Retail Trade	6.2	90	5.6	80	1.1	30/80/30	0.4
F.I.R.E.	15.5	90	14.0	90	1.4	5/90/5	0.5
Personal services	1.1	86	1.0	60	0.4	10/80/10	0.1
Business services	13.0	90	11.0	70	3.5	10/80/10	1.2
Entertainment	4.1	80	3.3	30	2.3	10/50/40	0.6
Health & social services	4.2	80	3.3	50	1.7	25/50/25	0.6
Education	0.9	80	0.7	99	0.0	5/80/15	0.0
Government	3.3	60	2.0	80	0.4	10/80/10	0.1
State/Local Electric utilities	1.4	80	1.2	75	0.3	30/40/30	0.1
Total	88.0		74.3		13.7		4.5

The adjustments that Rose and Lim identify deserve further attention. *Electricity importance* was defined as the percentage reduction in output caused by a 1% reduction in the availability of a utility lifeline service—effectively a measure of the relative importance of electricity to a sector's operation; using this adjustment reduces total losses by 16%. *Production rescheduling* rate refers to the ability of a sector to make up its production or sales at a later date; using this adjustment reduces total losses by an additional 69%. *Time of use adjustment* refers to the varying needs for electricity by a sector over a 24-hour period; using this adjustment reduces total losses further by an additional 10%. Thus, resiliency adjustments cumulatively reduce economic losses by 95%.

The contribution of both of these papers is to use input-output models to account for the linkages between sectors and pass the effects of a negative shock through a regional economy. Input-output models contain a static, linear model of all sales and purchases between all sectors in a regional economy in which parameters are often based on historical data. Other researchers have used the output of I/O models to devise shorthand multipliers for indirect effects from direct losses. For the purposes of a long-duration outage in San Francisco, indirect effects could be estimated using an I/O model encapsulating the Bay Area, California, the United States or even the world as a system.

Additionally, Rose and Lim's ex post resiliency adjustments to the results of I/O models provide a starting point for considering the ways in which businesses may adapt to the circumstances of a long-duration outage. I/O models do not allow for behavioral changes; yet, it is quite likely that a long-duration outage will induce businesses to take adaptive actions rather than simply suffer ongoing losses. The available adaptive actions will depend upon the nature of the business, the cost of adaptation, and the duration of the outage. For example, the time of use adjustment and production shifting adjustment used by Rose may not be applicable to a long duration (multiple weeks) outage. Some businesses may not be able to afford adaptive behaviors, such as relocation, and simply go out of business.

B.3.3 2003 Northeastern United States Outage

In August 2003, 45 million people in the northeastern United States and parts of Canada experienced a full outage for 16 hours, gradually recovering to full restoration of power over 72 hours in total. In the days following, several private consultancies released short studies estimating the economic costs of the blackout.

ICF Consulting (2003) released an estimate based on the ratio of cost per unserved kWh to price per kWh observed in Corwin and Miles. ICF calculated that outage costs per kWh in Corwin and Miles were 100 times the price of electricity per kWh. ICF then looked at the rate of recovery over the 72 hours of the blackout and calculated blackout costs at each period, based on calculated unserved kWh and price per kWh; to create an uncertainty range, ICF used 80 times the price of energy and 120 times the price of energy as lower and upper bounds to the estimate. Details of this calculation are presented in Table B-5.

Table B-5: ICF (2003) Calculation of 2003 Outage Costs

Period		Lost MW	Duration (Hrs)	Lost MWh	$/MWh	Cost of Blackout (2003 $)	
Start	End					Lower Bound	Upper Bound
8/14 - 4 PM	8/14 - 8 PM	61,800	4	247,200	$93	$1.8 Billion	$2.8 Billion
8/14 - 8PM	8/15 - 6 AM	30,900	10	309,000	$93	$2.3 Billion	$3.5 Billion
8/15 - 6 AM	8/15 - 10 AM	15,450	4	61,800	$93	$459.8 Million	$689.7 Million
8/15 - 10 AM	8/16 - 12 AM	13,200	14	184,800	$93	$1.4 Billion	$2.1 Billion
8/16 - 12 AM	8/16 - 10 AM	6,600	10	66,000	$93	$491 Million	$736.6 Million
8/16 - 10 AM	8/17 - 6 AM	2,000	20	40,000	$93	$297.6 Million	$446.4 Million

Period		Lost MW	Duration (Hrs)	Lost MWh	$/MWh	Cost of Blackout (2003 $)	
Start	End					Lower Bound	Upper Bound
8/17 - 6 AM	8/17 - 4 PM	1,000	10	10,000	$93	$74.4 Million	$111.6 Million
TOTAL			**72**	**918,800**		**$6.8 Billion**	**$10.3 Billion**

The Brattle Group (2003) released a paper with similar methods. Brattle made a simplifying assumption that half the interrupted load (30,900 MW) was offline for 4 hours and the other half offline for 8 hours; moreover, they used industry-wide averages for the affected customer mix. Brattle then calculated outage costs using cost per unserved kWh figures from previous surveys of residential and commercial customers. They arrive at an estimated $6 billion in nominal dollars.

Anderson Consulting (2003) took a different approach to Brattle and ICF, using macroeconomic measures to infer losses. Specifically, Anderson took the projected annual gross state product for each of the affected U.S. states in 2003, scaled it to a single day, and calculated the total earnings accruing to workers and investors based on the national average earnings share of output. These single-day earnings were then multiplied by fraction of output affected by the outage over the course of 72 hours to arrive at earnings losses during the full duration outage. Anderson then multiplied this value by 1.2 to account for indirect effects, with no source of this multiplier identified. To this, Anderson then added an estimate of losses due to food spoilage, power industry costs and costs to government to arrive at a total impact of $6.4 billion in nominal dollars. Table B-6 presents the tabulation of these costs. Anderson then constructs an uncertainty range by multiplying lost earnings figures by plus and minus 33% to produce lower and upper bounds.

Table B-6: Anderson Consulting (2003) Calculation of 2003 Outage Costs

States	Direct Effect, Lost Earnings (2003 $B)	Indirect Effect, Lost Earnings (2003 $B)	Spoiled Commodities (2003 $B)	Net Cost to Government (2003 $B)	Cost to Power Industry (2003 $B)	Total Economic Impact (2003 $B)
New York	$1.980	$0.198	$0.375	$0.033	$0.429	$3.015
Michigan	$0.653	$0.065	$0.124	$0.011	$0.141	$0.994
Ohio	$0.358	$0.036	$0.068	$0.006	$0.078	$0.545
New Jersey	$0.263	$0.026	$0.050	$0.004	$0.057	$0.400
Pennsylvania	$0.147	$0.015	$0.028	$0.002	$0.032	$0.223
Connecticut	$0.060	$0.006	$0.011	$0.001	$0.013	$0.091
Massachusetts	$0.003	$0.000	$0.001	$0.000	$0.001	$0.005
Vermont	$0.002	$0.000	$0.000	$0.000	$0.000	$0.003
All others	-	$0.347	-	-	$0.750	$1.097
Total	**$3.465**	**$0.693**	**$0.657**	**$0.058**	**$1.500**	**$6.373**

Interestingly, the Ohio Manufacturer's Association surveyed only firms in the manufacturing sector of Ohio to estimate costs to business from the 2003 blackout (ELCON, 2004). Based on survey responses of business interruption costs incurred by affected firms, OMA estimated that the cost to Ohio was $1.08 billion in nominal dollars. This figure is more than double the direct and indirect losses for Ohio estimated by Anderson Consulting.

Anderson et al. (2007) checked these prior estimates against an I/O model approach. Anderson et al. used the Regional Input-Output Multiplier System II, an I/O model, along with other macroeconomic indicators to approximate the impact of the blackout on the northeastern U.S. economy. Using the outage durations supplied by ICF, Anderson et al. calculated a direct loss of $2.12 billion in nominal dollars, based on the proportion of energy demand unmet over the course of the 3 days of the blackout and recovery. They then input this negative shock into their I/O model and calculate indirect costs of $4.41 billion, suggesting an indirect cost multiplier equal to 2 times direct costs. Anderson et al. concluded that the economic losses from the blackout totaled $6.53 billion in nominal dollars—a finding roughly in line with prior estimates.

Perhaps the greatest contribution these studies make is to demonstrate the use of back-of-the-envelope estimates to ascertain the magnitude of costs due to an outage. By scaling impacts from macroeconomic measures and previous surveys of costs per unserved kWh, as well as using multipliers for indirect effects, the magnitude of costs of a long-duration San Francisco outage may be quickly estimated—and may reasonably match results from a laborious modeling process. However, these methods contain many simplifying assumptions, and they may produce results very different than empirical work would show, such as demonstrated by the OMA survey.

B.3.4 2001 California Rolling Blackouts

Following efforts to deregulate its energy markets, California implemented rolling blackouts over six days in 2001 to avoid system-wide failure from supply shortages. On January 17–18, rolling blackouts were implemented only in PG&E's territory; on March 19–20 and May 7–8, rolling blackouts were implemented across all three investor-owned utilities in California. Rolling blackouts were implemented such that only a fraction of customers experienced an outage at any given time, with outages rotating across different groups of customers. While rolling blackouts occurred during several business hours on each of the 6 days, interruptions to any single customer typically lasted between 60 and 90 minutes.

AUS Consultants issued their study in May of 2001, during the ongoing supply shortages in California. The AUS study was fundamentally hypothetical in nature, as they sought to estimate costs associated with rolling blackouts over the summer to come. For this purpose, AUS assumed that rolling blackouts would culminate in 20 hours of outage over the course of the summer. AUS then surveyed commercial and industrial sector businesses across California about business interruption costs and behavior during prior rolling blackouts; results from the survey informed the estimated impacts of outages on business sectors overall, scaled to impact per hour of outage. AUS then calculated direct losses by multiplying losses per hour of outage by gross state product for each sector. AUS used multipliers for indirect losses derived from the Regional Input-Output Modeling System II, an I/O model built on regional data for 1997. They estimated that anticipated rolling blackouts would result in losses of $21.8 billion in nominal dollars. The tabulation of losses is shown in Table B-7.

Table B-7: AUS Consultants (2001) Estimate of 2001 Rolling Blackout Costs

Sector	RIMS II Multipliers			Losses (1996 $M)		
	Output	Earnings	Jobs	Direct	Indirect	Total
Agriculture, forest., fisheries	2.253	0.687	31.4	$181	$407	$588
Manufacturing				$1,216	$2,590	$3,805
Food & kindred products	2.16	0.45	15.5	$227	$490	$717
Paper products	1.842	0.427	12.4	$19	$35	$53
Chemicals/Petroleum	1.979	0.34	9	$245	$485	$729
Rubber & plastics	1.913	0.474	15.6	$13	$25	$38
Lumber & wood	2.085	0.545	19.2	$21	$45	$66
Stone, clay, glass	2.116	0.57	17.3	$54	$114	$168
Primary metals	1.962	0.466	13.3	$8	$16	$24
Fabricated metals	2.061	0.555	16.8	$30	$63	$93
Industrial machinery	2.243	0.597	15.2	$110	$248	$358
Electronic equipment	2.205	0.603	15.8	$335	$738	$1,073
Instruments and related	2.152	0.66	16.4	$103	$222	$325
Motor vehicles	2.016	0.444	12.9	$6	$12	$18
Other transport equip.	2.257	0.658	16.1	$31	$70	$101
Misc. manufacturing	2.196	0.591	21.4	$13	$29	$42
Electric, gas, & sanitary	2.135	0.382	9.5	$33	$70	$103
Wholesale trade	2.051	0.654	19.1	$525	$1,076	$1,600
Retail trade	2.102	0.688	30	$976	$2,051	$3,027
F.I.R.E.	2.142	0.587	17.5	$2,242	$4,804	$7,047
Services				$1,661	$3,934	$5,595
Personal services	2.333	0.79	40.3	$90	$209	$299
Business services	2.289	0.856	26.7	$888	$2,033	$2,921
Hotels/Amusement	2.604	0.85	31.5	$373	$972	$1,345
All other services	2.322	0.709	28.5	$310	$720	$1,030
Total Gross State Product				**$6,833**	**$14,932**	**$21,765**

Rose et al. (2005), on the other hand, examine the impact of the rolling blackouts on Los Angeles County after they occurred, representing an actual rather than hypothetical scenario. Rose et al. identified the geographic areas affected by each hour of each outage in SCE's service territory to estimate the direct business interruption costs to various sectors.[11] These results formed the input for an initial partial equilibrium model, which initially estimated direct losses within SCE's territory at $9.9

[11] Because of the advance warning associated with rolling blackouts, Rose et al. suggest that this number signifies only lost sales and does not include material/labor costs or equipment damage.

million in nominal dollars. Rose et al. then reran the model with production functions and elasticities adjusted for resiliency behaviors associated with productivity and input substitution, which reduced losses by 88% to $1.2 million. An additional adjustment to account for production rescheduling of firms further diminished losses to $266,000—a 97% reduction from initial estimates of direct losses. Rose et al. then expanded the scope of the analysis to all of LA County and ran a computational general equilibrium model, which incorporated further resiliency options and calculated the indirect costs of the SCE outage scenario. Rose et al. found that indirect losses were equal to 74% of direct losses.

Unfortunately, the article as written appears to have logical inconsistencies and ambiguities that make tabulation of cost estimates difficult. Nevertheless, we present our understanding of the article in Table B-8.

Table B-8: Rose et al. (2005) Estimate of 2001 Rolling Blackout Costs

Area	PE Direct Losses (2001 $M)			GE Indirect Losses (2001 $M)			Total Losses (2001 $M)		
	Base case	Resiliency options included	Production resched. included	Base case	Resiliency options included	Production resched. included	Base case	Resiliency options included	Production resched. included
SCE Territory	$9.9	$1.2	$0.3	$7.4	$0.9	$0.2	$17.3	$2.1	$0.5
LA County	$18.4	$1.9	Not given	$13.7	$1.4	*	$32.1	$3.4	*

* Rose et al. do not give this number, stating that the multiplier varies, "because sectoral net GE effects are distributed differently than sectoral PE effects and because the CGE model is non-linear." Without the multiplier given, the numbers cannot be determined; however, it stands to reason that the indirect effects multiplier is in the same general range of this CGE model and other I/O models.

These studies both demonstrate how the effect of outages can be modeled through regional economies. AUS demonstrate that the parameters of sophisticated models and indirect effects multipliers they suggest can be combined with survey data to model overall costs to an economy. Rose et al. demonstrate that sophisticated models that allow for adaptive behaviors—likely in the case of the advance notice associated with 2001 60 to 90 minute rolling blackouts—can drastically reduce estimates of outage costs. As noted above, available adaptive behaviors will vary.

B.3.5 2011 San Diego Outage

In September 2011, San Diego Gas & Electric experienced a full system outage that recovered over the course of 13 hours. In the direct aftermath, National University System's Institute for Policy Research (2011) released a policy brief estimating the cost of the outage to lie between $97 million and $118 million. This figure represents the sum of three estimates: perishable food losses, government overtime and production losses. In all three cases, NUS extrapolated numbers from prior events (2003 Northeastern U.S. Blackout, local government response to firestorms, 1996 Western U.S. Power Outage) to arrive at estimates. The back-of-the-envelope nature and limited scope of costs taken into account make this study at best a rough, lower bound estimate.

B.3.6 Hypothetical Long-duration Los Angeles Outage

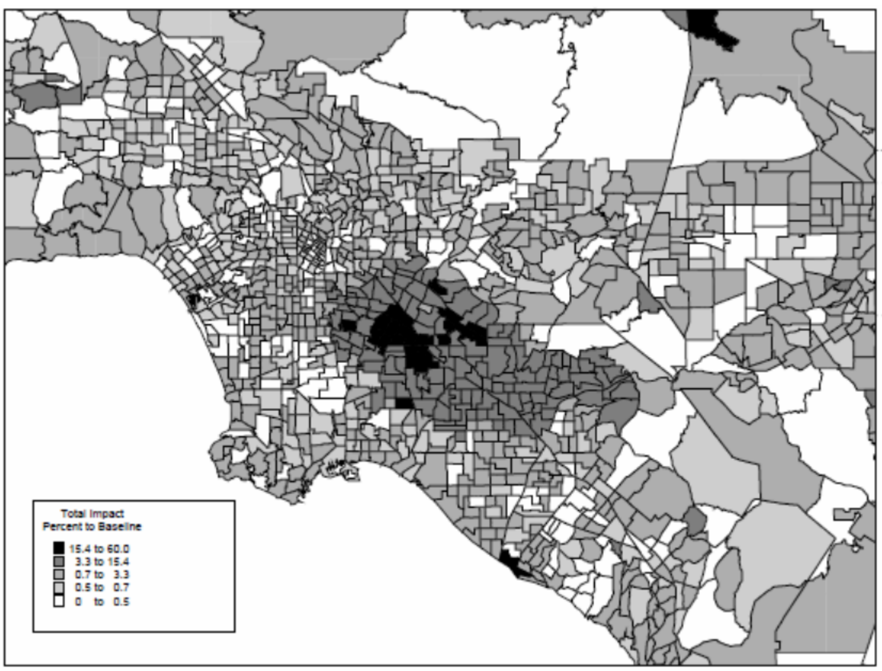
FSC examined two studies of hypothetical long-duration outages in the Los Angeles metropolitan area. Moore II et al. (2005) constructed a scenario of a one-month outage in Los Angeles and Orange Counties and used the Southern California Planning Model Version 2, an I/O model with spatial data, to predict the economic losses from such an outage. Moore II et al. scale annual gross output to a single month to represent the direct losses in the model; total costs are estimated to reach $12.1 billion in nominal dollars. The results of the I/O model are presented in Table B-9.

Table B-9: Moore II et al. (2005) Estimate of Losses from a Hypothetical One-month Outage

Loss Type	Losses (2005 $M)
Direct Losses	$7,412
Indirect Losses	$2,744
Induced Losses	$1,969
Travel Costs	$15
Total	**$12,140**

Moore II et al. used the spatial nature of their I/O model both to model impacts from altered transportation patterns and predicted the distribution of impacts geographically. Figure B-1 demonstrates the spatial results of the model, where economic losses are portrayed as a percent of baseline economic output in a given area.

Figure B-1: Geographic Distribution of Economic Losses from a Hypothetical One-month Outage



Rose et al. (2007) took a somewhat different approach to modeling the economic losses from a two-week outage in Los Angeles County. Rather than employ an I/O model, Rose et al. used a computational general equilibrium model to capture the indirect effects of their outage scenario, specifying production function for firms, consumption functions for households, expenditure functions for government, and income and price elasticities for households and government. The model incorporates inputs from the Impact Planning and Analysis database, which allows downscaling of macroeconomic indicators to the county level. Furthermore, several aspects of resiliency are applied to the model, including: interfuel substitution, adaptive electricity substitution (e.g., using physical labor in place of machinery), factor substitution, inventory drawdown, production rescheduling, alternative generation, and electricity importance. Results of the CGE model are presented in Table B-10. Rose et al. estimate that a two-week outage without resiliency leads to losses of $13.1 billion in nominal dollars; when production rescheduling, the most effective of resiliency options, is incorporated, losses reduce by 79% to $2.8 billion overall. However, it is important to note that these resiliency assumptions are based on a theoretical model and have not been verified through a survey. Indirect losses are roughly one quarter of direct losses.

Table B-10: Rose et al. (2007) Estimate of Economic Losses from Hypothetical Two-week Outage

Sector	Output baseline (2007 $M)	Direct losses (%)	Indirect losses (%)	Total losses (%)	Total losses (2007 $M)	Total losses adjusted for production rescheduling (2007 $M)
1. Agriculture	$1,398	-2.4	-7.3	-9.7	-$5	-$1
2. Mining	$2,589	-73.2	-1.6	-74.8	-$74	-$1
3. Construction	$28,770	-18.7	-29.9	-48.6	-$538	-$27
4. Food processing	$14,744	-56.5	-8.6	-65.1	-$369	-$18
5. Petroleum refining	$11,404	-29.7	-25.1	-54.8	-$240	-$2
6. Other nondurable mfg	$33,435	-71.2	-2.8	-73.9	-$951	-$48
7. Primary metals	$3,192	-30.1	-17.8	-48	-$59	-$1
8. Semiconductors	$1,133	-38.3	-7.8	-46	-$20	$0
9. Other durable mfg	$63,364	-73.1	-4.6	-77.7	-$1,894	-$19
10. Local private transportation	$1,039	0	-11.4	-11.4	-$5	-$4
11. Other transportation	$21,407	-5.2	-32.1	-37.2	-$306	-$214
12. Communications	$15,674	-23.3	-7.2	-30.6	-$184	-$111
13. Private electric utilities	$2,349	-99	0	-99	-$89	-$22
14. Gas utilities	$4,738	-22.9	-35.3	-58.2	-$106	-$27
15. Water utilities	$381	-55.5	-2.5	-57.9	-$8	-$1
16. Sanitary services	$1,149	-62.6	-1.6	-64.1	-$28	-$3
17. Wholesale trade	$35,676	-73	-0.2	-73.2	-$1,004	-$10
18. Retail trade	$27,761	-66.1	-8.5	-74.6	-$797	-$159
19. Real estate	$31,230	-73	-3.9	-76.8	-$923	-$92
20. Banking & credit	$19,759	-21.7	-11.2	-32.9	-$250	-$25
21. Security brokers	$8,153	-14.6	-15.4	-30	-$94	-$9
22. Insurance	$11,733	-66.6	-5.4	-72	-$325	-$33
23. Hotels & restaurants	$14,383	-43.3	-21.9	-65.2	-$361	-$144
24. Personal services	$4,301	-69.1	-2.2	-71.3	-$118	-$47
25. Business services	$59,026	-70	-3.1	-73.1	-$1,660	-$498
26. Computer services	$6,035	-11.7	-39.9	-51.6	-$120	-$72

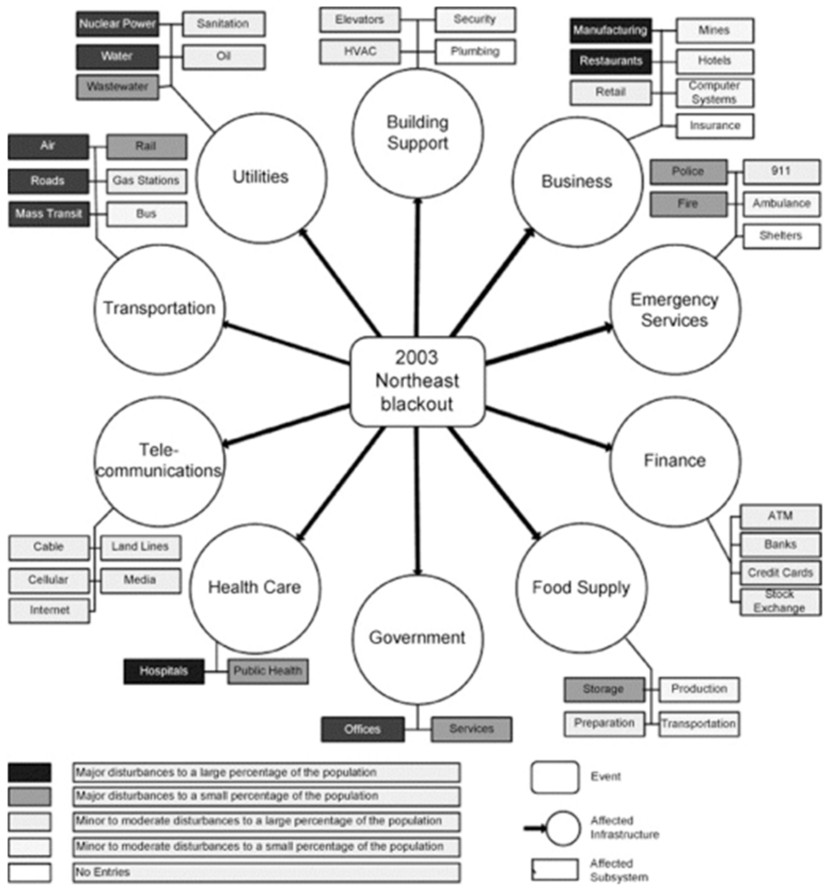
Sector	Output baseline (2007 $M)	Direct losses (%)	Indirect losses (%)	Total losses (%)	Total losses (2007 $M)	Total losses adjusted for production rescheduling (2007 $M)
27. Entertainment	$39,098	-57	-10.2	-67.1	-$1,010	-$707
28. Education	$5,015	-54.2	-31.2	-85.4	-$165	-$2
29. Health & social services	$30,138	-42.7	-32.2	-74.9	-$869	-$434
30. State & local electric utilities	$2,425	-99	0	-99	-$92	-$23
31. Local public transportation	$1,254	-9.1	-54.5	-63.5	-$31	-$21
32. Other government	$36,916	-5	-17.1	-22.1	-$314	-$63
Total	**$539,668**	**-47.9**	**-11.4**	**-59.3**	**-$13,010**	**-$2,839**

The main contribution of these studies is that they look at outages of long duration; their estimated costs thus serve as a guide to estimating the costs of a similarly long or longer duration outage in downtown San Francisco. In addition, Moore II et al., by using an I/O model with spatial data, illustrate graphically how areas that do not experience an outage can still be adversely affected. Rose et al. demonstrate how a CGE model, which allows for behavior change of firms and consumers using microeconomic principles, can allow for adaptive behavior when forecasting the impact of a negative shock. However, because this theoretical model has not been validated through primary data collection (i.e., a survey), it is unclear how realistic its assumptions are. A well-designed survey more accurately incorporates resiliency because it measures revenue losses after the respondent considers adaptive behaviors. However, those adaptive behaviors can be costly (i.e., the fuel cost of a backup generator), so it is important to measure these costs and factor them into a net estimate, which will be the most accurate measure of direct costs.

B.3.7 Issues Caused by Long-duration Outages

Long-duration outages create a set of challenges that shorter system disturbances rarely feature. Specifically, other systems that rely on electricity become compromised or inoperable, creating further difficulties. Brown et al. (2006) chart a number of infrastructure failure interdependencies during the 2003 U.S. Northeast blackout in Figure B-2; while not all of these failures are likely for the downtown San Francisco scenario, it is nevertheless illustrative of the impacts of a major outage.

Figure B-2: Infrastructure Failure Interdependencies from Power Outage (Brown et al., 2006)



At the outset of any major power outage, the set of costs is roughly the same: business interruption costs are incurred, labor costs associated with security and emergency services increase, transportation systems become congested, communications systems are interrupted and so on. Facilities may initiate alternative generation, and businesses may reschedule production. However, as an outage continues over the course of a single day, other costs are borne. Food spoilage and disposal not only imposes costs to businesses but can also cause a brief rise in related disease (for example, see Marx et al., 2006). Water service may become unavailable due to treatment equipment being out of service or offline pumps causing decreases in system pressure. Effluent from inactive sewage treatment equipment also poses threats to health and the local environment; during the Northeastern U.S. 2003 outage, at least 90 million gallons of untreated sewage spilled into local waterways (DePalma, 2006). Inoperable HVAC systems may cause inconvenience or, when coinciding with extreme temperatures, threats to health due to lack of heating or cooling. Elderly people may be particularly vulnerable due to reduced mobility and more fragile health. The combination of increasing emergency visits and power loss can degrade hospital operations (Klein et al., 2005). Overtime costs for public services increases substantially. The urban transportation system experiences severe congestion from ongoing lack of functioning traffic lights and other infrastructure; for example, during the Northeastern U.S. 2003 outage, congestion was severe, due to a combination of traffic light failure, electric train system shut down, and gasoline pump inoperability (Shaw, 2005). Similarly, communications systems can become overloaded, due to an increase in activity and/or communications equipment being out of service. Individuals cancel planned activities and may shift behavior to deal with lack of electricity. As residents use candles for lighting, incidences of fire increase substantially (for example, see SEMP 2006).

At a certain point, a long-duration outage comes to resemble a natural disaster. If an outage stretches to several days or longer, new costs are incurred: government assistance monies are spent, tourism declines, cancelled transactions result in lost taxes and so on. Alternative generation may not be possible for many facilities beyond several days; keeping hospitals and water treatment facilities operational becomes significantly more costly. Lack of working water, sanitation and HVAC makes residences difficult or impossible to live in. Continued transportation system challenges shift traffic patterns and slow delivery of goods. While costs associated with emergency services may decrease, security and public safety labor costs are likely to remain elevated. Businesses relocate on an emergency basis, or else shut down; individuals may relocate as well on a temporary basis. A torrent of litigation and insurance claims ensue. In the long run, insurance premia may rise.

Ultimately, an outage of duration longer than several weeks in a major downtown area would instigate an emergency response. In Auckland, New Zealand, a two-month outage in 1998 was partially mitigated by running cables from generators on industrial shipping boats into the local distribution system (see Newlove et al., 2003). While a full recovery is unlikely through such emergency measures, a long-duration outage in downtown San Francisco would almost surely invite similar measures to partially mitigate the outage. However, Embarcadero Substation serves over 27,000 customers in the downtown area, with a peak demand of more than 270 MW on a hot day and a normal peak demand of over 200 MW, and it is not evident how emergency measures would meet this demand.

B.4 Applicable Studies on Natural Disasters

Natural disasters often cause disruption to multiple, interlinked infrastructure systems. While there is a substantial literature on the costs associated with natural disasters, very few studies attempt to quantify the costs attributable specifically to the loss of electric power. In part, this is because the damage associated with the disaster may be difficult to disentangle from the costs caused by a power outage if a business' facility has experienced physical damage; in that case , the lack of electric service to the building may not be the binding constraint to resumption of business activity by the business or tenants. Further, the linkages between infrastructure systems often result in multiple failures; costs resulting from lack of power may be difficult to disentangle from lack of water and sewerage service (which may be caused by a lack of power or by physical damage).

B.4.1 Business Interruption Costs

The costs of natural disasters are generally enumerated as aggregate figures, derived from back-of-the-envelope estimates using macroeconomic figures. For example, in the aftermath of the 2011 Japanese earthquake and tsunami, several estimates from government and private sources estimated costs between $100 to $500 billion, primarily using macroeconomic indicators (Vervaeck and Daniell, 2011). Even when business interruption costs are estimated separately from physical damages, figures are rarely attributed to a particular cause. For example, Burton and Hicks (2005) used a spatial model with economic and hydrological factors to estimate aggregate costs of flooding from Hurricane Katrina. Although they reported business interruption losses (commercial revenue damages) separate from property damages and infrastructure damages (estimating that business interruption accounts for 3% of overall losses), they did not specify the cause of the business interruption.

Several studies have surveyed businesses on the causes of business interruption following a disaster. For example, Tierney (1996) surveyed businesses affected by the 1994 Northridge Earthquake on reasons for business closure, finding that 58.7% of respondents indicated "loss of electricity." Similarly, Gordon et al. (1998) surveyed businesses affected by the 1994 Northridge Earthquake to estimate the proportion of business interruption attributable to specific causes; "interruption to utility services" was mentioned by 63% of respondents, coming in just behind "employees attending to personal matters" (73%) and "damage to place of business" (72%). Although Gordon et al. use their survey results to estimate economic losses attributable to specific causes, there are distinct shortcomings with this method, and it does not disentangle business interruption due to power outage from other disaster-related causes.

Wein and Rose (2008) attribute overall costs of a natural disaster to specific sources of business interruption. As part of a multi-disciplinary effort to model the physical and economic impacts of a hypothetical magnitude 7.8 earthquake in southern California, Wein and Rose separately modeled each shock from the earthquake, such as physical damage to buildings, disruption of power, disruption of transportation systems and so on. These negative shocks were then input into a regional I/O model to calculate indirect losses. Wein and Rose conclude that total losses attributable to power outages following the hypothetical earthquake amount to $7.4 billion, representing roughly 8% of total losses associated with the earthquake (see Table B-11). Direct losses make up $4.4 billion of total losses, suggesting a multiplier of 0.65 for indirect losses from lack of power. These results must be understood within the context of the assumed power outage scenario. In this study, the hypothetical earthquake is assumed to cause widespread power outages, but utilities are expected to restore electric service to a majority of interrupted customers within 24 hours and around 75% of customers within a couple of days. Therefore, the costs for a 3-week to 7-week power outage in San Francisco would comprise a substantially larger portion of the total losses associated with an earthquake and the multiplier would also be larger.

Table B-11: Wein and Rose (2008) Estimates of Hypothetical Earthquake Costs by Source

Sector	Damages (2008 $M)			Interruptions (2008 $M)					Total (2008 $M)
	Buildings	High-Rises	Secondary (Fires)	Power	Water	Gas	Transportation	Ports	
Agriculture	7	2	23	20	443	1	3	16	515
Construction	712	18	710	72	1,783	8	5	49	3,357
Food, Drugs & Chemicals	425	158	2,111	350	5,851	25	33	119	9,072
Mining & Metals/ Minerals Processing & Mft.	56	24	407	58	1,349	18	5	36	1,954
High Technology	23	8	174	20	463	1	2	22	712
Other Heavy Industry	232	48	1,249	127	3,639	9	12	126	5,442
Other Light	234	69	1,386	157	3,205	9	14	103	5,177

Sector	Damages (2008 $M)			Interruptions (2008 $M)					Total (2008 $M)
	Buildings	High-Rises	Secondary (Fires)	Power	Water	Gas	Transportation	Ports	
Industry									
Air Transportation	15	16	189	35	226	1	4	3	488
Rail Transportation	6	6	41	12	109	0	1	2	178
Water Transportation	3	3	29	5	38	0	1	11	90
Highway & Light Rail Transportation	76	83	716	158	1,248	4	35	18	2,340
Electric Utilities	42	35	108	101	708	5	5	14	1,016
Gas Utilities	34	39	99	73	1,021	89	5	21	1,382
Water Utilities	1	1	3	1	41	0	0	0	47
Wholesale Trade	380	83	825	288	2,470	12	24	49	4,131
Retail Trade	431	127	914	364	2,401	21	47	40	4,344
Banks & Financial Institutions	89	37	279	101	652	6	7	11	1,182
Professional & Technical Services	1,085	720	5,647	1,050	6,268	73	82	120	15,045
Education Services	149	25	442	182	980	4	13	10	1,806
Health Services	1,349	429	905	509	3,215	17	30	43	6,498
Entertainment & Recreation	739	131	1,788	750	5,684	26	66	46	9,232
Hotels	249	368	63	50	456	2	4	3	1,196
Other Services	367	80	613	466	1,819	15	42	41	3,442
Gov't & Non-NAICS	193	430	1,177	232	1,506	11	15	33	3,597
Real Estate	618	95	808	1,254	2,885	202	43	24	5,928
Owner-occupied dwellings	533	121	1,733	913	4,567	253	17	37	8,173
Total	**8,049**	**3,156**	**22,438**	**7,348**	**53,029**	**812**	**514**	**998**	**96,343**
(as % of Overall Costs)	***8.4%***	***3.3%***	***23.3%***	***7.6%***	***55.0%***	***0.8%***	***0.5%***	***1.0%***	

In most ways, regional economic modeling of power outages is virtually indistinguishable from regional economic modeling of natural disasters. What varies is not the method underlying each approach, but rather the direct losses that serve as inputs to each model. Hence, any I/O model or CGE model meant to model indirect costs from a natural disaster can be adapted to modeling indirect costs from the power outage underlying a natural disaster—presuming one can identify the separate direct losses of a power outage from a natural disaster and ensure parameters associated with energy supply are accurately specified. Although Wein and Rose are not explicit about their method for estimating direct costs from power outages in an earthquake, they suggest a particular scenario of power service recovery and appear to follow methods demonstrated in prior work (see Rose et al., 2007).

B.4.2 Loss of Electric Power

While the loss of electric power is a direct result of many natural disasters, it can also be a driver in the costs of recovery from a disaster and, over time, may become the binding constraint to recovery. Put another way, there are negative externalities in an extended power outage beyond the direct market value of the unserved power. Descriptive accounts of recovery efforts without reliable power have been published, but FSC is not aware of studies that quantify the costs of delayed power restoration to recovery. Kajitani and Tatano (2009) used surveys of business resilience to utility service interruptions in Japan to show that, in the event of simultaneous power, water, and gas outages, the restoration of electricity before other lifelines will best aid recovery. This remains the closest to an effort aimed at quantifying the impact of electricity outages on recovery duration.

B.4.3 Business Resiliency

Surveys of business resilience are rare, despite the increasing interest in the literature on hazard loss estimation. The Applied Technology Council (1991) ATC-25 modeled sector-wide average levels of importance for each lifeline service, basing their research on a mix of expert opinion and engineering models. Surveys by Webb et al. (1999) focused on disaster preparedness generally, capturing specific measures of back-up generation availability. Kajitani and Tatano (2009) demonstrated a method for surveying businesses in Aichi and Shizuoka, Japan, on several factors associated with resilience, primarily focusing production levels due to lifeline disruption (i.e., electricity, water, gas) and tolerable production stoppage durations. Table B-12 presents findings of Kajitani and Tatano on tolerable stoppage durations, defined as the length of time that can elapse without economic losses. However, short duration outage cost studies in the United States show that a majority of customers experience outage costs, even for a 5-minute power outage, so it is likely that these results are specific to Japan and are not applicable to San Francisco.

Table B-12: Kajitani & Tatano (2009) Survey of Tolerable Stoppages in Aichi and Shizuoka, Japan

Manufacturing		Non-Manufacturing	
Sector	Days	Sector	Days
Food	3.03	Construction	4.31
Apparel & Textile	6.43	Wholesale & Retail	3.42
Wood & Wooden Products	10.15	Financial & Insurance	2.68
Glass Stone Clay	11.59	Real Estate	9.09
Paper Pulp	6.09	Transportation	1.84
Chemicals	7	Communication	2.55
Refiner & Coal	4.6	Medical Services	2.85
Metal Products	5.82	Other Public Services	7.25
Steel	5.82	Business Services	6.24
Nonferrous	3.75	Personal Services	3.28
Genreal Machinery	8.02	Agriculture	3.71
Precision Machinery	8.15	Mining	3.5
Elec. & Electron	5.86		

Manufacturing		Non-Manufacturing	
Sector	Days	Sector	Days
Transport Eq	3.22		
Misc. Manufacturing	6.3		
Average	**6.39**	**Average**	**4.23**

B.4.4 Other Considerations

Webb et al. (1999) surveyed businesses pre-disaster in Memphis and post-disaster in Los Angeles and found that few businesses have made preparations or plans in the event of a disaster. About 15% of businesses owned a backup generator, and less than 10% of businesses had arrangements to relocate in the event of a disaster. Larger firms tended to have more preparation than smaller firms. This work provides an initial sense of the level of disaster preparedness we expect to find in our survey.

Webb et al. also found that most businesses recovered after the five major disasters under study, with a majority of businesses affected by disasters reported recovering to pre-disaster business conditions. However, this does not mean that the business did not experience substantially costs during the recovery. They found that business' financial condition prior to a disaster, firm size, and larger economic trends were a greater predictor of recovery outcomes than disaster planning, all else being equal. These findings suggest that direct costs are meaningful only insofar as they are portrayed relative to a business' current financial condition and in the context of that business' market. For example, businesses in wholesale and retail sectors have far worse outcomes following major disruptions than other businesses, due to competitiveness and high rates of failure and turnover that characterize those sectors (Tierney, 2007).

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PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 13

ECONOMIC COSTS AND BENEFITS OF THE PROJECT

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ECONOMIC COSTS AND BENEFITS OF THE PROJECT

A. Introduction and Summary

1. Purpose and Scope

The purpose of this chapter is to explain how the economic benefits of the Embarcadero-Potrero 230 kilovolt (kV) Transmission Project (Project) are estimated and, in a benefit-cost analysis, compared to the Project's costs estimated in Chapter 5. This analysis shows that the Project's economic benefits exceed its costs by a comfortable margin, resulting in a ratio of benefits to costs of greater than three. Translated into dollars on a present value basis, the after-tax costs of the Project have a present value of $147 million to $169 million, and the present value of the after-tax benefits of the Project range from $513 million to $1.026 billion, resulting in a net benefit of $343 million to $878 million.

Also described below are some of the Project benefits that cannot be easily quantified, but are very real benefits of improving the reliability of electric service in San Francisco through the Project.

2. Organization of the Remainder of This Chapter

- Section B – The Benefits of This Reliability Investment Exceed Its Costs
- Section C – The Project Is Justified Based on an Economic Benefit-Cost Analysis

B. The Benefits of This Reliability Investment Exceed Its Costs

1. Pacific Gas and Electric Company Has Determined That, Given the Potential Impact of a Long Duration Outage, the Benefits of the Project Outweigh Its Costs

Both the HZ-1 and HZ-2 lines are at substantial risk of failure at multiple locations during a major Bay Area earthquake, and such an earthquake has a high probability of occurring within the likely operational life of these lines.[1] Failure of these lines, due to either seismic or non-seismic events, could

[1] See Chapter 6.

cause a lengthy loss of electricity in downtown San Francisco, with consequent high direct costs to customers served by the Embarcadero Substation. The impacts of such an outage will extend well beyond the customers directly affected by such an outage. People and businesses in the Bay Area and beyond will also be impacted, in some cases directly, and others indirectly. Some of these impacts can be quantified as indirect costs of an outage, while others can only be described qualitatively. An estimate of these direct and indirect costs is provided in the report "Downtown San Francisco Long Duration Outage Cost Study" (Cost Study) by Freeman, Sullivan & Co. (FSC), who were retained by PG&E to estimate the costs associated with power outages lasting from 24 hours to seven weeks specifically for customers (and tenants of customers) served by Pacific Gas and Electric Company's (PG&E) Embarcadero substation.[2] As set forth in Chapter 12, the FSC Cost Study estimates that the direct and indirect costs of a 7-week outage would range from $4 billion to almost $9 billion.

The Project will significantly reduce the likelihood that these costs will occur, as described in Chapters 7 and 10 of this testimony. PG&E has evaluated the economic cost of these outages on a probabilistic basis (where the estimated economic cost reflects the estimated probability that an outage will occur), and compared the result to the estimated cost of PG&E's construction and operation of the Project. The remainder of this chapter explains the methodology and assumptions used to estimate the Project costs and benefits.

It is important to recognize that this kind of cost-benefit analysis, based on probability weighted outcomes, is only one factor that policymakers may use in evaluating whether the proposed Project is prudent and needed. The California Public Utilities Commission (CPUC or Commission) may conclude that the economic and social impacts of a long duration outage (eight weeks or more) in downtown San Francisco justify the need for the Project, even if the probability of such an outage in any individual year is low. Moreover, an economic cost-benefit analysis compares the benefits and costs over a lengthy time period, assuming an equal probability of an outage each year of

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[2] See Chapter 12.

such time period and a "cost savings" each year if the Project is not built. While appropriate from a purely economic perspective, if a low-probability outage in fact occurs, the economic costs, potentially reaching $9 billion, vastly exceed the estimated $171 million cost of the project, before contingency. This is analogous to a homeowner considering the value of fire insurance. The probability of a fire is very low, so the *expected* (probability weighted) economic cost of loss of a home plus all the costs of staying in a temporary location may seem de minimis. But for many homeowners the loss of a home can be a financial disaster. Therefore the risk tolerance is heavily influenced by the possibility of intolerable financial damage. A similar view of the downtown area may be held; there is little comfort in the "expected," probability-weighted cost of a downtown outage in a given year, when the actual cost could be as high as $9 billion. The cost-benefit analysis does not consider the ability of the affected populations to absorb the financial impact if the low probability event occurs. Balancing the costs and disruptions of an actual outage against the cost of the Project is a policy decision for the Commission, which must also weigh the non-quantifiable benefits.

2. Other, Non-Quantifiable Benefits of the Project Cannot Be Captured in an Economic Benefit-Cost Analysis, But Also Justify the Project

As discussed in Chapter 14, the Project has several purposes and provides a number of benefits for PG&E's San Francisco transmission system. Besides providing a third cable to Embarcadero Substation to reduce the risk of a long duration outage caused by an overlapping loss of both HZ cables, the Project also facilitates other infrastructure projects in San Francisco and interconnects PG&E's 230 kilovolt and 115 kV systems. The economic cost-benefit analysis does not consider the benefits of these aspects of the Project.

Similarly, not all costs associated with a long duration electric service outage can be readily measured in dollars and cents, and thus do not lend themselves to inclusion in an economic benefit-cost analysis. These difficult to quantify impacts include environmental impacts, standard of living diminishment, and health and safety externalities.

a. Environmental impacts may result from the use of fossil fuel for temporary generating devices within the affected area, as well as the greater use of autos and buses to make up for any service curtailment of the Bay Area Rapid Transit or San Francisco Municipal transportation systems, since these systems rely on cleaner and more efficient energy sources. Loss of electric power at the cruise ship terminal in San Francisco could result in those ships switching to their own power, typically fuelled by the heavier and more polluting grades of oil. In addition, people may find themselves driving more and further, and there may be more emissions if the roads and highways experience higher volumes of traffic.

b. An extended outage will lead to substantial inconvenience, some of which is captured in the costs incurred by local businesses. But the additional time people spend rearranging their lives during the outage (as set forth in Chapter 11, restoration of an HZ cable could take up to eight weeks or more, depending upon the damage) will result in reallocation of their income as well as loss of leisure time, both contributing to a reduction in their standard of living. Although loss of income is captured in the economic analysis, many people will incur greater costs to carry out their daily lives, and as a result their enjoyment of life may be less than what they had prior to the outage. Many of the people living at the approximately 25,000 residential accounts served by Embarcadero Substation may have to leave their homes during the outage. The imposition on friends and relatives of people directly affected by the San Francisco outage may lead to some diminution of their standard of living.

c. The impact on health and safety is unknown. Although security almost certainly would be increased in the area served by the Embarcadero Substation during a sustained outage, the decrease in lighting, both outdoor and indoor, and unattended homes/buildings may lead to greater crime and vandalism.

d. As discussed in Chapter 9, the concern about taking an HZ cable out of service for months to accommodate construction of other underground infrastructure can block or alter such projects. The delay or absence of such projects may have other impacts on services in San Francisco. There may be cost impacts as well from delays or alterations.

While these unquantified additional outage costs and other benefits of the Project cannot be included in an economic analysis, decision makers should consider them, and a qualitative assessment of the value of avoiding these other outage costs and securing these other benefits further supports development of the Project.

C. The Project Is Justified Based on an Economic Benefit-Cost Analysis

1. The Methodology of the Benefit-Cost Analysis

PG&E and most other companies use Net Present Value (NPV), or discounted net cash flows, as the primary economic criterion when making investment decisions. NPV nets the costs from the benefits of the project and represents the value created by an investment or project. An economically attractive investment has an NPV greater than zero, and preference should be given to those projects that result in the highest NPV. NPV is calculated by estimating the after-tax cash inflows and outflows for a project and then discounting them to a present value using a weighted average cost of capital (also referred to as the discount rate).

In evaluating the NPV cost of a project, PG&E includes an immediate cash outflow equal to the capital expenditure to build or procure the project, and each year thereafter there are cash outflows for property taxes and insurance. Offsetting these annual cash outflows are savings in federal and state income taxes due to tax depreciation deductions as well as deductions for property taxes and insurance. Operations and Maintenance (O&M) costs associated with the project also result in annual cash outflows, which result in corresponding tax deductions that reduces income taxes by an amount equal to the combined state and federal income tax rate (41%) times the amount of the expense. For each year of the project’s life, these annual after-tax capital and expense costs are discounted to present day dollars to determine the NPV of the project’s cost.

In evaluating the NPV of the benefit of a project, PG&E includes annual after-tax costs of utility capital or O&M expenditures that will be avoided as a result of the project. For reliability projects, PG&E also evaluates the expected annual customer outage costs that will be avoided by the project. This annual avoided customer cost is based on value of service survey results applied to the number and type of customers affected by the outage and the project-related reduction in the probability of the outage occurring in each year. Because these costs have tax implications for business customers, PG&E reduces the annual outage cost by an amount equal to the combined state and federal income tax rate (41%) times the amount of the cost, as is done for operating expenses. For each year of the project's life, these annual after-tax benefits are discounted to present day dollars to determine the project's NPV benefit.

The difference between the net present value of benefits and the net present value of costs is the NPV of cash flow, or the value created by the project. The economic analysis can also divide the net present value of the benefits by the net present value of the costs to create a benefit-cost ratio (BCR). A BCR of greater than one indicates an economically attractive investment.

2. Assumptions for Benefit-Cost Analysis for the Project

a. Probability of a Seismic Event Causing Overlapping Outages of Both HZ Lines

PG&E's seismic consultant, Infra Terra, has opined in Chapter 6 that in a magnitude 7.8 or greater earthquake on the San Andreas fault there is a 91 percent probability of damage and concurrent loss of service for both the HZ-1 and HZ-2 lines, while in lesser magnitude earthquakes there are smaller though still significant probabilities of both HZ lines failing. Combining the probability of both HZ lines failing with the year-by-year probability of an earthquake of magnitude sufficient to cause dual failure, Infra Terra has estimated the HZ-1 and HZ-2 lines have an annual concurrent failure probability of 1 percent each year.

b. Probable Duration of Seismic-Caused Outage

As described in Chapter 11, the time required to restore service to the Embarcadero Substation will be governed by the amount of time required to locate the cable fault(s), the type and extent of damage, the availability of skilled labor, the availability of repair materials, the physical location of the damage, and the amount and condition of installed infrastructure surrounding the fault. Chapter 11 notes that estimated repair time can range from 8 to 16 weeks for a failure in a single location. Infra Terra's seismic study report in Chapter 6 notes there are multiple locations along both HZ lines where computed strains exceed failure criteria by a significant margin in an earthquake similar in size to the 1906 San Francisco event. With multiple failure locations, repair time would likely increase, perhaps even exceeding the higher end of the estimated range of 8 to 16 weeks. However, PG&E believes that in an emergency situation all necessary steps, both public and private, will be taken to expedite repairs. For the economic analysis of the probable cost to customers of the outage, PG&E is conservatively assuming the expected duration of the seismic-caused outage is seven weeks, and asked FSC to estimate the costs of a seven week outage in its Cost Study.

c. Probability of Non-Seismic Events Causing Overlapping Outages of Both HZ Lines

Chapter 9 describes the non-seismic event scenarios where a single HZ line can fail. "Dig-ins," overheating, uncontrolled thermo-mechanical bending, pipe pressure loss, and corrosion breaks are independent events, each with their own probability of occurrence. For the Embarcadero outage cost analysis, the probability of failure of one line *while the second line is on planned or unplanned outage* is the required input. This conditional probability is the product of the failure probability times the probability of the planned or unplanned outage of the other line. For instance, if a single cable fails on average once every 15 years, the annual probability of failure is 1/15 or 6.5 percent, while if one of the HZ cables is out of service for infrastructure work on average once every 10 years, the annual probability of it being out is 1/10 or 10 percent, and the conditional annual probability of this scenario causing an Embarcadero outage is 6.5 percent x 10 percent or 0.65 percent. This simple example must be further refined to account for the fact that the planned outage on an HZ cable can be deferred should there be a failure on the other HZ cable prior to the start of the outage for infrastructure work. Finally, the probability of each line having an outage in any year must be further refined to reflect the probability of such outages overlapping, as either line currently is capable of supplying sufficient power to Embarcadero Substation. Table 13-1 summarizes PG&E's transmission planning and operations departments' estimate, based upon best professional judgment and available empirical data, of the annual conditional probability of overlapping outages of the HZ cables for each of the non-seismic events identified in Chapter 9.

TABLE 13-1
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL PROBABILITY OF NON-SEISMIC EMBARCADERO OUTAGE

Line No.	Cause	Conditional Probability
1	One HZ cable has a failure and other HZ cable has a failure	0.170%/year
2	One HZ cable is out for utility infrastructure work and the other HZ cable fails	0.132%/year
3	Both HZ cables are simultaneously damaged by a co-located utility failure	0.034%/year

d. Probable Duration of Non-Seismic-Caused Outages

As noted above, potential non-seismic causes of an Embarcadero outage are independent events. Each not only has its own probability of occurrence, it also has its own expected time to repair. The repairs required and the probable duration of the outage are discussed in Chapter 9. Moreover, the extent of any overlap in each cable's outage must be estimated. The expected duration of an outage of Embarcadero Substation is summarized in Table 13-2 below.

TABLE 13-2
PACIFIC GAS AND ELECTRIC COMPANY
EXPECTED RESTORATION TIME FOR NON-SEISMIC EMBARCADERO OUTAGE

Line No.	Cause	Expected Duration
1	One HZ cable has a failure and other HZ cable has a failure	44 days
2	One HZ cable is out for utility infrastructure work and the other HZ cable fails	44 days
3	Both HZ cables are simultaneously damaged by a co-located utility failure	8 – 16 weeks

For the economic analysis of the probable cost to customers of the outage, PG&E is conservatively assuming the expected duration of an overlapping outage does not exceed seven weeks.

e. Improvement in Probability of Outage With Addition of New ZA-1 Line

Chapter 7 describes the significant reduction in earthquake-related outage risk afforded by the Embarcadero-Potrero 230 kV Transmission Project. Infra Terra estimated the annual probability of an earthquake causing failure of both the HZ-1 and HZ-2 lines to be one percent while their estimated annual probability of a seismic event causing those two lines <u>and</u> the ZA-1 line to fail is 0.038 percent.

Further, as Chapter 10 points out for non-seismic failure events, having three cables makes an outage of one cable less of concern, due in part to planned outage flexibility. In addition, although there are probabilities of different failure modes for the new cable, they are smaller than those probabilities for the existing cables, and having three cables introduces a second conditional probability factor, so the probability of all three cables failing is P(1) x P(2) x P(3). For instance, if the probability of a failure on ZA-1 is 0.7 percent annually, then the probability of all three lines failing in this scenario is less than 1/100 the conditional probability of the first two lines failing or, using the earlier numerical example, 0.0046 percent -v- 0.65 percent. Again, this probability calculation must be further refined to account for the likelihood of overlapping outages. Table 13-3 summarizes PG&E's transmission planning and operations departments' estimate, based upon best professional judgment and available empirical data, of the outage probabilities after construction of the Project.

TABLE 13-3
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL PROBABILITY OF NON-SEISMIC EMBARCADERO OUTAGE WITH ZA-1

Line No.	Cause	Conditional Probability	Expected Duration
1	One 230 kV cable has a failure and the other two cables have independent failures	0.00032%/year	32 days
2	One 230 kV cable is out for infrastructure work and the other two cables have independent or common mode failures	0.00463%/year	29 – 44 days
3	One 230 kV cable experiences a failure and the other two cables are damaged by a common-mode failure event	0.00256%/year	38 days

The reductions in the probabilities and durations of both seismic and non-seismic related outages are used in calculating the probability-weighted NPV of benefits to customers of the Project.

f. FSC Estimates of Direct and Indirect Economic Losses

Freeman and Sullivan & Co. were retained by PG&E to estimate both the direct and indirect economic losses stemming from a long-duration outage of the Embarcadero Substation. Direct costs were estimated through a survey of PG&E's downtown San Francisco large business customers, small and medium business customers, and business tenants of master metered building. The reported costs reflect the survey respondents' estimates of net revenue lost during the outage and recovery plus total out-of-pocket outage response costs, including costs for temporary/permanent relocation, idled personnel, and equipment and material repair/replacement. Applying the results of this survey to all business customers served by the Embarcadero Substation, FSC estimates the aggregate direct cost of a 7-week outage is $2.922 billion in 2013 dollars.

Because of lost revenue and increased costs to downtown businesses, there would be significant indirect spillover effects in the greater economy as a result of a long duration outage. These indirect costs are part of a chain reaction of economic losses stemming from costs to those businesses directly affected by the outage. These businesses and their employees would reduce consumption and investments that benefit other businesses outside the impacted area. Indirect costs may or may not also include public expenditures for emergency services, assistance programs, and public health concerns, depending on the study or model used. FSC notes that due to the complexity of indirect cost estimation, they did not attempt to measure those costs through a survey. Instead FSC developed a range of multipliers that is informed by hazard loss estimation literature. FSC's range of indirect outage costs is from one-half to two times direct costs, indicating that if PG&E's Embarcadero substation lost power for seven weeks, the total direct and indirect outage cost would range from $4.4 billion to nearly $8.8 billion.

Increasing economic activity in downtown San Francisco and general inflation are expected to cause these cost figures to grow over time. For the economic analysis, PG&E has used an annual escalation factor of 2.5 percent for the outage costs. This escalation factor reflects general inflation and expected growth in load in the area served by Embarcadero Substation.

g. Adjustment of Economic Loss in Seismic Scenario to Account for Earthquake-Caused Loss of Economic Output

The FSC survey measured the likely magnitude of lost business and employment as a result of a long duration outage. PG&E recognizes, however, that if the outage is caused by a major seismic event, many businesses will suffer direct and indirect costs due to earthquake damage alone, regardless of whether the power stays on. In this situation, attributing all benefit of avoiding FSC's estimated direct and indirect costs to the Project would result in an overstatement of benefits.

To adjust for this potential issue, PG&E reviewed a report for San Francisco's Department of Building Inspection that estimated the damage states of buildings after a magnitude 7.2 earthquake on the peninsula segment of the San Andreas Fault closest to San Francisco.[3] Of the nearly 5,000 privately owned San Francisco commercial buildings examined in that study, 18.7 percent were deemed likely to be unfit to occupy post-quake. Although businesses served by Embarcadero Substation are generally in newer buildings that are more resistant to seismic damage than the general population of San Francisco commercial buildings, PG&E has nevertheless chosen the conservative route for the economic analysis and reduced by 18.7 percent the total outage cost estimated by FSC. This 18.7 percent reduction represents PG&E's adjustment to account for earthquake-caused loss of economic output.

h. Expected Cost of the Project

The expected total capitalized cost of the project covering the design, construction, installation, and testing work described in Chapter 4 is $171 million. Incremental O&M cost for the transmission line and switchyard is forecast to be $78,000 in the first year of operation and escalates at 2.5 percent. The Project is expected to have a service life of 40 years, during which annual insurance costs will be 0.3 percent of gross book value and property taxes will be 1 percent of net book value. The federal tax depreciation life for this electric transmission project is 15 years and the state tax depreciation life is 30 years.

3. Results of Economic Benefit-Cost Analysis for the Project

The present value of expected after-tax direct and indirect earthquake-related outage costs expected to be avoided by the Project is $370 million, using the lower end of FSC's range of indirect cost multipliers. This expected benefit of the Project is calculated by discounting, at 7 percent, the FSC estimate of the cost of the outage (after tax) in each year of the 40-year study period (including escalation) reduced by the 18.7 percent adjustment factor described in Section 2g above and multiplied

[3] "Here Today—Here Tomorrow: The Road to Earthquake Resilience in San Francisco Potential Earthquake Impacts." Prepared for the Department of Building Inspection, City and County of San Francisco by the Applied Technology Council, 2010.

by the Project related reduction in the annual conditional probability of the outage. The present value benefit using the upper end of the indirect cost multiplier is $739 million.

The present value expected benefit due to the Project's expected reduction of the probability of non-seismic-event-related outages ranges from $143 million using the low end of indirect costs and $286 million using the high end. These values are calculated using the same approach described in the preceding paragraph, although they exclude the 18.7 percent earthquake damage adjustment factor.

Because the seismic and non-seismic related outages evaluated in this analysis are independent, the probability-weighted benefits of avoiding each outage type are additive. Therefore, the total present value benefit of the Project ranges from $513 million to $1.026 billion.

For the $171 million expected capital expenditure on the Project and $78,000 annual O&M expenses (escalating at 2.5%), the net present value of after-tax cash flows over a 40-year study period is $147 million. When we include the $26 million of contingencies in the capital expenditure, the net present value of costs rises to $169 million.

Comparing the present value of benefits with the present value of costs of the Project indicates the Project is clearly economic for customers. Even when relating the lower end of the expected benefits range and the upper end (with contingency) of the Project cost range, the NPV of cash flow is $343 million, a positive value indicating an economically attractive project. Stated in terms of benefit-cost ratio, the Project has a BCR of 3.0, again indicating the Project is economic. This NPV and BCR represent the lower end of the range of net Project benefits. Using the expected capital expenditure and the high end of indirect benefits produces a NPV of cash flow of $878 million and a BCR of 6.9.

Because, as noted in Chapter 1, there is a strong chance that PG&E will be required to install a third 230 kV line to Embarcadero at some point after approximately 2030 to meet load growth, a second economic analysis was performed to evaluate the economics of building the Project now versus waiting until 2030. In this analysis, the net present value (in 2015 dollars) of the cost of installing a third line in 2030 was deducted from the NPV cost of the Project, and the net present value of post-2030 benefits of probability-adjusted avoided outage costs (again in 2015 dollars) was deducted from the present value of benefits calculated for the 40-year study period. The results of this second analysis show the net present value of the cost of accelerating the third line construction by 15 years is $86 million (with contingencies) and the present value benefit of reducing outages in the 2015-2030 period is $296 million, using the low end of indirect outage costs.

The results of this second analysis show that, even when using conservative assumptions about costs and benefit, building the Project now is more economic than waiting until 2030. This analysis did not attempt to quantify the risk that different conditions in 2030, such as a loss of submarine or underground cable routes or substation expansion space due to other development, could significantly increase Project construction costs at that time, but simply escalated current estimated construction costs by 2.5 percent pursuant to PG&E Capital Accounting Guidelines.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 14

PURPOSE AND NEED FOR EMBARCADERO-POTRERO PROJECT

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A. Introduction

1. Purpose and Scope

The purpose of this chapter is to describe the purpose and need for the proposed Embarcadero-Potrero 230 kilovolt (kV) Transmission Project (the Project or proposed Project).

2. Organization of the Remainder of This Chapter

- Section B – The Project's Purpose is to Increase the Reliability of Electric Service in San Francisco
- Section C – Relevant Reliability Standards and Planning Considerations
- Section D – Reliability Risks to the Existing 230 kV Cables and How the Project Mitigates Them
- Section E – The Project Improves the Reliability of a "Lifetime" Service
- Section F – Interconnecting PG&E's 115 kV San Francisco Transmission Systems Provides Additional Reliability Benefits
- Section G – Planning Ahead to Maintain Reliable Electric Service
- Section H – The Project Is the Best Alternative to Address the Reliability Deficit in Downtown San Francisco

B. The Project's Purpose Is to Increase the Reliability of Electric Service in San Francisco

Pacific Gas and Electric Company (PG&E) has an obligation to provide reliable electric service to its customers, including those in downtown San Francisco. Considering the risk of an overlapping outage of both Martin-Embarcadero (HZ) underground cables serving Embarcadero Substation, the likely time it would take to restore service in the event of such an overlapping outage, and the very significant impact that such an outage would have on the population of San Francisco and the region, PG&E determined that a third 230 kV transmission line to Embarcadero Substation is needed to ensure reliable electric service.

There are both immediate and future reliability benefits to the Project. As discussed in Chapter 2, Embarcadero Substation is currently fed by the two HZ pipe-type 230 kV cables from Martin Substation, installed in 1974. These cables have been reliable to date. At present, and as projected through at least 2030, either one of the two existing 230 kV cables can deliver enough electricity to meet current and expected demand at Embarcadero Substation. However, as discussed in Chapters 6 and 8, there are low-probability, but very high impact, scenarios under which both HZ cables are out of service, causing a potentially lengthy loss of electricity in downtown San Francisco.

As discussed in Chapter 11, the time to restore an inoperable underground pipe-type cable can vary from approximately eight hours or less (for return of a line in maintenance to service) to as long as eight weeks or longer (to repair a single point of physical damage to the cable). In the event of an earthquake causing liquefaction that damages both HZ cables, it is uncertain when a single cable could be placed back in service as there may be multiple damaged cable segments that are difficult to find, multiple oil leaks that are difficult to find, debris and other impediments to finding the damaged pipe and cable locations, and insufficient skilled manpower, equipment and spare cable available to fix each point of damage.

The immediate benefits from the Project include:

- Providing a third transmission line into Embarcadero Substation that is expected to survive a major earthquake that has a high probability of damaging both HZ cables. The risk to the HZ cables is discussed in Chapter 6; the reduced seismic risk to the proposed ZA-1 cable is discussed in Chapter 7. PG&E’s proposed new Embarcadero-Potrero cable would avoid the areas of high liquefaction potential traversed by the existing HZ cables and will be designed to a performance objective of remaining operational after a major earthquake. The Project significantly increases the probability that at least one of three cables will remain operational following a major earthquake, and downtown San Francisco will have electrical service at a time when it will be sorely needed.
- Providing a third transmission line into Embarcadero Substation will eliminate the risk of an outage in downtown San Francisco under a scenario where one HZ cable may be out of service due to a planned or forced

outage, and the other cable suffers a forced outage. Non-seismic causes of planned and forced outages are discussed in Chapters 9 and 10. A third cable significantly reduces the risk that all three cables will be out of service at the same time.

- Providing a third transmission line into Embarcadero Substation will facilitate replacement or construction of other underground infrastructure. For example, as discussed in Chapter 9, the City and County of San Francisco's (CCSF) sewer replacement project along Cesar Chavez Street will require a relocation of a 1,000-foot section of one of the HZ cables. The relocation will require that the cable be de-energized for approximately four months to construct the new line section. PG&E and CCSF have agreed upon a temporary fix to the cable configuration in order to allow the sewer project to continue, with permanent relocation to be done after the proposed Embarcadero-Potrero 230 kV Transmission Project is permitted and constructed. Another CCSF sewer project is seeking relocation of the other HZ cable, and thus another lengthy outage. These are not the only utilities that intersect the HZ cables alignments. With only two cables, taking one out of service for relocation leaves downtown San Francisco at risk of an unplanned outage of the remaining cable.
- By connecting PG&E's Embarcadero Substation and Potrero Switchyard, the Project will also provide an interconnection for PG&E's San Francisco 230 kV and 115 kV transmission systems. Such an interconnection will provide a number of benefits to PG&E operations and reliability, including: (a) provide the 115 kV system with an additional source of power when the HZ cables are in operation; (b) facilitate the eventual replacement of the 115 kV cables, some of which are now 55-65 years old; and (c) provide power from the 115 kV system to the 230 kV system if the 115 kV system were operational, but both the HZ cables were not.

The Project will provide additional benefits in the future. At some point, PG&E likely will be required to install a third cable to Embarcadero Substation to meet the North American Electric Reliability Corporation (NERC) transmission planning reliability standards approved by the Federal Energy Regulatory Commission (FERC), as well as the California Independent System Operator Corporation's (CAISO) planning standards, for two reasons:

1) Unless downtown San Francisco energy usage stops growing, at some point, after approximately 2030 based on projected load growth, the customer load served by Embarcadero Substation will exceed the capability of one of the existing HZ cables. At that point, as discussed below, PG&E will be required to add a third cable to comply with the NERC reliability standards.

2) At some point, one or both of the existing HZ cables, installed in 1973, will need to be replaced. As the need for replacement becomes evident, PG&E will need to construct a third cable to Embarcadero Substation to comply with the NERC reliability standards so that Embarcadero Substation is not dependent on a single cable during the lengthy construction of the replacement cable.

Constructing a third cable now would address the eventual need for a third cable in the future, as well as reduce or eliminate the current risk of overlapping outages of the existing cables.

In its 2011-2012 Transmission Plan, the CAISO agreed with PG&E that a third cable is needed to ensure reliable electric service, concluding: "While the likelihood of the simultaneous loss of both circuits is low, the consequences of the outage are severe and require mitigation." (CAISO, 2012, page 107.) With respect to the Project, the Transmission Plan states: "The ISO has determined that this project is needed to address the reliability requirements of the area and is expected to be in-service in 2015." (CAISO, 2012, p. 108.)

Each of these points is discussed in more detail below.

C. Relevant Reliability Standards and Planning Considerations

PG&E is subject to both mandatory reliability standards and an obligation to provide reliable electric service to customers within its service area. The Project helps PG&E meets both of its obligations.

1. FERC and NERC Mandatory Reliability Standards

NERC is the electric reliability organization certified by FERC to establish and enforce reliability standards for the bulk power system. NERC develops and enforces reliability standards that are approved by FERC. NERC also assesses system adequacy annually; and it monitors the bulk power system. The NERC reliability standards are mandatory and set a floor for utility-owned transmission systems.

The NERC reliability standards for planning reinforcements for the transmission systems are the transmission planning (TPL) standards. Among other things, the TPL standards establish the required system performance upon the loss of one, two, or more elements of a transmission system.

Standard TPL-002-2b "System Performance Following Loss of a Single BES Element" was recently revised and was reapproved by the NERC Board of Trustees on February 7, 2013.[1] For the loss of a single element in an electric transmission system (an N-1 or Category B event), NERC Standard TPL-002-2b states that the system must be stable and remain within operating voltage limits and equipment thermal limits, and it does not permit the dropping of firm demand customers in most instances to keep the system within these limits. Although some minor exceptions are granted for a planned drop of firm demand customers under certain limited circumstances, in no instance can this apply to demand levels above 75 megawatts (MW). (See Footnote b to Table 1.)[2] For the downtown San Francisco area, the minimum load level is more than 100 MW.

Thus, under the NERC reliability standards, PG&E must be able to continue providing electrical service to customers served by the Embarcadero Substation despite the loss of one transmission line to Embarcadero Substation. Because PG&E currently has the two HZ transmission lines serving Embarcadero Substation, either one of which has the capability to serve the current load, PG&E currently is in compliance with NERC Reliability Standard TPL-002-2b.[3] However, over the last 20 years,

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1 http://www.nerc.com/files/TPL-002-2b.pdf.

2 Although FERC has not yet reviewed and approved the recently revised NERC Standard TPL-002-2b, FERC disapproved NERC's previous version of Footnote b on the ground that it might allow dropping of firm demand customers too often, and insisted that NERC revise the standard to further limit the planned dropping of firm demand. FERC Order No. 762, Docket No. RM11-18-000, 139 FERC ¶ 61,060 (April 19, 2012). Thus, PG&E expects that it will not be able to plan to drop firm demand (i.e., downtown San Francisco customers) if it were to lose one transmission circuit serving Embarcadero Substation.

3 Please note that the loss of any single transmission element identified in NERC Standard TPL-002-2b is subject to the same performance requirements under the conditions set forth in that Standard. For the purposes of the Project, however, PG&E's focus is on the HZ cables.

electric demand at Embarcadero Substation has grown at a rate of roughly 6 MW/year. If this rate of demand growth continues into the future, the peak demand at Embarcadero Substation will be close to 400 MW around 2030. At that point, an outage of one HZ cable could result in an overload of the other HZ cable. This would be a violation of NERC Reliability Standard TPL-002-2b. The proposed ZA-1 cable will eliminate this future overload problem for a single-element (N-1) outage.

The same issue will arise when one or both of the HZ cables, installed in 1974, require replacement. NERC Standard TPL-001-4 "Transmission System Planning Performance Requirements" requires the transmission planner to account for outages of system elements which will be out of service for more than six months.[4] For this situation, the new "normal" system operating condition is with that element removed from service; and, with that system operating condition, an N-1 outage would then look at a second element out of service—and dropping of firm demand above 75 MW is not permitted. Replacement of an HZ cable will take more than six months. Thus, under NERC Reliability Standards TPL-001-4 and TPL-002-2b, PG&E must be able to continue to serve Embarcadero Substation customers even if the remaining HZ cable went out of service during replacement of the other HZ cable. Because PG&E could not serve its Embarcadero Substation customers, regardless of the load at that point, if both cables serving the substation are out of service, PG&E would be in violation of NERC Reliability Standard TPL-002-2b unless a third cable were built before replacement of an HZ cable began.[5] The proposed ZA-1 cable also will eliminate this future overload problem for a single-element (N-1) outage.

In contrast, NERC Reliability Standard TPL-003-2b "System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)" does permit the planned/controlled interruption of electric supply to customers for an overlapping outage of two or more bulk electric

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4 http://www.nerc.com/files/TPL-001-4.pdf.

5 This assumes that PG&E is able to identify the need for replacement of the HZ cable before it fails.

system elements.[6] PG&E is in compliance with NERC Reliability Standard TPL-003-2b at this point in time because it would require an outage of both HZ cables to deprive Embarcadero Substation customers of electric service.

The NERC reliability standards, however, provide a floor for the reliability of electric service. NERC realizes that there are other factors that need to be evaluated when looking at dropping firm demand customers. For example, when a transmission planning entity looks at dropping load under footnote b, it must provide "an explanation of the effect of the use of Firm Demand interruption… on the health, safety, and welfare of the community."[7] Utilities, regional transmission system operators, and state public utilities commissions must evaluate whether greater reliability serves the public interest under specific circumstances.

2. CAISO Planning Standard and Approval

CAISO is responsible for the planning and operation of the electric transmission system in California. CAISO is regulated by FERC. The CAISO Planning Standards recognize that the NERC reliability standards for transmission planning are the "minimum standards that ISO needs to follow in its planning process."[8] The CAISO Planning Standards states: "The California ISO (ISO) tariff provides for the establishment of planning guidelines and standards above those established by NERC and WECC to ensure the secure and reliable operation of the ISO controlled grid. The primary guiding principle of these Planning Standards is to develop consistent reliability standards for the ISO grid that will maintain or improve transmission system reliability to a level appropriate for the California system."[9]

In Section 6 of the CAISO Planning Standards (Planning for New Transmission versus Involuntary Load Interruption Standard), the CAISO states: "This standard sets out when it is necessary to upgrade the

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6 http://www.nerc.com/files/TPL-003-2b.pdf.

7 NERC Standard TPL-001-3, Item 2.b. at page 9, in Section II on "Information for Inclusion in Item #3 of the Stakeholder Process."

8 California ISO Planning Standards (June 23, 2011) at page 3, found at http://www.caiso.com/Documents/TransmissionPlanningStandards.pdf.

9 *Id.* at p. 3.

transmission system … to eliminate load dropping otherwise permitted by WECC and NERC planning standards through transmission infrastructure improvements."[10] Item 4 of that section provides: "Upgrades to the system that are not required by the standards in 1, 2 and 3 above may be justified by eliminating or reducing load outage exposure, through a Benefit-to-Cost Ratio above 1.0 and/or where there are other extenuating circumstances."[11]

This CAISO guidance is consistent with the NERC guidance to the responsible transmission planning entity to evaluate the overall impact of an outage on the economy, health and welfare of the community.

PG&E submitted the proposed Project to the CAISO as part of its transmission planning process. The CAISO evaluated the potential outage risks to downtown San Francisco and the benefits provided by the proposed Project. After conducting its evaluation, the CAISO approved the Embarcadero-Potrero 230 kV Transmission Project in 2012: "The ISO has determined that this project is needed to address the reliability requirements of the area and is expected to be in-service in 2015. In the interim, the ISO will work with PG&E to ensure operations procedures are in place."[12]

3. CPUC Decision 96-09-045

In Decision 96-09-045, the California Public Utilities Commission (CPUC or Commission) addressed the need for reliable electric service and set requirements for utilities to provide annual reports on the customer service reliability of their electric systems. The CPUC's goal was to ensure that electric utilities in California provide high levels of service reliability to customers. The Commission stated: "The notion that customers are entitled to reliable service is an essential aspect of the regulatory compact. Utilities with service territories have an obligation to serve all customers in that service territory and provide a societal necessity, in this instance electricity." (D.96-09-045 at p. 5.) The Commission also recognized that ensuring reliability through addition of electric transmission and distribution infrastructure has a cost to ratepayers, but that "the goal of cost

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10 *Id*. at pp. 5-6.

11 *Id.* at p. 6.

12 CAISO's 2011-2012 Transmission Plan at p. 108. http://www.caiso.com/Documents/Board-approvedISO2011-2012-TransmissionPlan.pdf.

minimization is one subject to other constraints: reliability, environmental effects, and diversity of resources." (*Id.* at p. 6.)

In attempting to define the appropriate level of reliability in California, the Commission stated that the "Commission's consistent but perhaps more stringent standard is that reliability will not be allowed to degrade from the level Californians have become accustomed to in the absence of electric industry restructuring. That level has, until recently, been fairly high." (*Id.* at p. 10.) The Commission pointed out: "California has experienced outages due to earthquake (1989 Loma Prieta, 1994 Northridge), severe "firestorms" (1991 Oakland, 1995 Los Angeles), and severely windy rainstorms (1995 PG&E storms). Safeguarding against these types of contingencies, by building in added redundancy in the transmission and distribution systems beyond that needed when one necessary facility is affected (single contingency), is generally not reasonable due to the cost consequences and low probability of multiple contingencies." (*Id.*)

The Commission then noted: "However, matters of emergency preparation and responsiveness, as well as ongoing maintenance of the transmission and distribution system, have merited heightened attention and scrutiny to respond to public concern. Emergency preparation has long been an obligation of utilities." (*Id.*) Thus, the Commission concluded: "Although building an electrical system to preclude all outages is, if possible, not reasonable in cost, utilities nevertheless have a duty to have emergency preparedness plans … and respond reasonably to service restoration in deployment of available or attainable resources." (*Id.* at p. 43.)

In Decision 96-09-045, the Commission affirmed the NERC TPL Reliability Standards set the base for reliable electric service, noted that cost concerns generally would make it unreasonable to construct a system able to deliver power despite a loss of multiple elements, but also noted that cost concerns must be balanced against reliability, emergency preparedness, and service restoration. The Commission thus recognized that, while the NERC TPL standard permits load dropping for an N-2 Category C outage, a higher level of service reliability may be necessary in some instances.

4. PG&E Has Determined That the Project Is Reasonable and Appropriate to Provide Downtown San Francisco With Reliable Electric Service

PG&E has carefully evaluated its transmission system serving downtown San Francisco and determined that it is reasonable and appropriate to guard against the loss of both HZ cables supplying power to Embarcadero Substation. The critical factors in this decision, discussed in Chapters 3, 6, 11, 12 and 13 are:

- Embarcadero Substation serves over 30,000 customer accounts, including more than 25,000 residential accounts. The electricity provided to these accounts serves far greater numbers of residents, downtown San Francisco workers, clients, customers, and tourists.
- A major earthquake in the Bay Area poses a significant risk of damaging both HZ cables because they cross areas of known high liquefaction risk. Accommodation of known underground infrastructure development would take one HZ cable out of service for significant periods of time, leaving downtown San Francisco at risk of a forced outage on the other HZ cable when neither could be quickly restored to service. Other risks of overlapping outages also exist.
- Restoring a damaged HZ cable to service likely would take eight weeks or longer, depending upon the type of damage, the number of points of damage, the ability to locate each point of damage, and the availability of skilled manpower, specialized construction equipment and sufficient spare cable and/or pipe. The restoration time is significantly longer than expected to restore an overhead transmission line or a piece of substation equipment to service.
- The estimated economic loss from a seven week outage of Embarcadero Substation is $4.3 to nearly $8.8 billion, including both direct and indirect losses. The business losses will result in workers losing their jobs and some businesses closing. In addition, residents of approximately 25,000 homes will need to find another place to live until service is restored, and governments will incur response costs. Although a major earthquake that damages the HZ cables will cause physical damage to some buildings in downtown San Francisco as well, the significant

majority of PG&E's customers will need electricity after such an earthquake to live, work and rebuild.

Given these circumstances, PG&E concluded that it would not be appropriate to simply drop service to downtown San Francisco in the event both HZ cables are out of service, even if permitted under the NERC Reliability Standards.

PG&E's determination was further supported by additional benefits of the Project. As discussed below, the Project interconnects PG&E's 230 kV and 115 kV San Francisco transmission systems, reinforcing both and providing greater operational flexibility for maintenance and replacement work. As discussed above, a third cable will be required by NERC Reliability Standards in the future when either the demand for electricity from Embarcadero Substation exceeds the capability of a single HZ cable or when an HZ cable requires replacement. By constructing the third cable now, instead of at such later date, PG&E guards against having to drop its 30,000 downtown San Francisco customer accounts if both HZ cables are out of service.

For these reasons, PG&E believes that the Project is reasonable and appropriate to provide reliable electric service to its customers in downtown San Francisco.

D. Reliability Risks to the Existing 230 kV Cables and How the Project Mitigates Them

PG&E is concerned about two scenarios that could result in both HZ cables being out of service at the same time: (1) a single event forces both HZ cables out of service; or (2) one HZ cable is out of service, whether a planned or forced outage, and an event forces the other HZ cable out of service. PG&E would not take a planned outage on an HZ cable if the other HZ cable were on a planned or forced outage, as that would result in loss of service from Embarcadero Substation.

1. Without the Project, a Major Earthquake Threatens Embarcadero Substation's Power Supply

As discussed in Chapters 6 and 7, a sufficiently large earthquake in the Bay Area has a high probability of damaging both HZ cables, leaving

Embarcadero Substation without power. Seismic studies show that the two HZ cables are routed through areas which could experience high liquefaction during an earthquake. For a magnitude 7.8 earthquake on the San Andreas Fault line, and based on analysis of only two segments of each line, InfraTerra has estimated that the HZ-2 cable has a 92.2 percent probability of failure and the HZ-1 cable has a 96 percent probability of failure. For a magnitude 7.0 earthquake on the Hayward Fault, InfraTerra estimates a 56.1 percent probability of at least one failure in the HZ-1 cable and a 58.9 percent probability of at least one failure in the HZ-2 line. Considering all potential earthquakes in the Bay Area, InfraTerra estimates a 33 percent probability of at least one earthquake-induced failure in the HZ-1 line and a 30.8 percent probability of at least one earthquake-induced failure in the HZ-2 line in the next 30 years, and failure probabilities of 48.7 percent and 45.8 percent for the next 50 years for the HZ-1 and HZ-2 lines, respectively. Most importantly, InfraTerra estimates the probability of concurrent failure of both HZ lines as 91.1 percent in the San Andreas 7.8 moment magnitude (M) earthquake, 48.2 in the Hayward 7.0 M earthquake, 26 percent over the next 30 years, and 39.4 percent over the next 50 years. As discussed in Chapter 11, earthquake damages to the HZ lines could take 8-16 weeks, or more, to repair and restore electric service to downtown San Francisco.

By contrast, as discussed in Chapter 4, the new ZA-1 cable is being designed to meet a performance objective of withstanding the expected 84th percentile ground motions from a magnitude 7.8 earthquake on the San Andreas Fault. The new line has been routed to avoid the areas of highest liquefaction risk. As discussed in Chapter 7, InfraTerra estimates the failure probability for the ZA-1 cable, depending upon the ultimate strength and flexibility of the submarine cable, to be between 4.6 percent and 8.1 percent in the San Andreas 7.8 M earthquake, between 0.8 percent and 1.6 percent in the Hayward 7.0 M earthquake, between 0.6 percent and 1.2 percent over the next 30 years, and between 0.9 percent and 1.9 percent over the next 50 years. The Potrero 230 kV Switchyard equipment is being designed to Institute of Electrical and Electronic Engineers Standard 693 “High” seismic qualification.

As discussed in Chapter 7, the new line is expected to significantly reduce the probability of a loss of service to Embarcadero following the design earthquake, both because the ZA-1 line is more seismically resilient and because there will be three rather than two transmission lines serving Embarcadero Substation. As discussed in Chapter 7, InfraTerra estimates the failure probability for all three cables (HZ-1, HZ-2 and ZA-1), depending upon the ultimate strength and flexibility of the submarine cable, to be between 4.6 percent and 8 percent in the San Andreas 7.8 M earthquake, between 0.8 percent and 1.6 percent in the Hayward 7.0 M earthquake, between 0.6 percent and 1.1 percent over the next 30 years, and between 0.9 percent and 1.9 percent over the next 50 years. Although no infrastructure can be guaranteed to survive any possible earthquake, the new ZA-1 cable will be designed to provide high confidence that it will remain operational, and thus is expected to be able to transmit power delivered into Potrero from Trans Bay Cable (TBC) and the 115 kV system up to downtown San Francisco even after an earthquake capable of damaging both HZ cables.

2. Without the Project, Planned or Unplanned Outages of Both of PG&E's Existing 230 kV Cables Would Force Embarcadero Substation Out of Service

As discussed in Chapter 9, the HZ underground cables can be out of service for maintenance work, as a result of a third-party "dig-in" that damages the pipe or cable pipe, as a result of damage caused by failure of other infrastructure such as a water or sewer main, or to accommodate other, nearby utility infrastructure work.

If one HZ cable is out for routine maintenance work, a forced outage of the other cable would likely result in an outage lasting only several hours, because the cable that is out for maintenance would be returned to service as quickly as safely possible. A cable that is forced out of service by a "dig-in" or failure of other utility infrastructure almost certainly would take longer to repair, and could take days to weeks depending upon the nature of the damage. If both cables were forced out of service, the restoration time could be days to weeks, again depending on the nature of the damage.

If one HZ cable is out of service due to other utility infrastructure work, a forced outage of the other HZ cable could result in an extended outage, depending on how long it takes to return either cable to service. For example, CCSF's sewer replacement project along Cesar Chavez Street will require the relocation of approximately 1,000 feet of the HZ-2 cable, requiring PG&E to take the HZ-2 cable out of service for four to five months. A forced outage of the HZ-1 cable at that time would result in a loss of power to downtown San Francisco. How long it would take to restore service would depend upon how close PG&E was to completing the HZ-2 relocation project and the nature of the damage to the HZ-1 cable. To avoid this risk, PG&E and the City have agreed to a temporary set-up with the HZ-2 cable and the new sewer line, until the new ZA-1 cable is in-service, at which time the HZ-2 cable will then be taken out of service and relocated. Recently another conflict with the HZ-1 cable was discovered as the City started replacing a section of sewer line at Zoe and Bryant Streets. A third cable would allow PG&E to take a cable out of service to accommodate these needed infrastructure improvements without placing downtown San Francisco at risk of a power outage.

PG&E attempts to minimize the risks of overlapping outages. Because PG&E must perform regular maintenance on its underground electric transmission system, and the above-ground portions of the lines that connect into the substation buses, much of the planned maintenance work on the HZ cables is scheduled for off-peak periods (like weekends) to minimize potential customer impacts should there be an unplanned outage of the other HZ cable. If one HZ cable were on an extended forced or planned outage, PG&E would attempt to minimize the risk of a "dig-in" by patrolling the route of the other HZ cable to detect any construction activity. Some risks, such as a water or sewer main break, undetected corrosion or insulation breakdown, are more difficult to guard against.

The new ZA-1 cable would make it significantly less likely that Embarcadero Substation would be forced out of service. As discussed above, the new ZA-1 cable would be able to transmit power to Embarcadero Substation that is delivered to the Potrero Switchyard by the TBC and PG&E's 115 kV system.

3. Other Cities Have Suffered Significant Loss of Electric Service as a Result of Aging Infrastructure

At some point, the underground 230 kV and 115 kV cables will need to be replaced because of capacity limitations or due to deteriorating performance as the cables age. There are concerns when old underground electric infrastructure starts failing. One concern is that the failure of one cable results in other, old equipment loading more heavily, which could result in a second failure. Then the remaining components in the system are even more heavily loaded, which could lead to other failures and a complete shut-down of the system. In this “cascading failure” scenario, the result is a severely damaged electric system that would require extensive repairs. Other cities have experienced this problem.

Chicago had a series of major service disruptions to its downtown area in August 1999. These service interruptions impacted thousands of customers and resulted in long outages. The outages were caused by old, deteriorated equipment in the Commonwealth Edison system: “What began as a routine problem with a splice on a power line cascaded into a series of three blackouts that stretched across downtown and lasted up to 11 hours… In the last two weeks, the grid has blinked on and off in a series of major outages, including a widespread blackout during the worst heat wave of the summer.”[13]

Another example is the city of Detroit, which has had several outages to its downtown area due to aging infrastructure. In June 2011, there was an extended outage to parts of downtown Detroit when an old underground cable owned by the Detroit Public Lighting Department failed. That failure resulted in higher loadings on other cables that subsequently also failed, knocking out power to municipal buildings, police stations and fire departments.[14]

PG&E’s underground transmission lines in San Francisco have been very reliable to date, and are expected to remain operational for some time yet. However, the HZ cables have been in operation for 39 years, and some

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13 “Downtown Blackouts – Power Fails, Sparks Fly,” *Chicago Tribune* article on August 13, 1999.

14 “Outage puts negative spotlight on Detroit's aging lighting dept,” *Detroit News* article on June 11, 2011.

of the 115 kV cables have been in operation even longer. It is reasonable to assume they will require replacement at some point, and it is not certain that PG&E will detect an impending failure with sufficient lead time to construct additional cables before failure.

E. The Project Improves the Reliability of a "Lifeline" Service

PG&E participates in disaster planning for San Francisco through such organizations as the CCSF-organized Lifelines Council, which seeks to create a more resilient city as discussed in various studies performed by The San Francisco Planning and Urban Research Association (SPUR). SPUR describes a "resilient" city as follows:

> Resilient communities have an ability to govern after a disaster has struck. These communities adhere to building standards that allow the power, water, and communication networks to begin operating again shortly after a disaster and that allow people to stay in their homes, travel to where they need to be, and resume a fairly normal living routine within weeks. They are able to return to a "new" normal within a few years. They are resilient communities because such a blow from nature remains a disaster, but does not become a catastrophe that defies recovery.
>
> (SPUR, The Resilient City: Defining What San Francisco Needs From Its Seismic Mitigation Policies (Feb. 2009) ("Resilient City") at 4.)

Through the Lifelines Council, the City, other government organizations, and business seek to promote policies that increase the City's resilience to a major earthquake.

Among other issues, SPUR focused on the need for "lifelines" to be functioning following a major earthquake:

> In disaster planning, much attention is paid to the role of buildings – how will they perform in a major earthquake? How long will they take to repair? Will people be able to stay in their homes after a quake, or will they need temporary shelter? Less attention is paid to the role of the infrastructure systems that support urban life, which we call our "lifelines." <u>By "lifeline," we mean the utility systems that bring us our water, electricity and natural gas</u> and the transportation systems that allow us to get around, including public transit, ports and airports, and road infrastructure. As with buildings, <u>lifelines are critical to our ability to recover from an earthquake</u>. If our buildings are not "serviceable," nobody can live or work in them. San Francisco's capabilities for response to, and recovery from, an earthquake are highly dependent on the condition of lifelines in the wake of such a disaster.
>
> (SPUR, Lifelines: Upgrading Infrastructure To Enhance San Francisco's Earthquake Resilience (Feb. 2009) ("Lifelines Study") at 3 (emphasis added).)

To enhance the City's resiliency, SPUR identified performance objectives within a timeline following a major earthquake. Critically, SPUR assumes that the vast majority of San Francisco residents will "shelter in place," i.e., stay in their homes. SPUR identifies the performance objectives as including, within 24 hours: "All occupied households are inspected by their occupants and less than 5 percent of all dwelling units are found unsafe to be occupied. Residents will shelter in place 1 in superficially damaged buildings even if utility services are not functioning." Within 72 hours, however: "Ninety percent of the utility systems (power, water, waste water, and communication systems) are operational and serving the facilities supporting emergency operations and neighborhoods." (Resilient City at 5.)

To support this performance objective, the Lifeline Study proposed expected performance goals for lifeline utilities, including:

> **Resume 100 percent of service within 4 hours, with backup systems if necessary**
>
> Critical response facilities - including emergency housing centers – need to be supported by utility and transportation systems critical to their success. This level of performance assures that these systems will be available within four hours of the disaster. It requires a combination of well built buildings and systems, provisions for making immediate repairs as needed, and redundancy within the networks that allows troubled spots to be isolated.
>
> **Establish control of the system and resume 90 percent of service within 72 hours; resume 95 percent of service within 30 days; and resume 100 percent of service within four months**
>
> Housing and residential neighborhoods require utility and transportation systems be restored quickly <u>so that these areas can brought back to livable conditions</u>. There is time to make repairs to lightly damaged buildings and replace isolated portions of the networks or create alternate paths for bridging around the damage. There is time for parts and materials needed for repairs to be imported into damaged areas. These systems need to have a higher level of resilience and redundancy than the systems that support the rest of the City. (Lifelines Study at 9 (emphasis added).)

As discussed in Chapter 11, restoring a damaged HZ cable to service could take 8 weeks or more. In the Lifelines Study, SPUR noted that its "goals assume the occurrence of the 'expected' earthquake, defined as an earthquake that can reasonably be expected to occur once during the useful life of a system. For San Francisco's buildings, this earthquake is defined as having a 10 percent chance of occurrence in 50 years. As described in the [Resilient City], a magnitude 7.2 earthquake on the peninsula segment of the San Andreas Fault would produce this level of shaking in most of the City. Since lifeline systems generally serve cities and regions for well over 100 years, a larger 'expected' earthquake should be considered," (Lifelines Study at 9 (emphasis added)), meaning that lifelines should be expected to perform at a significantly higher level than ordinary structures and systems. In the report attached to Chapter 7, based on analysis of two segments of each line, InfraTerra found that the HZ-1 and HZ-2 cables would have a 48.2 percent probability of concurrent failure from a magnitude 7.0 earthquake on the Hayward Fault. The magnitude 7.0 Hayward Fault scenario results in significantly lower levels of shaking than the magnitude 7.2 San Andreas event cited in the Resilient City studies due to greater distance from the Hayward fault as well as slightly lower magnitude. Because the two cables traverse many of the same areas of high liquefaction hazard, their performance is highly correlated. The probability of concurrent failure of the HZ cables in a magnitude 7.2 San Andreas event is therefore likely to be significantly higher than the values reported by InfraTerra for the magnitude 7.0 Hayward Fault earthquake. The ZA-1 line will mitigate the risk of losing the lifeline electric service provided by the HZ cables.

F. Interconnecting PG&E's 115 kV and 230 kV San Francisco Transmission Systems Provides Additional Reliability Benefits

As discussed in Chapter 2, currently there is no interconnection between PG&E's 230 kV and 115 kV transmission systems in San Francisco. As a result, neither system can provide support to the other system in the event of outages.

The new ZA-1 line will interconnect the 230 kV and 115 kV systems within the City. For normal system conditions, with all system components in service, power flow on the new ZA-1 line will be about 40 to 50 MW from Embarcadero down to Potrero. When the HZ cables are out, the ZA-1 can supply all power needed by Embarcadero Substation, without overloading the 115 kV system.

In addition, the new ZA-1 line, when the HZ cables are in service, could transmit power from Embarcadero Substation to Potrero Switchyard, and thus to the 115 kV system if needed. This helps reduce power flow on the 115 kV cables bringing power into the City should there be outages of several 115 kV lines or TBC. For a single outage of TBC during peak load conditions, the new ZA-1 cable will transmit over 100 MW of power down to the 115 kV system. For overlapping outages of TBC and another 115 kV cable bringing power into the City, the ZA-1 cable could provide over 130 MW of power to the 115 kV system.

The support that the ZA-1 cable provides to the 115 kV system will be helpful in the future when some of the older 115 kV import cables need to be replaced. By 2030, three of the 115 kV cables bringing power into the City from Martin will be more than 70 years old:

- Martin – Larkin No. 1 (HY-1) 115 kV Cable – 82 years old
- Martin – Hunters Point No. 1 (HP-1) 115 kV Cable – 82 years old
- Martin – Hunters Point No. 3 (HP-3) 115 kV Cable – 72 years old

Replacing each of these cables will require that the cable be out of service for possibly up to a year. Without the new ZA-1 cable, should TBC be out of service during one of these cable replacements, the remaining five 115 kV cables supplying the City from Martin Substation would have to supply all of the power to the substations served by the 115 kV system. With the new ZA-1 cable, should TBC be out of service during the replacement of one of these 115 kV import cables, the ZA-1 cable would provide over 130 MW of power down to Potrero from the 230 kV system.

G. Planning Ahead to Maintain Reliable Electric Service

As discussed above, the Project provides immediate reliability benefits to downtown San Francisco by providing a third source of power into Embarcadero Substation. It also significantly increases the operational flexibility to do maintenance work on both the 230 kV and 115 kV systems serving the City. The Project also provides long-term system capacity benefits.

NERC Reliability Standards require that PG&E be able to serve Embarcadero Substation customers despite the loss of one transmission line. If growth continues at a rate similar to what has occurred over the last 20 years, then peak demand at Embarcadero Substation could be over 400 MW sometime after 2030. At that point, if one HZ cable is out of service, the remaining HZ cable cannot serve all Embarcadero customers. This is a violation of NERC reliability criteria and would need to be corrected by adding a third cable to provide the needed capacity on the 230 kV system. (Upgrading the existing HZ cables is not a viable option and is discussed in more detail below.)

In addition, even if there were no further load growth in downtown San Francisco, a third cable will be required by NERC reliability criteria when one of the HZ cables must be replaced. The existing HZ cables have reliably served the downtown area for the last 39 years and are expected to continue to provide reliable service into the future. However, as the HZ cables age, there will be an increased chance that one of the cables could experience a failure, which could necessitate replacing all or a section of the cable. Replacing a segment could take several months to complete, while replacing the entire line could take up to a year or more. During that time, the downtown area would be completely dependent upon the other HZ cable, which would violate NERC reliability criteria if the work was expected to take more than six months. Leaving aside the NERC reliability criteria, PG&E would not consider it prudent to have only a single cable serving downtown San Francisco for months.

Given these immediate and long-term benefits, it is prudent to increase the capacity of the 230 kV system by constructing a third 230 kV cable to help supply Embarcadero Substation. By constructing the new cable now, there is a significant decrease in the risk of an outage to the downtown area. It provides greater flexibility in being able to de-energize a cable to do maintenance or other infrastructure work. And it provides additional system capacity to help meet the long-term needs of the City.

H. The Project Is the Best Alternative to Address the Reliability Deficit in Downtown San Francisco

The Project is the best alternative to address the reliability and future capacity issues with the existing 230 kV system supplying Embarcadero Substation. The Project provides a third source of power to Embarcadero. The Project will also provide a connection point between the 230 kV system and the 115 kV system at the Potrero Switchyard, which is supplied by TBC and two strong cables from Martin Substation.

PG&E evaluated various alternatives to the Project, but found the Project to provide the best way to address both present and future reliability needs for downtown San Francisco.

1. New Generation or Energy Storage Are Not Feasible Alternatives

New generation or energy storage are not feasible alternatives to the Project. These alternatives cannot meet the need for additional electric service reliability addressed by the Project, or provide the other benefits of the Project.

A key objective of the Project is to provide a high likelihood of continued electric service to downtown San Francisco in the event of overlapping outages of both HZ transmission lines serving PG&E's Embarcadero

Substation. Embarcadero serves over 30,000 customers in the downtown area, with a peak demand of more than 270 MW on a hot day. On a typical weekday, Embarcadero Substation has a minimum electric demand of more than 100 MW and a peak demand of over 200 MW, which means that the energy consumption in the downtown area on a typical weekday is more than 3,800 megawatt-hours. Depending upon the nature of the HZ cable outages, restoration of service could take eight weeks or longer depending on the nature of the damage.

As a result, for these other alternatives to provide electric service to Embarcadero customers that is equivalent to the proposed Project, there would need to be over 200 MW of distributed generation and energy storage facilities installed in the downtown area—with the capability of providing power 24/7 for at least eight weeks. This would be the equivalent of a major power plant with associated transmission and fuel supply infrastructure. Renewable energy distributed generation, such as solar or wind, is not a feasible option because it is intermittent; thus, the potential generation units most likely would be natural gas-fired. PG&E is not aware of any suitable locations for such a generation facility (or many smaller generation units) or sufficient storage units in downtown San Francisco, does not believe it would be feasible to timely obtain permits for 200 MW of natural gas-fired generation facilities in downtown San Francisco, and thus has not attempted to calculate the cost of installing such generation units and the associated system upgrades in downtown San Francisco. The cost, however, would be significant and exceed the cost of the Project. Energy storage facilities are not a feasible alternative, not only due to siting and cost considerations, but because they lack capacity to provide energy during an outage that could last up to eight weeks.

2. Energy Efficiency and Demand Response Programs Are Not Feasible Alternatives

The Project addresses the loss of all power to Embarcadero Substation and the approximately 30,000 customer accounts it serves. Energy efficiency and demand response programs are not a feasible alternative to the Project. Energy efficiency and demand response programs can slow demand growth and can reduce local load levels in emergencies, but these programs cannot mitigate the potential loss of all power to downtown customers if both HZ cables are out of service.

3. Retrofitting the HZ Cables Is Not a Feasible Alternative

The Division of Ratepayers Advocates asked whether the HZ cables could be modified or retrofitted to protect against the risk of an outage due to liquefaction-induced damage, and, if so, whether such modification could thus be an alternative to the Project. As discussed in Chapter 2, the HZ cables are 230 kV High Pressure Fluid Filled Pipe Type cables. Each HZ transmission line is roughly seven miles long, with roughly 40-foot pipe segments welded together, running under City streets. According to an analysis performed by InfraTerra, the HZ transmission lines include about 43 underground concrete vaults regularly spaced along the pipelines for pulling the cables through the pipelines. The HZ pipelines combined also cross as many as 144 other significant utilities (such as brick sewers, concrete sewers, water pipelines and gas pipelines) in close proximity of the HZ pipelines. Many of these utilities are located within a few inches of the HZ pipelines.

Modification of the existing HZ cables is not a feasible alternative to the Project. The existing pipelines cannot be easily (or cost-effectively) retrofitted to strengthen them against strains imposed by liquefaction. Although it may be theoretically possible to do so, it is not practical. Any retrofit scheme will require excavation of several miles of City streets to expose the most threatened segments of the pipelines and apply strengthening schemes. Such schemes potentially could include: encasement of pipelines, where feasible, in steel-reinforced concrete; where feasible, support sections of pipes and vaults on pile supports down to bedrock; and efforts to strengthen likely several hundred of the over 1,500 joints in the pipelines. Many of these schemes may not be practical due to utility congestion in the City streets, traffic impacts and construction noise.

Moreover, such an effort would be cost prohibitive and such retrofit schemes would have much greater uncertainty in their effectiveness compared to the proposed Project given the location of the HZ lines and extent of the hazard. During the 1906 earthquake, several feet of liquefaction imposed deformations were observed at multiple locations along the alignment of the HZ lines.

Finally, strengthening of each line and the vaults would likely require de-energizing the line, which would leave only one cable serving the Embarcadero Substation during construction. Taking one of the HZ lines out of service for an extended period would be imprudent and may violate NERC reliability criteria depending on the duration of the outage. PG&E further notes that such efforts to strengthen the existing HZ cables, at enormous expense and with uncertain results, would still leave only two transmission lines serving the Embarcadero Substation. Thus, it would not address the future need for a third cable.

Replacement of one or both of the HZ cables also is not a feasible or rational alternative to the Project. First, the replacement line would continue to traverse significantly greater areas of known high liquefaction risk than the proposed ZA-1 line. Second, replacement of either HZ line would require construction of a third line as PG&E would not take one HZ line out of service during construction because that would leave only a single HZ cable serving Embarcadero Substation during construction. This would be imprudent and would violate NERC/FERC reliability criteria due to the duration of the outage. The proposed Project is construction of such a third line—along an alignment that also avoids areas of major liquefaction hazard currently traversed by the HZ cables; connects PG&E’s 115 kV and 230 kV transmission systems in San Francisco; and connects Embarcadero Substation to the Potrero Switchyard, which has TBC as a source of energy other than Martin Substation.

4. Other Transmission Alternatives Are Not Feasible, More Costly, or Do Not Provide the Same Benefits as the Project

PG&E looked at other transmission system reinforcement options to the proposed Project. However, these options were either not feasible, more expensive and/or did not achieve the same overall benefits as the Project.

a. Expansion of 115 kV Network to Include Embarcadero Substation Is More Expensive and Disruptive

The proposed Project seeks to enhance the reliability of electric service in downtown San Francisco by adding a third transmission line to Embarcadero Substation and interconnecting PG&E's 230 kV and 115 kV transmission systems in San Francisco. PG&E considered and rejected transmission alternatives that would have constructed a third line to Embarcadero from other PG&E substations in San Francisco for a number of reasons, including space requirements, capacity of the local 115 kV system, ease of constructability, cost and future expansion capability.

To interconnect the 230 kV and 115 kV systems in the City, a new 230/115 kV transformer and related equipment must be installed at one of PG&E's substations on the 115 kV network. Since Embarcadero does not have sufficient room to install a 230/115 kV transformer and the associated 115 kV equipment, the new 230/115 kV transformer and 230 kV equipment must be installed at the 115 kV substation to which a 230 kV line to Embarcadero Substation interconnects. Moreover, the substation from which the third transmission line to Embarcadero Substation originates must have a robust enough supply from the 115 kV system to not only manage its load within the 115 kV system, but also to supply the load at Embarcadero if the existing Martin-Embarcadero (HZ) 230 kV cables fail. Potrero is the termination point for both the TBC and the newly replaced 115 kV import cables from Martin. This is the strongest station on the 115 kV system.

Project constructability and cost are also major factors in developing the Project. In addition to the substation space constraints mentioned above, there are no "existing transmission paths" either between Embarcadero Substation and any other San Francisco substation on PG&E's 115 kV system. Thus, any connection between Embarcadero Substation and other PG&E 115 kV substations would require construction of a new transmission line under City streets.

The Project is superior to transmission alternatives that interconnect Embarcadero to PG&E 115 kV San Francisco substations other than Potrero Switchyard.

b. Alternative Transmission Lines to Embarcadero More Expensive and May Not Achieve the Same Level of Benefits

Alternative transmission alternatives that construct a line between Embarcadero Substation and a PG&E substation that is not part of PG&E’s 115 kV San Francisco system do not achieve the same benefits as the Project because they do not interconnect PG&E’s 230 kV and 115 kV San Francisco transmission systems. As a result, such other alternatives do not allow either of the systems to reinforce each other as may be needed. In addition, some of the other alternatives, such as a 230 kV transmission line from PG&E’s San Mateo Substation to Embarcadero or from a PG&E East Bay substation to Embarcadero, would involve a much longer and hence more expensive transmission line, and almost certainly take longer to permit and construct. The Project is the best alternative to achieve PG&E’s goals for the proposed Project.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 15

ENERGY DIVISION VARIANCE AUTHORITY FOR THE EMBARCADERO-POTRERO 230 KV TRANSMISSION PROJECT

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ENERGY DIVISION VARIANCE AUTHORITY FOR THE EMBARCADERO-POTRERO 230 KV TRANSMISSION PROJECT

A. Introduction

1. Purpose and Scope

This chapter supports Pacific Gas and Electric Company's (PG&E) request that the California Public Utilities Commission (CPUC or Commission) grant the Energy Division staff authority to approve variances to the Project that do not require supplemental or subsequent analysis under the California Environmental Quality Act (CEQA).

2. Organization of the Remainder of This Chapter

- Section B – Energy Division Should Have the Flexibility to Respond to Unanticipated Changes in the Project if There Is No New Significant Adverse Environmental Effect
- Section C – Minor Refinements of an Approved Project May Be Necessary or Desirable
- Section D – Potential Minor Refinements May Be Outside the Limited Variance Authority Given Energy Division on Recent Projects

B. Energy Division Should Have the Flexibility to Respond to Unanticipated Changes in the Project if There Is No New Significant Adverse Environmental Effect

On August 12, 2013, the CPUC's Energy Division issued its Draft Initial Study/Mitigated Negative Declaration (IS/MND) for the Project in accordance with CEQA. The Draft IS/MND concludes that all Project-related environmental impacts could be reduced to a less than significant level with the incorporation of feasible mitigation measures.

As noted in PG&E's Application: "To avoid incurring significant costs before the Commission approves the Project, final engineering will be performed after the Commission has completed its CEQA review and approved the Project or an alternative thereto. Final engineering sometimes results in minor modifications to the project design." (Application at 20.) In addition, new information learned post-approval and during construction can also lead to a need to make minor refinements to the Project. Further, interactions with other agencies and property owners after approval of a project can also lead to a desire to make minor refinements to the Project, if it accommodates another party without adding significantly to costs or delaying the schedule, and if the modification has no significant adverse environmental impact.

Under CEQA Guideline § 15162(a), a supplemental Environmental Impact Report (EIR) is required if the lead agency determines that "[s]ubstantial changes are proposed in the project which will require major revisions of the previous EIR or negative declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects." PG&E's Application requests that the Commission explicitly order that the Energy Division shall be authorized to determine whether a minor Project refinement would result in new significant environmental effects or a substantial increase in the severity of previously identified significant effects. If a proposed change to the approved Project would result in new significant environmental effects or a substantial increase in the severity of previously identified significant effects, then Energy Division would determine that a Petition for Modification (PFM) of the Commission Decision granting the Certificate of Public Convenience and Necessity (CPCN) must be filed and a supplemental CEQA document must be prepared if the proposed change is pursued. On the other hand, if a proposed change to the approved Project would not result in new significant environmental effects or a substantial increase in the severity of previously identified significant effects, then the Energy Division should be authorized by the Commission's CPCN Decision to grant any requested minor Project refinement required during final engineering and construction.

The following testimony explains the kind of circumstances that can lead to a requested refinement of an approved project, and why a petition to modify a Commission decision approving the project is not an adequate substitute for authorizing the Energy Division to approve refinements found to not have any new or more severe significant environmental effects.

C. Minor Refinements of an Approved Project May Be Necessary or Desirable

As a result of the need to evaluate potential environmental impacts of electric projects under CEQA, and to mitigate any significant environmental impacts to the extent feasible in accordance with CEQA, the Energy Division prepares a detailed "project description," including Applicant-proposed measures for reducing impacts from the project, for use in preparing either an IS/MND or an EIR. The Commission then may approve construction of the project or a project alternative as described in the applicable CEQA document, along with any applicable mitigation measures detailed in a Mitigation Monitoring, Reporting, and Compliance Program (MMRCP).

Because the Commission's approval is a prerequisite for the project, the project description and the MMRCP usually are prepared before final engineering is performed, including site-specific subsurface investigation, and before discretionary and ministerial permits are obtained from other federal, state and local government agencies. As a result, sometimes minor changes to either or both the project description or mitigation measures are necessary or desirable, despite both the Applicant's and Energy Division's best efforts to anticipate and address potential future issues.

D. Potential Minor Refinements May Be Outside the Limited Variance Authority Given Energy Division on Recent Projects

In several recent decisions, the Commission has provided Energy Division with limited "variance" authority. For example, on PG&E's Application for a Permit to Construct its Shepherd Substation, the Commission's Order approving the project states:

> Energy Division may approve requests by Pacific Gas & Electric Company (PG&E) for minor project refinements that may be necessary due to final engineering of the Shepherd Substation Project <u>so long as</u> such minor project refinements are located <u>within the geographic boundary of the study area</u> of the Final Mitigated Negative Declaration and do not, without mitigation, result in a <u>new significant impact or a substantial increase in the severity</u> of a previously identified significant impact based on the criteria used in the environmental document; <u>conflict with any mitigation measure</u> or applicable law or policy; or <u>trigger an additional permit requirement</u>. PG&E shall seek any other project refinements by a petition to modify this decision.

See Decision 13-05-019 at 14 (emphasis added); *accord* Decision 12-06-039 at 21-22.

This limited variance authority, if extended to the present Project, could require that PG&E institute a new proceeding and seek a full vote of the Commission, through a petition for modification of the original decision on this Project, in order to make minor refinements to the Project. That result may occur even if the Energy Division determines that the change would have no significant adverse impact on the environment, or even if the change would benefit the environment. PG&E submits that requiring an extensive and burdensome proceeding that in no way is required by CEQA or any other state law is not a prudent or efficient use of the Commission's resources.

PG&E has experienced circumstances on past electric projects in which a minor refinement to the project approved by the Commission has been necessary, desirable, or both. Although PG&E has worked with Energy Division on the proposed Embarcadero-Potrero 230 kV Transmission Project to identify potential future issues so that they could be addressed in the IS/MND, PG&E is aware that not all future events can be anticipated. PG&E provides a few examples of issues that could arise—even though PG&E has no information that such issues will arise—to illuminate the potential need for minor refinement to the Project.

1. Minor Refinements on Past Projects

On past projects, PG&E has requested minor project refinements that had no significant environmental effect. Some have been granted while others have not. None of the examples below appear to be allowed without a petition for modification under the limited variance authority found in the Shepherd Substation Decision:

- On the Palermo-East Nicolas 115 kV Reconstruction Project, PG&E found that the storage and office space planned for the project was inadequate, given that a large number of poles were to be delivered at the same time. PG&E requested a variance to lease an existing industrial yard to use as additional storage and a construction staging area. PG&E's environmental consultant reviewed the proposed site to determine whether there would be any new or more severe environmental impacts as a result of the use of the construction yard. Their analysis concluded that the use would be consistent with existing zoning, historic use, and surrounding uses, and found no additional impacts. PG&E needed a few routine ministerial city permits, none of which independently required additional CEQA review, to meter electricity and use a mobile office building. Energy Division granted the variance, even though the pre-existing construction yard was not in the original project study area and additional ministerial permits were needed. If Energy Division had not granted the variance, construction likely would have been delayed a year (due to very specific seasonal windows to avoid impacts to protected species), increasing construction costs (demobilization and remobilization costs plus renegotiation of supply contracts) and forcing agricultural landowners to lose another growing season (with resulting claims for losses).

- On the Palermo-East Nicolas 115 kV Reconstruction Project, PG&E requested use of a different helicopter landing zone (LZ) after the owners of the property planned for the LZ denied PG&E use of the land. PG&E requested a variance to lease an existing graveled parking lot and storage area for an alternative LZ. Biological and cultural surveys found that there would not be any new or more severe environmental impacts. Energy Division granted the variance, even though the pre-existing parking and storage areas were not in the original project study area. If Energy Division had not granted the variance, PG&E would have had to use a more distant LZ approved in the project's IS/MND, thereby increasing emissions, noise impacts, construction costs, and safety risks.
- On the Palermo-East Nicolas 115 kV Reconstruction Project, PG&E requested a variance to allow for the relocation of a small portion of an access route in order to provide a greater level of worker and public safety and environmental resource protection. The originally planned route followed an existing agricultural road, which had fallen out of use and would have required grading to deal with ruts and significant trimming of two oak trees that overhang it. There also were low-hanging distribution lines immediately to the south of this road that could have presented a danger to crews moving large equipment in the area. PG&E proposed to shift access travel to the north across a field, which did not require grading. Biological and cultural surveys found that there would not be any new or more severe environmental impacts. Energy Division approved the variance, even though the minor re-route (approximately 150 feet) was not specifically identified in the project description. If Energy Division had not granted the variance, clearing the approved

access road would have resulted in additional ground disturbances, impacts to protected heritage oak trees, and a safety threat to workers.

- On the Crazy Horse Canyon Switching Station Project, PG&E originally proposed using water from PG&E yards for dust control and landscaping related to the project. The Energy Division studied that proposal and included it in an IS/MND for the project. PG&E later realized that it could reduce traffic and vehicle-related air emissions by drawing water from a hydrant on San Juan Grade Road, which was 0.5 miles from the site rather than 5-10 miles for the PG&E yards. The Energy Division approved the minor project modification after it found it introduced no new potential significant impacts. PG&E then consulted with the city of Salinas, which stated that it preferred PG&E use other hydrants, or other privately metered sources of water, rather than the hydrant identified by PG&E in its request to the Energy Division. All of these alternative water sources were similarly close to the project site. PG&E proposed, and the CPUC approved, use of any of these alternative sites because they created no new potential for significant impacts. If Energy Division had not granted the modification, PG&E would have traveled much longer distances to obtain water for the project, resulting in additional environmental impacts through air emissions, increased traffic impacts, and increased costs.

These kind of minor project refinements occur on essentially every major infrastructure project because it is impossible to foresee everything that may occur during later engineering and construction. In the past, Energy Division primarily has looked to whether the refinement causes any new or more severe environmental impacts in deciding whether to authorize a change to the approved project.

2. Potential Minor Modifications on the Proposed Project

PG&E expects that on the proposed Project, as in the examples described above from past projects, unanticipated circumstances will cause the need for minor modifications to the very detailed Project Description incorporated into the IS/MND by the Energy Division. For example, PG&E's contractor could find physical impediments or obstacles on the Bay floor that were not detected through the remote surveys completed, and these impediments or obstacles could necessitate minor changes in the Project alignment. Similarly, the potholing conducted as part of final engineering in the underground portions of the route may uncover obstacles or features that require minor adjustments to the project alignment. Additional geotechnical borings could lead to desired changes in the location or alignment of Horizontal Directional Drilling borings or transition manholes to decrease the risk of liquefaction. Available storage or staging areas could change. PG&E is aware that other, unanticipated events or conditions may make minor changes in the Project necessary, desirable or environmentally beneficial.

3. A Petition for Modification Usually Is Not a Viable Alternative

Where the Energy Division lacks authority to issue a variance, the option to PFM of the approval decision usually will not be feasible due to its impact on the project schedule and concomitant cost increases. If unopposed, a PFM likely will take at least two months. If opposed, a PFM likely would take a minimum of three months, and more likely much longer.[1] At almost any phase of a major construction project, the time required for a PFM will cause a delay, leading to an increase in project costs. If the need for a minor modification arises after contractor resources have been committed to mobilize on a date certain, or construction has begun, each day of delay can result in very significant cost increases.

The end result would be that minor modifications which require a PFM, even when the Energy Division finds that such a modification will not have a new or more severe environmental impact, will not be sought regardless of whether the modification is beneficial, unless the project could not otherwise proceed. In addition to creating administrative inefficiencies, this outcome could lead to increased ratepayer costs, landowner inconvenience, less reliable electric service, and/or greater environmental impacts.

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[1] Under Commission Rule of Practice and Procedure 16.4, a petition to modify a Commission decision must be served on at least the parties to the original proceeding, other parties have 30 days to file a response, a reply may be filed within 10 days thereafter, an Administrative Law Judge then normally will issue a proposed decision within 90 days, parties will have 20 days to comment and 5 days for reply comments, and some time thereafter the proposed decision will be on the Commission's agenda.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

STATEMENTS OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF WITNESS ALAIN J. BILLOT

Q 1 Please state your name and business address.

A 1 My name is Alain J. Billot, and my business address is Pacific Gas and Electric Company, 275 Industrial Rd., San Carlos, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a senior consulting project manager in the Electric Transmission Project Management Department of Electric Operations. In this capacity, I am responsible for managing major projects from inception to completion.

Q 3 Please summarize your educational and professional background.

A 3 I received a certificate in project management from the University of California, Berkeley in 1994, a bachelor of science degree in business/information systems from the University of Phoenix in 1997, a Stanford certified project manager certificate in 2007 and was certified as a project management professional by the Project Management Institute in 2010. I started my career with PG&E in 1983 as a contractor and was hired permanently in 1986. I held several clerical, engineering assistance and financial management training positions in the Diablo Canyon, Substation, Hydro Generation until 1991 when I was hired as a project management analyst in the Transmission System Business Unit Project Management group. In 1995, I was promoted to project manager then to senior project manager in 1999 and to senior consulting project manager in 2011. My responsibilities consist of managing multi-year, major projects in the $10 to 200 million range that typically involve complex scope and regulatory permitting under CEQA such as permit to construct and certificates of public convenience and necessity. Some of the most significant projects I have or am managing include: relocating over 100 PG&E gas and electric transmission and distribution electric facilities and installing several substations to power the Bay Area Rapid Transit to San Francisco Airport Expansion project, installing additional new substations to power for the SFO Expansion, reconductoring the San Mateo to Martin number four 115 kV transmission line, installing the Jefferson-Martin 230 kV project, Martin to Hunters Point 115 kV cable and Oakland C-X three 115 kV cable, replacing and upgrading the Martin 115 kV bus, the main source of transmission power to San Francisco and the northern Peninsula and the Russell City Energy Center Interconnection project, including installing a generation tie line, a new 230 kV substation, reconductoring of major transmission lines and upgrading the regional electric transmission protection system. I am currently working on the new Embarcadero to Potrero 230 kV cable project which includes a new 230 kV transmission switchyard; building a new 230 kV transmission bus at Embarcadero substation; the reconductoring of the Pittsburg to San Mateo Bay crossing 230 kV line and the San Francisco and Oakland Emergency Underground Transmission Restoration Project.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Embarcadero-Potrero Transmission Reliability Project proceeding:

- Chapter 4, "PG&E's Proposed Embarcadero-Potrero 230 kV Transmission Project":
  - Sections 4-1 through 4-25
- Chapter 5, "Cost Estimate for PG&E's Proposed Project."
  - Attachment 5A, "Project Cost Estimate."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MARK A. BURNHAM

Q 1 Please state your name and business address.

A 1 My name is Mark A. Burnham, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a senior underground transmission line specialist in PG&E's Electric Operations-Transmission and Work Methods and Procedures group. I support underground transmission line work in the San Francisco Bay Area.

Q 3 Please summarize your educational and professional background.

A 3 I received a bachelor of science degree in Civil Engineering from Colorado State University and obtained my Professional Engineer license from the state of Colorado. I started my professional career as a consulting transmission project design engineer in 1979 with a Colorado electrical consulting firm, responsible for design of overhead transmission projects for utilities and rural electric associations. In 1989, I began working at PG&E as a contract overhead transmission line design engineer and, in 1991, became a full-time PG&E employee. As a project design engineer, I supervised overhead design engineers to ensure safe, efficient, and successful transmission line projects.

Following that, I became a supervising specialist for Substation Engineering, Quality Assurance where I coordinated preparation and execution of substation maintenance and construction compliance assessments in accordance with internal and external standards. In 2005, I began supervising the underground transmission maintenance crew at Martin Service Center and in 2007 I became the underground transmission specialist responsible for creating and reviewing underground transmission maintenance and construction work procedures.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Embarcadero-Potrero Transmission Reliability Project proceeding:

- Chapter 9, “Potential Non-Seismic Outages of Existing San Francisco 230 kV Transmission Lines.”
- Chapter 10, “Potential Non-Seismic Outages of New Embarcadero-Potrero 230 kV Transmission Lines”:
  - Section 10-C, “Potential Non-Seismic Outages of Underground Portion of ZA-1.”
- Chapter 11, “Restoration Time for Transmission Line Outages.”
  - Section 11-B, “Potential Outages and Restoration Times for Existing HZ Cables.”
  - Section 11-C, “Potential Outages and Restoration Times for Proposed ZA-1 Cable.”

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF THOMAS J. CANNON

Q 1 Please state your name and business address.

A 1 My name is Thomas J. Cannon, and my business address is Pacific Gas and Electric Company, 2180 Harrison Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the principal engineer in Electric Asset Management, responsible for supervising eight electric distribution planning engineers and initiating internal projects to improve Reliability and Capacity in San Francisco and East Bay.

Q 3 Please summarize your educational and professional background.

A 3 I received a bachelor of science degree in electrical engineering from Pennsylvania State University. I first began working at PG&E as an engineer in 1990, working as an electric distribution planning engineer for 15 years in the Concord office. In 2005, I left PG&E and took a job at Pennsylvania Power & Light as a senior transmission protection engineer where I worked for two years. In 2007, I returned to PG&E as the principal engineer in the San Francisco office. I am a registered Professional Engineer in California.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Embarcadero-Potrero Transmission Reliability Project proceeding:

- Chapter 3, "PG&E's Embarcadero Substation."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF ERIC M. FUJISAKI

Q 1 Please state your name and business address.

A 1 My name is Eric M. Fujisaki, and my business address is Pacific Gas and Electric Company, 6111 Bollinger Canyon Road, San Ramon, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am principal civil engineer in the Substation Engineering Services Department where I provide direction and support for substation and transmission line projects on seismic design issues and the seismic qualification of substation equipment, and develop seismic and structural design criteria.

Q 3 Please summarize your educational and professional background.

A 3 I received a bachelor of science degree in civil engineering from the University of Hawaii, and a master of science degree in engineering with an emphasis on structural engineering from the University of California at Berkeley. I am a registered civil engineer in the state of California. I began working for PG&E in 1980 as a design engineer in the hydro power house design group. Soon after this, I worked as a civil engineer in the Diablo Canyon Power Plant (DCPP) design verification project where I was involved in seismic analysis and modification design of several power block structures. Following licensing and commencement of operations of the plant, I worked on various projects at DCPP including the Long-Term Seismic Program, Individual Plant Examination, and design basis documentation project. In 1997, I joined the Electric Substation/ Transmission Department where I have worked on seismic evaluation and retrofit of substation buildings and equipment seismic qualification, and provided technical direction for PG&E, for a number of user-driven directed research projects conducted by the Pacific Earthquake Engineering Research Center related to the seismic performance of electric substation equipment. During my time in this department, I have actively participated in industry standard-making organizations and currently serve as chair of the Institute of Electrical and Electronic Engineers (IEEE) 693 working group on seismic design of substations, vice-chair of the IEEE 1527 working group on seismic design of bus work, member of the American Society of Civil Engineers 113 Committee on the design of substation structures, and written or co-authored a number of technical papers and research reports related to substation equipment seismic qualification, performance, and design.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Embarcadero-Potrero Transmission Reliability Project proceeding:

- Chapter 8, "Seismic Risk to Other System Components Serving Embarcadero Substation."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MICHAEL C. HERZ

Q 1 Please state your name and business address.

A 1 My name is Michael C. Herz and my business address is Pacific Gas and Electric Company, 3400 Crow Canyon Road, San Ramon, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the electric and magnetic fields (EMF) program manager for PG&E. I am responsible for communicating information about the issue of EMF to customers and employees. I also oversee the EMF portion of new and upgraded company projects, including strategies for communication, mitigation and public involvement. I have performed over 1,000 magnetic field measurements for residential customers, schools and businesses.

Q 3 Please summarize your educational and professional background.

A 3 I have been an employee of PG&E for 28 years. Before assuming my current responsibilities in 1993, I was an electric transmission engineer responsible for San Francisco and San Mateo counties. My duties included magnetic field measurements for customers and presentations on the EMF issue. From 1986 to 1989, I was an electric distribution planning engineer, responsible for planning, maintenance, and operation of the electric distribution system in Contra Costa County.

I received a bachelor of science degree in electrical engineering from California State University, Fresno. I am a registered professional electrical engineer in the state of California. I am a member of the following organizations: Power Engineering Society of IEEE, Eta Kappa Nu - Electrical Engineering Honor Society, Tau Beta Pi - National Engineering Honor Society, and Phi Kappa Phi - National Honor Society.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Embarcadero-Potrero Transmission Reliability Project proceeding:

- Chapter 4, "PG&E's Proposed Embarcadero-Potrero 230 kV Transmission Project":
  - Section E, "PG&E's Compliance With CPUC EMF Policies."
  - Attachment 4A, "EMF Design Guidelines for Electric Facilities."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

Infra • Terra

CHRISTOPHER HITCHCOCK, PG, CEG
PRINCIPAL ENGINEERING GEOLOGIST

Mr. Hitchcock is a Certified Engineering Geologist (CEG) with over 20 years of expertise in geologic mapping and engineering geology, including leading major geotechnical investigations for the California Department of Water Resources, Pacific Gas & Electric Company, State of California Emergency Management Agency, Alameda County, and the Federal Veterans Administration. He has been a Principal or co-Principal Investigator on fourteen research projects sponsored by the U.S. Geological Survey's National Earthquake Hazard Reduction Program (NEHRP) and the National Science Foundation (NSF) to assess earthquake and slope stability hazards. Results of Mr. Hitchcock's geologic mapping of range-front faults including the Monte Vista and Shannon faults have been published by the USGS (Open File Report 94-187), incorporated into various city and county Seismic Safety Elements, and have been used for scenario earthquake planning by the Association of Bay Area Governments (ABAG).

Academic Background

University of Utah, Salt Lake City, UT: M.S., Geology, 1993
University of California, Santa Barbara, CA: B.S., Geology, 1990
(National Merit Scholar, UC Regents' Scholar)

Qualifications

Certified Engineering Geologist, California, No. 2017
Professional Geologist, California, No. 6522
Licensed Engineering Geologist, Washington, No. 2472
Licensed Geologist, Washington, No. 2472
Certified Geographic Information Systems (GIS) Professional (GISP), No. 00059777
Competent Person Certification (OSHA - Trenching)

Professional History

InfraTerra, Inc., San Francisco, California, Principal Engineering Geologist, Co-Founder
Fugro Consultants, Principal Engineering Geologist, 2008 - 2011
William Lettis & Associates, Inc., Staff to Principal Engineering Geologist, 1993 - 2008

Professional Experience

Mr. Hitchcock has been lead engineering geologist, and Task Order Manager, for providing continuing on-call geotechnical support for the California Department of Water Resources (DWR), including on-call support of dam and levee engineering for Division of Engineering since 2003. Mr. Hitchcock has provided review services for Alameda County and Cities of Vallejo, Piedmont, Orinda, Lafayette, and Pleasanton. His responsibilities have included reviews of geotechnical and environmental reports and field reviews of landslide repairs for subject properties. Much of his project experience relates to geologic and seismic hazard evaluation combined with geotechnical characterization for geographically-distributed water supply systems.

Mr. Hitchcock has managed or supported seismic reliability and site geotechnical assessments for major regional water supply systems, including:

- Landslide investigations and repairs for the CDWR South Bay Aqueduct system including two emergency landslide repairs of the Aqueduct in Milpitas and for the Del Valle pipeline in Livermore;

- Geologic and seismic studies in support of system reliability studies for major water supply systems in northern California (Sonoma County Water Agency, Contra Costa Water Agency, City of Hayward, and DWR State Water Project);

- Geotechnical siting, seismic evaluation, and landslide investigations for new proposed reservoirs (DWR Dyer Reservoir, DWR Tehachapi Afterbay, DWR Crafton Hills, and DWR Sites and Golden Gate dam sites).

- Former Deputy Contract Manager and Fugro Representative responsible for administering $25 million IDIQ contract for Dam and Levee Engineering Services for USACE South Pacific Division (5 years, Fugro JV with HDR).

<u>Mr. Hitchcock's professional background includes the following engineering geology evaluations of site conditions for critical facilities:</u>

U.S. Veterans Adminstration, San Francisco Veterans Administration Medical Center, San Francisco, California. Project manager for comprehensive slope evaluation and phased assessment of geologic and geotechnical conditions associated with slope and pavement distress observed north of Veterans Drive, opposite buildings of the San Francisco Veterans Administration Medical Center (SFVAMC). The assessment of the subject slope included reviewing existing geologic data and historic aerial photographs, mapping cracks in the pavement and distress, drilling borings and installing inclinometers, and monitoring the inclinometers. He managed and completed detailed geologic mapping of the distressed slopes, constructed geologic cross sections, and provided geometry and depths of inferred landslides. Slope stability options developed for the facility included surface and groundwater control, grading remediation, and retaining structures (including micropile and cantilever/tie-back soldier pile walls).

California Department of Water Resources, Dyer Reservoir, Livermore. Project manager and lead engineering geologist for assessment of foundation conditions of the proposed Dyer Reservoir, part of the South Bay Aqueduct. Assisted DWR personnel in the excavation and documentation of test pits for the characterization of foundation soils. Completed exploratory trenching to evaluate the extent and activity of landslides adjacent to Dyer Dam and Reservoir. Work performed by Mr. Hitchcock included review of available reports, interpretation of aerial photography, and excavation of trenches and test pits to expose landslide deposits and evaluate activity of an ancient landslide in the vicinity of the dam site. Mr. Hitchcock participated in, and provided advice for, review by DWR Division of Safety of Dams.

California Department of Water Resources, Del Valle Emergency Landslide Investigation and Repair. Performed investigation of landslide triggering, landslide repair construction monitoring, and pipeline replacement and backfill monitoring. Work included geologic analysis of borehole data to identify depth and geometry of slide plane. Managed and performed interpretation of LiDAR-based topographic surveying, geologic mapping, and site inspections and monitoring during repair construction.

Trans European Motorway (TEM), Landslide and Fault Rupture Hazard Mapping and Evaluation, Turkey. Project manager for geologic-geotechnical mapping and evaluation of fault rupture and landslide hazards to highway viaduct, tunnel, and roadway alignment for the Trans European Motorway (TEM) that connects Istanbul and Ankara, the Turkish capitol, for the Turkish Highway Department. A 15-kilometer section of the TEM was damaged by surface fault rupture, tunnel collapse, and landslides triggered by the 1999 Izmit and Duzce earthquakes. The damaged section of the highway included an elevated concrete viaduct, large-diameter tunnel, and embankment fill sections in steep mountainous terrain crossed by numerous active faults. The study included geologic mapping, fault trench/rupture investigations, landslide evaluation, and development of recommendations for hazard mitigation. Work managed and performed by Mr. Hitchcock included detailed mapping and trenching of surface fault rupture produced by the November 1999 Düzce earthquake.

Governor's Office of Emergency Services, La Conchita Slope Stabilization Project, Geological Study and Risk Assessment, Landslide Mapping, Southern California. Project manager and lead geologist for geological characterization, including detailed mapping and subsurface exploration, of the La Conchita landslide under static and dynamic (earthquake). The La Conchita landslide is unique in that it is bisected by the active Red Mountain fault. The 2004 landslide into the community of La Conchita killed ten people and blocked the main railroad and highway access along the Ventura Coast. Mr. Hitchcock was responsible for developing GIS-based geologic and hazard maps that integrate 30-cm resolution LiDAR, geotechnical borings, and field mapping to characterize both the slide and the fault. He worked closely with A3Geo to develop an all-inclusive analysis of surface and subsurface conditions for the formulation of different hazard mitigation options. These findings will serve as the basis for formulating risk assessment of various options and associated conceptual budgets.

Sandia National Labs, Hydrogeologic Site Characterization, Albuquerque, New Mexico. Performed geologic mapping and hydrogeologic description of surficial deposits for use in numerical hydrologic models for remediation of Kirtland Air Force Base. Mr. Hitchcock was also responsible for the design and implementation of a drilling program to characterize near-surface deposits. The products of this study included digital (GIS) maps of surficial deposits, detailed geologic cross-sections, and three-dimensional hydrogeologic models that show near-surface flow and transport patterns.

South Texas Power Nuclear Operating Company COL Application, Matagorda County, Texas. Performed ground and aerial reconnaissance fieldwork as well as literature review and analysis in support of South Texas Power's Combined License. Mr. Hitchcock's work contributed to revising regional and local seismic source models critical for site design and contributed to evaluating the potential for surface rupture within the site area.

Nuclear Waste Storage Facilities, Skull Valley, Utah and southern New Mexico. Participated in evaluations of active faults in the vicinity of proposed private nuclear waste storage facilities in central Utah and southern New Mexico, reviewed by the Nuclear Regulatory Commission (NRC). Efforts include characterization of local and regional potential seismic sources for ground motion hazard analysis conducted in support of a site characterization study for a temporary spent-fuel storage facility. Mr. Hitchcock was responsible for calculating deterministic ground motions for multiple proposed sites, compiling and evaluating available information on possible seismic sources, and managing site-specific drilling studies that documented the presence of active fault offsets.

Windfarm Siting Feasibility Studies, Pacific Gas & Electric Company, California. Lead engineering geologist responsible for geotechnical evaluation of existing conditions and potential geohazards for:

- PG&E West Butte Wind Project, Geohazard Site Evaluation, OR. Project manager for desktop evaluation of West Butte wind farm power generation site in Oregon. Tasks included analyses of slope, rippability, geologic conditions, and potential geologic hazards for the site area.

- PG&E Iron Mountain and Port San Luis Wind Farm Projects - Road Constructability Evaluation, CA. Project manager for office-based assessment of transmission corridor and proposed tower locations. Tasks completed included reconnaissance-level assessment included collection of geologic and soil data, analysis of aerial photography, development of road layers, estimation of road rippability, calculation of the volumes of rock and soil removal required for road construction.

- PdV Wind Energy and Infill Project – Independent EIR Review, Kern County, CA. Provided independent technical review of geology, seismic, and soils sections of

Environmental Impact Report for proposed Wind Energy facility and associated powerlines.

Mr. Hitchcock's professional background includes the following professional peer review services and engineering geology for schools and hospitals:

City of Vallejo, Hiddenbrooke Residential Development, northern California. As City reviewer, Mr. Hitchcock performed office and field-based reviews of grading operations for the "Reflections I", "Reflections II", "The Summit", and "The Orchard" residential developments in Hiddenbrooke, Vallejo. The developments consist of single-family homes and an 18-hole golf course. Geotechnical issues involve slope failure hazards, expansive soil conditions, and settlement hazards on cut/fill slopes. Mr. Hitchcock conducted field reviews of site conditions, including inspection of backcuts, keyways, and landslide repairs during grading operations.

City of Pleasanton, Geologic Reviews of Proposed Residential Developments, Pleasanton, California. As City reviewer, Mr. Hitchcock performed office and field-based reviews of site conditions and grading operations for proposed residential developments along Foothill Road, Clara Lane, and Vineyard Avenue in Pleasanton. Geotechnical issues involve slope failure hazards, expansive soil conditions, and settlement hazards on cut/fill slopes. Seismic issues reviewed include fault rupture hazards associated with the Calaveras fault and secondary faults. Mr. Hitchcock conducted field reviews of site conditions; including inspection of trenches, test pits, and grading operations.

Piedmont Unified School District, Geotechnical Study and Geologic Hazards Evaluation, Beach Elementary School Improvements, Piedmont, California. Lead Certified Engineering Geologist for geotechnical field exploration and laboratory-testing program to characterize surface subsurface conditions in order to evaluate the geotechnical, geologic hazard and seismology aspects for proposed school improvements.

Santa Clara Unified School District, Lateral Spreading Analysis, Wilcox High School, Santa Clara, California. Lead Certified Engineering Geologist responsible for conducting geological and geotechnical peer review of earthquake-related lateral spreading hazard to school buildings**.**

Ohlone College, Student Support Services Building, Science Modular Project, and Below Grade Water Intrusion (BGWI) Project, Fremont. Mr. Hitchcock performed geologic hazards evaluation for the proposed new Student Support Services Building, Science Modular Project, and Below Grade Water Intrusion (BGWI) Project located at the Ohlone College Campus. Geologic and seismic hazards evaluated as part of these projects includes site geotechnical conditions, liquefaction hazard, fault rupture hazard, landslide hazard, and strong ground shaking. The studies included development of supplemental geotechnical recommendations, reviewed by the State of California.

San Ramon Unified School District, New Southwest Middle School, Environmental Impact Report, Northern California. Project manager for the preparation of the hydrology, water quality, geologic, soils, geotechnical, and seismic hazards chapters of the EIR document for San Ramon Valley Unified School District. Specific concerns expressed by the School District and the general public included: landslide and erosion hazards that might be exacerbated by the planned grading and cutting of hillsides; the proximity of the site to several known active faults; surface runoff volumes and quality will be altered by the project; and ground-water levels and quality might be affected by the planned development.

Washington Hospital, Emergency Department Expansion, Geotechnical and Geologic Hazards Update, Mowry Avenue, Fremont. Mr. Hitchcock performed a geologic hazards evaluation update for the Washington Hospital Healthcare System for the proposed expansion of the Emergency Department at the Washington Hospital, located at 2000 Mowry

Avenue in Fremont, California. The study included review of site conditions, previous reports, and development of supplemental geotechnical recommendations.

Mr. Hitchcock's professional background includes the following route assessment and studies for existing and proposed lifelines:

Shell, CO2 Sequestration Pilot Project, Pipeline Routing, Southern California (2012). Project manager and lead engineering geologist for evaluation of geohazards for selection of alternative routes for high-pressure pipelines to carry CO2 from refineries to injection wells. Office and field-based evaluation of routes included integration of published geologic and seismic hazard maps, interpretation of LiDAR and InSAR data, evaluation of major fault crossings, landslide inventory mapping, and interpretation of offshore bathymetric data to optimize possible pipeline routes.

InterOil, Papua New Guinea Elk/Antelope Gas Condensate Project. Managed and performed field- and office-based engineering geology and geotechnical studies for a proposed 120-km long LNG pipeline in the Gulf Provence of Papua New Guinea (PNG). Performed detailed desktop and field evaluation of slope stability, erosion, soft soils, liquefaction susceptibility, and fault crossings for proposed pipeline routes and directional bores under major rivers in triple-canopy rainforest based on interpretation of remote sensing data, LiDAR, and extensive helicopter and ground reconnaissance. Provided detailed GIS of geologic and seismic hazards with pipeline routing options.

Cache Creek Casino Natural Gas Pipeline, Pipeline Corridor Geotechnical Evaluation, Northern California. Project manager and lead engineering geologist for development of maps that identify and rank potentially significant geologic hazards along a private gas pipeline route between PG&E Line 400 and Cache Creek Casino in Capay Valley. Hazards evaluated for this study by Mr. Hitchcock included fault crossings, potential slope instability and areas of significant erosion. Input for design included detailed characterization for a major direction bore undercrossing of Cache Creek.

Southern California Gas Company, Line 1004 Directional Bore Landslide Repair. Project manager for detailed study of the geotechnical viability of mitigation options for a pipeline impacted by coastal landslides, rerouting and landslide mitigation alternatives were fully investigated. Geologic interpretation of high-resolution, publicly available IFSAR and privately-flown LiDAR data were used to evaluate alternative routes around active and potentially active landslides. Geotechnical borings through the landslide ultimately provided sufficient information for directional drilling beneath the active landslide and replacement of the existing pipeline within the directional bore, returning it to full service.

Southern California Gas Company, Line 6906 Liquefaction Hazard Assessment, Southern California. Project manager for liquefaction hazard screening study of proposed gas supply pipeline 6906 in San Bernardino, California. Mr. Hitchcock performed a comprehensive review of relevant topographic, geologic and soils engineering maps and reports, aerial photographs, groundwater contour maps, the history of liquefaction in the area, and other relevant published and unpublished reports. Based on results of the liquefaction hazard screening, Mr. Hitchcock conducted quantitative liquefaction analyses of selected borings within areas of potentially moderate to high liquefaction hazard and prepared a report for review by the California Energy Commission.

Liquefaction Susceptibility Mapping, Southern California Gas Company, Southern California. Lead Geologist responsible for the detailed liquefaction susceptibility mapping of over fifty 1:24,000 scale, 7.5 minute quadrangles (~83,50 square km) covering Ventura, Los Angeles, and Orange counties for the Southern California Gas Company. The GIS-based mapping effort integrated layers of Quaternary geology, groundwater, and borehole data that were used to assess and delineate areas of low, moderate, high, and very high liquefaction susceptibility. The FWLA susceptibility mapping provides a much more detailed representation of the liquefaction hazard, than do the regulatory Liquefaction Hazard Zones established by the California Geological Survey. The digital susceptibility maps were readily incorporated into the SoCalGas GIS system to facilitate the evaluation of liquefaction hazards to their pipeline network.

Southern California Gas Company, Geologic and Geotechnical Evaluation of Proposed Pipeline Alignments, Ventura, California. Office-based geotechnical study for two proposed, onshore LNG export pipeline alignments in Ventura County, California. Managed compilation and interpretation of existing liquefaction maps, geologic maps, CGS landslide/liquefaction zones and ground motions, ground water maps, soil maps, and compiling existing geotechnical borings. Hazard analysis also included liquefaction analysis of geotechnical borings using the Seed Simplified approach.

Geotechnical and Geohazard Electrical Corridor Studies, Pacific Gas & Electric Company, California. Provided geologic and seismic assessments and supporting foundation studies for proposed substation facilities including the proposed Paso Robles – Estrella Substation and the Yerba Buena NaS battery facility, the Oro Loma substation project, and electrical vaults in Palo Alto. Lead engineering geologist responsible for geotechnical evaluation of existing conditions and potential geohazards for:

- PG&E Moss Landing-Salinas-Soledad-Hollister Tower 115-kV Reconductoring/ Reroute. Project manager for office-based evaluation of geohazards.
- Balch Sanger 115kV Tower Replacement. Lead engineering geologist for characterization of tower foundation conditions and geologic hazards.
- McCall-Kingsburg 230 kV Steel Pole Designs. Lead engineering geologist for characterization of foundation conditions for pole design.
- PG&E Caribou - Palermo 115 kV Reconductoring/ Reroute, Palermo, CA. Project manager for field-based assessment of foundation conditions at proposed tower locations.
- PG&E Fulton-St. Helena proposed 230 kV line, St. Helena, CA. Project manager for field-based assessment of transmission corridor and proposed tower locations.
- PG&E Missouri Flat - Gold Hill #1 & 2 115 kV line, Folsom, CA: Desktop corridor geologic and geotechnical assessment.
- PG&E Rio Oso - Gold Hill 230 kV Reconductoring Project, Sacramento, CA. Reviewed erosion, ground shaking, corrosion, slope stability, and other hazards for proposed tower and pole locations for reconductoring/reinforcement.
- PG&E West Point-Valley Springs 115 kV reconductoring, CA. Desktop corridor geologic and geotechnical assessment.
- Kern-Old River 2 70 kV Line Pole Replacement. Provided input on foundation geotechnical conditions.

Pacific Gas & Electric Company, El Dorado Water Project, Landslide Hazard Evaluation, Riverton, California. Mr. Hitchcock performed a geologic and geotechnical investigation of landslides along the El Dorado Canal in the Sierra Nevada, to: (1) assess risk to future operations of the canal, (2) develop recommendations to mitigate landslide hazards, and (3) develop a repair and monitoring program to “winterize” the canal. He conducted detailed mapping and cataloged mapped landslides in terms of location, size, type of movement, and hazard to the canal.

CHRISTOPHER HITCHCOCK, PG, CEG
PRINCIPAL ENGINEERING GEOLOGIST

Mr. Hitchcock's professional experience includes the following engineering geologic assessment for system-wide reliability studies:

Pacific Gas & Electric Company, System-wide Seismic Vulnerability Assessment Program, Northern California. Project manager for ongoing assessment of landslide, fault rupture, and liquefaction hazards along high-pressure natural-gas transmission pipelines in northern California for Pacific Gas & Electric (PG&E). Ongoing responsibilities include mapping and characterization of active landslides, evaluation of liquefaction hazards at pipeline crossings of major streams and rivers, and evaluation of potential fault rupture hazards.

Sonoma County Water Agency Water, Risk Assessment of Water Supply System, Northern California (2001-Ongoing). Project manager and lead engineering geologist for assessment of geologic and seismic hazards to SCWA's water supply system, which includes 17 reservoirs, 9 major pipelines, and 8 pump stations. Mr. Hitchcock managed and conducted evaluation of geologic and seismic hazards to the system. Phases of study included a regional hazard analysis followed by site-specific drilling and dynamic stability analyses of key water supply facilities. The assessment was used for comprehensive risk modeling of system vulnerabilities, development of retrofit priorities, and cost-benefit assessment for preparation of a retrofit budget and application for FEMA assistance.

Contra Costa Water District, Fault Vulnerability Assessment of Water Supply System, Northern California. Lead engineering geologist responsible for evaluating potential fault rupture displacement of large-diameter (20" or greater) water supply pipelines across the Concord fault. Damage to the aqueducts would substantially disrupt the supply of water to a population of approximately 230,000 people.

California Department of Water Resources, Delta Risk Management Study, Sacramento-San Joaquin Delta, California. Source characterization study, performed under the auspices of the Delta Risk Management Study. Prepared model of seismic sources in the Delta for probabilistic evaluation of ground shaking hazard to levees. Work involved: analysis of geotechnical bore-hole data; preparation of local and regional structure contour maps to assess locations of folds and faults in the subsurface; development of balanced geologic cross-sections; characterization of blind thrust faults as seismic sources (maximum earthquake; slip rate); evaluation of uncertainty in source parameters; preparation of source parameters for inclusion in probabilistic model; and preparation of technical report.

City of Hayward, Fault Vulnerability Assessment of Sewer and Water Main System, Northern California. Lead engineering geologist for evaluation of fault rupture hazard to the water and sewer system within the City of Hayward. Tasks completed included compilation and review of previous subsurface trenching and mapping studies, field mapping using GPS and GIS to delineate active creeping traces of the Hayward fault, and delineations of the location, amount, and width of possible ground deformation.

East Bay Municipal Utility District, Seismic Hazard Assessment for South Reservoir, Hayward, California. Project manager for evaluation of seismic rupture and ground shaking hazards to South Reservoir. Work managed and performed by Mr. Hitchcock included evaluation of potential fault rupture at the reservoir, estimation of peak horizontal ground accelerations (PGA), and calculation of potential rupture offset of reservoir embankments.

California Department of Water Resources, South Bay Aqueduct Reliability Assessment (2010). Project manager for on-going assessment of potential geologic hazards to the South Bay Aqueduct, the major water system supplying the southern San Francisco Bay Area. Work performed by Mr. Hitchcock includes the evaluation of the activity of active portions of ancient landslide complexes crossed by the Aqueduct.

Mr. Hitchcock's professional experience includes the following fault rupture evaluation studies:

Pacific Gas & Electric Company, Natural Gas Pipelines L-103, L-181b, L-310, L-21A/B, L-131, L-303, and L-107 Fault Rupture Vulnerability, Northern California. Project manager and lead seismic geologist responsible for evaluating potential fault rupture hazards along the Calaveras fault near Sunol (Lines 107 and 303), the Hayward fault in Fremont (Line 131), and San Pablo (Line 105b), the San Andreas fault near San Juan Bautista (Lines 103 and 181b) and Bitterwater (Line 310), and the Rodgers Creek fault (Lines 21A and 21B). For these major gas transmission pipeline fault crossings, Mr. Hitchcock conducted and supervised subsurface trenching to define the fault location and width, and interacted with pipeline engineers to develop appropriate rupture mitigation plans.

California Department of Water Resources, Sites and Golden Gate Dam Sites, northern California. Field manager for a comprehensive, three-year study of seismic hazards in the northwestern Sacramento Valley as part of the Phase II Fault and Seismic Hazards Investigation (Integrated Storage Investigations: North of Delta Offstream Storage Investigation). Evaluated strong ground shaking and potential surface fault displacements at two sites under consideration for construction of new dams in the northwestern Sacramento Valley. Work managed and performed by Mr. Hitchcock included field mapping, paleoseismic trenching, and quantitative geomorphic analyses.

California Department of Water Resources, Tehachapi Second Afterbay Project, southern California. Project manager and lead geologist responsible for an independent analysis of the Pinon Hill Fault located near the proposed Tehachapi Second Afterbay project. Office and field analyses were conducted in order to provide observations and recommendations on potential surface fault rupture hazards at the Tehachapi Second Afterbay dam site from strands of the Pinon Hill Fault.

U.S. Bureau of Reclamation, Monticello, East Park, and Stony Gorge Dams, Northern California. Mr. Hitchcock was responsible for geomorphic assessment of Quaternary active faults in the vicinity of Monticello, East Park, and Stony Gorge Dams for the U.S. Bureau of Reclamation. This study focused on providing input to deterministic analyses of strong ground motions for the dams.

Waste Management, Inc., Simi Landfill, Simi Valley, California. Project manager for an evaluation of the presence or absence of faults within the proposed expansion area of the Simi Landfill. Mr. Hitchcock participated in a comprehensive field study to evaluate surface faulting hazard. Mr. Hitchcock was responsible for literature compilation and review, interpretation of aerial photographs, and field and aerial reconnaissance of the site and vicinity. Based on the findings of our study, recommendations were developed to help WMI evaluate the feasibility of expansion at the site.

Waste Management, Inc., Bluebonnet Landfill, Houston, Texas. In order to evaluate the presence or absence of faults within the proposed expansion area of the Bluebonnet Landfill, Mr. Hitchcock participated in a comprehensive field study to evaluate surface faulting hazard associated with recently reactivated aseismic, high slip rate normal faults related to buried salt domes and regional growth faults in Houston, Texas. Mr. Hitchcock was responsible for literature compilation and review, interpretation of aerial photographs, and field and aerial reconnaissance of the site and vicinity. Based on the findings of our study, recommendations were developed to help WMI evaluate the feasibility of expansion at the site.

CHRISTOPHER HITCHCOCK, PG, CEG
PRINCIPAL ENGINEERING GEOLOGIST

Mr. Hitchcock's background includes the following peer-reviewed research:

US Geological Survey, Paleoseismic, Geologic, and, Geomorphic Research Studies on Earthquake Hazards. Principal or co-Principal Investigator on twelve research projects sponsored by the U.S. Geological Survey's National Earthquake Hazard Reduction Program (NEHRP), the National Science Foundation (NSF), and the Southern California Earthquake Center (SCEC). These studies include evaluation of fault-related deformation associated with the Monte Vista, Cascade, and Silver Creek faults in Santa Clara County. Mr. Hitchcock's liquefaction susceptibility maps have been incorporated into hazard zone maps by the California Geological Survey (CGS).

National Science Foundation, Seismic Source characterization, San Fernando Valley, Southern California. Principal co-investigator for a NSF-funded geomorphic study of surface deformation above active thrust faults within northern San Fernando Valley. This study applied quantitative geomorphic techniques to evaluate potential earthquake sources in the epicentral area of the 1994 Northridge earthquake and possible surface deformation from 'blind' thrust faults similar to those mapped by Mr. Hitchcock in the Santa Clara Valley.

National Science Foundation, Liquefaction Hazard Mapping, Simi Valley, Southern California. Principal investigator for evaluation of liquefaction hazards within Simi Valley. This National Science Foundation (NSF) funded study included detailed mapping of Quaternary geology and analyses of geotechnical borings to delineate areas of high liquefaction hazard. Products include digital (GIS) geologic and liquefaction susceptibility maps produced in cooperation with the California Geological Survey (CGS) Seismic Hazards Mapping Program. These products were incorporated into CGS's official liquefaction hazard zone maps and are being used by the City of Simi Valley and Ventura County for planning purposes.

Department of Energy, Research Grant for Geothermal Development. Principal co-investigator responsible for cost analyses of exploration models for EGS system using CO2 as heat transfer medium.

US Mineral Management Service (MMS), Submarine Mudflow Susceptibility Mapping Study, Gulf of Mexico. Project manager and lead Principal Investigator for MMS-funded research project to delineate mudflow failures, sediments susceptible to future slope failure, and areas of relative stability in the Mississippi Delta. Mr. Hitchcock developed and tested a geomorphology-based approach to map mudflow susceptibility on the sea floor bottom to provide hazard information for the siting and design of future pipelines and structures. As part of the project, Mr. Hitchcock used available bathymetric data to delineate areas of relative sea floor stability over the past century, areas of active mudflow transport, and areas of mudlobe deposition.

Environmental Impact Reports/Studies (EIR/EIS) Preparation, Various Clients, California

Mr. Hitchcock was responsible for preparation/review of geology, groundwater, and soils sections for:

- City of Brisbane, Brisbane Baylands Project (ongoing). Reviewing EIR for proposed development of approximately 700 acres of the Brisbane landfill.
- City of San Ramon, Henry Ranch Residential Development. Responsible for preparing geologic, soils, geotechnical, and seismic hazards sections.
- San Ramon Valley Unified School District, New Southwest Middle School. Responsible for preparing hydrology, water quality, geologic, soils, geotechnical, and seismic hazards chapters of the EIR document.

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City of Hayward, Seismic Safety Element, Northern California. Mr. Hitchcock evaluated the current state-of-knowledge of geologic and seismic hazards in the City of Hayward and updated the Safety Element for the City. The Seismic Safety Element establishes policies and programs to protect the community from risks associated with seismic hazards. As part of the update, Mr. Hitchcock reviewed existing geologic literature (e.g., consultants reports, published maps, reports) for Hayward, as well as state-of-the-art research into the seismic hazards and geology of the area. Five primary GIS-based geologic and seismic hazard maps were updated at 1:24,000-scale (covering 162 square km), including: (1) strong ground shaking, (2) fault rupture, (3) liquefaction, (4) slope instability, and (5) water inundation from tsunami or dam-failure.

County of Ventura, Geologic Mapping, Southern California. Project manager and lead geologist for Quaternary geologic mapping and evaluation of liquefaction hazards within Ventura County. Developed digital Quaternary geology and liquefaction susceptibility maps in close cooperation with the Geologic Survey (CGS) for the County of Ventura Resource Management Agency as part of a comprehensive, integrated seismic hazards mapping program in Ventura County. Maps developed by Mr. Hitchcock have been incorporated into the County of Ventura's GIS database for characterization of potential seismic hazards to pipelines and associated facilities, as required by recent State legislation, and for emergency response planning.

Professional Affiliations

Member, American Geophysical Union (AGU)
Member, American Society of Civil Engineers (ASCE)
Member, Geological Society of America (GSA)

Selected Relevant Publications

Fenton, C. H., and Hitchcock, C.S., 2002, Recent geomorphic and paleoseismic investigations of thrust faults in Santa Clara Valley, California: Association of Engineering Geologists (AEG) Special Volume, Engineering Geology Practice in Northern California.

Hart, James D., Zulfiqar, N., Lee, C.H., Dauby, F., and Hitchcock, C.S., 2004, A unique pipeline fault crossing design for a highly focused fault, Proceedings of the 2004 International Pipeline Conference, Calgary, Alberta, Canada.

Hitchcock, C.S., Slayter, D.L., Sundermann, S.T., Zellman, M.S., Givler, R.W., Lee, C-H., Manegold, W., Nishenko, S., Sun, J. and Ferre, K., “Hazard Mapping With GIS”, Pipeline and Gas Technology, November-December 2008, 50-53.

Hitchcock, C.S., Gailing, R., Lindvall, S, 2008, Geotechnical assessment of mitigation of a high-pressure pipeline across active landslides: Design of a directional bore in southern California: Proceedings of the 7th International Pipeline Conference: Calgary, Alberta, Canada

Hitchcock, C.S., Givler, R., Angell, M.M., and Hooper, J.R., 2006, A pilot study for regionally-consistent hazard susceptibility mapping of submarine mudslides: Offshore Technology Conference, OTC 18323.

Hitchcock, C.S., Nishenko, S., Lee. C., Sun, J., Sundermann, S., Zellman, M, and R. Givler, 2006, GIS-based seismic hazard mapping for pipeline integrity management: IPC2006-10351, Proceedings of 2006 International Pipeline Conference, Calgary, Alberta, Canada.

Hitchcock, C.S., and Kelson, K.I., 1999, Growth of late Quaternary folds in southwest Santa Clara Valley, San Francisco Bay area, California: Implications of "triggered slip" for seismic hazard and earthquake recurrence: Geology, v. 26, n. 5., p. 391-394.

Hitchcock, C. S., Kelson, K. I., and Thompson, S. C., 1994, Geomorphic investigations of deformation along the northeastern margin of the Santa Cruz Mountains: U.S. Geological Survey Open-File Report 94-187, 52 pages, 2 plates, scale 1:24,000.

Hitchcock, C.S., and Wills, C.J., 2000, Quaternary Geology of the San Fernando Valley, Los Angeles County, California: California Division of Mines and Geology Map Sheet 50, 1 plate (color), map scale 1:48,000.

Lee. C.-H., Manegold, W., Nishenko, S., and Hitchcock, C., 2009, Pacific Gas and Electric Natural Gas System Preparations for a Future Hayward Earthquake, 2009 TCLEE Conference, Lifeline Earthquake Engineering in a Multihazard Environment.

Wills, C.J., and Hitchcock, C.S., 1999, Late Quaternary sedimentation and liquefaction hazard in San Fernando Valley, Los Angeles County, California: Environmental and Engineering Geoscience, v. 5, no. 4, p. 419-440.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF CHAPIN F. KOCH

Q 1 Please state your name and business address.

A 1 My name is Chapin F. Koch, and my business address is Pacific Gas and Electric Company, 245 Market Street, 10th Floor, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am manager, Environmental for Electric Transmission Planning and Permitting. I oversee a staff of about 50 environmental planners, biologists, cultural resource specialists and environmental field specialists who obtain discretionary permits and who manage environmental compliance during and after-construction of transmission and substation facilities.

Q 3 Please summarize your educational and professional background.

A 3 I received my bachelor of science degree in geology from St. Lawrence University, my master of science degree in geology from Ohio State University and my master of business administration from Stanford University. I started my career working for Exxon Co. USA as an exploration geologist in Houston, Texas. In 1987, I left Exxon to pursue a master's in business administration at Stanford; after graduating I joined Levine-Fricke, an engineering and science consulting firm focused on remediation and restoration of contaminated sites. I remained at Levine-Fricke for 10 years where I had become the Vice President of Strategic Planning. In 1999, I joined Essex Environmental as the Vice President of Operations. In this role, I helped a small start-up company of 20 technical personnel grow to 120 over the next several years. My job was to oversee all project activities supporting permitting and compliance of major gas and electric transmission lines. I joined PG&E in 2009 as the manager of Environmental Planning and Permitting. In this role, I was responsible for permitting and compliance of projects for multiple lines of business including gas, electric, hydroelectric and renewables. In 2012, I become the manager of Environmental for Electric Transmission, where my focus has been on major electric transmission projects.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Embarcadero-Potrero Transmission Reliability Project proceeding:

- Chapter 15, "Energy Division Variance Authority for the Embarcadero-Potrero 230 kV Transmission Project."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF KEVIN C. KOZMINSKI

Q 1 Please state your name and business address.

A 1 My name is Kevin C. Kozminski, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a senior advising engineer in the Transmission System Asset Development Department, responsible for the implementation of transmission system reinforcement and reliability projects in the San Francisco Peninsula, South Bay and Central Coast areas.

Q 3 Please summarize your educational and professional background.

A 3 I received a bachelor of science degree in physics and a bachelor of arts degree in German Literature from Penn State University, a master's degree in electric power engineering from Rensselaer Polytechnic Institute, and a master's degree in business administration, with an emphasis in finance, from Rollins College. From 1981 to 1990, I worked for Westinghouse Electric, designing and testing large generators. I was also a member on two teams that investigated generator failures at power plants.

In 1990, I joined PG&E as an employee in the engineering and construction department responsible for the Diablo Canyon Nuclear Power Plant, working in the turbine-generator system design group. Between 1993 and 1994, I worked in PG&E's Electric Generation Planning Department as a generation planner. In that position, I performed generation adequacy studies, and I testified for PG&E in the California Energy Commission's 1994 Electricity Report Proceedings. Following that, I worked in PG&E's Transmission Planning Department from 1995 to 1998. I was responsible for studying the electric transmission system in PG&E's Mission Division and developing system reinforcement projects, such as the Tri-Valley Reinforcement Project. In 1998, I moved to a PG&E subsidiary, PG&E Energy Services, where I was the manager for customer account transfers. Our group put together the paperwork to transfer customer accounts from the local utility to PG&E Energy Services. We also prepared the daily load forecast for our schedulers.

I returned to PG&E's Transmission Planning Department in 1999, performing Reliability Must-Run studies in conjunction with the California Independent System Operator Corporation to determine the generation needed in various parts of the PG&E system to ensure system reliability. In 2000, I worked for Southern California Edison Company in their Transmission Planning Department, where I performed their annual bulk system assessment and also performed generation interconnection studies.

I came back to PG&E in late 2000. Since then, I have worked in several positions related to transmission system planning and transmission project implementation. Over the last five years, my main area of responsibility has been the San Francisco Peninsula, South Bay and Central Coast areas. In 2001, I testified before the California Public Utilities Commission (CPUC or Commission) on the need for the Northeast San Jose Transmission Reinforcement Project. And I helped put together the information filed in the Proponents Environmental Assessment for the Santa Cruz 115 kilovolt Reinforcement Project, filed with the CPUC in January 2012.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Embarcadero-Potrero Transmission Reliability Project:

- Chapter 2, "PG&E's Existing San Francisco Transmission Systems."
  - Attachment 2A, "Length and Age Data for Underground Electric Transmission Cables in San Francisco."
- Chapter 11, "Restoration Time for Transmission Line Outages":
  - Section B, "Overview."
- Chapter 14, "Purpose and Need for Embarcadero-Potrero Project."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

AHMED NISAR, PE
PRINCIPAL

Mr. Nisar has 25 years of consulting experience in earthquake engineering, structural engineering and risk assessment. His project experience includes natural hazard risk and reliability assessment of lifeline systems, linear and non-linear dynamic analysis, seismic hazard analysis, retrofit design, and seismic review of structures. Mr. Nisar specializes in analysis and design of heavy civil infrastructure such as large diameter pipelines, dams, water tanks and mass concrete structures. Mr. Nisar has extensive experience with local and international codes and criteria documents applicable to seismic/structural engineering. Mr. Nisar is an experienced project manager and has demonstrated his project management skills on many large multi-disciplinary infrastructure projects. Many of these projects have required sophisticated numerical analyses, multiple of subject matter experts and presentations to a range of stakeholders and technical advisory panels.

Academic Background

M.S., University of California at Berkeley, Berkeley, California, 1988.
B.S., Civil Engineering, University of Engineering and Technology, Lahore, Pakistan, 1986

Professional Training

ATC-20 Post Earthquake Safety Evaluation and Buildings

Professional History

InfraTerra, Inc., San Francisco, California, 2011 – Present
MMI Engineering, a Geosyntec Company, Oakland Creek, Associate, 2001 - 2011
URS/Dames & Moore, San Francisco, California 1989 - 2001
Putterman/Davis, San Francisco, California 1988 - 1989
Nisar-ul-Haq Associates, Multan, Pakistan 1986 - 1987

Professional Experience

Mr. Nisar's professional background includes the following:

Infrastructure Systems Reliability

Multihazard reliability assessment of large geographically dispersed infrastructure systems such as water transmission and distribution. Broad expertise and understanding of system operations, geographical distribution of multiple hazards and their interaction with a correspondingly distributed system of source, storage, treatment, and pumping facilities interconnected with pipelines. Managed integrated system reliability studies for numerous water and wastewater systems and helped clients develop long term capital improvement programs. Key projects include:

- Project Manager and Technical Lead for seismic reliability assessment of two underground 230 kV High Pressure Fluid Fill pipelines for the Pacific Gas & Electric Company. Each line is more than 7 miles long and traverses a rage of subsurface conditions consisting of areas of high liquefaction and lateral spread hazard. Reliability assessment was performed through detailed assessment and quantification of liquefaction and lateral spread hazard and computing the seismic response of high pressure pipelines by performing nonlinear soil structure interaction analysis. Monte Carlo simulations were performed to estimate the probability of failure for a repeat of the 1906 San Francisco Earthquake and a major earthquake on the Hayward Fault.

- Project Manager for fault crossing design of the new 66-inch diameter Alameda Siphon #4 and a 66-inch diameter overflow pipeline crossing the Calaveras fault for the San Francisco PUC. The project involved development of fault crossing design recommendations through detailed nonlinear analyses (using ANSYS) of the pipeline to withstand approximately 5 feet of surface offset without failure and full pressure integrity to maintain 180 million gallons per day of flow. The analysis included consideration of the nonlinear material properties of the pipeline and the surrounding soil and the expected displacement profile from a major surface rupturing event. The project also included assessment of three existing pipelines (69-inch reinforced concrete cylinder pipe, 90-inch welded steel pipe, and 96-inch pre-stressed concrete cylinder pipe) crossing the fault. The project involved detailed consideration of the location of shutoff valves (located close to the fault rupture zone) and the pipeline connection to the Coast

Ranges Tunnel portal. The project also included a structural assessment of the tunnel portal, a 10.5-foot diameter 50-foot long pipe, and an 80-foot tall tunnel overflow shaft subjected to close to 1.0g of peak ground acceleration.

- Project Manager for nonlinear analysis of 78-inch diameter 30-foot high drain intake riser pipe for the San Pablo Reservoir, East Bay Municipal Utility District (EBMUD). The work was performed to assess the adequacy of the intake pipe to support a new 55 kip heavy valve without failure. The reservoir is located less than 2 kilometers from the Hayward fault, a major seismic source in the San Francisco Bay Area.

- Project Manager and Technical Lead for the seismic reliability assessment of water transmission system serving central Seattle for an M6.7 earthquake on the Seattle fault, a major seismic source that runs through central Seattle and is believed to have produced a Magnitude 7.0 or greater earthquake in about 900 A.D that resulted in a 22-foot vertical offset. Other significant seismic source for the Seattle area is the offshore Cascadia Subduction Zone considered capable of producing an earthquake as large as Magnitude 9.0. A detailed non-linear soil structure interaction analysis was performed for the 42-inch 430 pipeline to study its seismic response from transient ground deformations resulting from travelling wave effects and general incoherency in ground motions as well as the dynamic response of the pipeline within the Ship Canal. The ship canal is a 920-feet long tunnel connected to two 60-feet tall vertical shafts on either side.

- Project Manager and Technical Lead for seismic reliability of 11 elevated water tanks in Stockton, Chico and Hamilton City for the California Water Services Company. The elevated tanks range in capacity from 25,000 gallons to 500,000 gallons supported on 100 to 120 feet tall steel towers that are approximately 80 to 100 years old. The project included preliminary assessment of seismic hazards including strong ground shaking and liquefaction potential and dynamic analysis of the structure. Conceptual retrofit schemes were developed to estimate order of magnitude cost estimates for retrofit.

- Project Manager and lead engineer for the design of a 36-inch diameter pipeline crossing the Rodgers Creek fault for the Sonoma County Water Agency. The project includes geologic investigations to locate the fault and non-linear soil-structure interaction analysis to design the pipeline to withstand the imposed surface fault displacement on the order of several feet. Project ongoing.

- Project Manager and lead engineer for multi-hazard reliability assessment for Sonoma County Water Agency. The Agency supplies water to approximately 600,000 people in eight major cities and water districts in Sonoma and northern Marin County. The system includes diversion (10 conventional and 5 collector wells), transmission (83 miles of aqueduct up to 48-inch diameter), pumping (9 booster pump stations), and storage facilities (17 steel storage tanks). Developed recommendations to improve the reliability of the system subject to multiple natural hazards such as earthquake, flood, fire, landslides, liquefaction, fault rupture hazard, drought, erosion, and scour. Performed a comprehensive assessment of the system and developed prioritized recommendations for a ten year Capital Improvement Plan and developed the FEMA approved Local Hazard Mitigation Plan (LHMP). Presentation of the results of the study to various stake holders.

- Project Manager and lead engineer for Contra Costa Water District's Treated Water Reliability Improvements (TWRI) – Fault Crossings project. The District serves a population of over a quarter million people. Several of its large diameter pipelines (ranging in size from 12 inches to 42 inches) cross the Concord Fault. The Concord Fault is part of the San Andreas Fault System and can produce a surface rupturing earthquake. Developed mitigation strategies and design recommendations for pipeline fault crossings. Developed a detailed emergency response field guide to help the District's field crew to rapidly isolate damaged sections of the pipelines.

- Project Manager for the liquefaction mitigation design for Sonoma County Water Agency's collector wells and river diversion system (RDS). Each collector well has a reinforced concrete caisson with 16-feet outer and 13-feet inner diameter. The total length of the caissons ranges from 108 to 126-feet. Near the bottom, each caisson has 8 to 10-inch diameter perforated pipes that extend as much as 100 feet into the surrounding aquifer. Approximately 60 to 80 percent of the total length of the caissons is located below ground and pass through potentially liquefiable layers. The caissons are vulnerable to damage from liquefaction induced lateral spread. Mitigation designs being considered include deep soil mix, slope regarding or use of strategically located sheet pipe walls. Project ongoing.

Infra • Terra

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- Project Manager for mitigation of a 48-inch pipeline vulnerable to damage from liquefaction induced lateral spread hazard at a major river crossing for the Sonoma County Water Agency. Mitigation options being considered include both open trench and trenchless methods. Project ongoing.

- Project Manager and lead engineer for the reliability assessment and retrofit design of City of Hayward's water and sewer pipelines crossing the Hayward Fault. The Hayward Fault is a major fault that runs through the City of Hayward. The fault is capable of producing an earthquake of magnitude greater than 7.0 with associated surface fault displacements on the order of 5 to 6 feet. A detailed mitigation methodology was developed that consisted of a combination of pipeline replacement, bypass, and isolation for over 70 water and sewer pipelines totaling over 2 miles in length. The seismic reliability assessment included detailed mapping of the Hayward fault through a detailed review of aerial photographs, fault trenching studies, and field reconnaissance using hand-held PDA and GIS systems. Pipeline replacement included new pipeline design with specialized high strength steel pipe with welded joints. Isolation was recommended for redundant pipelines and bypassing of key distribution lines was achieved with specialized potable water flexible hoses. The project also included the design of the deployment and retrieval system for the flexible hose, identification of existing or new isolation valves and new fire hydrants, and the development of detailed emergency response plans.

- Seismic and structural evaluation and development of design and retrofit standards for Marin Municipal Water District's Backbone Water Distribution System. The system includes 16 steel tanks ranging in capacity from 0.2 to 5 million gallons, two water treatment facilities, and a reclamation plant. Reviewed the seismic performance of tanks in accordance with AWWA D-100 for welded tanks and the Modified Manos approach using site-specific ground motion criteria. The system also included several pump stations and water reservoirs. GIS mapping of various geotechnical and geologic hazards was also performed. Retrofit prioritization using the vulnerability and criticality of each facility was established and seismic retrofit of key components of the system performed.

- Performed seismic vulnerability assessment of City of Salem, Oregon water and wastewater distribution system. The fresh water system consisted of 14 water storage reservoirs (both steel and concrete) with up to 10 million gallons capacity, 22 water pump stations, a SCADA communications facility, one water treatment facility, and fresh water wells. The wastewater system consisted of 30 sewage lift stations and 3 diversion structures. Established seismic retrofit priorities and cost estimates using seismic vulnerability and criticality ratings through a risk evaluation matrix.

- Performed detailed seismic risk evaluation of wastewater collection system operated by the Monterey Regional Water Pollution Control Agency (MRWPCA). Detailed mapping of seismic and geologic hazards was performed to assess the vulnerability of wastewater piping and ten pump stations that serve the entire Monterey Peninsula, California.

- Seismic vulnerability assessment of three wastewater treatment plants for Tri City Services District of Clackamas County, Oregon. The plants included the Tri-City Water Pollution Control facility, the Kellogg Creek facility, and the Hoodland facility. Each facility was evaluated for life safety, public health, direct and indirect property damage, business interruption, and environmental damage potential under seismic hazards that included strong ground shaking, liquefaction, landslides, lateral spreading, and surface fault rupture. The seismic evaluation included a review of all process tanks such as clarifiers, digesters, and aeration basins; buildings, including components and non-structural elements; pump houses; and process piping. Recommendations included conceptual retrofit schemes and cost estimates of vulnerable components.

- Designed seismic retrofit of control buildings at San Geronimo and Bon Tempe Water Treatment Plants owned by the Marin Municipal Water District. Retrofit of several water tanks was also performed. The retrofit included adding flexible piping connections and anchorage of tanks.

- Performed detailed analysis to study the failure mechanism of a 1.5 million gallon steel water tank. Non-linear dynamic analysis was performed using DYNA software. The tank was located within a few hundred feet of the San Andreas Fault. Conventional AWWA analysis showed the tank to fail during a repeat of the 1906 Earthquake on the San Andreas Fault. The purpose of the analysis was to identify the failure mechanism and estimate the rate of water flowing out of the tank. The estimated flow rate was used to design a deflection wall to protect adjacent homes.

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- Performed seismic and structural evaluation and development of retrofit concepts for 39 water storage reservoirs, ranging in size from 5000 to 1,500,000 gallons capacity, located throughout the State of California for the Southern California Water Company. The reservoirs consist of both above ground and underground steel and concrete tanks. The evaluation was performed using AWWA D-100 and AWWA D-103 procedures for steel tanks and AWWA D-110 for prestressed concrete tanks.

- Performed seismic vulnerability assessment of Eugene/Springfield Water Pollution Control Facility (WPCF), Eugene, Oregon. The WPCF has a hydraulic flow capacity of 175 mgd. Various components included in the assessment included: a pre-treatment facility (195 mgd), primary and secondary clarifiers (approx. 1.5MG each), aeration basins with both coarse air and fine bubble diffusers, a chlorine treatment facility, anaerobic digesters (1.2MG each), sludge holding tanks, gravity belt thickeners, and several on site building structures.

- Performed detailed seismic evaluation of 47 water storage reservoirs in the city of Makkah, Saudi Arabia. The reservoirs range in size from one million cubic meters to 3,000 cubic meters. Detailed finite element analysis of several reservoirs was performed. The reservoirs included circular concrete, circular steel, and rectangular concrete. Upgrade recommendations were also developed.

- Project Manager for City of Berkeley underground fresh water reinforced concrete cistern design project. The project requires CEQA permitting, public involvement, engineering design, and preparation of plans, specifications, and construction inspection.

Earthquake Ground Motion Criteria

Development of site-specific ground motions using probabilistic and deterministic seismic hazard analysis for numerous sites located in areas of high, moderate, and low seismicity, including northern and southern California, Washington, Oregon, Alaska, Utah, Tennessee, Georgia, North Carolina, South Carolina, Venezuela, Chile, Papua New Guinea, Peru, Angola, and Java. Project scope includes seismic source characterization through an assessment of fault and area sources, detailed assessment of regional seismicity and tectonic setting, and development of site-specific design response spectra and spectrum compatible acceleration time histories for critical facilities ranging from petrochemical, Liquefied Natural Gas (LNG), offshore platforms, water/wastewater lifelines, and building structures. Key projects include the following:

- Probabilistic seismic hazard analysis for an 8-mile gas pipeline offshore Trinidad. The site is located in a complex tectonic environment with numerous shallow and subduction zone source zones. Strength Level Earthquake (SLE) and Ductility Level Earthquake (DLE) estimates were developed including estimates of Peak Ground Velocity (PGV) for pipeline analysis.

- Developed seismic design criteria for the Caspian Pipeline Consortium (CPC) Expansion Project tank farm site, located in the Russian Federation in the Region of Krasnodar, derevnya Yuzhnaya-Ozereevka. The site is located in the north Caucasus along the eastern margin of the tectonically active Black Sea basin and just south of the Sea of Azov. Probabilistic and deterministic seismic hazard analyses were performed to develop maximum considered earthquake (2,500 year return period) and design earthquake (two thirds of MCE) ground motions.

- Developed seismic design criteria for the Emirates National Oil Company (ENOC) Dubai refinery. The ENOC refinery is located on the northern Arabian tectonic plate on the west coast of the Oman peninsula along the Persian Gulf coast. The Arabian plate is a stable continental region with low seismic activity, especially in the vicinity of the Dubai area. The project included an assessment of ground motions from the active but more distant seismic sources such as the Zagros Collision Belt and the Makran Subduction Zone. The seismic hazard assessment included an assessment of the hazard from the historically less active but close-in sources such as the sources in the Oman Peninsula, the Dibba fault, which is believed to be the source of the May 2002 magnitude 5.1 earthquake, and the West Coast fault, a northeast trending structure along the UAE coastline.

- Developed seismic design criteria using probabilistic and deterministic seismic hazard analysis procedures for the Camisea LNG facility located near Lima, Peru. The site is located in one of the most tectonically active regions of the world, where large Interface earthquakes, with magnitudes greater than 7.0, occur with an average recurrence interval of 17 to 20 years. The project included detailed characterization of major seismic sources including shallow crustal sources and the subduction zone (both interface and intraslab zones). Detailed assessment of historic seismicity was performed to develop magnitude recurrence parameters for each zone. Consideration was given to incompleteness of historic record, mislocation of earthquakes, and duplicate reporting of events. Developed design response spectra for Operating Basis Earthquake (OBE) and Safe Shutdown Earthquake (SSE) design as per the requirements of NFPA 59A.

- Developed seismic design criteria using probabilistic seismic hazard analysis procedures for an LNG facility located in West Africa. The site is located in an area of relatively low seismic activity in a remote part of the world without a comprehensive network of seismographic stations. A detailed assessment of the historic seismicity using many different seismicity catalogs was performed to develop the seismic source model. Important seismic sources were characterized through consideration of seismicity distribution and tectonic and geologic setting. Developed design response spectra for Operating Basis Earthquake (OBE) and Safe Shutdown Earthquake (SSE) design as per the requirements of NFPA 59A.

- Performed an independent technical review of the seismic design criteria for offshore platform sites at Piltun, Lunskoye, and Terminal Loading Unit (TLU). The two platforms are located east of the northern Sakhalin Island and the TLU is located along the southern coast. Performed an assessment of the approach and the evaluation used by the design consultant to develop the seismic design response spectra. Provided comments to Shell International Exploration and Production, Inc. and Shell Energy Investment Company (SEIC) Ltd. Major seismic sources such as the Piltun, and the Vodopadniy Brook Fault Zone were considered to assess the design consultant's recommendations. Deterministic assessment of likely ground motions from the May 25, 1995 magnitude 7.1 Neftegorsk earthquake were also performed for this review.

- Developed design ground motion criteria for Chevron's offshore platform (LL652) in Lake Maricabo, Venezuela. The ground motion criterion was developed for several probability levels based on API RP2A requirements. Spectrum compatible acceleration time histories for dynamic analysis were also developed.

- Developed site-specific seismic ground motion criteria for seismic analysis of Ok Tedi Ball Mills. The site is located in Papua New Guinea, a region of very high seismicity, where an average of two earthquakes between magnitude 7.0 and 8.0 occur every year. Uniform probability response spectra with a 10% and 50% probability of exceedence in a 50 year period were developed. Site-specific acceleration time histories were also developed for the above defined probability levels.

- Developed seismic design criteria using probabilistic seismic hazard analysis procedures for the Arauco Pulp Paper plant in San José de la Mariquina near Valdivia, Chile. The site is located in one of the most tectonically active regions of the world. Numerous magnitude 8+ earthquakes have occurred along the subduction zone off the Chilean coast. The largest historically recorded magnitude 9.5 great Chilean earthquake of 1960 occurred in this region. Developed design response spectra for 50%, 10%, 5%, and 2% probability of exceedence in a 50 year period.

- Developed design response spectra for the Lewiston-Queenston steel arch bridge that spans the Niagara Gorge between the U.S. and Canada, 6 kilometers downstream from Niagara Falls. The ground motions were developed based on a project specific criterion, drawing upon elements of the U.S Federal Highway Administration, Applied Technology Council (ATC-32) and AASHTO LRFD, which included a functional level (15% probability of exceedence in 75 years) and a safety level (3% probability of exceedence in 75 years) criteria. Because the Niagara Gorge is a steep-sided valley incised into bedrock ridge top, amplification factors were developed and included in the final recommendations.

- Developed design ground motion criteria using probabilistic and deterministic seismic hazard analysis procedures. Developed site specific response spectra for various probability levels including 10% and 50% probability of exceedence in 50 years and a corresponding set of acceleration time histories for multiple facilities located in California. Some of the key projects are Los Angeles County medical center facilities in Los Angeles, High Desert Hospital in Lancaster, San Francisco International Airport's new International terminal building, Oakland City Hall (base isolation design), Channing House, Palo Alto (base isolation), and the GAP Headquarters building in San Francisco.

- Developed design ground motion criteria for Chevron Long Wharf at the Chevron Richmond Refinery. The ground motion criterion was developed for several probability levels and also for a deterministic magnitude 7.0 earthquake on the Hayward Fault located within 10 kilometers from the site. Also developed multiple sets of spectrum compatible acceleration time histories for dynamic analysis.

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- Developed detailed seismic design criteria for the intake and outlet structures at the Potrero power plant in San Francisco. The site was underlain by substantially varying subsurface conditions from shallow bedrock to deep Bay Mud deposits. Probabilistic seismic hazard analysis was used to determine bedrock response spectrum, which was modified through detailed site response analysis. Developed multiple sets of acceleration, velocity, and displacement time histories for use in dynamic analysis of the intake and outfall structures.

- Developed seismic design criteria using probabilistic seismic hazard analysis procedures for the structural repairs of Wharves 6, 6½, and 7 at the Oakland Army Base, California. These wharves were damaged as a result of the 1989 Loma Prieta earthquake. Developed site-specific acceleration time histories in addition to the site-specific design response spectra for different probability levels.

- Development of a suite of earthquake acceleration time histories for seismic probabilistic risk analysis (PRA) using the Latin Hypercube approach for the Finnish nuclear utility TVO's Olkiluoto site. A suite of 30 time histories consisting of two horizontal and one vertical component were developed. The time histories were matched to the uniform hazard spectrum such that both the spectrum of each time history and the median and one standard deviation spectra of the suite of time histories matched a given set of constraints.

- Developed site-specific seismic hazard evaluations for Intel's microprocessor manufacturing facilities located in Santa Clara, California; Albuquerque, New Mexico; Dupont, Washington; and Hillsboro, Oregon. Performed probabilistic seismic hazard analysis to develop site dependant response spectra for different probability levels.

- Developed seismic design criteria using probabilistic seismic hazard analysis procedures for numerous sites in the eastern United States. The projects included: (1) Hospital Complex, Statesboro, Georgia for Hospital Management Associates; (2) Concourse Corporate Center III, Atlanta, Georgia for Faison Corporation; (3) Wildwood Office Building Complex, Atlanta, Georgia for Cousins Real Estate Corporation; (4) Office Building Complex in Alpharetta, Georgia for Automatic Data Processing; (5) Piedmont Center Building, Atlanta, Georgia for P.C. Operations; (6) Humanities Building, Dalton College, Dalton, Georgia for Georgia State Board of Regents; (7) Emory University Hospital Expansion, Atlanta, Georgia for Emory University Hospital, Inc.; (8) Gwinnett Marriott Expansion, Duluth, Georgia for Cornerstone Real Estate Advisors; (9) Piedmont Hospital Complex, Atlanta, Georgia for Piedmont Hospital, Inc.; (10) Promina Kennestone Hospital Women's and Children's Center and Facilities Management Plant Buildings in Marietta, Georgia for W.R. Adams, Inc.; (11) Lakeside Commons II, Atlanta, Georgia for Yarmouth Group, Inc.; (12) Academic Building, Southern College of Technology, Marietta, Georgia for University of Georgia Board of Regents; (13) Science and Allied Health Building, Kennesaw State College, Kennesaw, Georgia for the University of Georgia Board of Regents; (14) Hospital Expansion, Rome, Georgia for Columbia HCA; (15) Junior High and High School, Stone Mountain, Georgia, for the DeKalb County School District; (16) University of Georgia Campus at Athens, Georgia; (17) Lake Norman Regional Medical Center, Mooresville, North Carolina for Health Management Associates; (18) Hospital Complex, Hartsville, South Carolina for Health Management Associates, Inc.; (19) Replacement Hospital Complex, Florence, South Carolina for Quorum Health Group; (20) Vanderbilt Children's Hospital, Nashville, Tennessee.

- Developed design ground motion criteria using probabilistic and deterministic seismic hazard analysis procedures. Developed site specific response spectra for various probability levels including 10% and 50% probability of exceedence in 50 years and a corresponding set of acceleration time histories for multiple facilities located in California. Some of the key projects are Los Angeles County medical center facilities in Los Angeles, High Desert Hospital in Lancaster, San Francisco International Airport's new International terminal building, Oakland City Hall (base isolation design), Channing House, Palo Alto (base isolation), and the GAP Headquarters building in San Francisco.

- Developed seismic design criteria using probabilistic seismic hazard analysis procedures for nonlinear analysis of Pier J at the Port of Long Beach, California. Site-specific acceleration time histories were developed in addition to the site-specific design response spectra for different probability levels.

- Performed probabilistic seismic hazard analysis for the Chashma power plant site in Pakistan for Sogreah Consultants, France.

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- Performed site-specific seismic hazard evaluations for Eastman Chemical Company facilities in Columbia, South Carolina; Batesville, Arkansas; and Kingsport, Tennessee. Recommendations for design ground response spectra were developed.

Special Studies and Research

- Project Manager of probabilistic coastal flood risk study for a major development near the eastern bank of the Hudson River, Manhattan, New York. The study considers hurricanes, tides, sea level rise, nor'easter, wind generated waves, and freshwater flow in the Hudson, in a consistent probabilistic framework. Flood estimates were developed for 100 and 500 year return periods for the next century. A fully probabilistic treatment of hurricanes was included by considering genesis point simulation and probabilistic assessment of hurricane parameters such as maximum wind speed, radius to maximum wind, forward velocity, pressure deficit, and heading. Using importance sampling, more than 10,000 synthetic storms were developed and used to compute storm surge using SLOSH, specialized hydrodynamic analysis software. Verification of storm surge was performed using ADCIRC software.

- Project Manager for nonlinear soil-structure interaction analysis of two miles of 115kV high voltage transmission cable and a ductbank for Pacific Gas & Electric Company. The underground ductbank traverses complex geotechnical conditions consisting of Young Bay Mud overlying dense soils. The ductbank is located less than 2-miles from the Hayward Fault.

- Project Manager and technical lead for nonlinear incremental thermal stress-strain analysis (NISA) for mass concrete elements of the Inner Harbor Navigation Canal (IHNC) hurricane protection system for New Orleans, Louisiana. Recommendations for crack control were developed. The project included thermal analysis of the Gulf Intercostal Waterway (GIWW) sector and bypass gates and the Bayou Bienvenue (BB) lift gate. The GIWW sector gate consists of two swing gates with foundation slab dimensions of 370 x 160 feet with 8-foot thick concrete structural slab over 6-foot thick tremie. The gate has two 42-foot tall monoliths with plan dimensions of 14 x 25 feet. The foundation slab for the bypass gate has plan dimensions of 210 x 121 feet. The slab is 6-foot thick concrete over 4 feet of tremie. The foundation slab for the BB gate has plan dimensions of 138 x 76 feet. The slab is 9-foot thick concrete over 4 feet of tremie. The BB gate has two 30-foot tall monoliths with plan dimensions of 34 x 10 feet.

- Performed a detailed site development feasibility study for a proposed 80,000 to 100,000 metric tons per year capacity polypropylene plant in Port Qasim, Karachi, Pakistan for Marubeni Corporation. Relevant topographic maps, navigation channel maps, seismic and tectonic maps, and information on local and regional geotechnical and geologic conditions were obtained from a variety of personal and public sources. The feasibility study also included collecting information on sources and transportation of raw materials in the area and a limited market study for polypropylene use in Pakistan. Ranking of three potential sites in the greater Port Qasim area was performed through consideration of multiple aspects of site development considerations including potential hazards such as earthquakes, flooding, and erosion.

- Project Manager and technical lead for the development of natural hazard probabilistic risk assessment (PRA) techniques for Chevron Oil Company facilities. The project involves development of a methodology for the definition of probabilistic hazard analysis techniques, development of component fragility curves, fault tree and event tree development, and consequence analysis.

- Performed research studies funded by National Science Foundation (NSF), Building Seismic Safety Council (BSSC), California Divisions of Mines and Geology (CDMG), and California Department of Transportation (CalTrans). Key studies included system identification of recorded building motions from 1989 Loma Prieta, 1986 Mt. Lewis, and 1984 Morgan Hill earthquakes, and motions from the 1979 Imperial Valley earthquake and full scale dynamic tests at Meloland Road Overcrossing. These procedures used time-dependent measurements of acceleration, velocity, or displacement histories at various locations of a structure to estimate dynamic properties of the structure through an optimizing algorithm.

- Performed evaluation of UBC and 1991 NEHRP Seismic Design Provisions using MODE-ID system identification procedures, a state of the art methodology developed at CalTech by Professor James L. Beck. The methodology uses time-dependent measurements of acceleration, velocity, or displacement histories at various locations of a structure to estimate dynamic properties of the structure through an optimizing algorithm. Acceleration records from two instrumented buildings in San Jose during the 1989 Loma Prieta, 1986 Mt. Lewis, and 1984 Morgan Hill earthquakes were analyzed using MODE-ID to determine the dynamic characteristics of each building under each earthquake scenario. Variations in building period and damping ratio for different vibration modes within the earthquake and from one earthquake to the other were studied. The results were presented to NSF and BSSC.

- Performed system identification using MODE-ID for a three story instrumented parking structure using ground motions obtained during the 1994 Northridge Earthquake. Created a detailed three dimensional SAP90 model of the structure and calibrated the finite element model with the dynamic characteristics obtained from a system identification study. The project was funded by CDMG.

- Performed independent static and dynamic earthquake, wind, tornado, and tornado missile analysis of the special shield doors on the primary confinement barrier for the vitrification cell at the West Valley Nuclear facility. The analysis verified that the design met DOE and site-specific SAR requirements as well as identified margins of safety in the design. Certain elements of the design required strengthening as a result of this analysis and mitigation schemes were developed for this purpose.

- Performed independent static and dynamic analyses of double walled stainless steel piping systems and pipe supports in underground trenches. Used CESAR II and SAP90 programs to independently verify piping design performed by EBASCO and to establish margins of safety under extreme environmental loading (multiple levels) of the Design Basis Earthquake for a high level nuclear waste transfer system located at West Valley, New York.

- Calibration of a detailed three dimensional SAP90 model of the Great Western Bank and the Town Park Towers building to the dynamic properties obtained under the 1989 Loma Prieta Earthquake, 1986 Mt. Lewis Earthquake, and 1984 Morgan Hill Earthquake using the system identification methodology of MODE-ID. The project was funded by CDMG.

- Performed a detailed study of the dynamic response of Meloland Road Overcrossing using the data obtained from full-scale dynamic testing of the bridge. The dynamic testing was performed by quick release of an inclined jack using 72 kip and 140 kip loads. The free vibration response of the bridge was recorded by thirteen accelerometers located along the bridge span and at the abutments. Recorded data was analyzed using MODE-ID system identification procedures, a state of the art methodology developed at CalTech by Professor James L. Beck. The methodology uses time-dependent measurements of acceleration, velocity, or displacement histories at various locations of a structure to estimate dynamic properties of the structure through an optimizing algorithm. Detailed assessment of the predominant frequencies of vibration and damping characteristics of the bridge were studied. The project was funded by California Department of Transportation (CalTrans).

- Performed a detailed system identification analysis of the Meloland Road Overcrossing using recorded acceleration along the bridge span from the 1979 Imperial Valley Earthquake. The system identification was performed using the MODE-ID system identification methodology. Detailed Fourier spectrum analysis of the recorded motion was also performed. Insights into the dynamic response of the bridge were obtained by identifying different modes of vibration, damping, mode shapes, and participation factors. The models showed excellent comparisons between the actual and predicted response of the bridge.

- A detailed three dimensional finite element analysis using the SAP90 program was performed. The analysis used free field time histories from the 1979 Imperial Valley Earthquake. The analysis model was verified by comparison of the structure's dynamic characteristics with the identified dynamic characteristics from the system identification analysis.

Seismic Retrofit Design

- Project manager for seismic assessment and retrofit recommendations for the Santa Clara Valley Water District's Rinconada water treatment plant control building. The control building features a four story concrete bearing wall system with significant vertical and plan irregularities. Independent technical reviewer on the seismic assessment of control building at the Penetencia water treatment plant and buildings at the Vasona pump station and meter shop. Involvement in both the planning study and design phases of the project.

- Performed seismic retrofit design of control buildings for the Marin Municipal Water District San Geronimo and Bon Tempe water treatment plants. The buildings were retrofitted to meet post-earthquake functionality requirements. Both treatment plants are located within 15 kilometers from the San Andreas Fault. Creative solutions such as tying two buildings together were used to meet the performance requirements with a low construction cost. The retrofit also included non-structural elements, components, and equipment.

- Project Manager of seismic retrofit design of three key buildings located in Milpitas, California for Lifescan Corporation. The buildings were retrofitted to meet performance standards of business continuity following a major earthquake.

- Project Manager of seismic retrofit design of three municipal service center buildings for the City of Palo Alto. The buildings were retrofitted to meet a short time occupancy performance standard.

- Project engineer for seismic retrofit design of a two story multi-use wood frame building in Monterey and parking structures for the California State Universities in San Francisco, Fullerton, and San Jose.

Seismic Risk Analysis

- Performed structural/seismic assessment of several hundred buildings for the purposes of estimating Earthquake Probable Maximum Loss (PML). The scope of work included assessing geologic hazards such as liquefaction, landslides, surface fault rupture, and lateral spread, estimating earthquake ground motions with different probabilities of exceedence, and developing earthquake damage functions for building structures. Seismic hazards and building damage functions were combined together to estimate earthquake losses as a percentage of building replacement value. The loss estimates are used by lenders, insurers, reinsurers, rating agencies, and owners to evaluate their financial risk exposure. Buildings evaluated included high-rise buildings of steel and concrete construction, masonry infill buildings, unreinforced masonry buildings, buildings of light metal construction, tilt-up buildings of different ages and configurations, and wood frame structures.

- Assessment of seismic risk to Accenture facilities located in Chengdu, People's Republic of China.

Numerical Analysis of Large Dams

Mr. Nisar's experience includes seismic analysis of existing dams to meet safety requirements of Division of Safety of Dams (DSOD) and Federal Energy Regulatory Commission (FERC). Key projects include:

- Project Manager for the non-linear incremental thermal stress strain analysis for a 220-foot high roller compacted concrete thick arch dam in Ponce, Puerto Rico for the US Army Corps of Engineers, Jacksonville District. The dam has a total crest length of 1,317 feet with flood control storage capacity of 9,484 acre-feet. The analysis modeled the incremental construction of the dam, consisting of 12-inch thick RCC layers, with consideration of adiabatic temperature rise due to internal heat generation from the hydration of RCC, loss of heat to the atmosphere from the surface due to convection, heat gain due to solar radiation, and heat loss to water pool. The analysis also modeled the effect of creep, shrinkage, and aging of concrete to estimate cracking, location of contraction joints, and movement across the contraction joints. The analysis was performed using the state-of-the-art ABAQUS computer program.

- Structural design of St. Anthony Falls (SAF) stilling basin for drainage improvements at the Kern Valley Sanitary Landfill in Kern County, California. The structure has a change of elevation of 24 feet and a total crest length of 80 feet. A series of floor and chute blocks are used for energy dissipation. The structure was designed for both hydraulic and seismic loading.

- Performed three dimensional advanced numerical analysis using EACD3D for the seismic evaluation of Pardee Dam, a 345 foot high curved concrete gravity dam. The analysis considered foundation-structure and fluid-structure interaction including the effects of absorptive reservoir bottom. Site-specific ground motions developed for the site were used for evaluation. The analysis results were prepared for review by FERC.

- Performed three dimensional analysis for sliding stability of Pardee Dam. Iterative analysis was performed to study the progressive cracking of the dam base due to uplift under probable maximum flood (PMF).

AHMED NISAR, PE
PRINCIPAL

- Performed three dimensional advanced numerical analysis for the seismic evaluation of Kennedy Mines Dam, a 50-foot high multiple arch tailings dam. Site-specific estimates of ground motion developed for the site were used in the analysis. The dam was analyzed and the safety of the dam assessed under both probable maximum flood and earthquake ground motion conditions.

- Performed two dimensional advanced numerical analysis for the seismic evaluation of Bull Run Dam, a concrete arch gravity dam. Performed analysis considering the effects of fluid structure interaction using EACD2D dam analysis program.

- Performed preliminary assessment of the 319-foot high Warm Springs Dam and the 164-foot high Coyote Valley Dam for Sonoma County Water Agency. The Warm Springs Dam, an earth-fill embankment with a crest length of 3,000 feet, impounds Lake Sonoma with a gross pool of 381,000 acre-feet. The Coyote Valley Dam, an earth-fill embankment with a crest length of 3,500 feet, impounds Lake Mendocino with a gross pool of 122,400 acre-feet. An assessment of the dams was performed as part of a natural reliability improvement project for the water district.

Investigative Studies

- Crack investigation study for the Sonoma County Water Agency's Mirabel 3 and 4 pump stations. Two of Sonoma County Water Agency's pump stations were exhibiting cracking in the roof slab and exterior shear walls. The investigative effort included detailed three dimensional finite element modeling of the pump stations. The crack pattern and cause of cracking was accurately predicted. Work also included detailed modeling of the structures under earthquake loading.

- Investigation study for air products and chemicals generator support system. The generators were exhibiting alignment differentials of a few thousandths of an inch, causing operations shutdown of critical processes. The generators were supported on 7-foot thick concrete pads. A detailed three dimensional model of the generator support structure was developed to study the state of stress and possible cracking due to fatigue loads. A high precision survey (using Leica TPS5000 theodolite having an angular accuracy of 0.5 seconds approximately equal to 0.012 mm at a range of 5 meters) and water table data was also collected and correlation between deformations and water table fluctuations were developed. The results of the data indicated that the compressor misalignment was related to groundwater fluctuations at the site.

Post Earthquake Field Reconnaissance

- Member Earthquake Engineering Research Institute's (EERI) Learning from Earthquakes (LFE) reconnaissance team for the October 8, 2005 magnitude 7.6 earthquake in the northern Pakistan/Kashmir region. The earthquake resulted in over 80,000 casualties with over 1.5 million homeless.

- Developed a systematic methodology for assessment and reporting for over several hundred buildings and structures following the 1994 Northridge earthquake. The work included assessment and reporting of over 100 buildings ranging from mid- to high-rise office buildings, police stations, and correction facilities for the City and County of Los Angeles. Twenty-five warehouse type structures were assessed for Catellus.

- Developed a systematic methodology for damage assessment and collection of damage statistics for several hundred homes damaged during the 1994 Northridge Earthquake for Aetna insurance company.

- Performed post earthquake damage assessment of buildings located in Oakland following the 1989 Loma Prieta earthquake for the City of Oakland.

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PRINCIPAL

Professional Affiliations

Member EERI (Earthquake Engineering and Research Institute)

Member SEAONC (Structural Engineering Association of Northern California)

Member ASCE (American Society of Civil Engineers)

Member AWWA (American Water Works Association)

Member USSD (United States Society of Dams)

Member ACWA (Association of California Water Agencies)

Publications

A. Nisar, A. Nervik, A. Li, “Fault Crossing Design of 66-inch Pipeline, San Francisco Hetch-Hetchy Water System”, American Society of Civil Engineers, Pipelines 2013 Conference, Fort Worth, Texas, June 23 – 26, 2013.

Nisar, A., Vossoughi, F. and Alpdogan, C., “Design Considerations for Mass Concrete Elements of Flood Gates for New Orleans Hurricane Protection Project,” Solutions to Coastal Disasters Conference organized by the Coasts, Oceans, Ports and Rivers Institute (COPRI) of the American Society of Civil Engineers (ASCE) to be held in Anchorage, Alaska, June 26-29, 2011.

Guisbert, S., Zekkos, D. and Nisar, A., “Time vs. Frequency domain ground motion modification: Effects on site response analyses and seismic displacements,” Ninth U.S. National and Tenth Canadian Conference on Earthquake Engineering, Toronto, Canada, 2010.

Nisar, A., Lee, D., Doumbalski, N. and Fieberling, E., “Seismic Response of San Pablo Reservoir Drain Intake,” 6th U.S. – Japan Workshop on Water System Seismic Practices, Water Research Foundation, Taipei, Taiwan, October 14-16, 2009.

Nisar, A. “Seismic Design Criteria for the Maleo Producer, Madura Straits,” Offshore Technology Conference, Houston, Texas, May 2008.

Nisar, A., Dollar, D., Jacob, P., Chu, D., Logie, C. and Li, G., “Nonlinear Incremental Thermal Stress Strain Analysis for Portugues Dam; An RCC Gravity Arch Dam,” 28th United States Society of Dams Annual Meeting and Conference, Portland, Oregon, April 2008.

Nervik, A., Nisar, A., Christensen, A., Li, A. and Mueller, C., “Numerical Simulation of Buried Pipe Response to Strong Ground Shaking and Fault Rupture,” The Northern California Pipe User’s Group 16th Annual Sharing Technologies Seminar, Berkeley, CA, February 21, 2008.

Nisar, A. and Doumbalski, N., “Fault Crossing Design of a Critical Large Diameter Pipeline,” 5th Water System Seismic Conference, jointly organized by Water Research Foundation formerly American Water Works Association Research Foundation, Japan Water Works Association and East Bay Municipal Utility District, Oakland, California, August 8, 2007.

Nisar, A. and Summers, P.B., "Practical Guidance for Seismic Evaluation and Retrofit of Petrochemical Facilities" First International Conference on Disaster Reduction, Davos, Switzerland, August 27 - September 1, 2006.

Nisar, A., Scawthorn, C., Stillman, C., Jasperse, J., Gur, T. and Villet, W.C.B., “Multi-hazard Reliability for a Major Water Utility Agency in the San Francisco Bay Area,” 8th National Conference on Earthquake Engineering, San Francisco, California, April 2006.

Nisar, A., Honegger, D., Ameri, A., Summers, P.B., Hitchcock, C., Liu, A. and Louie, H., “Mitigation of Fault Rupture Hazard to Water Mains of a Major Metropolitan in the San Francisco Bay Area,” 13th World Conference on Earthquake Engineering, Vancouver, B.C. Canada, August 2004.

Contributing author: ASCE special publication on Seismic Design and Evaluation of Petrochemical Facilities.

AHMED NISAR, PE
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Contributing author: Reliability and Restoration of Water Supply Systems for Fire Suppression and Drinking Following Earthquakes, a publication of National Institute of Standards and Technology (NIST).

Hilmy, S., Werner, S.D., Nisar, A., Beck, J.L., “Analysis of Strong-Motion Records from a Parking Structure During the 17 January 1994 Northridge Earthquake,” California Divisions of Mines and Geology Office of Strong Motion Studies, CSMIP/00-04 (OSMS 00-06), March 2000.

Nisar, A. and Golesorkhi, R., “Development of Vertical Design Response Spectrum in the Near-Field,” 5th International Conference on Seismic Zonation, Nice France, Oct. 1995.

Adib, A., Villet, W.C.B. and Nisar, A., “Prestressed Concrete Piles Under Seismic Loading: Case History,” 3rd International Conference on Recent Advances in Geotechnical, Earthquake Engineering and Soil Dynamics, St. Louis, MO, Apr. 1995.

Nisar, A., Werner, S.D., Beck, J.L., “Use of System Identification of Recorded Building Motions from Loma Prieta Earthquake to Assess UBC Seismic Design Provisions,” Proc. 10th World Earthquake Engineering Conference, Madrid, Spain, Aug 1992.

Werner, S.D., Beck, J.L. and Nisar, A., “Analysis of Building Records from 1989 Loma Prieta, 1984 Morgan Hill, and 1986 Mt. Lewis Earthquakes,” Proceedings of ASCE Structural Congress, San Antonio TX, Apr. 1992.

Werner, S.D., Nisar, A., Beck, J.L., “Use of Strong Motion Records to Assess Seismic Response Characteristics and UBC Seismic Design Provisions for Buildings - Performance of Man-Made Structures,” NEHRP Report on Congress on the Loma Prieta, CA Earthquake (in preparation).

Werner, S. D., Beck, J.L. and Nisar, A., “Full Scale Dynamic Tests and Seismic Excitation of a Bridge Structure,” Proc. 4th U.S. National Earthquake Engineering Conference, Palm Springs, CA, May 1990.

HARRY ORTON PEng.

PRINCIPAL ELECTRICAL ENGINEER AND OWNER ORTON CONSULTING ENGINEERS INTERNATIONAL LTD.

EDUCATION

Master of Applied Science, Electrical Engineering, University of British Columbia, Vancouver, Canada, 1969.

Bachelor of Engineering (Honours), Electrical Engineering, University of New South Wales, Australia, 1966

PROFESSIONAL AFFILIATIONS

Harry is very active in the IEEE, Insulated Conductors Committee (ICC) as past-Chairman of Task Group A2D on the Characteristics of Semiconductive Shields, Chairman of the Submarine Cable Working Group C11D, past Chairman of Task Group F10D on Cable Accessory Diagnostics, Chairman of the Networking Luncheon and immediate past Chairman of the Transnational Subcommittee on Underground Cables.

Harry is on the International Scientific and Technical Committees of Jicable (Paris) and the Asian based CMD (Conference on Monitoring and Diagnostics). He is a member of CIGRE based in Paris and is the Convener of Working Group B1.23 on the mitigation of EMF's from underground power cables, a member of Working Group B1.27 on the Testing of Long AC Submarine Cables and a member of Working Group B1.40 on a Guide for Offshore Submarine Cables.

Harry is a member of the Vancouver Board of Trade, the Hong Kong Canada Business Association and is a Registered Professional Engineer in the Province of British Columbia, Canada.

SUMMARY OF EXPERIENCE

After graduation in 1969, Harry worked at BC Hydro as an Electrical Research Engineer where he helped build one of the largest utility-based research centres in North America. For over twenty years he worked as a specialist in the field of underground and submarine power transmission and distribution cables and accessories. He progressed to the level of section supervisor in charge of Insulation Studies and then to Manager of Technical Activities. He has been a project manager on Canadian Electricity Association (CEA, Montreal) and Electric Power Research Institute (EPRI in Palo Alto, California) underground cable research projects from 1977 to 1995 and was Chairman of the Cable Failure Task Force from 1987 until 1993.

In 1994 he went into his own consulting engineering business as an underground power cable specialist. He is now Principal and owner of Orton Consulting Engineers International Ltd. based in Vancouver and affiliated with the International Consulting Engineers. Contract work takes him to the US, Asia, The Middle East and to Europe.

Harry has given invited presentations and seminars in Australia, Brunei, Canada, China, Hong Kong, Indonesia, India, Japan, Korea, Malaysia, New Zealand, Singapore, Sweden and the US. At present he holds three US, Canadian and International patents on cable diagnostics. A book entitled "Long-life XLPE Insulated Cables" joint with Rick Hartlein of Georgia Tech was published in 2006.

AWARDS

In 2005 Harry received the IEEE, ICC Distinguished Technical Service Award for his long-term involvement with the Insulated Conductors Committee and was inducted into the EIC Hall of Fame in October 2007.

"IEEE Technical Council Committee of the Year Award", Insulated Conductors Committee, Transnational Activities Committee. 2002-2003

“Review of Metro Vancouver 230 kV Transmission Supply Development”, Consulting Engineers of BC, Award of Merit, Category 4 - Soft Engineering, with John Woodcock, Sandwell Engineering, 2003.

RELEVANT EXPERIENCE

Orton Consulting Engineers International Ltd., Vancouver, B. C. Canada.
Principal Electrical Engineer. 1994-Present:

- Developed submarine and underground cable specifications for clients according to international standards published by AEIC, ANSI, IEEE, IEC and ICEA.
- Contributed to international standards on testing and EMF mitigation of underground and submarine cables for IEEE and guides for CIGRE.
- Carried out cable manufacturing plant audits and inspections.
- Presented training seminars on LV, MV, HV and EHV underground and submarine cables to clients worldwide.
- Provided expert witness services for mediation and litigation situations.
- Provided witnessing services for power cable manufacture and testing in cable manufacturing plants located in Malaysia, China, Japan, Scandinavia and Europe.
- Worked with diagnostic providers to assess underground and submarine power cable condition to determine replacement criteria.
- Witnessed onsite testing of newly installed and in-service power cables.
- Provided consulting services in laboratories for cable condition assessment.
- Made comparisons between cable supplier’s bids to determine the best supplier in response to RFP’s.
- Conducted site inspections to assess transmission and distribution cable remaining life and maintenance requirements.
- Carried out forensic investigations on LV, MV HV and EHV ac and dc cables and their accessories to determine route cause of failures and to make recommendations to prevent further failures.
- EOR services on rejuvenation of MV cables.
- Recommended submarine cable and land based cable site location.
- Completed technical specifications and evaluated bids for submarine and underground cable procurement.
- Demonstrated the importance of quality control to ensure that manufacturing process expectations are met.
- Provided condition assessment for all designs of in-service cables.
- Consultation for the design, manufacture, installation and operation of all voltages classes from 5 to 500 kV of underground power cables.
- Consultation for offshore and onshore wind farm cable design and installation.

PROFESSIONAL DEVELOPMENT

Partial List of Main Projects as an Underground Cable Specialist

No.	Date	Projects	Position/Duties
1	June/2012-Current	**Embarcadero Potrero Submarine Cable Project**: The project is a 230 kV XLPE subsea cable in the downtown core of San Francisco interconnecting the city to PG&E's network via a submarine cable located in the Bay.	Consulting services on the cable specification, bid evaluation, plant inspection and installation.
2	Feb/2012-Current	**Bell Island Project**: The project is a 25 kV submarine cable failure investigation for Newfoundland Power.	Forensic evaluation and recommendation on cable replacement.
3	July/2011-Current	**HVDC Directlink**: The project is a ±80 kV dc condition assessment investigation for APA in Australia.	Consulting services and condition assessment
4	June/2012--Current	**Woolner Substation Cables**: The project is a new installation of 66 kV XLPE insulated cable for Darwin Power and Water, Australia.	Updated specification, plant audits in Korea and Malaysia, plant inspection and testing, site inspection
5	Feb/2010-Current	**LIRC Expert Retention Consulting:** Provide expert consulting services for NUSCO and Nexans on the 145 kV XLPE submarine cable failure in Long Island Sound.	Attend litigation meetings, forensic analysis and edit reports on the cable failure.
6	Nov/2012-Current	**RailCorp Power Cable Specifications**: This project will update their existing 5 to 66 kV power cable specifications and bring them into line with international standards.	Review exiting client specifications and make recommendations for updates.
7	Oct/2012-Jan/2013	**Vancouver Island Submarine Cable Rejuvenation Project:** Act as EOR for BC Hydro on a 25 kV submarine cable rejuvenation project with Novinium.	Witnessed cable injection at three sites and presented a report. As EOR confirmed that all components satisfied ANSI standards.
8	Jan/2013	**Submarine Cable Seminar for RT Casey**: The project was designed to train and inform RT Casey employees in New Orleans of the latest trends in the submarine power cable industry.	Conducted a two day seminar on the latest information available on subsea cables.
9	Nov/2010-Apr/2011	**30 Year Condition Review of Cable 41 Sydney South to Beaconsfield West:** 330 kV SCFF Cable Condition Assessment for Transgrid, Australia.	Assessed condition of the 30 year old cable with recommendations for continued in-service life
10	Sept/2009-Jan/2011	**Change Island Submarine Cable Replacement:** For Newfoundland Hydro - 25 kV cable terminations have been failing causing concern about remaining service life	Carried out forensic investigation and made recommendations for continued service life.
11	Aug/2009-Mar/2010	**Underground Power Cable Gas Release Project:** Investigate recent manhole fires and explosions on CLP distribution network in Kowloon, Hong Kong.	Presented a report with reference to IEEE Standard 383, IEC 60331 and BS 6387
12	Aug/2010-Nov/2011	**Norwood-St Leonards-Mowbray Transmission Underground Cable:** Re-write cable specification for Transend, Tasmania, 110	Updated cable specification, carried out plant audit and FAT at

		kV XLPE power cable and accessories, witness cable manufacture and FAT at LS Cables.	LS Cables in Korea.
13	Oct/2010-Jan/2011	**Churchill Falls Generating Station Cables:** Condition assessment of 245 kV SCFF generator cables on Units 5, 6 and 7 for NALCOR Energy.	Provided replacement criteria for generator cables based upon DGA analysis.
14	April/2008-Jun/2008	**HVDC Submarine Cable Site Location:** Provide consulting services to PLN Indonesian on the location of the ±500 kV HVDC submarine cable between Sumatra and Java	Carried out site inspections and presented a report recommending cable location and necessary subsea protection

RECENT PUBLICATIONS

Harry has published 55 papers on the applications of underground transmission, offshore submarine cables, distribution power cables and accessories. The following is a list of recent publications.

1. “Testing of Long AC Submarine Cables”, with Anders Gustafsson, et al, CIGRE WG B1.27, January 2012. CIGRE TB 490, Published in February 2012.

2. “Submarine Cable Metallic Sheath Diagnostic”, with Avaral Rao, Dave Hicks and Dave Gung, Jicable 2011 Proceedings, Paper A.7.1, Page 262, Volume 1, 19-23 June 2011.

3. “Impact of Electromagnetic Fields on Current Ratings and Systems”, with Paolo Maioli, Heiner Brakelmann, Jarle Bremnes, Frederic Lesur, Josu Orella Sanez and Jacco Smit, Jicable 2011 Proceeedings, Paper B.1.1, Page 382, Volume 1, 19-23 June 2011.

4. “Improved Cooling of High Voltage Cables”, with Detlef Wald, Herbert Nyffenegger, and George Anders, Jicable 2011 Proceedings, Paper C.10.4, , Page 245, Volume 2, 19-23 June 2011.

5. “Impact of Electromagnetic Fields on Current Ratings and Systems”, with Paolo Maioli, Heiner Brakelmann, Jarle Bremnes, Frederic Lesur, Josu Orella Sanez and Jacco Smit, Paper 55, EMF ELF Colloquium, Paris, France March 24-25, 2011.

6. “Fluid-filled Underground Transmission Cable Condition Assessment”, with Lisa Ogawa and David Arnold, Conference Record of the 2010 IEEE International Symposium on Electrical Insulation, Page 565, San Diego, California, 6-10 June 2010.

7. “Requirements for Different Components in Cables for Offshore Applications”, with Detlef Wald, Roman Svoma, CIRED Prague, 8-11 June 2009.

8. “Condition Assessment of Fluid-Filled MV and HV Underground Power Cables”, CEATI Underground Cable Workshop, Vancouver, BC Canada, March 4-5, 2008

9. “Long-Life XLPE Insulated Power Cables”, with Rick Hartlein, Nigel Hampton, Hakan Lennartsson and Ram Ramachandran, Conference on the Applications of Polymers to Electrical Apparatus, October 4-6, 2007, Bangalore, India.

10. “Long-life XLPE Insulated Power Cables”, with Rick Hartlein, Nigel Hampton, Hakan Lennartsson and Ram Ramachandran, Jicable 2007, Versailles, France, Paper 5.1.5, Page 593.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF RICHARD A. PATTERSON

Q 1 Please state your name and business address.

A 1 My name is Richard A. Patterson, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a senior manager in the Economic and Project Analysis Department.

Q 3 Please summarize your educational and professional background.

A 3 I received my bachelor of science degree in electrical engineering from the University of California, Berkeley, and a master of business administration degree in finance from the California State University, Hayward.

In 1985, I joined PG&E as an analyst in the Revenue Requirements Department, working on modeling and forecasting of capital expenditures, depreciation and related items for short- and long-term planning and rate cases. In 1986, I transferred to the Rates Department to work on marginal cost analysis, returning to the Revenue Requirements Department in 1987 as a senior analyst responsible for preparing forecasts of book and tax depreciation for planning and rate filings. From 1988-1992, I was a supervisor in the Revenue Requirements Department, where I was responsible for the development of PG&E's depreciation policies. In 1992, I transferred to the Financial Planning and Analysis Department as a senior financial analyst. I assumed my present position in 1994.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Embarcadero-Potrero Transmission Reliability Project proceeding:

- Chapter 13, "Economic Costs and Benefits of the Project."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

FREEMAN, SULLIVAN & CO.

A MEMBER OF THE FSC GROUP

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Michael J. Sullivan, Ph.D. – Chairman and Principal Consultant

Professional Profile

Dr. Sullivan was a co-founder of FSC and is a recognized expert in utility business planning, research design and program evaluation. He has directed more than a dozen outage cost studies over the past 25 years. He has testified in front of the California Public Utilities Commission concerning the methods, procedures and results obtained in outage cost surveys. He has conducted outage cost surveys for Pacific Gas & Electric Company, Duke Energy, Southern Companies, Cinergy, Puget Sound Energy, Salt River Project, San Diego Gas and Electric, Mid American Energy, Alabama Power and Mississippi Power.

In addition to his work in outage cost surveying, Dr. Sullivan has published a number of authoritative reports and papers concerning outage cost estimation and the use of interruption cost measurements in utility planning and policy making. Among the works he has authored are:

- *The Outage Cost Estimation Guidebook.* (with Dennis Keane) Prepared for Electric Power Research Institute, EPRI Technical Report 106082.
- *How to Assess the Economic Consequences of Smart Grid Reliability Investments*. November 29, 2010. (with Josh Schellenberg). Prepared for National Association of Regulatory Utility Commissioners and the Illinois Commerce Commission.
- *How to Estimate the Value of Service Reliability Improvements.* July 2010. (with Josh Schellenberg, Matthew Mercurio and Joseph Eto). Conference Proceedings: 2010 IEEE Power & Energy Society General Meeting. Minneapolis, MN.
- *Estimated Value of Service Reliability for Electric Utility Customers in the United States* June 2009 (with Matthew Mercurio and Josh Schellenberg), for Lawrence Berkeley National Laboratory LBNL 2132E.
- *Reliability Worth Assessment in Electric Power Delivery Systems*. (with Chowdhury, A., Mielnik, T., Lawton, L. and Katz, A.). Presented at the IEEE Power Engineering Society Conference. Denver, CO.
- *Power Interruption Costs to Industrial and Commercial Consumers of Electricity*. (with Terry Vardell and Mark Johnson). IEEE Transactions on Industry Applications, Vol. 33.
- *Interruption Costs, Customer Satisfaction and Expectations For Service Reliability*. (with T. Vardell, N. Suddeth and A. Vogdani). IEEE Transactions on Power Systems, Vol. 11.

Dr. Sullivan is a member of the Institute of Electrical and Electronic Engineers (IEEE), the American Statistical Association, the American Sociological Association and the American Association of Public Opinion Researchers. He has worked in the power industry for more than 30 years. He holds a Ph.D. in sociology with specializations in research methods and statistics.

Education

Ph.D. Washington State University, *Sociology–Research Methods and Statistics*, Pullman, WA (1984)

B.A. University of California, *Political Science*, Riverside, CA (1973)

Relevant Project Experience

2012 Value of Service Study—PG&E—Dr. Sullivan directed PG&E's 2012 Customer Value of Service Study. PG&E was ordered by the CPUC to study the cost of service interruptions for its electricity customers and to measure their willingness to pay for service reliability. FSC was retained by PG&E to carry out this study and report the results to PG&E and the CPUC. To complete this work, FSC surveyed all of PG&E's rate classes and gathered information about outage costs using industry standard measurement protocols. Results were filed with the CPUC and were used by PG&E in transmission and distribution planning and evaluation of smart grid initiatives.

2012 Value of Service Study—Southern Company—Dr. Sullivan directed Southern Company's 2012 Customer Value of Service Study. Southern Company was ordered by the Georgia Public Utilities Commission to study the cost of service interruptions for its electricity customers and to measure their willingness to pay for service reliability. FSC was retained by Southern Company to carry out this study and report the results to Southern Company and the Georgia PUC.

Southern Company, Power Quality and Value of Service Customer Needs Assessment (2007)—In 1998, Dr. Sullivan directed FSC's Value of Service (VOS) study for Southern Company, addressing their customers' willingness to pay for reliable electric service. Nine years later, Southern Company's management retained FSC again to assess its customers' power quality needs and its employees' familiarity with and knowledge of power quality issues.

PG&E, Value of Service Reliability Study 2005—PG&E was ordered by the CPUC to study the cost of service interruptions for its electricity customers and to measure their willingness to pay for service reliability. FSC was retained by PG&E to carry out this study and report the results to PG&E and the CPUC. To complete this work, FSC surveyed all of PG&E's rate classes and gathered information about outage costs using industry standard measurement protocols. The interruption cost and willingness to pay measurements were obtained using mail surveys and executive in-person interviews. FSC integrated the results from the 2005 outage cost study with data from prior PG&E value of service studies (conducted in 1989, 1991 and 1993) and conducted statistical comparisons to determine whether and how much outage costs and customer expectations about reliability had changed over time. In addition, FSC estimated customer damage functions for all major customer classes in PG&E's territory, providing insights into factors that affect outage costs and their impact, as well as allowing tailored estimates of customer interruption costs for specific banks, circuits, substations and transmission lines. The data was also incorporated into a meta-database of customer interruption costs from surveys conducted across various regions of the U.S. and analyzed. Results of the study, including interruption cost estimates and customer damage functions, were reported to PG&E and the CPUC and filed as part of its 2006 General Rate Case.

SDG&E's Non-Core Customer Interruption Cost Study—Directed FSC's study of non-core gas customers of the San Diego Gas and Electric Company to determine the economic costs they would experience given natural gas outages of different durations. These cost estimates were used to establish an appropriate level of investment in their gas distribution system and were filed with the California Public Utilities Commission.

U.S. Department of Energy, Meta Analysis of Value of Service Studies—Directed FSC's meta-analysis of value of service studies carried out by utilities between 1987 and 2002. In this project, FSC researchers obtained survey responses from major utilities and other entities in the United States that had conducted customer interruption cost surveys between 1987 and 2002; estimated customer damage functions describing the relationships between outage costs experienced by customers and outage characteristics (i.e., type, duration, time of day and season), and customer characteristics (i.e., customer type, geographical location, size and business activities).

Cinergy's Customer Value of Service Studies—Directed FSC's survey of 200 of the largest and most sensitive customers of Cinergy as well as 400 of their small and medium-sized commercial and industrial customers to determine their satisfaction with service, cost of interruptions and expectations for service reliability. Cinergy uses these costs estimates in targeted marketing and in evaluating transmission and distribution reliability investments.

Customer Value of Service Study—Duke Power Company, System Planning Department, Charlotte, North Carolina—Duke Power Company uses customer interruption costs in a number of reliability planning applications to represent the economic benefits obtained from decision alternatives. Directed FSC's survey of 1,500 residential and 1,250 small and medium-sized commercial and industrial customers of Duke Power Company to update Duke Power's interruption costs in 1997.

Sacramento Municipal Utility District's Power Quality Surveys—Directed FSC's on-site interviews with selected large commercial and industrial customers to identify causes and costs of power quality problems for purposes of evaluating the economic benefits associated with enhanced transmission services.

Duke Power's Customer Value of Service Study—Directed FSC's survey of 210 of the largest and most sensitive customers of Duke Power Company, 1,250 of its small and medium-sized commercial and industrial customers, and 1,500 of its residential customers to determine their satisfaction with service reliability, costs of interruption and expectations for service reliability. In addition, FSC developed a circuit level interruption cost data base for the utility, which contained estimated costs for different kinds of service interruptions for all of the transmission and distribution circuits on the Duke Power System. The study was jointly funded by Duke Power and the Electric Power Research Institute.

PG&E's Agricultural Value of Service Survey—Directed FSC's design and management of a combined telephone and mail survey of 1,500 agricultural customers to estimate interruption costs experienced under different conditions.

Other Project Experience

Evaluation of Impacts of OPOWER Home Energy Reports—PG&E—Since the summer of 2010, Dr. Sullivan has directed FSC's study of the impacts of OPOWER Home Energy Reports on residential home energy consumption.

Evaluation of Impacts of Energy Scorecard—Salt River Project—Dr. Sullivan is assisting SRP in the design and execution of an evaluation of a pilot study of its Energy Scorecard Service. This service is a home energy report similar to the product offered by OPOWER except that it will be transmitted to customers solely through electronic means.

Design of Commercial and Industrial Dynamic Pricing Pilot—HECO—In 2011, Dr. Sullivan directed the design of a Commercial and Industrial Dynamic Pricing Pilot for HECO. The pilot is intended to assess the usefulness of dynamic pricing in meeting short and long term capacity requirements arising out of the increasing installation of renewable resources on the island of Oahu.

Evaluation of Impacts of Smart Phone Controllable Thermostat—PG&E—Dr. Sullivan is one of three senior consultants from FSC working with PG&E, Honeywell and OPOWER to design and carry out a pilot study of the use of a new smart phone enabled programmable thermostat.

Evaluation of Smart Meter Enabled Rates and Technologies—KCP&L—Dr. Sullivan is directing FSC's effort to evaluate the impacts of time of use rates in combination with in home displays, programmable communicating thermostats and home area networks.

Ancillary Services Pilot—Phase I for Pacific Gas and Electric Company and Lawrence Berkeley National Laboratory—In the summer of 2009, Dr. Sullivan designed and directed a pilot study of the ability of PG&E's 130,000 customer air conditioner direct control program to provide 10-minute reserve in the CAISO ancillary services market. The results of this effort were published in a report to the California Public Utilities Commission entitled: 2009 SmartAC Ancillary Services Pilot available from the California Public Utilities Commission.

Ancillary Services Pilot Phase II—Pacific Gas and Electric Company and Lawrence Berkeley National Laboratory—Dr. Sullivan is currently leading a project to develop statistical algorithms for predicting the load impacts of PG&E's SmartAC customer load control program on a day ahead and 10-minute ahead basis for purposes of bidding in the California ancillary services market.

Design of Information Feedback Pilot—Electric Power Research Institute—Dr. Sullivan and Dr. George are assisting Centerpoint (under contract with EPRI) in developing a pilot study of the use of in home display devices to foster energy efficiency on the part of residential customers.

Design of Information Feedback Pilot—Central Maine Power—Dr. Sullivan and Dr. George were retained by Central Maine Power to design an information feedback pilot intended to test the impacts of different feedback strategies on customer electricity consumption

Design of Information Feedback Pilot—Philadelphia Electric Company—Dr. Sullivan and Dr. George have been retained by Philadelphia Electric Company to design a pilot project to develop an effective combination of marketing strategy, pricing and technology to be used in conjunction with the deployment of its AMI system.

Design of Pricing and Information Feedback Pilot—Sacramento Municipal Utility District—Dr. Sullivan and Dr. George are assisting SMUD in designing the Customer Behavior Study (CBS) to be implemented in the context of its Smart Grid Investment Grant.

Smart Grid Investment Grant Technical Advisory Group (TAG)—Lawrence Berkeley National Laboratory and the U.S. Department of Energy (DOE)—Dr. Sullivan and Dr. George are key members of a technical advisory group that offers assistance to utilities that are carrying out Customer Behavior Studies (CBS) in conjunction with the Smart Grid Investment Grants.

Electric Power Research Institute Protocols for Designing Information Feedback and Pricing Trials—Dr. Sullivan and Dr. George worked with EPRI to develop protocols and guidelines for the design of customer feedback experiments appropriate for examining the impacts of information feedback and time-varying pricing options enabled by Smart Grid investments. These protocols are designed to help guide the design of customer trials that will clearly establish causality between program treatments and changes in consumer behavior. Another objective is to establish a common set of outputs that will support comparisons of impacts and data pooling across various utility trials. The results of the effort were published in: *Guidelines for Designing Effective Information Feedback Pilots: Research Protocols* (2010) – publically available on the EPRI website.

Understanding the Impact of Lifestyles and Perceptions on DR Behavior—Dr. Sullivan led a team of experts that investigated how customer lifestyles and perceptions influence energy use and how such information can be used to improve DR program effectiveness. The results of the project have been provided in draft form to the California Demand Response Measurement and Evaluation Committed.

California Investor-Owned Utility Consortium, Demand Response Load Impact Protocols Development—Dr. Sullivan worked with the FSC experts to develop a comprehensive set of protocols and guidance for estimating the load impacts of DR resources for the three California investor-owned utilities: Pacific Gas & Electric, San Diego Gas & Electric and Southern California Edison. The final product was a set of protocols and guidance for planning and conducting load impact evaluations of DR programs and time-varying pricing, which encompassed both ex post evaluation and ex ante estimation.

Lawrence Berkeley National Laboratory, Demand Response Valuation—Phase I—Directed FSC's assistance in scoping out a robust demand response benefit-cost valuation framework tailored to California.

Lawrence Berkeley National Laboratory, Incentives and Rate Design for Efficiency and Demand Response—Phase I—Directed FSC's assistance in identifying and developing alternative incentives and rate designs to support long-run integration of demand response into the California electric industry landscape.

California Institute for Energy and the Environment, White Paper on Behavioral Assumptions Underlying Energy Efficiency Programs—This white paper examined the assumptions underlying the design and implementation of energy efficiency programs and the basis and validity of these assumptions. The paper was developed for CIEE and subsequently distributed to the various stakeholders within California's energy efficiency arena.

California Institute for Energy and the Environment, White Paper on Experimental Design Parameters for Energy Efficiency Programs—This white paper examined how experimental design a) is currently being used in designing and implementing energy efficiency programs; both in California as well as in other markets, and b) could be used or improved relative to future energy efficiency initiatives within California. The paper was developed for CIEE and subsequently distributed to the various stakeholders within California's energy efficiency arena.

Large West Coast Utility, Solar Power Demand Study—Directed FSC's client to assess the impact, feasibility and market potential for a proposed solar program designed to increase solar presence in local communities and provide additional solar educational resources.

Employment History

1984–Present	Founder, *Freeman, Sullivan & Co. (FSC)*, San Francisco, CA
1984–1991	Operations Coordinator for Load Management, Rate Department, *PG&E*, San Francisco, CA
1984, 1988	Lecturer, Haas *School of Business Administration; University of California, Berkeley*, CA
1980–1981	Vice President, *Kendall Associates*, San Francisco, CA
1979–1980	Program Coordinator, *Seattle Energy Office, Executive Department*, City of Seattle, WA
1978–1979	Associate Senior Scientist, *Kendall Associates*, San Francisco, CA
1974–1978	Survey Project Manager and Teaching Assistant, Joint Appointment in the *Social Research Center and Sociology Department at Washington State University*, Pullman, WA
1972–1973	Research Associate, *Office of Public Affairs, University of California*, Riverside, CA

Awards

- Highest Honors, College of Letters and Sciences, U.C. Riverside (1973)
- National Science Foundation Summer Fellowship in Research (1972)
- Associate Editor, Western Sociological Review (1975–1978)

Publications

2012 Evaluation of Southern California Edison's 10/10 Program. March 19, 2013. (with Josh Schellenberg, Stephen George and Sam Holmberg).

Neighbor Comparisons Programs Save Energy, but What Drives Savings. Chicago, 2013. (with Brian Smith and Candice Churchwell). Presented at Proceedings of the International Energy Program Evaluation Conference.

Using Residential AC Load Control in Grid Operations: PG&E's Ancillary Services Pilot. (with Josh Bode, Bashar Kellow, Sarah Woehleke and Joseph Eto). IEEE Transactions on the Smart Grid. (Forthcoming 2013).

Incorporating Residential AC Load Control Into Ancillary Services Markets: Measurement and Settlement. (with Josh Bode, Dries Berghman and Joseph Eto). Energy Policy (Forthcoming 2013).

Electric Vehicle Forecast for a Large West Coast Utility, July 2011. (with Josh Schellenberg). Proceedings of the IEEE Power & Energy Society General Meeting 2011.

Experimentation and the Evaluation of Energy Efficiency Programs: Will the Twain Meet? May 2011. (with Edward Vine, Carl Blumstein, Loren Lutzenhiser and Bill Miller). Presented at IEPEC.

Assessing Energy Savings Attributable to Home Energy Reports. May 2011. (with Brian Smith). Presented at IEPEC.

How to Assess the Economic Consequences of Smart Grid Reliability Investments. November 2010. (with Josh Schellenberg). Report to the National Association of Regulatory Utility Commissioners.

Smart Grid Economics: The Cost Benefit Analysis. April 2011. (with Josh Schellenberg). In Renew Grid.

How to Estimate the Value of Service Reliability Improvements. July 2010. (with Josh Schellenberg, Matthew Mercurio and Joseph Eto). Conference Proceedings: 2010 IEEE Power & Energy Society General Meeting. Minneapolis, MN.

Guidelines for Designing Effective Energy Information Feedback Pilots: Research Protocols. April 2010. (with Stephen George). Prepared for Electric Power Research Institute. EPRI Report 1020855.

Estimated Value of Service Reliability for Electricity Customers in the United States, (with Matthew Mercurio and Josh Schellenberg), Office of Electricity Delivery and Reliability, US Department of Energy, LBNL 2132E, June 2009.

Using Experiments to Foster Innovation and Improve the Effectiveness of Energy Efficiency Programs. March 2009. Prepared for California Institute for Energy and Environment and the California Public Utilities Commission's Energy Division.

Behavioral Assumptions Underlying Energy Efficiency Programs for Businesses. January 2009. Prepared for CIEE Behavior and Energy Program and California Institute for Energy and Environment.

A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys. 2004. (with Leora Lawton, Ph.D., Kent Van Liere, Ph.D., Aaron Katz and Joseph Eto). Prepared for Energy Storage Program, Office of Electric Transmission and Distribution, U.S. Department of Energy, LBNL-54365.

Reliability Worth Assessment in Electric Power Delivery Systems. June 6–8, 2004. (with Ali Chowdhury, A., Tom Meilnik., Leora Lawton and Aaron Katz.). Presented at the IEEE Power Engineering Society Conference. Denver, CO.

The Numbers Game: Statistics in Construction Defect Litigation. Fall 2003. (with Jill Lifter). Prepared for Association of Defense Counsel of Northern California and Nevada. Defense Comment, Vol. 18, No. 3.

The Use of Statistics in Construction Defect Defense. Spring 2003. Prepared for The Critical Path, Defense Research Institute Construction Law Committee Newsletter.

Power Interruption Costs to Industrial and Commercial Consumers of Electricity. December 1997. (with Terry Vardell and Mark Johnson). Prepared for IEEE Transactions on Industry Applications, Vol. 33.

Modeling Residential Customers' Heating System Choices. July 1996. (with Dennis Keane). Prepared for Electric Power Research Institute. Final Report of Project 3902-02. EPRI Technical Report 106530.

Power Interruption Costs to Industrial and Commercial Consumers of Electricity. May 1996. (with Terry Vardell and Mark Johnson). Prepared for Conference Record, IEEE and Commercial Power Systems Technical Conference.

Interruption Costs, Customer Satisfaction and Expectations For Service Reliability. May 1996. (with T. Vardell, N. Suddeth and A. Vogdani). Prepared for IEEE Transactions on Power Systems, Vol. 11.

Outage Cost Estimation Guidebook. December 1995. (with Dennis Keane.). Prepared for Electric Power Research Institute Final Report of Project 2878-04. EPRI Technical Report 106082.

Can Dispatchable Pricing Options Be Used To Delay Distribution Investments? Some Empirical Evidence. May 1994. (with Keane, D. and Cruz, R.). In *Proceedings Load Management: Dynamic DSM Options For the Future.* Prepared for Electric Power Research Institute.

Reliability Service Options at PG&E. 1993. (with Dennis Keane.) In *Service Opportunities For Electric Utilities: Creating Differentiated Products.* Schmuel Oren and Stephen Smith, Eds. Prepared for Kluwer Academic Publishers.

Controlling Non-Response and Item Non-Response Bias Using Computer Assisted Telephone Interviewing Techniques. June 1991. Prepared for Sawtooth Software Conference Proceedings. Reprinted in Quirk's Market Research Quarterly. April 1992.

Good Organizational Reasons for Bad Evaluation Research. September 1989. (with Michael Hennessey.). Prepared for Evaluation Practice. Vol. 10, No. 4, pp. 41-50.

Implementing Dispatchable Load Management Projects. April 1988. (with Michael Hennessey.) Prepared for Public Utilities Fortnightly.

Surveying U.S. Teenager's Attitudes About, & Experiences With, Violence. Fall 2003. (David Musick., Charles DiSogra and Catherine Coffey.). In *Social Insight*. Vol. 8, pp. 52-59.

The Development of Social Power Structures in Small Groups. August 1983. Ph.D. Dissertation.

Can You Create Structural Differentiation in Social Power Structures in the Laboratory? December 1978. (with Louis Gray). In *Social Psychology*.

Social Matching Over Multiple Reinforcement Domains: An Explanation of Local Exchange Imbalance. March 1982. (with Louis Gray., Max von Broembsen and Wanda Griffith.). In *Social Forces*. Vol. 61, pp. 156-182.

Group Differentiation: Temporal Effects of Reinforcement. March 1982. (with Gray, L.N. and von Broembsen, M.). In *Social Psychology Quarterly*. Vol. 45 pp. 44-49.

Issues of Design and Analysis in Evaluation Research. August 1975. (with Duane Alwin.) In *Sociological Methods and Research*.

Patterns of Geothermal Lease Acquisition in the Imperial Valley. 1974. University of California Press.

Professional and Community Associations

- Marketing Research and Intelligence Association (Membership Number 1602781)
- American Association of Public Opinion Researchers
- American Statistical Association
- Association of Energy Services Professionals

- Defense Research Institute
- Institute of Electrical and Electronic Engineers

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MANHO YEUNG

Q 1 Please state your name and business address.

A 1 My name is Manho Yeung, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 My current position at PG&E is the senior director of System Planning and Reliability. In this capacity, I am responsible for PG&E's electric system planning, asset management and reliability. This position includes both electric transmission and distribution facilities.

Q 3 Please summarize your educational and professional background.

A 3 I received a bachelor of science degree in electrical engineering from the Georgia Institute of Technology in 1980. I received a master of science degree in electrical engineering from the Santa Clara University in 1986. I have been employed by PG&E since 1980 and have over 30 years of electric power system planning, engineering and energy policy experience.

I started my career with PG&E in 1980 and worked in PG&E's Electric Transmission Planning Department between 1980 and 1987 as a transmission planning engineer responsible for local transmission expansion projects. Between 1988 and 1992, I worked in PG&E's Electric Generation Planning Department as a senior electric generation planner. In that position, I managed PG&E's participation and testified for PG&E as its principle generation planner in the California Energy Commission's 1988 and 1990 Electricity Report Proceedings, and the Biennial Resource Plan Update Proceedings at the California Public Utilities Commission.

In 1993, I worked as the administrative assistant to the Senior Vice President and general manager of PG&E's Electric Supply Business unit. Between 1993 and 1997, I was the director of engineering in PG&E's Grid Maintenance and Construction Department. In that position, I was responsible for the engineering and design of PG&E's electric transmission lines, electric substations and system protection equipment. Between 1997 and 2006, I was PG&E's manager of Electric Transmission Planning in the

Electric Transmission and Distribution Engineering Department. In that position, I was responsible for PG&E's electric transmission grid expansion plan, electric transmission capacity project implementation and electric transmission interconnection planning matters.

In 2006, I started an assignment in PG&E's Energy Procurement organization as its director of System Integration Policy and Planning. In that position, I was responsible for PG&E's wholesale electric market issues and integrating supply-side, demand-side and transmission resources into PG&E's long-term procurement planning process. This assignment was refocused between April 2007 and December 2008 as PG&E's director of Integrated Resource Planning responsible for long term energy procurement plan and resource planning matters.

In January 2009, I started an assignment in PG&E's Electric Operations organization as its director of Electric Transmission Planning and Asset Strategy. In that position, I was responsible for PG&E's electric transmission planning and asset management. In November 2009, that position was expanded to director of Electric Planning, Strategy and Engineering with additional responsibilities in electric distribution planning, electric transmission line engineering and electric substation engineering. In November 2010, that position was changed to director of Electric Planning and Strategy and director of Engineering, Protection and Automation with responsibilities in electric distribution planning removed and automation added.

In October 2011, I started my current assignment as PG&E's senior director of System Planning and Reliability.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Embarcadero-Potrero Transmission Reliability Project:

- Chapter 1, "Introduction."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.