RAS 4856

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

DOCKETED
USNRC

September 17, 2002 (1:55PM)

OFFICE OF SECRETARY
RULEMAKINGS AND
ADJUDICATIONS STAFF

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:

G. Paul Bollwerk, III, Chairman
Dr. Jerry R. Kline
Dr. Peter S. Lam

SERVED September 17, 2002

In the Matter of	Docket No. 72-26-ISFSI
PACIFIC GAS AND ELECTRIC CO.	ASLBP No. 02-801-01-ISFSI
(Diablo Canyon Power Plant Independent Spent Fuel Storage Installation)	September 17, 2002

MEMORANDUM AND ORDER
(Schedules for Submissions Regarding Issues Proffered by 10 C.F.R. § 2.715(c) Interested Governmental Entities; Forwarding Additional Participant Submissions for Record Inclusion)

During the September 10-11, 2002 initial prehearing conference, in response to an offer by the NRC staff to provide a further submission outlining its views on the question of the standard that governs the admission of issues proffered by governmental entities seeking to participate in an agency adjudicatory proceeding pursuant to 10 C.F.R. § 2.715(c), the Board established the following schedule (Tr. at 170):

Staff Submission: Wednesday, September 25, 2002

Responses by Other Participants: Wednesday, October 9, 2002

Additionally, during the initial prehearing conference several documents were provided to the Board and the other participants in support of various arguments. Those documents, which are described below along with a transcript reference to their distribution, are being submitted to the Office of the Secretary as attachments to this issuance for inclusion with the record. However, because all other participants were provided with copies of these documents

Template=SECY-039

SECY-02

during the initial prehearing conference, the Office of the Secretary need not serve the attached documents on the other participants.

The documents are as follows:

Attachment A -- Letter from Seamus Slattery to G. Paul Bollwerk, Licensing Board Chairman (Aug. 29, 2002) (Tr. at 21)

Attachment B -- Arguments and Comments of the Diablo Canyon Independent Safety Committee [(DCISC)] Presented at the Prehearing Conference (Sept. 10, 2002) (Tr. at 32)

Attachment C -- Daniel Rubin, Capitol Called 9/11 Flight Target, The Tribune, Sept. 9, 2002, at A1 (Tr. at 82).

Attachment D -- Letter from James R. Hall, Senior Project Manager, NRC Office of Nuclear Material Safety and Safeguards to Lawrence F. Womack, Vice President, Nuclear Services, Diablo Canyon Power Plant (Aug. 29, 2002) (Tr. at 179)

Attachment E -- PG&E Letter DCL-01-119, Encl. 2, Proposed Corporate Structure of PG&E Corporation [(PG&E Corp.)] and Principal Subsidiaries after Implementation of Plan of Reorganization, at 1 (Bates No. 3001) (Tr. at 261)

Attachment F -- PG&E Corp. and Pacific Gas and Electric Company [(PG&E)] United States Securities and Exchange Commission Form 10-Q for the Quarterly Period Ended June 30, 2002 (Tr. at 335)

Attachment G -- Letter from Gregory M. Rueger, Senior Vice President-Generation and Chief Nuclear Officer, PG&E, to NRC Document Control Desk (Nov. 30, 2001) (Tr. at 346)

Attachment H -- Safety Analysis Report, Diablo Canyon ISFSI, Figures 2.6-40 to -42 (Tr. at 356)

It is so ORDERED.

FOR THE ATOMIC SAFETY
AND LICENSING BOARD*

G. Paul Bollwerk, III
ADMINISTRATIVE JUDGE

Rockville, Maryland

September 17, 2002

* Copies of this memorandum and order (without the accompanying attachments) were sent this date by Internet e-mail transmission to counsel for (1) applicant PG&E; (2) petitioners San Luis Obispo Mother For Peace, et al.; (3) San Luis Obispo County, California, Port San Luis Harbor District, California Energy Commission, and DCISC; and (4) the staff.

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of)
)
PACIFIC GAS AND ELECTRIC CO.) Docket No. 72-26-ISFSI
DIABLO CANYON POWER PLANT)
)
(Independent Spent Fuel Storage)
Installation))

CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing LB MEMORANDUM AND ORDER (SCHEDULES FOR SUBMISSIONS REGARDING ISSUES PROFFERED BY 10 C.F.R. § 2.715(c) INTERESTED GOVERNMENTAL ENTITIES; FORWARDING ADDITIONAL PARTICIPANT SUBMISSIONS FOR RECORD INCLUSION). (THIS DOCUMENT WAS SERVED WITHOUT THE ATTACHMENTS) have been served upon the following persons by U.S. mail, first class, or through NRC internal distribution.

Office of Commission Appellate
Adjudication
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Administrative Judge
G. Paul Bollwerk, III, Chair
Atomic Safety and Licensing Board Panel
Mail Stop - T-3 F23
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Administrative Judge
Peter S. Lam
Atomic Safety and Licensing Board Panel
Mail Stop - T-3 F23
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Administrative Judge
Jerry R. Kline
Atomic Safety and Licensing Board Panel
Mail Stop - T-3 F23
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Stephen H. Lewis, Esq.
Angela B. Coggins, Esq.
Office of the General Counsel
Mail Stop - O-15 D21
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Lorraine Kitman
P.O. Box 1026
Grover Beach, CA 93483

Docket No. 72-26-ISFSI
LB MEMORANDUM AND ORDER (SCHEDULES FOR SUBMISSIONS REGARDING ISSUES PROFFERED BY 10 C.F.R. § 2.715(c) INTERESTED GOVERNMENTAL ENTITIES; FORWARDING ADDITIONAL PARTICIPANT SUBMISSIONS FOR RECORD INCLUSION). (THIS DOCUMENT WAS SERVED WITHOUT THE ATTACHMENTS)

Peg Pinard
San Luis Obispo County Supervisor
County Government Center
1050 Monterey Avenue
San Luis Obispo, CA 93408

Diane Curran, Esq.
Harmon, Curran, Spielberg
& Eisenberg, L.L.P.
1726 M Street, NW, Suite 600
Washington, DC 20036

David A. Repka, Esq.
Brooke D. Poole, Esq.
Winston & Strawn
1400 L Street, NW
Washington, DC 20005-3502

Klaus Schumann
Mary Jane Adams
26 Hillcrest Drive
Paso Robles, CA 93446

Robert R. Wellington, Esq.
Robert W. Rathie, Esq.
Wellington Law Offices
857 Cass Street, Suite D
Monterey, CA 93940

Seamus M. Slattery, Chairman
Avila Valley Advisory Council
P.O. Box 58
Avila Beach, CA 93424

Lawrence F. Womack, Vice President
Nuclear Services
Diablo Canyon Power Plant
P.O. Box 56
Avila Beach, CA 93424

Richard F. Locke, Esq.
Pacific Gas & Electric Company
77 Beale Street, B30A
San Francisco, CA 94105

Thomas D. Green, Esq.
Thomas D. Waylett, Esq.
Adamski, Moroski & Green, LLP
444 Higuera Street, Suite 300
San Luis Obispo, CA 93401-3875

Barbara Byron
Nuclear Policy Advisor
California Energy Commission
1516 Ninth Street, MS 36
Sacramento, CA 95814

Docket No. 72-26-ISFSI
LB MEMORANDUM AND ORDER (SCHEDULES FOR SUBMISSIONS REGARDING ISSUES PROFFERED BY 10 C.F.R. § 2.715(c) INTERESTED GOVERNMENTAL ENTITIES; FORWARDING ADDITIONAL PARTICIPANT SUBMISSIONS FOR RECORD INCLUSION). (THIS DOCUMENT WAS SERVED WITHOUT THE ATTACHMENTS)

Darcie L. Houck, Esq.
California Energy Commission
Chief Counsel's Office
1516 Ninth Street, MS 14
Sacramento, CA 95814

Evangeline S. Ngbea
Office of the Secretary of the Commission

Dated at Rockville, Maryland,
this 17th day of September 2002

ATTACHMENT A

SEP 03 2002

Avila Valley Advisory Council
P.O. Box 58
Avila Beach, CA 03424

August 29, 2002

G. Paul Bollwerk, Chairman
Atomic Safety and Licensing Board
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Subject: Diablo Canyon ISFSI Licensing Proceeding, Docket No. 72-26

Dear Judge Bollwerk,

On May 22, 2002, on behalf of the Avila Valley Advisory Council and in conjunction with San Luis Obispo County Supervisor Peg Pinard, I filed a petition for leave to intervene and request for hearing in this proceeding. I signed the petition on behalf of AVAC.

Since then, AVAC has hired attorney Diane Curran to represent it in this proceeding. Therefore she, and not I, will be representing AVAC before the ASLB.

Sincerely,

Seamus Slattery

Cc: Service list

ATTACHMENT B

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	
	)	Docket No. 72-26-ISFSI
PACIFIC GAS AND ELECTRIC CO.,	)	
DIABLO CANYON POWER PLANT	)	ASLBP No. 02-801-01-ISFSI
	)	
	)	
[Independent Spent Fuel Storage Installation]	)	
	)	Date: September 10, 2002
	)	

ARGUMENTS AND COMMENTS OF THE DIABLO CANYON INDEPENDENT SAFETY COMMITTEE PRESENTED AT THE PREHEARING CONFERENCE

INTRODUCTION

The Diablo Canyon Independent Safety Committee ("Safety Committee") on August 20, 2002, requested in writing to participate in the instant matter as an interested state agency in accordance with 10 C.F.R. §2.715(c). The several arguments, facts and points made and presented in the Safety Committee's written request are incorporated by reference here. Pacific Gas and Electric Company ("PG&E"), by response to Safety Committee's request dated August 30, 2002, has stated its opposition to the request. Staff of the NRC has responded to Safety Committee's request by supporting it on the basis that Safety Committee is, by its very definition, an interested state agency. The following arguments and comments are submitted pursuant to the "Initial Prehearing Conference Argument Schedule," included in a Memorandum and Order dated September 3, 2002.

ARGUMENT AND COMMENTS

The question here is whether the Safety Committee is an interested state agency whose representatives should be afforded participation status as provided in 10 C.F.R. §2.715(c). The regulation is short on definition. However, there are several factors that support the Safety Committee's status as an interested state agency. To begin, the Safety Committee was established as a result of a settlement agreement entered into, among others, by the State of California. Its actual creation was by means of a decision of the California Public Utilities Commission ("CPUC"), an arm and instrumentality of the state. Subsequent CPUC decisions have extended the life of the Safety Committee on the basis that the public has a continuing interest in the plant's safety. Its very existence derives from and through the State of California. Each of its members is appointed by state officials - the Governor, Attorney General, and Chairperson of the California Energy Commission. Despite PG&E's protests to the contrary, "agency," as used in the regulation at issue here, does not categorically require establishment through a constitution, enabling statute or regulation. That the Safety Committee may be a hybrid not fitting nicely in PG&E's notion of state agency does not dispel the clear and compelling certainty that it was specifically created by the state to perform a legitimate governmental function.

Citing *Power Authority of New York* (James A. Fitzpatrick Nuclear Power Plant; Indian Point, Unit 3), CLI-00-22, 52 NRC 266, NRC Staff states its support for Safety Committee participation. NRC Staff is particularly impressed, as was the Commission in *Power Authority*, with safety and the specific interest of the prospective participant in assuring the public that a nuclear facility will operate without incident. Here, the Safety Committee has stated previously its interest in the safe operation of the ISFSI and has made the point that in doing so it is carrying out its state-mandated responsibility to assure the safety of operations at Diablo Canyon.

The Safety Committee is clearly not a general purpose planning advisory board of the sort rejected as a hearing participant in the decision cited by PG&E as *Yankee Rowe* [sic], CLI-98-12, 48 NRC 185. Rather, the stated purposes and charges of the Safety Committee put it directly at interest in the ISFSI matter, where the integration of the ISFSI into existing facility systems raises important questions concerning continued safety of the plant.

The apparently unqualified rejection, as 10 C.F.R. §2.715(c) participants, of "advisory" bodies in the decision cited as *Yankee Rowe* [sic] did not persuade NRC Staff, nor does it persuade us, that the Safety Committee is not qualified to represent the interests it is legally bound to address by direction of the State of California. Of paramount concern here is according participant status to an agency created by the state to assure and protect the safety and interests of the citizens of the state. At the Safety Committee's last public hearings in June of this year several residents of San Luis Obispo County appeared and requested that the Safety Committee intervene in the instant proceedings.

Why PG&E is forwarding what amounts to a technical argument to keep the Safety Committee out of the hearing mainstream is unclear. PG&E should welcome the active participation of any agency that will bring the experience and intellect regarding atomic plant safety that the Safety Committee possesses. Please, then, exercise your considerable discretion and allow participant status to the Safety Committee.

Thank you, and I reserve my remaining time for rebuttal.

Robert R. Wellington

Robert R. Wellington, Esq.
Legal Counsel
Diablo Canyon Independent Safety Committee

ATTACHMENT C

Newspaper of the Central Coast • SanLuisObispo.com

THE TRIBUNE

50¢ INCLUDES TAX

SAN LUIS OBISPO COUNTY, CALIFORNIA

MONDAY, SEPTEMBER 9, 2002

AT OUTDOORS, C6

the weight off

nds build strength, flexibility

IN SPORTS, C1

Sampras in Open

He captures 14th Grand Slam

IN LOCAL, B1

Start a cab's tab?

Taxis shuttle young partiers home

THE THREAT OF TERRORISM Remaining vigilant a year later

Capitol called 9/11 flight target

PLOTTERS ALSO CLAIM AL QAEDA ORIGINALLY THOUGHT OF STRIKING NUCLEAR FACILITIES

BY DANIEL RUBIN
KNIGHT RIDDER TRIBUNE

BERLIN — The U.S. Capitol was the target of the hijacked United Airlines Flight 93 that crashed Sept. 11 in rural Pennsylvania, two of the plotters reportedly have told the Arab al-Jazeera television channel.

The plotters also said that the Al Qaeda terror organization planned the attacks over two and a half years, and originally considered striking U.S. nuclear facilities.

The claims were made in a Sunday Times of London article written by Yosri Fouda, London bureau chief for the Arab television channel al Jazeera, which has ties to Al Qaeda that cloud the credibility of its reports.

In June, Fouda writes, he traveled to a secret location in Karachi, Pakistan, to interview Khalid Shaikh Mohammed, the man U.S. authorities believe masterminded the Sept. 11 plot, and Ramzi Binalshibh, the logistical brains of the Hamburg, Germany, terror cell. Both men are wanted by the FBI.

Both men insisted that Osama bin Laden was alive, but Fouda noted that one of them once referred to the Al Qaeda leader in the past tense. He came away from the interview convinced that bin Laden was dead.

The al Jazeera report will air Thursday, one day after the first anniversary of the suicide hijackings that killed more than 3,000 people in New York, suburban Washington, D.C., and rural Pennsylvania.

Over two days in June, Mohammed, 38, and Binalshibh, 30, sketched for Fouda how members of the cell communicated in Internet chat rooms and through e-mail, with lead hijacker Mohamed Atta once pretending he was an American writing his German girlfriend, Jenny.

Atta used code for the targets, referring to the World Trade Center as the Faculty of Town Planning, the Pentagon as the Faculty of Fine Arts and Capitol Hill as the Faculty of Law, Binalshibh told Fouda.

Please see PLANE, A4

Plane

From Page A1

The article contends that after a July summit in Spain, Atta gained full authority to select the targets and the date for the attack, and that on Aug. 29, 2001, he announced the timing to Binalshibh in a 3 a.m. phone call, conducted in German.

"A mate of mine bothered me with this puzzle and I was hoping you would help me solve it. Two sticks, a dash and a cake with a stick — what is it?"

Binalshibh quickly read this as 11-9, the European and Arabic way of writing the 11th of September.

"The attacks were designed to cause as many deaths as possible and havoc and to be a big slap for America on American soil," Fouda quoted Mohammed as saying. Mohammed, who identified himself as head of Al Qaeda's military committee, boasted of having a "Department of Martyrs" with scores of volunteers willing to fight in "the jihad against the infidels and the Zionists."

The article makes some claims that contradict German investigators.

Fouda wrote that the phone call from Atta reached Binalshibh in the apartment they once shared at 54 Marien Strasse in Hamburg. But all members of the Hamburg cell had moved out of that apartment by March 1, 2001, according to German investigators and Thorstein Albrecht, a Hamburg real estate agent representing the landlord.

Fouda also wrote that Atta had been a "sleeper" in Germany since 1992, when he moved from Cairo, where he had studied engineering. But Klaus Ulrich Kersten, Germany's top police official, said in an interview last month that it was likely that Atta was recruited into Al Qaeda in the late 1990s, and that he had come to Germany to study.

An Al Qaeda representative called Fouda to set up the interview, he wrote. The al Jazeera reporter recounted how he was instructed to fly to Islamabad, then Karachi, in June, and traveled in three cars and a rickshaw before being led blindfolded into a fourth-floor apartment where the two Al Qaeda planners waited.

ATTACHMENT D

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

August 29, 2002

Mr. Lawrence F. Womack
Vice President, Nuclear Services
Diablo Canyon Power Plant
P.O. Box 56
Avila Beach, CA 93424

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE DIABLO CANYON INDEPENDENT SPENT FUEL STORAGE INSTALLATION APPLICATION (TAC NO. L23399)

Dear Mr. Womack:

By letter dated December 21, 2001, the Pacific Gas and Electric Company (PG&E) submitted an application to the U.S. Nuclear Regulatory Commission (NRC) for a 10 CFR Part 72 license to build and operate an independent spent fuel storage installation (ISFSI) at the Diablo Canyon Power Plant site. On March 25, 2002, NRC notified you that we had completed our acceptance review of the application and had found that the application contained sufficient information for the staff to initiate our technical review. On May 9, 2002, we provided you with our schedule to complete the technical review of the application. The NRC staff, with the assistance of the Center for Nuclear Waste Regulatory Analyses (CNWRA), has completed its initial review of your application and has determined that additional information is required to assess compliance with 10 CFR Part 72.

Enclosed is the staff's request for additional information (RAI). This information is needed for us to continue our review of your ISFSI application. We request that you respond to each item in the RAI. As identified in our May 9, 2002, schedule letter, your response to the enclosed RAI is expected by October 15, 2002. If you are unable to meet the October 15, 2002, milestone, you must notify us in writing, at least 2 weeks prior to that date, of your new response date and the reasons for the delay. The staff will then assess the impact of the new response date and will issue a revised schedule.

We are willing to meet with you to discuss and clarify the enclosed RAI. Based on preliminary discussions with your staff, we have tentatively agreed to a meeting on or about September 19, 2002, to be held at the CNWRA offices in San Antonio, Texas. A public meeting notice will be issued shortly, when the meeting arrangements are finalized.

Please reference Docket No. 72-26 and TAC No. L23399 in future correspondence related to this licensing action. If you have any questions, please contact me at (301) 415-1336.

Sincerely,

James R. Hall

James R. Hall, Senior Project Manager
Licensing Section
Spent Fuel Project Office
Office of Nuclear Material Safety
and Safeguards

Docket No. 72-26 (50-275, -323)
TAC No. L23399

Enclosure: Request for Additional Information

cc: Mailing List

Diablo Canyon Power Plant, Units 1 and 2

cc:
NRC Resident Inspector
Diablo Canyon Nuclear Power Plant
c/o U.S. Nuclear Regulatory Commission
P.O. Box 369
Avila Beach, CA 93424

Dr. Richard Ferguson, Energy Chair
Sierra Club California
1100 11th Street, Suite 311
Sacramento, CA 95814

Rochelle Becker
San Luis Obispo
Mothers for Peace
1037 Ritchie Rd.
Grover Beach, CA 93433

Chairman
San Luis Obispo County Board of
Supervisors
Room 370
County Government Center
San Luis Obispo, CA 93408

Mr. Truman Burns
Mr. Robert Kinosian
California Public Utilities Commission
505 Van Ness, Room 4102
San Francisco, CA 94102

Mr. Steve Hsu
Radiologic Health Branch
State Department of Health Services
P.O. Box 942732
Sacramento, CA 94327-7320

Diablo Canyon Independent Safety
Committee
ATTN: Robert R. Wellington, Esq.
Legal Counsel
857 Cass Street, Suite D
Monterey, CA 93940

Regional Administrator, Region IV
U.S. Nuclear Regulatory Commission
Harris Tower & Pavilion
611 Ryan Plaza Drive, Suite 400
Arlington, TX 76011-8064

Christopher J. Warner, Esq.
Pacific Gas & Electric Company
Post Office Box 7442
San Francisco, CA 94120

Mr. David H. Oatley, Vice President
Diablo Canyon Operations and
Plant Manager
Diablo Canyon Nuclear Power Plant
P.O. Box 3
Avila Beach, CA 93424

Telegram-Tribune
ATTN: Managing Editor
1321 Johnson Avenue
P.O. Box 112
San Luis Obispo, CA 93406

Mr. Ed Bailey, Radiation Program Director
Radiologic Health Branch
State Department of Health Services
P.O. Box 942732 (MS 178)
Sacramento, CA 94327-7320

Mr. Robert A. Laurie, Commissioner
California Energy Commission
1516 Ninth Street (MS 31)
Sacramento, CA 95814

Ms. Charlotte Alexander
Vice President, Special Projects
Green Car Group
1241 Johnson Avenue #356
San Luis Obispo, CA 93401

Ellen Carroll
Environmental Coordinator
Department of Planning and Building
County of San Luis Obispo
County Government Center, Room 310
San Luis Obispo, CA 93408

The Honorable Lois Capps
Member, United States
House of Representatives
ATTN: Greg Hass, District Representative
1411 Marsh Street
San Luis Obispo, CA 93401

Enclosure

PACIFIC GAS AND ELECTRIC COMPANY
DOCKET NO. 72-26
TAC NO. L23399

REQUEST FOR ADDITIONAL INFORMATION

On December 21, 2001, the Pacific Gas and Electric Company (PG&E) submitted a license application to the U.S. Nuclear Regulatory Commission (NRC), to construct and operate an on-site independent spent fuel storage installation (ISFSI), in accordance with 10 CFR Part 72. The on-site ISFSI will store spent nuclear fuel and associated non-fuel hardware from Units 1 and 2 of the Diablo Canyon Power Plant. The proposed Diablo Canyon ISFSI will use the Holtec HI-STORM dry cask storage system, which employs multi-purpose canisters placed inside overpacks to store the spent nuclear fuel. Documents associated with this submittal include the License Application, Environmental Report, Safety Analysis Report, Emergency Plan, Technical Specifications, Quality Assurance Program, and a Preliminary Decommissioning Plan.

This document, entitled Request for Additional Information (RAI), contains additional information requirements identified by the NRC staff during its review of the PG&E application for a 10 CFR Part 72 license for the Diablo Canyon ISFSI. Each individual RAI describes information needed by the staff for it to complete its review of the application and determine whether PG&E has demonstrated compliance with the regulatory requirements. Applicable regulatory requirements are specified in the individual question or comment. The format of this RAI follows the chapters of NUREG–1567, "Standard Review Plan for Spent Fuel Dry Storage Facilities (NRC, 2000)," except for the addition of RAI Chapters 17, Environmental Review, Chapter 18, Materials, and Chapter 19, Editorial Comments.

The staff's technical review was carried out in accordance with the applicable NRC regulations in 10 CFR Parts 20 and 72, and the NRC guidance contained in NUREG–1567, and in NUREG–1536, "Standard Review Plan for Dry Cask Storage Systems (NRC, 1997)." Note that RAI items may refer to the Spent Fuel Project Office's (SFPO) Interim Staff Guidance (ISG). The ISG was developed as a result of management decisions on several key issues related to the review and approval of spent fuel storage systems and represents positions discussed in meetings with the Nuclear Energy Institute. The current ISG will be incorporated into the next revisions of NUREG-1567 and NUREG-1536.

Chapter 1. Introduction and General Description

The staff has no comments regarding the general description of the proposed Diablo Canyon ISFSI. The applicant has provided adequate information in the Safety Analysis Report such that the reviewer and other interested parties could become familiar with the pertinent, nonproprietary features of the ISFSI.

Chapter 2. Site Characteristics

2-1. Identify all sources of information used in the aircraft crash hazard analysis to support an evaluation of whether an aircraft crash is a credible hazard to the proposed facility.

- This information is necessary to determine compliance with 10 CFR §72.94(a), §72.94(b), §72.94(c), and §72.98(a).

2-2. Provide the calender year for the flight statistics (for each flight corridor) used to support the evaluation of the aircraft crash hazard analysis.

- This information is necessary to determine compliance with 10 CFR §72.94(a), §72.94(b), §72.94(c), and §72.98(a).

2-3. Provide technical bases for the estimated effective area of the facility for all aircraft types, as given in the Diablo Canyon ISFSI Safety Analysis Report. The technical bases should be consistent with the established methodologies for estimating the effective area of a given facility for a given aircraft, for example, Section 3.5.1.6 of NUREG–0800 (NRC, 1987), or any other standards.

- This information is necessary to determine compliance with 10 CFR §72.94(a), §72.94(b), §72.94(c), and §72.98(a).

2-4. Provide technical bases for the crash rate value (C), for each type of aircraft used in the Diablo Canyon ISFSI Safety Analysis Report. The technical bases should follow from an accepted methodology, such as the one documented in NUREG–0800 (NRC, 1987b).

- This information is necessary to determine compliance with 10 CFR §72.94(a), §72.94(b), §72.94(c), and §72.98(a).

2-5. Provide reasonable estimates for future aircraft activities in the vicinity of the proposed ISFSI facility and an estimate of the cumulative crash hazard of all types of aircraft that may fly in the vicinity of the proposed site. These analyses should follow an established methodology, such as the one documented in NUREG–0800 (NRC, 1987).

- This information is necessary to determine compliance with 10 CFR §72.94(a), §72.94(b), §72.94(c), and §72.98(a).

2-6. Provide information describing the (i) type of activities carried out by military aircraft in the vicinity of the proposed facility; (ii) possible ordnance carried by military aircraft, if any; and (iii) any potential hazard from the ordnance of these aircraft.

- This information is necessary to determine compliance with 10 CFR §72.94(a), §72.94(b), §72.94(c), and §72.98(a).

2-7. Provide additional information to determine whether missile tests at Vandenberg Air Force Base could be a credible hazard to the proposed facility. This information should account for the number, type(s), and paths of missiles being tested in a year and describe the safety precautions to be implemented prior to and during tests.

- This information is necessary to determine compliance with 10 CFR §72.94(a), §72.94(b), and §72.94(c).

2-8. Provide information on potential accidents at nearby facilities and transportation routes, as described in NUREG–1567 (NRC, 2000). No information is given in the Safety Analysis Report as to why potential accidents at the Diablo Canyon Power Plant or on nearby transportation routes would not present a credible hazard to the proposed ISFSI.

- This information is necessary to determine compliance with 10 CFR §72.94(a), §72.94(b), §72.94(c), and §72.98(a).

2-9. Provide information and analysis to determine whether any sharing of utilities and services between the proposed ISFSI and the existing nuclear power plant increases the probability or consequences of an accident or possible malfunction of structures, systems, or components important to safety, or reduces the safety margin for any technical specification of either facility.

- This information is necessary to determine compliance with 10 CFR §72.122(k)(4).

2-10. Provide information and analysis to ensure that the cumulative effects of the combined operations of the proposed ISFSI facility and existing nuclear power plant will not constitute an unreasonable risk to the health and safety of the public.

- This information is necessary to determine compliance with10 CFR §72.122(e).

2-11. Provide information to show that any of the ISFSI structures, systems, and components important to safety that would be shared with the nuclear power plant will not impair the capability of either facility to perform its safety function, including the ability to return to a safe condition in the event of an accident.

- This information is necessary to determine compliance with10 CFR §72.122(d).

2-12. Provide clarification of the precipitation data presented in Subsections 2.3.1 and 2.3.2 of the Diablo Canyon ISFSI Safety Analysis Report.

Specifically address whether the maximum hourly amount of precipitation recorded in the Diablo Canyon area was 5.97 cm [2.35 in] or 8.33 cm [3.28 in]. Similarly, address whether the maximum amount of precipitation in a 24-hr period was 8.33 cm [3.28 in] or 15.19 cm [5.98 in]. Provide the average annual precipitation that is more appropriate for the ISFSI site, either the average annual precipitation of 40.64 cm [16 in] reported for the "area" or the 54.69 cm [21.53 in] reported for San Luis Obispo.

NUREG–1567 (Section 2.4.3.1) states that the applicant must provide precipitation extremes for the region.

- This information is necessary to determine compliance with 10 CFR §72.24(a), §72.90(a), §72.90(b), §72.92(a), §72.92(b), §72.98(a), and §72.122(a).

2-13. Provide the data source for the precipitation data presented in Sections 2.3.1 and 2.3.2 of the Diablo Canyon ISFSI Safety Analysis Report.

NUREG–1567 (Section 2.4.3.1) states that the applicant should discuss data sources and reliability.

- This information is necessary to determine compliance with 10 CFR §72.24(a), §72.90(a), §72.90(b), §72.92(a), §72.92(b), §72.98(a), and §72.122(a).

2-14. Provide the data and analyses used to support the statement that a maximum tsunami would not cause any flooding at the ISFSI site.

NUREG–1567 (Section 2.4.4.6) states that the applicant should analyze the history of tsunami in the region. The analysis should include all potential tsunami generators, such as specific faults, fault zones, volcanoes, and potential landslide areas.

- This information is necessary to determine compliance with 10 CFR §72.24(a), §72.90(a), §72.90(b), §72.92(a), §72.92(b), §72.98(a), and §72.122(a).

2-15. Provide analysis to demonstrate the potential effects of a tsunami (either from an offshore earthquake or an earthquake-induced submarine landslide) on the stability of the Patton Cove landslide area. Resulting wave erosion could exacerbate slide potential at Patton Cove.

- This information is necessary to determine compliance with 10 CFR §72.24(a), §72.90(a), §72.90(b), §72.92(a), §72.92(b), §72.98(a), and §72.122(a).

2-16. Provide analysis to demonstrate that the subsurface materials at the proposed storage-pad site are sufficiently competent to withstand the storage-pad foundation loading during a design-basis earthquake.

The analysis provided in Section 2.6.4 of the Diablo Canyon ISFSI Safety Analysis Report is not adequate because (i) the effects of preexisting structural features (such as joints, bedding planes, and clay beds) on potential failure modes of the subsurface materials were not adequately considered in the analysis; and (ii) the potential stress distributions that may control the behavior of the subsurface materials during an earthquake were not adequately considered in the analysis. The stress distributions arise from (i) initial stresses in the subsurface materials, (ii) gravitational loads from the pads and casks, (iii) seismic loading of the subsurface materials from the free-field ground motion, and (iv) seismic loading associated with the inertia of the pads and casks.

- This information is necessary to determine compliance with 10 CFR §72.24(a), §72.24(b), §72.24(d), §72.90, §72.92, §72.102(d), and 10 CFR §72.122(b)(2).

2-17. Provide data to show that the proposed transport route roadway is sufficiently far from the Patton Cove landslide such that an encroachment of the slide into the transport route can be considered unlikely.

The information provided in Section 2.6.5 of the Diablo Canyon ISFSI Safety Analysis Report does not include an adequate description of the subsurface materials and interfaces in the area between the transport route and the existing slide.

- This information is necessary to determine compliance with 10 CFR §72.24(a), §72.24(b), §72.24(d), §72.90, §72.92, and §72.122(b)(2).

2-18. Provide an assessment of the stability of the natural slope above and below the proposed storage-pad site during a design-basis earthquake.

The analysis provided in the Diablo Canyon ISFSI Safety Analysis Report is not adequate because (i) an assessment of the potential effects of a design-basis earthquake on the stability of the slope is not provided; and (ii) estimates of seismically induced displacements of potentially unstable masses were calculated using the Newmark sliding block analysis method, but the uncertainties of using the Newmark method for the ground-motion magnitudes associated with the design-basis earthquake were not evaluated.

- This information is necessary to determine compliance with 10 CFR §72.24, §72.90, §72.92, and §72.122(b)(2).

2-19. Provide site-response assessment of the vibratory ground motions for the proposed transport route roadway between the nuclear power plant and the Diablo Canyon ISFSI pad; or provide sufficient justification of why a seismic event that may cause cask drop, overturn of the transporter, or sliding of the transporter off the transport route is not credible (as described in Section 8.2.1.2.1 of the Diablo Canyon ISFSI Safety Analysis Report).

Unlike the power plant and the storage-pad locations, which are founded on bedrock, the proposed transport route is underlain by soils and manmade fill. The site response of these soils and manmade fill could change the amplitude and spectral frequency content of the input vibratory ground motions used in seismic design analyses of the transporter and casks. The conclusion provided by the Applicant in Section 8.2.1.2.1 of the Diablo Canyon ISFSI Safety Analysis Report is that the limited exposure time of the radioactive material during transportation from the power plant to the Cask Transfer Facility (12 hr per year, which is equal to a yearly probability of 1.37×10^{-3}), makes this a noncredible accident scenario. This conclusion requires further justification.

- This information is necessary to determine compliance with 10 CFR §72.24(a), §72.24(b), §72.24(d), §72.90, §72.92, §72.102(b), §72.122, §100.20, and §100.23.

Chapter 3. Operational Systems

3-1. Provide a complete operational description of the cask transporter during the following operations:

(a) Loading of the cask transport frame onto the cask transporter

(b) Transport to the Cask Transfer Facility (for example, what allowances are made for transverse slope of the road outside the Fuel Handling Building and operational controls of the transporter)

(c) Upending and downending of cask transport frame at the Cask Transfer Facility (for example, what defense-in-depth design features or operational controls prevent tipover during upending and prevent motion past vertical)

(d) Transfer of multi-purpose canisters to the storage cask (for example, what are the steps to attach the restraints for the transporter and controls to ensure that the multi-purpose canister does not bind during transfer)

(e) Transport of loaded storage cask to the storage-pad

(f) Placement of storage cask on the storage-pad (e.g., alignment process and torque sequence for bolts)

This information is necessary to allow the reviewers to assess the ability of the transporter to perform its tasks. This should include discussion of the design features, operator controls, and administrative controls. Section 5.1.1.3 of the Diablo Canyon ISFSI Safety Analysis Report contains only a brief narrative description that is supported in part by Figure 5.1.1 of the Diablo Canyon ISFSI Safety Analysis Report.

- This information is necessary to determine compliance with 10 CFR §72.24(b) and §72.128(a).

3-2. Provide details of the Cask Transfer Facility jack screw controls that are used to ensure a uniform lift of the storage cask.

Section 4.2.1.2 and 4.4.5 of the Diablo Canyon ISFSI Safety Analysis Report and supporting design calculations contain only a limited discussion of the operational characteristics of the cask transporter facility. The information should include a detailed discussion of the devices relied on to automatically shutdown the jack screw in a safe condition in the event of a failure. Moreover, the rationale for not classifying the jack screw controls and related safety features as important-to-safety must be provided. The Cask Transfer Facility jacks are classified as Category B, Important to Safety in Table 4.5.1 of the Diablo Canyon ISFSI Safety Analysis Report, but the table is unclear and does not include the jack screw controls. NUREG–1567 (Section 3.4.3) states that the applicant must provide a clear narrative description or flowcharts of the systems and system equipment and controls used to assure safety.

- This information is necessary to determine compliance with10 CFR §72.24(b) and §72.128(a).

3-3. Provide a description of the structural details and function of the seismic restraint of the cask transporter and storage cask in the Cask Transfer Facility, including associated diagrams. This should include the restraints themselves as well as their attachment points to both the transporter and the foundation.

The description given in Section 5.1.1.3 of the Diablo Canyon ISFSI Safety Analysis Report is insufficient. NUREG–1567 (Section 3.4.3) states that the applicant must provide a clear narrative description or flowcharts of the systems and system equipment and controls used to assure safety.

- This information is necessary to determine compliance with 10 CFR §72.24(b) and §72.128(a).

Chapter 4. Structures, Systems, and Components and Design Criteria Evaluation

4-1. Provide a classification for the cask transport frame and any other components present but not listed in Table 4.5-1 of the Diablo Canyon ISFSI Safety Analysis Report.

The Diablo Canyon ISFSI Safety Analysis Report does not include the cask transport frame in Table 4.5-1 and does not classify it as a Category A, B, C, or not-important-to-safety item. As identified within the text of the Diablo Canyon ISFSI Safety Analysis Report, the main function of the cask transporter frame is to facilitate rotation of the loaded transfer cask from vertical to horizontal position, or vice versa, at the Fuel Handling Building/Auxiliary Building and Cask Transfer Facility. NUREG–1567 (Section 4.4.2) states that the applicant must identify all structures, systems, and components, and provide a rationale for the identification.

- This information is necessary to determine compliance with 10 CFR §72.24(n).

4-2. Provide the structural design criteria and bases (e.g., enhanced safety factors, redundant systems, or both) for exclusion of cask drop events during handling and transport.

The Diablo Canyon ISFSI Safety Analysis Report (Section 4.3.2.1.2) states that mechanical design features and administrative controls provide a defense-in-depth approach to preventing load drops during lifting and handling without specifying the structural design criteria and bases. A simple statement that design is according to the applicable guidelines of NUREG–0612 is not adequate. Justification for exclusion of cask drops should be provided. Otherwise, there is a need to establish a cask lifting height limit. Specific design analysis and calculation for the components of lifting and handling system should be provided. NUREG–1567 (Section 4.5.3) states that the principal design criteria and bases for structures, systems, and components important to safety must be provided.

- This information is necessary to determine compliance with 10 CFR §72.24(c)(1) and (2), and §72.120(a).

4-3. Provide justification for the proposed Diablo Canyon Licensing Basis Velocities for Tornado-Generated Missiles in the form of (i)15.24-cm [6 in] diameter Schedule 40 pipe, (ii) 2.54-cm [1 in] diameter steel rod, (iii) utility pole, and (iv) 30.48-cm [12 in] diameter Schedule 40 pipe, listed at the bottom of Table 3.2-2 of the Diablo Canyon ISFSI Safety Analysis Report.

According to Section 3.2.1.1 of the Diablo Canyon ISFSI Safety Analysis Report, the tornado-generated missiles evaluated for the Diablo Canyon ISFSI are a compilation of those from the 1996 Diablo Canyon Power Plant Final Safety Analysis Report Update; NUREG–0800 (NRC, 1987), Section 3.5.1.4 Spectrum II missiles; and three 500-kV tower missiles specific to the Diablo Canyon ISFSI site. A review of the table indicated that the descriptions and masses for four missiles identified in the first sentence of this comment are consistent with Missiles B, C, D, and E of the Spectrum II missiles listed in NUREG–0800 (NRC, 1987); however, the associated velocity values are substantially smaller than those provided in NUREG–0800 (NRC, 1987).

- This information is necessary to determine compliance with 10 CFR §72.92(a) and §72.122(b).

4-4. Provide information to verify that the forces imposed on the transporter roadway, from the fully loaded transporter, are within design criteria of the as-built pavements and subgrade.

Section 4.3.2.1.1 of the Diablo Canyon ISFSI Safety Analysis Report only states that, "It is designed with two steel tracks to spread out the load on the transport route surface as a distributed pressure load."

- This information is necessary to determine compliance with 10 CFR §72.24(b) and §72.24(c).

Chapter 5. Installation and Structural Evaluation

5-1. Provide an evaluation to support the conclusion that the concrete will not break out of the storage pads prior to failure of the ductile metal members.

The Diablo Canyon ISFSI Safety Analysis Report (Section 3.3.2.3, ISFSI Concrete Storage Pad: Design Criteria) states that the design strength capacity of the embedded base plate, concrete bearing, and diagonal tension shear capacity are in accordance with the design provisions of American Concrete Institute 349-97 and the embedded anchorage will meet the ductile anchorage provisions of the Proposed Draft New Appendix B to American Concrete Institute 349-97 (dated October 1, 2000). Supporting evidence that the concrete will not break out prior to failure of the ductile metal members is not provided in the Diablo Canyon ISFSI Safety Analysis Report. An evaluation of concrete breakout strength in tension of a group of anchor rods considering spacing and edge distance should be provided.

- This information is necessary to determine compliance with 10 CFR §72.24(a), §72.24(b), §72.24(c), §72.24(d), §72.24(i), and §72.122(b).

5-2. Specify how Pacific Gas and Electric will identify changes to the final construction design and analysis of the Diablo Canyon ISFSI storage pad and the Cask Transfer Facility.

Section 4.2 of the Diablo Canyon ISFSI Safety Analysis Report states that final construction design and analysis of the Diablo Canyon ISFSI storage pad and the Cask Transfer Facility will be completed during the detailed design phase of the project and that no significant changes are anticipated from the information presented. Section 5.4.3 of NUREG–1567 (NRC, 2000) indicates that design descriptions should include sufficient detail to support a detailed review and evaluation, and that design analyses should be prepared such that they may be readily audited to permit determination of the sources of expressions used, values of material properties, data from other supporting calculations, and assumptions. In addition, this information is needed to assess compliance with the applicable codes, standards, and other functional design requirements (i.e., structural design requirements for off-normal and accident loading conditions).

- This information is necessary to determine compliance with 10 CFR §72.24(a), §72.24(b), §72.24(c), §72.24(d), §72.24(i), and §72.122(b).

5-3. Provide details on the heat from hydration during placement of the concrete in the storage pads.

This is a massive structure based on the 1.9-m [7.5-ft] thickness and the overall size of the individual pads. Heat generated during hydration may result in unacceptable cracking of the pad structure. Cracking of the pad may adversely affect the ability of the anchor system for the storage casks to perform its intended safety functions.

- This information is necessary to determine compliance with 10 CFR §72.24(a), §72.24(b), §72.24(c), §72.24(d), §72.24(i), and §72.122(b).

5-4. Identify what stresses are imposed in the surrounding foundation rocks as a result of the static and dynamic loading of the Cask Transfer Facility and assess the potential consequences. This assessment should include the technical basis for the failure criteria used and a quantification of the factors of safety.

Section 4.4.5 of the Diablo Canyon ISFSI Safety Analysis Report contains only a brief discussion of the main shell. Sufficient detail and supporting analysis must be provided to identify the load paths, demand, and capacity of the various components.

- This information is necessary to determine compliance with 10 CFR §72.24(a), §72.24(b), §72.24(c), §72.24(d), §72.24(i), and §72.122(b).

5-5. Provide the material specifications and mechanical properties for the seismic anchor system including the embedment plate, compression coupling blocks, anchor rods, and anchor plates.

NUREG–1567 (Section 5.4.1.3) states that the Safety Analysis Report must (i) establish compatibility of materials and coatings to be used with the environments to be experienced; (ii) provide tables with material properties and allowable stresses and strains associated with temperature, as appropriate; and (iii) establish appropriate corrosion allowances and demonstrate these allowances are acceptable in the applicable structural analyses. Section 4.4.5.3 of the Diablo Canyon ISFSI Safety Analysis Report contains a statement that the main shell at the Cask Transfer Facility and its foundation are sufficient, but no supporting information is provided.

- This information is necessary to determine compliance with 10 CFR §72.24(a), §72.24(b), §72.24(c), §72.24(d); §72.24(i), and §72.122(b).

5-6. Provide additional information on the structural design and analyses of the Cask Transfer Facility given in Holtec Report No. HI–2012626, including (i) the main shell and the method used to anchor it to the surrounding concrete; (ii) the jack support platform; (iii) the lifting platform; and (iv) the Cask Transfer Facility concrete structure and the method used to anchor it to the surrounding rock foundation.

NUREG–1567 (Section 5.4.4.4) states that design analyses should be prepared such that they may be readily audited to permit determination of the sources of expressions used, values of material properties, data from other supporting calculations, and assumptions. Furthermore, NUREG–1567 (Section 5.5.4.) states that the following must be identified: (i) all dimensions, including locations, sizes, configurations, and weld specifications; (ii) structural materials with defining standards or specifications, including test requirements such as brittle fracture testing; (iii) fabrication, assembly, and test procedures for assemblies and subassemblies; and (iv) weld materials and weld codes, including pre- and post-heat requirements.

- This information is necessary to determine compliance with 10 CFR §72.24(a), §72.24(b), §72.24(c), §72.24(d); §72.24(i), §72.82, and §72.122(b).

5-7. Provide an assessment of potential impact loads between the storage cask and the Cask Transfer Facility during an earthquake, or justify why they do not need to be considered as part of the analysis identified in Section 4.4.5 of the Diablo Canyon ISFSI Safety Analysis Report.

NUREG–1567 (Section 5.5.1.4) states that normal, off-normal, and accident load conditions should be defined and evaluated.

- This information is necessary to determine compliance with 10 CFR §72.24(a), §72.24(b), §72.24(c), §72.24(d), §72.24(i), and §72.122(b).

5-8. The analysis of the Cask Transfer Facility under seismic loading, given in Holtec Report No. HI–2012626, is performed using a quasi-static method. Provide the engineering basis for the assumption that the various components can be considered rigid. For example, identify what the axial mode of the screw jacks is when loaded by the HI-STORM 100 storage cask and multi-purpose canister. Identify what the buckling load for the screw jacks is when the system is at the top of its travel.

- This information is necessary to determine compliance with 10 CFR §72.24(a), §72.24(b), §72.24(c), §72.24(d), §72.24(i), and §72.122(b).

5-9. Provide operational and design details of the proposed fail-safe features identified in Section 3.3.3.2 of the Diablo Canyon ISFSI Safety Analysis Report that are intended to automatically shut-down the cask transporter into a safe, stopped, and braked condition if the operator is injured for any reason while handling a loaded cask.

NUREG–1567 (Section 5.5.4.) states that text descriptions along with drawings, figures, tables, and specifications included in the application should fully describe structures, systems, and components important to safety.

- This information is necessary to determine compliance with 10 CFR §72.24 and §72.82.

5-10. Provide design analyses and calculation packages for the cask transporter, including (i) slings and special lifting devices; (ii) cask transporter lift points, overhead beam, vehicle body, and seismic restraints; and (iii) lifting towers.

NUREG–1567 (Section 5.4.4.4) states that design analyses should be prepared such that they may be readily audited to permit determination of the sources of expressions used, values of material properties, data from other supporting calculations, and assumptions. Furthermore, NUREG–1567 (Section 5.5.4.) states that the design analyses must identify: (i) all dimensions, including locations, sizes, configurations, and weld specifications; (ii) structural materials with defining standards or specifications, including test requirements such as brittle fracture testing; (iii) fabrication, assembly, and test procedures for assemblies and subassemblies; and (iv) weld materials and weld codes, including pre- and post-heat requirements.

- This information is necessary to determine compliance with 10 CFR §72.24(a), §72.24(b), §72.24(c), §72.24(d), §72.24(i), §72.82, and §72.122(b).

5-11. Provide design analyses and calculation packages that justify the assumption that the components of the cask transporter including (i) overhead beam, (ii) vehicle body, and (iii) lifting towers are rigid to 33 Hz.

Use of static design assumes that the elements are rigid within the frequency range of the loading. Structural beam properties needed to ensure a rigid structure are more stringent than those required to resist other loadings. NUREG–1567 (Section 5.5.4.4) states that all load combinations for structures, systems, and components important to safety must be appropriately evaluated.

- This information is necessary to determine compliance with 10 CFR §72.24(a), §72.24(b), §72.24(c), §72.24(d), §72.24(i), and §72.122(b).

5-12. Provide or reference design analyses and calculation packages on the seismic restraints of the cask transporter at the Cask Transfer Facility. This should include the restraints themselves as well as their attachment points.

- This information is necessary to determine compliance with 10 CFR §72.24(a),

§72.24(b), §72.24(c), §72.24(d); §72.24(i), and §72.122(b).

5-13. Provide an evaluation of the effects of torque on the embedded anchor rods.

The torque is the result of applying the preload (698 kN/anchor [157 kips/anchor]) to the cask anchor studs. The cask anchor studs are threaded into compression/coupling blocks that enable the anchor studs to be preloaded to approximately 698 kN [157 kips]. However, the embedded anchor rods are threaded into the coupling blocks and the torque applied to the anchor studs will be transmitted to the anchor rods. The anchor system must perform its safety function and is of a unique design. The uniqueness is associated with the high preload of the anchor studs, the use of coupling blocks, the depth of embedment, and the interaction between the anchor studs and the embedded anchor rods. NUREG–1567 (Section 5.4.1.4) states that design analyses should be prepared such that they may be readily audited to permit determination of the sources of expressions used, values of material properties, data from other supporting calculations, and assumptions.

- This information is necessary to determine compliance with 10 CFR §72.24(a), §72.24(b), §72.24(c), §72.24(d), §72.24(i), and §72.122(b).

Chapter 6. Thermal Evaluation

6-1. Provide the insolation source data collected by the California Irrigation Management Information System during the period May 1, 1986, to December 31, 1999, at the site 12 mi [19.31 km] from the proposed ISFSI location.

NUREG–1567 (Sections 2.4.3.1 and 6.5.3) states that this information should be provided by the applicant. This information is necessary to confirm that the Diablo Canyon site parameters are within the parameters analyzed for the HI-Storm 100 system.

- This information is necessary to determine compliance with 10 CFR §72.92(b) and §72.122(b)(3).

6-2. Provide clarification of the units used to quantify the Diablo Canyon Power Plant spent nuclear fuel rod burnup limits in Footnote (a) of Table 3.1-2 in the Diablo Canyon ISFSI Safety Analysis Report.

NUREG–1567 (Section 6.5.2.2) states that this information is needed to establish acceptable storage fuel cladding temperatures under normal, off-normal, and accident conditions.

- This information is necessary to determine compliance with 10 CFR §72.24, §72.26, and §72.44.

6-3. Provide the monthly average temperatures for the Diablo Canyon site.

This information is required to ensure the long-term environmental temperatures of the site are bounded by the cask limiting condition of operation. NUREG–1567 (Section 6.5.3) state that this information should be provided by the applicant.

- This information is necessary to determine compliance with 10 CFR §72.92(b) and §72.122(b)(3).

6-4. Provide thermal analyses of the ISFSI storage pad and Cask Transfer Facility concrete structure.

NUREG–1567 (Section 6.5.2.3) states the maximum calculated concrete temperatures should be assessed and must not exceed the material temperature criteria for normal, off-normal, and accident conditions.

- This information is necessary to determine compliance with 10 CFR §72.92(a), §72.92(b), §72.92(c), §72.122(b), and §72.128(a).

6-5. Provide clarification and rationale explaining the difference between the highest recorded hourly temperature of 36.1 °C [97 °F] and the extreme hot ambient temperature of 40 °C [104 °F] for the Diablo Canyon site.

NUREG–1567 (Sections 2.4.3.1 and 6.5.3) states that this information should be provided by the applicant.

- This information is necessary to determine compliance with 10 CFR §72.92(a), §72.92(b), §72.92(c), §72.122(b), and §72.128(a).

6-6. Provide clarification as to the maximum net allowable decay heat load and concomitant uncertainty for each applicable multipurpose canister and verify that these values are bounded by the assumed values used to analyze the normal, off-normal, and accident conditions in the cask Diablo Canyon ISFSI Safety Analysis Report.

NUREG–1567 (Section 6.5.3) states that this information should be provided by the applicant.

- This information is necessary to determine compliance with 10 CFR §72.92(a), §72.92(b), §72.92(c), §72.122(b), and §72.128(a).

6-7. Provide a revision of the proposed Technical Specifications for the ISFSI that includes an administrative procedure to prohibit transfer cask handling operations at environmental temperatures below -18 °C [0 °F].

Section 8.1.2.3 of the Diablo Canyon ISFSI Safety Analysis Report states that administrative procedures based on DC ISFSI TS 5.1.3 prohibit cask handling operations at environmental temperatures below -18 °C [0 °F]. Technical Specification 5.1.3 does not appear to contain this limitation, however. NUREG–1567 (Section 6.5.2.1) states that this information should be provided by the applicant.

- This information is needed to determine compliance with 10 CFR §72.24(h).

6-8. Revise Section 10.2.2.3 of the Diablo Canyon ISFSI Safety Analysis Report, Multi-Purpose Canister Drying Characteristics, to adopt the appropriate sections of Appendix 2.B, The Forced Helium Dehydration System, from the Holtec HI-STORM 100 Final

Safety Analysis Report, Amendment 1.

The Forced Helium Dehydration System is a new drying method. As a result, the Diablo Canyon ISFSI Safety Analysis Report should be revised to include the recommended analyses and a description of the acceptance testing procedures that will be implemented for the Forced Helium Dehydration System. NUREG-1567 (Section 6.5.1.2) states that the Safety Analysis Report should provide evidence that (i) the liquid in the cask does not boil during fuel assembly transfer operations to avoid uncontrolled pressures on the cask and the connected dewatering, purging, and recharging system(s); (ii) an adequate subcooling margin has been identified and a corresponding operating procedure to prevent boiling that may result in an inadvertent criticality due to optimum moderator conditions has been provided; and (iii) the ISFSI maximum temperature (under normal conditions) of the pool water and other water that may be used in the cask cavity during loading and unloading operations is below the temperature assumed in the cask criticality safety analysis if a time restriction exists in the corresponding technical specifications.

- This information is needed to determine compliance with 10 CFR §72.24(i).

6-9. Provide clarification as to whether a Vacuum Drying System will be used at the Diablo Nuclear Power Plant for drying canisters containing moderate and high burnup spent fuel as an alternative method to the Forced Helium Dehydration System.

If the Vacuum Drying System is used, the temperature of the fuel could be high enough to cause hydrides to reorient in a radial direction in highly oxidized high burnup fuel cladding. NUREG–1567 (Section 6.5.2.2) states that the Safety Analysis Report should address burnup dependent effects that could potentially lead to a failure of the cladding and dispersal of the fuel during transfer and handling operations.

- This information is needed to determine compliance with 10 CFR §72.24(i).

Chapter 7. Shielding Evaluation

The staff has not identified any additional information regarding the applicant's shielding evaluation.

Chapter 8. Criticality Evaluation

8-1. Provide a description of the differences between the multi-purpose canister-24E and multi-purpose canister-24EF and discuss how these differences allow fuel debris to be loaded into the multi-purpose canister-24EF compared to the multi-purpose canister-24E.

A review of the drawings has found some differences between the multi-purpose canister-24E and multi-purpose canister-24EF, but it is not clear how these differences affect the criticality performance of the canister and how the calculation models have accounted for these differences. Such differences are not addressed in Table 6.3.3 or

Figure 6.3.1A of the HI-STORM 100 Safety Analysis Report.

- This information is necessary to determine compliance with 10 CFR §72.124(a), §72.124(b), §72.126(a), and §72.236(a).

8-2. Provide the configurations for the various missing fuel rod and collapsed fuel cases referenced in Section 6.4.4.2.2 of the HI-STORM 100 Safety Analysis Report that were used to model the "realistic" assembly configurations. This information may be supplied by illustrations or a more detailed description in the text. Provide enough detail so that independent calculations can be performed.

- This information is necessary to determine compliance with 10 CFR §72.124(a), §72.124(b), §72.126(a), and §72.236(a).

8-3. Provide a table of the results for all the criticality cases analyzed, as summarized in Table 6.4.9 of the HI-STORM 100 Safety Analysis Report. Clarify the fuel configurations assumed in the pressurized water reactor damaged fuel analysis, and explain how to compare these results to the data plotted in Figure 6.4.14 of the HI-STORM 100 Safety Analysis Report.

Table 6.4.9 only gives the maximum calculated value for a series of cases. The table should give the calculated value for each case along with a short description of the different configurations assumed in each case. For example, Section 6.4.4.2.2 of the HI-STORM 100 Safety Analysis Report states that lattice spacings from 8x8 to 27x27 (20 different lattices?) were analyzed but does not describe how half rods of the lattice were treated and how the lattice was centered or modeled off-center in the damaged fuel container. A maximum, typical, and minimum pellet diameter was analyzed for each lattice spacing, but individual results are not tabulated. In addition, figure 6.4.14 of the HI-STORM 100 Safety Analysis Report uses the parameter, fuel mass per unit length, but does not tie this to the lattice configuration for each data point.

- This information is necessary to determine compliance with 10 CFR §72.124(a), §72.124(b), §72.126(a), and §72.236(a).

8-4. Clarify the configuration assumed for the fuel debris analysis and how it differs from the damaged fuel model. Specify the number of fuel pellets that are assumed to change to powder. Indicate whether broken clumps or chunks of fuel (including shapes, sizes and spacing) were considered.

- This information is necessary to determine compliance with 10 CFR §72.124(a), §72.124(b), §72.126(a), and §72.236(a).

Chapter 9. Confinement Evaluation

The staff has not identified any additional information regarding the applicant's confinement evaluation.

Chapter 10. Conduct of Operations Evaluation

10-1. Provide a statement as to whether the Diablo Canyon ISFSI would contain any structures, systems, or components important to safety, for which functional adequacy or reliability have not been demonstrated. Provide a schedule showing how any safety questions for these items would be resolved prior to initial receipt of spent nuclear fuel or high-level waste.

- This information is needed to determine compliance with 10 CFR §72.24(i).

10-2. Provide a more complete description of the delegations of authority, required skills, and experience levels for the Diablo Canyon ISFSI management organization.

In particular, (i) define any responsibilities of the Director of Site Services relative to the Station Director; (ii) identify the responsibilities and reporting relationships of subordinates to the Director of Site Services; (iii) specify the qualifications and responsibilities for the ISFSI Specialists, Security Staff, the Director of Maintenance Services, the Manager of Radiation Protection, the Manager of Operations, the Manager of Chemistry and Environmental Operations, and any of their subordinates who may have responsibilities important to safety; (iv) identify whether persons other than the Station Director require designation of personnel to act in their absence; and (v) identify any positions having stop-work authority other than the Station Director. This information is required to allow the staff to determine that reporting relationships and assignments of responsibility are adequate to support safe operations at the Diablo Canyon ISFSI as specified in Section 10.4.1 of NUREG–1567.

- This information is needed to determine compliance with 10 CFR §72.28(c).

10-3. Provide an assessment that demonstrates that the proposed additional 11 staff members are sufficient to safely conduct the range of operations that might be required simultaneously at both the power plant and the ISFSI.

An assessment is needed as to whether the additional 11 staff members required for ISFSI operations (as discussed in Sections 9.1.2, 9.1.5, and 9.1.6.1 of the Diablo Canyon ISFSI Safety Analysis Report) will require that overall Diablo Canyon Power Plant staffing levels be increased. The Diablo Canyon ISFSI Safety Analysis Report should confirm that this additional staffing is sufficient for operating circumstances that could arise simultaneously at the power plant and the ISFSI.

- This information is needed to determine compliance with 10 CFR §72.40(a).

10-4. Provide supporting information for the determination that accidents and emergencies at the Diablo Canyon ISFSI can be adequately managed by personnel trained for power plant emergencies. A rationale is required for the fact that the minimum on-shift staffing requirements shown in Table 5.1 of the Emergency Plan do not require any additional personnel, nor personnel trained in ISFSI operations.

- This information is needed to determine compliance with 10 CFR §72.32(b) and §72.40(a).

10-5. Provide supporting information for the determination that no emergency equipment in addition to that provided for the Diablo Canyon Power Plant is required to support potential emergencies at the Diablo Canyon ISFSI.

Clarification is required for the allocation and location of any emergency equipment specifically for the Diablo Canyon ISFSI. The description of emergency facilities and equipment in Chapter 7 of the Diablo Canyon Power Plant Emergency Plan does not identify any such equipment that would be located within the ISFSI or that would be provided specifically for use by the ISFSI.

- This information is needed to determine compliance with 10 CFR §72.32(b) and §72.40(a).

10-6. Describe the mechanism in place for the case where accident conditions at the ISFSI continue to degrade to the point where the accident level should be escalated to a more severe emergency class.

The ISFSI emergency actions levels are at the Notification of Unusual Event (NOUE), with no apparent means for progression to the Alert level.

- This information is needed to ensure compliance with 10 CFR §72.32.

10-7. Describe the communication equipment available for staff to report emergencies from the ISFSI to the Control Room.

- This information is needed to ensure compliance with 10 CFR §72.32.

10-8. Describe how information about the ISFSI will be incorporated into the emergency plan training for staff and off-site responders, such as fire and police.

- This information is needed to ensure compliance with 10 CFR §72.32.

Chapter 11. Radiation Protection Evaluation

11-1. Provide a description of all nonfuel hardware at the plant which could be inserted into a fuel assembly prior to the assembly being loaded into a canister.

The SAR indicates that burnable poison rod assemblies and thimble plug devices are no longer in use in the core and therefore the inventory of these types of nonfuel hardware will not increase. Rod cluster control assemblies are still used. Other types of nonfuel hardware which are currently in inventory at the plant and could be placed in the canister need to be identified. (SAR Section 7.2.1.4, Nonfuel Hardware Source)

- This information is needed to determine compliance with 10 CFR §72.104.

11-2. Provide a summary of the sky-shine analyses prepared for the dose calculations. (SAR Section 7.3.2, Shielding)

- This information is needed to determine compliance with 10 CFR §72.104.

11-3. Provide a figure which identifies the location of the nearest resident.

The SAR indicates nearest resident is located 2,414 meters from the ISFSI but does not indicate which sector. (SAR Section 7.5, Offsite Collective Dose)

- This information is needed to determine compliance with 10 CFR §72.104 and 10 CFR Part 20.

11-4. Provide a summary description of the analyses performed to determine the dose to an individual at the DCPP site boundary.

- This information is needed to determine compliance with 10 CFR §72.104.

11-5. Provide an analysis which demonstrates compliance with the 40 CFR Part 190 dose rate limit of 25 mrem/year from all site sources.

- This information is needed to determine compliance with 10 CFR Part 20.

Chapter 12. Quality Assurance Evaluation

The staff has not identified any additional information regarding the applicant's Quality Assurance evaluation.

Chapter 13. Decommissioning Evaluation

The staff has not identified any additional information regarding the applicant's decommissioning evaluation.

Chapter 14. Waste Confinement

The staff has not identified any additional information needs regarding the applicant's waste confinement evaluation.

Chapter 15. Accident Analysis

15-1. Provide detailed information for the selection process and analysis used to eliminate a particular hazard from further consideration.

It is not clear how the potential off-normal and accident events have been selected for further consideration. This information is necessary to demonstrate that all appropriate potential hazards have been considered in the Diablo Canyon ISFSI Safety Analysis Report.

- The information is needed to determine compliance with 10 CFR §72.92(a), §72.92(b), §72.94(a), and §72.94(b).

15-2. Provide information on what safety features and/or administrative procedures would be used to avoid a potential collision between the cask transporter or other on-site vehicle and a storage cask, a transportation cask, the transfer facility, or the storage pad. In addition, describe any measures, such as safety features or administrative procedures relied on to mitigate the consequences from such hazards.

This information is necessary to determine whether collision of vehicles with important-to-safety structures is a credible hazard at the proposed facility.

- This information is needed to determine compliance with 10 CFR §72.122(b)(1), §72.122(e) and §72.122(g).

15-3. Provide an assessment of a cask drop of less than design-allowable height.

NUREG–1567, Subsection 15.5.1.1, Cask Drop Less than Design Allowable Height, indicates that drops of the casks at less than their allowable design heights during handling operations are hypothetical off-normal scenarios that the applicant must evaluate. An acceptable alternative to evaluating drops of the various fuel confinement components at less than design allowable heights is to demonstrate that their integrity and fuel spacing geometry will not be compromised when subjected to postulated drop and tipover accident scenarios. NRC considers the consequences of drops less than the allowable design heights to be bounded by these accident scenarios.

15-4. Provide an assessment of storage and transfer cask drops.

NUREG–1567, Subsection 15.5.2.2, Cask Drop, indicates that drops of the casks are hypothetical accident scenarios that must be evaluated by the applicant. Alternatively, provide justification for why such events are non-credible (see RAI # 4-2)

- This information is needed to determine compliance with 10 CFR §72.128(a).

15-5. Provide the technical bases for the proposed setback distances of transient sources of combustibles.

Site topography and potential thermal load must be considered in the development of these bases. Specifically address the 7,300 l [2,000 gal] tanker truck that will routinely pass near the ISFSI site on its way to the maintenance shop.

- This information is needed to determine compliance with 10 CFR §72.122(c).

15-6. Provide an analysis to justify the assertion that a potential fire in any existing stationary fuel tanks would not pose a hazard to the ISFSI facility. Provide additional information on the type(s) of fuel, capacity of the fuel tanks, construction of the tanks, and the safety features.

- This information is needed to determine compliance with 10 CFR §72.122(c).

15-7. Provide additional information to justify assumptions used in calculating the effects of wild fires in calculation HI–2012615, "Evaluation of Site-Specific Wild Fires for the Diablo

Canyon ISFSI," regarding the characteristics of the site-specific wild fires (e.g., flame height, flame front velocity, fireline intensity).

- This information is needed to determine compliance with 10 CFR §72.122(c).

15-8. Provide analyses on explosion-generated missiles for Explosion Event Scenarios 1 through 3 to show that these missiles would not affect the ability of structures, systems, and components important to safety to perform their intended safety functions.

In the Diablo Canyon ISFSI Safety Analysis Report, the applicant cites existing information and analyses provided in Regulatory Guide 1.91 (NRC, 1978). The information and analyses in Regulatory Guide 1.91 are intended, however, for an overpressure that does not exceed 6.9 kPa [1.0 psi]. Regulatory Guide 1.91 clearly states that "If the overpressure criteria of this guide are exceeded, the effects of missiles must be considered." For Explosion Event Scenarios 1 through 3, as listed in Table 8.2-11 of the Diablo Canyon ISFSI Safety Analysis Report, the associated incident over-pressures are more than 6.9 kPa [1 psi]. Consequently, the effects of explosion-generated missiles due to Explosion Event Scenarios 1 through 3 must be analyzed.

- This information is needed to determine compliance with 10 CFR §72.122(c).

15-9. Provide the analysis that concluded that the risk of an explosion of the gasoline tanker truck, having a capacity of 7,300 l [2,000 gal] of fuel, will not affect the safety functions of the ISFSI and Cask Transfer Facility.

The applicant states in Section 8.2.6 of the Diablo Canyon ISFSI Safety Analysis Report that a probabilistic risk analysis, based on Regulatory Guide 1.91, was performed to show that the risk of this accident scenario is insignificant, but this analysis was not submitted for staff review.

- This information is needed to determine compliance with 10 CFR §72.122(c).

15-10. Provide an analysis to demonstrate that the probability and risk of an explosion in the transformers due to an electrical fault while the transfer cask is in the proximity will not impair the essential safety functions of the ISFSI or Cask Transfer Facility.

Section 8.2.6, Explosion, of the Diablo Canyon ISFSI Safety Analysis Report cites the risk acceptance criteria of Regulatory Guide 1.91 (NRC, 1978). This analysis was not submitted to the staff for review.

- This information is needed to determine compliance with 10 CFR §72.122(c).

15-11. Provide information and analysis to demonstrate that any explosion of the hydrogen bottles, shown in Figure 2.2-1 to be located close to the path of the transporter and the ISFSI pads, will not pose an undue hazard to structures, systems, and components important to safety at the proposed facility.

The Diablo Canyon ISFSI Safety Analysis Report did not provide the capacity of the hydrogen bottles or the maximum number of such bottles that can be stored at a given time. Additionally, no analysis has been provided.

- This information is needed to determine compliance with 10 CFR §72.122(c).

15-12. Provide the maximum amount of acetylene to be stored in one bottle. Describe the physical or administrative controls that would prevent more than one acetylene or propane bottle from being transferred in a single trip.

NUREG–1567 (Section 15.5.2.4) states that this information should be provided in the Safety Analysis Report.

- This information is needed to determine compliance with 10 CFR §72.122(c).

15-13. Provide an analysis to demonstrate that any explosion of the vapor cloud resulting from rupture of the propane and gasoline storage tanks, considering atmospheric dispersion, will not generate an air overpressure that may pose undue hazard to structures important to safety at the proposed facility.

Any atmospheric dispersion of the vapor cloud can bring the flammable mixture closer to the structures, systems, and components important to safety than the distances used in the analyses given in the Diablo Canyon ISFSI Safety Analysis Report and calculation HI–2002512. A delayed ignition of the vapor cloud may produce an unacceptable level of air overpressure near the structures important to safety.

- This information is needed to determine compliance with 10 CFR §72.122(c).

15-14. Provide information on how gasoline, diesel, propane, acetylene, and other combustible materials would be supplied to the facility.

If gasoline, diesel, and propane are replenished using tanker trucks, the size and number of the trucks that may be present at any time, and the location of the trucks with respect to structures, systems, and components important to safety should be provided. Analysis should also be presented to demonstrate that the tanker trucks would not pose any undue hazard to the facility. Similar information and analysis should be submitted for combustible and explosive materials supplied in bottles (e.g., acetylene, hydrogen).

- This information is needed to determine compliance with 10 CFR §72.122(c).

15-15. Provide justification for the electrical resistivity values used to assess the consequences of lightning strike and 500-kV transmission line drop on the HI-STORM 100 storage cask and HI-TRAC transfer cask.

According to the American Society for Metals (1985), electrical resistivity for American Iron and Steel Institute-Society of Automotive Engineers (AISI–SAE) Grade 1042 carbon steel is 17.1 $\mu\Omega$-cm at 20 °C (68 °F). AISI–SAE Grade 1042 carbon steel is relevant because it has a chemical composition that is similar to the outer shell material, SA 516 Grade 70. NUREG–1567 (Section 15.5.2.5) states that a discussion of the structural materials or components that might be damaged by heat or mechanical forces generated by passing electrical current to ground should be provided by the applicant.

- This information is needed to determine compliance with 10 CFR §72.122(b)(1) and §72.122(b)(2).

15-16. Provide an assessment of the potential consequences of a lightning strike or 500-kV transmission line drop on the site transporter while a cask is being transferred.

NUREG–1567 (Section 15.5.2.5) states that a discussion of the structural materials or components that might be damaged by heat or mechanical forces generated by passing electrical current to ground should be provided by the applicant.

- This information is needed to determine compliance with 10 CFR §72.122(b)(1) and §72.122(b)(2).

15-17. Provide an analysis of the potential lateral and axial sliding distances that the transporter may slide on the roadway during an earthquake.

In Section 8.2.1.2.1 of the Diablo Canyon ISFSI Safety Analysis Report, analysis is provided to demonstrate limited sliding of the transporter on those portions of the roadway underlain by bedrock. No such analysis is provided for vibratory ground motions on portions of the roadway underlain by soil and manmade fill (see RAI 2-19). The applicant should provide analyses demonstrating that the transporter will remain on the roadway, within a safe margin from the edge of the roadway, during the design basis ground motions.

- This information is needed to determine compliance with 10 CFR §72.92(a) and §72.122(b).

15-18. Provide a detailed basis for the bounding values of large, intermediate, and small tornado missiles (see RAI 4-3).

- This information is needed to determine compliance with 10 CFR §72.24 (c)(1), §72.24(c)(2), §72.92(a) §72.92(b), §72.92(c), and §72.122(b).

15-19. Provide analyses or technical bases to demonstrate that the bounding large missile,1,800 kg [4,000 lb], would not cause damage to the cask transfer facility that results in a drop of transfer cask from the top of overpack or damage to the overpack.

- This information is needed to determine compliance with 10 CFR §72.92(a) and §72.122(b).

15-20. Provide calculations to demonstrate that the transporter would not overturn while moving a loaded transfer cask to the Cask Transfer Facility and a loaded storage cask to the storage pads due to an impact by a design-basis tornado missile.

It is stated in Section 4.3.2.1.2, Design, that "the cask transporter is designed to withstand Diablo Canyon Power Plant design-basis tornado winds and tornado-generated missiles without overturning, dropping the load, or leaving the transporter route," but the design analysis was not presented. Alternatively, the applicant may present an analysis demonstrating that there are no radiological consequences even if the transporter overturns.

- This information is needed to determine compliance with 10 CFR §72.122(c).

15-21. Provide a technical basis to support the statement in Section 8.2.2.2.2, Transfer Operations at the CTF, of the Diablo Canyon ISFSI Safety Analysis Report that "cask transport and transfer operations will not be conducted during severe weather. The top of the multiple-purpose canister will only be exposed for a short duration (nominally less than 4 hours). Therefore, in the configuration with the lid removed, a tornado missile impact is not credible."

This conclusion lacks a sufficient technical basis because an acceptable definition of credible was not provided. Alternatively, the applicant can provide information to demonstrate that the exposed multipurpose canister would be able to withstand impact of any tornado-generated missiles without loss of its safety functions. In addition, the applicant should define "severe weather."

- This information is needed to determine compliance with 10 CFR §72.92(a), §72.92(b), §72.92(b), and §72.122(b).

15-22. Provide the analyses that demonstrate collapse of the electrical transmission towers will not adversely affect the multipurpose canister while at the Cask Transfer Facility or the loaded overpacks stored on the pads.

NUREG–1567 (Section 15.4.3) states that the applicant must list and evaluate accidents that are specific to the design.

- This information is needed to determine compliance with 10 CFR §72.122.

15-23. Provide a fire analysis of a loaded overpack inside the Cask Transfer Facility.

This scenario may arise as the result of a fuel spill from the 7,300 l [2,000 gal] gasoline tanker truck that passes near the facility on a regular basis. NUREG–1567 (Section 15.4.3) states that the applicant must list and evaluate accidents that are specific to the design.

- This information is needed to determine compliance with 10 CFR §72.122.

Chapter 16. Technical Specifications

16-1 Provide Technical Specifications (TS) that follow the format and content of the HI-STORM 100 storage system.

The criticality aspects of the Diablo Canyon ISFSI Safety Analysis Report rely on the approved HI-STORM 100 storage system. The Diablo Canyon ISFSI Safety Analysis Report shows that the fuel to be loaded at Diablo Canyon falls within the bounds of fuel already approved for the HI-STORM 100 system. The staff's approval of the HI-STORM 100 application, as amended, was based, in part, on the TS also approved for that system. The applicant should use the previously approved documents (HI-STORM 100

Safety Analysis Report and accompanying Technical Specifications) as a basis in developing the Diablo Canyon ISFSI TS, with appropriate changes to reflect any limitations or site specific features (such as the applicable multipurpose canister and fuel types). Alternatively, the applicant must sufficiently describe and justify differences between the proposed TS for the Diablo Canyon ISFSI and those approved by the staff for the HI-STORM 100 system.

- This information is needed to determine compliance with 10 CFR §72.44(c).

16-2. Develop a maintenance program for the purpose of monitoring and verifying the preload of the HI-STORM 100SA overpack anchor studs. Specify the coating to be used on the exposed surfaces of the anchor studs and the embedment plate for corrosion protection. The program should also specify the time interval for periodic inspection of the anchor studs. This program should be included in the Technical Specifications.

Section 4.2.1.1.6 of the Diablo Canyon ISFSI Safety Analysis Report states that: "Each cask is compressed against the embedment plate using 16 studs. Each stud is preloaded to approximately 157,000 lbf." In addition, Section 8.2.1.2.3.1 of the Diablo Canyon ISFSI Safety Analysis Report states that: "The preloaded cask anchor studs are threaded into compression/coupling blocks to ensure a continuous compressive state of stress at the interface between the lower surface of the HI-STORM 100SA overpack and the top surface of embedment plate. The continued contact ensures development of interface friction forces sufficient to resist lateral movement of overpack base relative to the embedment plate. It also ensures that the ISFSI storage pad embedment structure provides the resisting moment to stabilize the system under seismic loading." To be certain that the anchorage system will maintain its safety functions during an earthquake, it is important that the anchor stud preload will not be reduced over the design life of the anchorage system.

- This information is needed to determine compliance with 10 CFR §72.24(a), §72.24(b), §72.24(c), §72.24(d), §72.24(n), and §72.44(c).

Chapter 17. Environmental Review

The following information is needed in order to for the staff to complete its review of PG&E's Environmental Report (ER) for the proposed action of constructing and operating an ISFSI at the Diablo Canyon site. The ER was submitted in accordance with the requirements of 10 CFR §51.61and 10 CFR §72.34. (Chapters and sections identified in these comments refer to the applicant's ER.)

17-1 Provide a concise description identifying the purpose of the proposed action.

Chapter 1, Proposed Activities, provides the facility background, need for the proposed action, and schedule but does not include a written statement identifying the purpose of the proposed action.

10 CFR §51.45(b) states that the applicant's environmental report shall contain a description of the proposed action and a statement of its purposes.

- This information is needed to determine compliance with 10 CFR §51.45(b).

17-2 Provide wind roses which show the average meteorology for the site. Provide information to show any seasonal variation in wind speed and direction.

Section 2.4.2, Local Meteorology, does not provide this information. Wind speed and direction are necessary to determine the radiological impact from the proposed action.

- This information is needed to determine compliance with 10 CFR §51.45(b)(1).

17-3 Provide a description of the calculations or provide the calculation packages for determining atmospheric dispersion factors for normal and accident conditions. This information is necessary to determine the radiological impact from the proposed action. (Section 2.4.4 Diffusion Estimates)

- This information is needed to determine compliance with 10 CFR §51.45(b)(1).

17-4 Describe how this area is of great spiritual importance to a local Native American and assess how the ISFSI may impact that spiritual importance. (Section 2.9.6, Native American Consultation)

This information is needed to determine if the proposed action may cause indirect cultural or historical impacts to the area.

- This information is needed to determine compliance with 10 CFR §51.45(c).

17-5 Provide a summary of the response from the Tribal Elders of the Santa Ynez band of Chumash to the letter dated August 7, 2000, sent by PG&E. (Section 2.9.6, Native American Consultation)

This information is needed to determine if the proposed action may cause indirect cultural or historical impacts to the area.

- This information is needed to determine compliance with 10 CFR §51.45(c).

17-6 Provide a description of the environmental impacts expected from the alternative actions which were considered. (Chapter 8, Siting and Design Alternatives)

The regulations in 10 CFR Part 51 require the environmental impact from both the proposed action and the alternatives be described.

- This information is needed to determine compliance with 10 CFR §51.45(b)(3).

17-7 Identify all permits and approvals needed from the State of California, and also from local and county officials, and the dates they were, or will be, received. Provide the names and telephone numbers of the local, county, and State of California officials responsible for issuing the necessary permits for the ISFSI. (Chapter 9, Environmental Approvals and Consultation)

- This information is needed to determine compliance with 10 CFR §51.45(d).

Chapter 18. Materials

18-1. Describe the considerations and criteria that are or will be used at Diablo Canyon to classify fuel as either intact or damaged for storage in the proposed ISFSI. Provide information on any tests or inspections conducted to determine the fuel condition.

- The information is needed to determine compliance with 10 CFR §72.124(a), 10 CFR §72.124(b), and 10 CFR §72.236(m).

18-2. Provide the following information for the storage of damaged fuel:

(a) Whether any of the fuel assembly structure is mechanically damaged or has geometrical changes to the assembly structure such that the assembly cannot be handled using normal (i.e., crane and grapple) handling methods.

(b) Whether the fuel assemblies have missing or displaced structural components such as grid spacers, and

(c) Whether any of the fuel is no longer in the form of a fuel bundle and consists of debris, loose fuel pellets, or rod segments.

Subcriticality and adequate confinement of the spent fuel must be maintained under all conditions of storage and transportation. In addition, the spent fuel must be readily retrieved from the storage systems and the design of spent fuel storage casks should consider ultimate disposition by the Department of Energy.

- The information is needed to determine compliance with 10 CFR §72.124(a), 10 CFR §72.124(b), and 10 CFR §72.236(m).

18-3. Provide information for fuel retrievability under normal, off-normal and accident conditions.

- The information is needed to determine compliance with 10 CFR 72.122(l) and 10 CFR 72.236(m).

18-4. Provide an analysis of the potential for fuel reconfiguration during storage operations for ZIRLO and Zircaloy-4 (See ISG-11, Revision 2). This analysis should include low burnup fuel and high burnup fuel.

The analyses should discuss cladding temperatures for normal, off-normal, repeated thermal cycling, and accidents. Additionally, the applicant should indicate the oxide thickness and methodology used to determine the thickness. Proposed TS 5.1.3.i. should be revised, as appropriate.

- This information is needed to determine compliance with 10 CFR §72.122(h)(1).

18-5. Provide a table that clearly indicates the burnups, cooling times, exact quantity of different rods, and temperatures (normal, off-normal, and accident) for all fuel types (i.e., Zirlo, Zircaloy-4, etc.) to be stored at the Diablo Canyon ISFSI.

The application contains conflicting and confusing information concerning temperature limits and which fuel types are high burnup.

- The information is needed to determine compliance with 10 CFR §72.122(h)(1).

18-6. Provide the Diablo Canyon ISFSI Safety Analysis Report sections that identify the allowable cladding types and temperature limits and the helium backfill gas parameters.

Revise Table 3.4-2, to adopt Appendix 4A to incorporate the temperature limits for high burnup fuel. Appendix A of the Diablo Canyon ISFSI Safety Analysis Report indicates that Sections 4.2.6.1 and 4.2.6.2 of the Diablo Canyon ISFSI Safety Analysis Report contain the required information. However, the version of the Diablo Canyon ISFSI Safety Analysis Report submitted to NRC does not include these two sections. The concern is that cladding types, temperature limits, and helium backfill parameters could affect the integrity of the spent nuclear fuel cladding.

- The information is needed to determine compliance with 10 CFR §72.122(h)(1).

18-7. Revise Diablo Canyon ISFSI Safety Analysis Report Section 10.2.4.1, to adopt the corrosion allowance tables that provide an alternate criterion in lieu of the guidance in NRC ISG-15 for high burnup Zircaloy-4 fuel cladding. The values are given in Table 4.A.4 and 4.A.5 of Appendix 4.A of the Holtec Safety Analyses Report, amendment 1.

- The information is needed to determine compliance with 10 CFR §72.122(h)(1).

18-8. Provide information on any alternatives to American Society of Mechanical Engineers Boiler and Pressure Vessel Code and clearly specify which alternatives have not been approved by the NRC.

It is recognized by the staff that not all of the requirements of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code may be practical at the Diablo Canyon ISFSI. Alternatives to the American Society of Mechanical Engineers Boiler and Pressure Vessel Code must, however, be evaluated and approved by staff.

- This information is needed to determine compliance with 10 CFR §72.122(a), §72.122(b), and §72.122(c).

18-9. Provide current manufacturer data sheet(s) for all of the coating(s) to be applied to all safety significant carbon steel components of the transfer and storage casks.

It is unclear if the approved Carboline 890 or Thermaline 450, as listed on Page 3-4 of the Holtec Safety Evaluation Report, will be used on the transfer cask. Provide documentation that the selected coating will perform as required considering expected neutron and gamma radiation and specific conditions expected during immersion in borated water. Provide temperatures for the inner and outer surfaces of the overpack that are coated and verify that these temperatures do not exceed the maximum continuous or noncontinuous recommended temperature for the coating. Provide information that indicates the coatings used on the storage casks can be repaired. Section 4.4.3 of the Diablo Canyon ISFSI Safety Analysis Report indicates that storage cask repair and maintenance may require reapplication of corrosion inhibiting materials on accessible external surfaces. According to Carboline data (1996, 2002), the maximum surface temperature for application is 51.7 °C [125 °F]. Damage to the overpack coating may not be properly repaired if the surface temperature of the overpack exceeds the maximum temperature for the proper application of the coating.

- This information is needed to determine compliance with 10 CFR §72.122(a), §72.122(b), §72.122(c), and §72.236(g).

18-10. Provide documentation that the operating procedures for cask loading and unloading include provisions for detecting the presence of hydrogen and preventing the ignition of combustible gases. Buildup of hydrogen, which may evolve as a result of corrosion reactions in borated water, may create a fire hazard.

- This information is needed to determine compliance with 10 CFR §72.24(c)(3).

18-11. Provide the following information on the fabrication of the transfer and storage casks:

(a) Specifications for weld filler materials for the multiple-purpose canisters the HI-TRAC transfer casks, and the storage overpacks including associated American Welding Society classification.

(b) The preheat and post weld heat treatment temperatures for the storage overpacks and the HI-TRAC transfer casks.

(c) Holtec's position paper DS 213 cited in HI-STORM Final Safety Analysis Report Chapter 9 and any additional information used to assess the critical flaw size in accordance with the American Society of Mechanical Engineers Section XI methodology.

- This information is needed to determine compliance with 10 CFR §72.122(a).

18-12. Provide the penetrant testing requirements for the multi-purpose canister closure weld.

Different penetrant testing requirements are identified in Diablo Canyon ISFSI Safety Analysis Report Section 4.4.1.2.3 and the HI-STORM Final Safety Analysis Report Drawing 1393 Sheet 1. The Diablo Canyon ISFSI Safety Analysis Report Section 4.4.1.2.3 indicates penetrant testing of the multiple-purpose canister closure weld, if used instead of ultrasonic testing, will be performed on the root pass, at ½ the weld thickness and on the final pass. However, the HI-STORM Final Analysis Report Drawing 1393 sheet 1 indicates penetrant testing will be performed after the root pass, after the final pass and twice after intermediate passes.

- This information is needed to determine compliance with 10 CFR §72.24(c)(3) and §72.122(a).

18-13. Provide the coefficient of thermal expansion for bolting materials used on the HI-STORM storage overpacks and the HI-TRAC transfer casks as well as the thermal expansion coefficients for the storage overpack and transfer cask materials of construction over the entire range of temperatures expected during normal, off-normal, and accident conditions.

Differences between the thermal expansion coefficients of the bolting materials and the overpack and transfer cask materials may lead to either higher than anticipated bolt stresses or reduced mechanical integrity of the transfer cask and overpack closures.

- This information is needed to determine compliance with 10 CFR §72.122(a), §72.122(b), and §72.122(c).

18-14. Provide specifications of the materials to be used for the seismic anchor. In particular, the applicant should address the following:

(a) Compatibility of materials and coatings to be used with the Diablo Canyon ISFSI environment

(b) Tables with material properties and allowable stresses and strains associated with temperature, as appropriate

(c) Appropriate corrosion allowances used in the structural analyses.

- This information is needed to determine compliance with 10 CFR §72.122(a), and §72.122(b).

18-15. Provide a revised Materials evaluation, to evaluate the potential reaction between the aluminum heat conduction elements, Boral, stainless steel in the MPC and the spent fuel pool water with respect to its impact on the safe operation and performance of the cask under normal, off-normal, and accident conditions. Also, revise the operating procedures to include appropriate controls for detecting the presence of hydrogen and preventing the ignition of combustible gases during cask loading and unloading.

The evaluation should consider: (1) water temperature change during loading and unloading, (2) the generation of reactive gases due to irradiation, (3) the generation of gases due to the aluminum and the stainless steel basket, and (4) the welding of the MPC lid, including pre- and post- weld heat treatments. Reaction of the heat conduction elements with the spent fuel pool water and/or steel components may produce hydrogen in concentrations close to the lower explosive limit of hydrogen.

- This information is needed to determine compliance with 10 CFR §72.122(b).

18-16. Demonstrate that the coatings to be used on all carbon steel components of the transfer and storage casks are non-reactive with the spent fuel pool water and that they will remain adherent when exposed to the various environments of the Diablo Canyon ISFSI.

The most prevalent environments include: immersion in spent fuel pool water during loading and unloading operations and the relatively high temperature (elevated temperatures cause degradation in normal coatings), high radiation (including neutrons), and dry inert gas environment encountered during storage, the potential for mechanical damage through abrasion or erosion, and environment exposure duration.

In accordance with 10 CFR §72.122 (c), non-combustible and heat resistant materials must be used whenever practical, and in accordance with §72.122 (h)(1), the spent fuel cladding must be protected from degradation that leads to gross ruptures. The concern is that any degradation of coating material, including gases or particulates that originate from a deteriorating coating, could affect the integrity of the cladding. Further, in accordance with §72.236 (h), the cask, and cask components, must be compatible with wet or dry spent fuel loading and unloading facilities. Thus, the coatings must remain intact and adherent to perform their intended functions during all loading and unloading operations.

- This information is needed to determine compliance with 10 CFR §72.122(b), §72.122(c), and §72.122(h)(1).

18-17. Revise the Diablo Canyon ISFSI SAR to include section 3.4.1 from the Holtec SAR on Chemical and Galvanic Reactions.

The reference tables evaluating each component (i.e., stainless steel, concrete, neutron absorber, coatings, shielding material, etc.) should also be included in the Diablo Canyon ISFSI SAR.

Chapter 19. Editorial Comments

The following revisions to the Diablo Canyon ISFSI SAR are requested to demonstrate compliance with 10 CFR §72.11.

19-1. Provide a complete PGE-009-CALC-001 package. Pages 4 and 12 are missing from the PGE-009-CALC-001 package.

19-2. Revise Drawing No. 3769, Figure 4.2-6, Section A-A. The current version of that figure shows an anchor system differing from the Diablo Canyon ISFSI Safety Analysis Report description and design (e.g., no compression coupling block).

19-3. Correct page 10.2-1 of the Diablo Canyon ISFSI Safety Analysis Report. The eleventh bullet states "SFSC time limitation while seated in the **cast** transfer facility (CTF)." Please change it to read "SFSC time limitation while seated in the **cask** transfer facility (CTF)."

19-4. Correct the title of the second column of Table 10.2-7 in the Diablo Canyon ISFSI Safety Analysis Report. The column title should read "Assembly Decay Heat" instead of "Assembly Burnup".

19-5. Provide a reference in the Diablo Canyon ISFSI Safety Analysis Report to the design details and analysis of the storage-pads that are contained in Pacific Gas and Electric

Company Calculation Nos. 52.27.100.704 "Non-Linear Seismic Sliding Analysis of the ISFSI Pad," 52.27.100.705 "Embedment Support Structure," and 52.27.100.707 "ISFSI Cask Storage Pad Seismic Analysis."

19-6. Provide a reference in the Diablo Canyon ISFSI Safety Analysis Report to the design and design analysis of the Cask Transfer Facility that is contained in Pacific Gas and Electric Company Calculation Nos. 52.27.100.708 "Cask Transfer Facility (Reinforced Concrete)," and OQE-10 "Structural Evaluation of Diablo Canyon Cask Transfer Facility."

19-7. Provide a reference in the Diablo Canyon ISFSI Safety Analysis Report to the design and design analysis, showing that the cask transporter will not fail by tornado or tornado missile impact, that is contained in Pacific Gas and Electric Company Calculation Nos. 52.27.100.703 "Design Basis Wind and Tornado Evaluation for DCPP," and OQE–9 "Transporter Stability on Diablo Canyon Dry Storage Travel Paths." .

REFERENCES

American Society for Metals. *Metals Handbook, Desk Edition.* Edited by H.E. Boyer and T.L. Gall. Metals Park, Ohio: American Society for Metals. 1985.

Carboline Company. Carboline 890—Product Data Sheet. St: Louis, MO: Carboline Company, June 1996.

Carboline Company. Carboguard 890 and 890 LT—Product Data Sheet. St: Louis, MO: Carboline Company, June 2002.

NRC. *Evaluations of Explosions Postulated to Occur on Transportation Routes Near Nuclear Power Plants.* Regulatory Guide 1.91. Revision 1. Washington DC: NRC, 1978.

NRC. NUREG–0612. *Control of Heavy Loads at Nuclear Power Plants.* Washington, DC: NRC, 1980.

NRC. NUREG–0800. *Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants.* Washington, DC: NRC, 1987.

NRC. Regulatory Guide 3.61. *Standard Format and Content For a Topical Safety Analysis Report for Spent Fuel Storage Casks.* Washington, DC: NRC, 1989a.

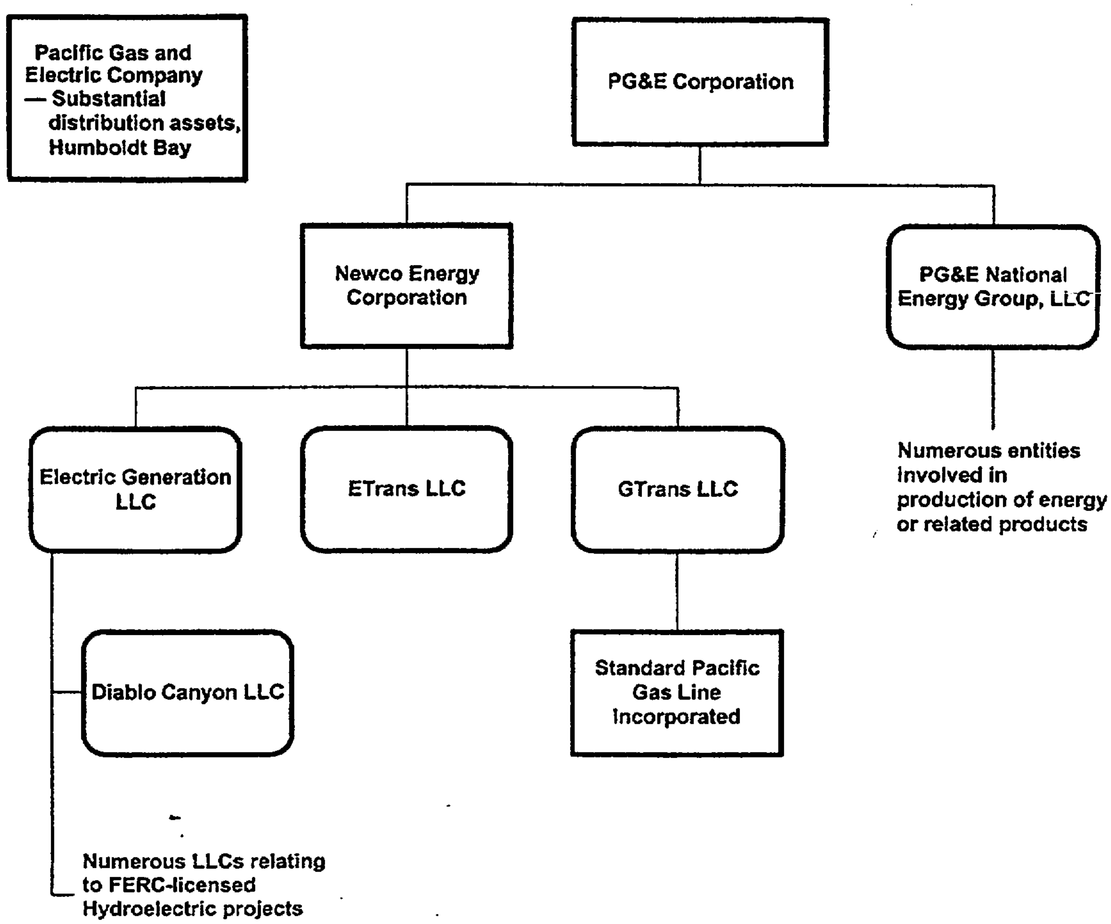
NRC. Regulatory Guide 3.62. *Standard Format and Content for the Safety Analysis Report for Onsite Storage of Spent Nuclear Fuel Storage Casks,* Revision 0. Washington, DC: NRC, 1989b.

NRC. *Standard Review Plan for Dry Cask Storage Systems.* Final Report. NUREG–1536. Washington, DC: NRC, 1997.

NRC. *Standard Review Plan for Spent Fuel Dry Storage Facilities.* Final Report. NUREG–1567. Washington, DC: NRC, 2000.

ATTACHMENT E

Proposed Corporate Structure of PG&E Corporation and Principal Subsidiaries After Implementation of Plan of Reorganization



Note: PG&E Corporation and PG&E National Energy Group to be renamed.

ATTACHMENT F

This information is updated by Edgar Online, an electronic data retrieval system for financial documents filed with the Securities and Exchange Commission (SEC). Edgar Online is not part of PG&E Corporation's website and this link to Edgar Online does not mean that PG&&E Corporation endorses or accepts any responsibility for the content, or the use, of Edgar Online.

(Mark One)

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C., 20549
FORM 10-Q

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15 (D) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2002

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________ to __________

Commission File Number	Exact Name of Registrant as specified in its charter	State or other Jurisdiction of Incorporation	IRS Employer Identification Number
1-12609	PG&E Corporation	California	94-3234914
1-2348	Pacific Gas and Electric Company	California	94-0742640

Pacific Gas and Electric Company 77 Beale Street P.O. Box 770000 San Francisco, California 94177	PG&E Corporation One Market, Spear Tower Suite 2400 San Francisco, California 94105
(Address of principal executive offices)	(Zip Code)
Pacific Gas and Electric Company (415) 973-7000	PG&E Corporation (415) 267-7000

Registrant's telephone number, including area code

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act 1934 during the preceding twelve months (or for such shorter period that the registrant was required to file such reports), and (2) have been subjec such filing requirements for the past 90 days.

Yes __x__ No ______

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of latest practicable date. _

Common Stock Outstanding, July 30, 2002:

PG&E Corporation	393,183,174 shares
Pacific Gas and Electric Company	Wholly owned by PG&E Corporation

PG&E CORPORATION AND
PACIFIC GAS AND ELECTRIC COMPANY,
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2002
TABLE OF CONTENTS

PART I. FINANCIAL INFORMATION
ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

PG&E CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions, except per share amounts)

	Three months ended June 30,		Six months ended June 30,	
	2002	**2001**	**2002**	**2001**
Operating Revenues				
Utility	$ 2,714	$ 2,309	$ 5,167	$ 4,871
Energy commodities and services	3,038	2,701	5,352	6,812
Total operating revenues	5,752	5,010	10,519	11,683
Operating Expenses				
Cost of energy for utility	703	67	852	3,300
Cost of energy commodities and services	2,823	2,335	4,876	6,174
Operating and maintenance	833	894	1,756	1,580
Impairments and write-offs	265	-	265	-
Depreciation, amortization, and decommissioning	336	259	656	514
Reorganization professional fees and expenses	18	8	34	8
Total operating expenses	4,978	3,563	8,439	11,576
Operating Income	774	1,447	2,080	107
Reorganization interest income	19	32	41	32
Interest income	24	42	44	77
Interest expense	(361)	(312)	(695)	(559)
Other income (expense), net	(21)	4	(3)	(5)

Income (Loss) Before Income Taxes	435	1,213	1,467	(348)
Income taxes provision (benefit)	156	463	557	(147)
Income (Loss) From Continuing Operations	279	750	910	(201)
Cumulative effect of a change in an accounting principle (net of income taxes of $42 million)	(61)	-	(61)	-
Net Income (Loss)	$ 218	$ 750	$ 849	$ (201)
Weighted Average Common Shares Outstanding	366	363	365	363
Earnings (Loss) Per Common Share, from Continuing Operations, Basic	$ 0.76	$ 2.07	$ 2.50	$ (0.55)
Net Earnings (Loss) Per Common Share, Basic	$ 0.60	$ 2.07	$ 2.33	$ (0.55)
Earnings (Loss) Per Common Share, from Continuing Operations, Diluted	$ 0.75	$ 2.07	$ 2.46	$ (0.55)
Net Earnings (Loss) Per Common Share, Diluted	$ 0.59	$ 2.07	$ 2.29	$ (0.55)

The accompanying Notes to the Consolidated Financial Statements are an integral part of these statements.

PG&E CORPORATION
CONSOLIDATED BALANCE SHEETS
(in millions)

	Balance at	
	June 30, 2002	**December 31, 2001**
ASSETS		
Current Assets		
Cash and cash equivalents	$ 5,100	$ 5,421
Restricted cash	372	195
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $95 million and $89 million, respectively)	3,117	3,016
Regulatory balancing accounts	133	75
Price risk management	508	381
Inventories	444	462
Prepaid expenses and other	436	223

Total current assets	10,110	9,773
Property, Plant and Equipment		
Utility	26,585	25,963
Non-utility:		
Electric generation	3,022	2,848
Gas transmission	1,520	1,514
Construction work in progress	2,867	2,426
Other	202	195
Total property, plant and equipment (at original cost)	34,196	32,946
Accumulated depreciation and decommissioning	(14,295)	(13,831)
Net property, plant and equipment	19,901	19,115
Other Noncurrent Assets		
Regulatory assets	2,200	2,319
Nuclear decommissioning funds	1,345	1,337
Price risk management	574	426
Other	2,649	2,892
Total other noncurrent assets	6,768	6,974
TOTAL ASSETS	$ 36,779	$ 35,862

PG&E CORPORATION
CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

	Balance at	
	June 30, 2002	**December 31, 2001**
LIABILITIES AND STOCKHOLDERS' EQUITY		
Liabilities Not Subject to Compromise		
Current Liabilities		
Short-term borrowings	$ 344	$ 330
Long-term debt, classified as current	48	381
Current portion of rate reduction bonds	290	290
Accounts payable:		
Trade creditors	2,076	1,289
Regulatory balancing accounts	239	228

Other	629	530
Interest payable	355	26
Income taxes payable	1,049	610
Price risk management	548	277
Other	925	905
Total current liabilities	6,503	4,866
Noncurrent Liabilities		
Long-term debt	8,227	7,297
Rate reduction bonds	1,310	1,450
Deferred income taxes	1,491	1,666
Deferred tax credits	149	153
Price risk management	751	434
Other	3,698	3,688
Total noncurrent liabilities	15,626	14,688
Liabilities Subject to Compromise		
Financing debt	5,611	5,651
Trade creditors	3,356	5,555
Total liabilities subject to compromise	8,967	11,206
Commitments and Contingencies (Notes 1, 2, 3, and 6)	-	-
Preferred Stock of Subsidiaries	480	480
Utility Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures	-	300
Common Stockholders' Equity		
Common stock, no par value, authorized 800,000,000 shares, issued 390,713,785 and 387,898,848 shares, respectively	6,093	5,986
Common stock held by subsidiary, at cost, 23,815,500 shares	(690)	(690)
Accumulated deficit	(155)	(1,004)
Accumulated other comprehensive income (loss)	(45)	30
Total common stockholders' equity	5,203	4,322
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 36,779	$ 35,862

The accompanying Notes to the Consolidated Financial Statements are an integral part of these statements.

PG&E CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Six months ended June 30, 2002	Six months ended June 30, 2001
Cash Flows From Operating Activities		
Net income (loss)	$ 849	$ (201)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	656	514
Deferred income taxes and tax credits, net	(178)	120
Price risk management assets and liabilities, net	238	(30)
Other deferred charges and noncurrent liabilities	620	(174)
Loss on impairment of assets	265	-
Cumulative effect of a change in accounting principle	61	-
Reversal of ISO accrual (Note 2)	(970)	-
Net changes in operating assets and liabilities :		
Accounts receivable	(55)	1,445
Accounts payable	106	621
Inventories	18	(109)
Income taxes payable	439	1,241
Regulatory balancing accounts, net	(47)	332
Other working capital	(168)	(791)
Net change in liabilities subject to compromise (Note 2)	(972)	-
Other, net	(468)	(116)
Net cash provided by operating activities	394	2,852
Cash Flows From Investing Activities		
Capital expenditures	(1,680)	(1,102)
Proceeds from sale-leaseback	340	-
Other, net	85	(115)
Net cash used by investing activities	(1,255)	(1,217)
Cash Flows From Financing Activities		
Net borrowings (repayments) under credit facilities and short-term borrowings	14	(1,033)
Long-term debt issued	1,546	2,275
Long-term debt matured, redeemed, or repurchased	(1,081)	(844)
Common stock issued	61	-
Dividends paid	-	(109)
Net cash provided by financing activities	540	289
Net change in cash and cash equivalents	(321)	1,924
Cash and cash equivalents at January 1	5,421	2,430
Cash and cash equivalents at June 30	$ 5,100	$ 4,354

Supplemental disclosures of cash flow information

Cash received for:		
Reorganization interest income	$ 42	$ 32
Cash paid for:		
Interest (net of amounts capitalized)	874	302
Income taxes (net of refunds)	294	(1,241)
Reorganization professional fees and expenses	9	-
Transfer of liabilities and other payables subject to compromise (to) from operating payables and liabilities	(475)	10,960

The accompanying Notes to the Consolidated Financial Statements are an integral part of these statements.

PACIFIC GAS AND ELECTRIC COMPANY, A DEBTOR-IN-POSSESSION
CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions)

	Three months ended June 30,		Six months en[d] June 30,	
	2002	**2001**	**2002**	
Operating Revenues				
Electric	$ 2,193	$ 1,497	$ 3,971	$
Gas	521	812	1,196	
Total operating revenues	2,714	2,309	5,167	
Operating Expenses				
Cost of electric energy	505	(362)	339	
Cost of gas	198	429	513	
Operating and maintenance	640	676	1,409	
Depreciation, amortization, and decommissioning	294	222	565	
Reorganization professional fees and expenses	18	8	34	
Total operating expenses	1,655	973	2,860	
Operating Income (Loss)	1,059	1,336	2,307	
Reorganization interest income	19	32	41	
Interest income	-	17	-	
Interest expense				
Contractual interest expense	(229)	(195)	(443)	
Noncontractual interest expense	(54)	(62)	(103)	
Other expense, net	(1)	(2)	(6)	

Income (Loss) Before Income Taxes	794	1,126	1,796	
Income tax provision (benefit)	325	424	731	
Net Income (Loss)	469	702	1,065	
Preferred dividend requirement	6	6	12	
Income (Loss) Available for (Allocated to) Common Stock	$ 463	$ 696	$ 1,053	$

The accompanying Notes to the Consolidated Financial Statements are an integral part of these statements.

PACIFIC GAS AND ELECTRIC COMPANY, A DEBTOR-IN-POSSESSION
CONSOLIDATED BALANCE SHEETS
(in millions)

	Balance at	
	June 30, 2002	**December 31, 2001**
ASSETS		
Current Assets		
Cash and cash equivalents	$ 3,771	$ 4,341
Restricted cash	54	53
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $50 million and $48 million, respectively)	1,879	1,931
Related parties	17	18
Regulatory balancing accounts	133	75
Inventories:		
Gas stored underground and fuel oil	170	218
Materials and supplies	120	119
Prepaid expenses and other	66	80
Total current assets	6,210	6,835
Property, Plant and Equipment		
Electric	18,613	18,153
Gas	7,972	7,810
Construction work in progress	356	323
Total property, plant and equipment (at original cost)	26,941	26,286
Accumulated depreciation and decommissioning	(13,325)	(12,929)
Net property, plant and equipment	13,616	13,357

Other Noncurrent Assets		
Regulatory assets	2,169	2,283
Nuclear decommissioning funds	1,345	1,337
Other	1,308	1,325
Total other noncurrent assets	4,822	4,945
TOTAL ASSETS	$ 24,648	$ 25,137

PACIFIC GAS AND ELECTRIC COMPANY, A DEBTOR-IN-POSSESSION
CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

	Balance at	
	June 30, 2002	**December 31, 2001**
LIABILITIES AND STOCKHOLDERS' EQUITY		
Liabilities Not Subject to Compromise		
Current Liabilities		
Long-term debt, classified as current	$ -	$ 333
Current portion of rate reduction bonds	290	290
Accounts payable:		
Trade creditors	966	333
Related parties	102	86
Regulatory balancing accounts	239	228
Other	288	289
Interest payable	352	26
Income taxes payable	788	295
Deferred income taxes	4	65
Other	529	599
Total current liabilities	3,558	2,544
Noncurrent Liabilities		
Long-term debt	3,019	3,019
Rate reduction bonds	1,310	1,450
Deferred income taxes	970	1,028
Deferred tax credits	149	153
Other	2,882	2,724
Total noncurrent liabilities	8,330	8,374

Liabilities Subject to Compromise		
Financing debt	5,611	5,651
Trade creditors	3,559	5,733
Total liabilities subject to compromise	9,170	11,384
Commitments and Contingencies (Notes 1, 2, 3, and 6)	-	-
Preferred Stock With Mandatory Redemption Provisions		
6.30% and 6.57%, outstanding 5,500,000 shares, due 2002-2009	137	137
Company Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures		
7.90%, 12,000,000 shares, due 2025	-	300
Stockholders' Equity		
Preferred stock without mandatory redemption provisions		
Nonredeemable, 5% to 6%, outstanding 5,784,825 shares	145	145
Redeemable, 4.36% to 7.04%, outstanding 5,973,456 shares	149	149
Common stock, $5 par value, authorized 800,000,000 shares, issued 326,926,667 shares	1,606	1,606
Common stock held by subsidiary, at cost, 19,481,213 shares	(475)	(475)
Additional paid-in capital	1,964	1,964
Reinvested earnings (Accumulated deficit)	64	(989)
Accumulated other comprehensive income (loss)	-	(2)
Total stockholders' equity	3,453	2,398
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 24,648	$ 25,137

The accompanying Notes to the Consolidated Financial Statements are an integral part of these statements.

PACIFIC GAS AND ELECTRIC COMPANY, A DEBTOR-IN-POSSESSION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Six months ended June 30,	
	2002	**2001**
Cash Flows From Operating Activities		
Net income (loss)	$ 1,065	$ (292)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	565	439
Deferred income taxes and tax credits, net	(123)	12
Price risk management assets and liabilitites, net	-	(38)
Other deferred charges and noncurrent liabilities	592	(272)
Reversal of ISO accrual (Note 2)	(970)	-
Net changes in operating assets and liabilities:		

Accounts receivable	99	619
Income taxes receivable	-	1,120
Inventories	47	(108)
Accounts payable	(132)	606
Income taxes payable	493	-
Regulatory balancing accounts payable, net	(47)	332
Other working capital	(35)	(120)
Net change in liabilities subject to compromise (Note 2)	(947)	-
Other, net	23	366
Net cash provided by operating activities	630	2,664
Cash Flows From Investing Activities		
Capital expenditures	(743)	(575)
Net proceeds from sale of assets	5	-
Other, net	13	34
Net cash used by investing activities	(725)	(541)
Cash Flows From Financing Activities		
Net borrowings (repayments) under credit facilities and short-term borrowings	-	(28)
Long-term debt matured, redeemed, or repurchased	(474)	(252)
Other, net	(1)	(1)
Net cash used by financing activities	(475)	(281)
Net change in cash and cash equivalents	(570)	1,842
Cash and cash equivalents at January 1	4,341	1,344
Cash and cash equivalents at June 30	$ 3,771	$ 3,186
Supplemental disclosures of cash flow information		
Cash received for:		
Reorganization interest income	$ 42	$ 32
Cash paid for:		
Interest (net of amount capitalized)	683	265
Income taxes (net of refunds)	353	(1,120)
Reorganization professional fees and expenses	9	-
Transfer of liabilities and other payables subject to Compromise (to) from operating payables and liabilities	(297)	11,148

The accompanying Notes to the Consolidated Financial Statements are an integral part of these statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1: GENERAL

Organization and Basis of Presentation

PG&E Corporation was incorporated in California in 1995 and became the holding company of Pacific Gas and Electric Company, a debtor-in-possession, and its subsidiaries (the Utility) on January 1, 1997. The Utility, incorporated in California in 1905, is the predecessor of PG&E Corporation. The Utility delivers electric service to approximately 4.8 million customers and natural gas service to approximately 4.0 million customers in Northern and Central California. Both PG&E Corporation and the Utility are headquartered in San Francisco. As discussed further in Note 2, on April 6, 2001, the Utility filed a voluntary petition for relief under the provisions of Chapter 11 of the United States Bankruptcy Code (Bankruptcy Code) in the United States Bankruptcy Court for the Northern District of California (Bankruptcy Court). Pursuant to Chapter 11, the Utility retains control of its assets and is authorized to operate its business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court.

PG&E Corporation's other significant subsidiary is PG&E National Energy Group, Inc. (PG&E NEG) and its subsidiaries, headquartered in Bethesda, Maryland. PG&E NEG was incorporated on December 18, 1998, as a wholly owned subsidiary of PG&E Corporation. Shortly thereafter, PG&E Corporation contributed various subsidiaries to PG&E NEG. PG&E NEG and its subsidiaries are principally located in the United States and Canada, and are engaged in power generation and development, wholesale energy marketing and trading, risk management, and natural gas transmission. PG&E NEG's principal subsidiaries include: PG&E Generating Company, LLC, and its subsidiaries (collectively, PG&E Gen), PG&E Energy Trading Holdings Corporation and its subsidiaries (collectively, PG&E ET), and PG&E Gas Transmission Corporation and its subsidiaries (collectively, PG&E GTC), which includes PG&E Gas Transmission, Northwest Corporation and its subsidiaries (collectively, PG&E GTN) and North Baja Pipeline, LLC (NBP). PG&E NEG also has other less significant subsidiaries.

This Quarterly Report on Form 10-Q is a combined report of PG&E Corporation and the Utility. Therefore, the Notes to the unaudited Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation's unaudited Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, PG&E NEG, and other wholly owned and controlled subsidiaries. The Utility's unaudited Consolidated Financial Statements include its accounts and those of its wholly owned and controlled subsidiaries.

PG&E Corporation and the Utility believe that the accompanying unaudited Consolidated Financial Statements reflect all adjustments that are necessary to present a fair statement of the consolidated financial position and results of operations for the interim periods. All material adjustments are of a normal recurring nature unless otherwise disclosed in this Form 10-Q. All significant intercompany transactions have been eliminated from the unaudited Consolidated Financial Statements.

This quarterly report should be read in conjunction with PG&E Corporation's and the Utility's Consolidated Financial Statements and Notes to the Consolidated Financial Statements incorporated by reference in their combined 2001 Annual Report on Form 10-K, and PG&E Corporation's and the Utility's other reports filed with the Securities and Exchange Commission (SEC) since their combined 2001 Annual Report on Form 10-K was filed.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions. These estimates and assumptions affect the reported amounts of revenues, expenses, assets, and liabilities and the disclosure of contingencies. Actual results could differ from these estimates.

At December 31, 2001, amounts previously classified as short-term investments were reclassified as cash equivalents in the balance sheets and statements of cash flows of PG&E Corporation and the Utility. As a result, such amounts have been reclassified in the accompanying statements of cash flows for the six months ended June 30, 2001, to be consistent with the current year presentation.

Earnings (Loss) Per Share

Basic earnings (loss) per share are computed by dividing net income (loss) by the weighted average number of common shares outstanding during the period. Diluted earnings per share are computed by dividing net income, adjusted for convertible note interest and amortization, by the weighted average number of common shares outstanding plus the assumed issuance of common shares for all dilutive securities.

The following is a reconciliation of PG&E Corporation's net income (loss) and weighted average common shares outstanding for calculating basic and diluted net income (loss) per share.

	Three months ended June 30,		Six months ended June 30,	
(in millions, except per share amounts)	2002	2001	2002	200

Income (Loss) from continuing operations	$ 279	$ 750	$ 910	$ (
Cumulative effect of accounting change	(61)	-	(61)	
Net Income (Loss)	218	750	849	(
Interest expense on 7.50% Convertible Subordinated Notes [1]	-	-	-	
Net Income (Loss) for Diluted Calculations	$ 218	$ 750	$ 849	$ (
Weighted average common shares outstanding, basic	366	363	365	
Add: Employee Stock Options and PG&E Corporation shares held by grantor trusts	5	-	5	
PG&E Corporation Warrants [2]	-	-	-	
7.50% Convertible Subordinated Notes	1	-	-	
Shares outstanding for diluted calculations	372	363	370	
Earnings (Loss) Per Common Share, Basic				
Income (Loss) from continuing operations	$ 0.76	$ 2.07	$ 2.50	$ ((
Cumulative effect of accounting change	(0.16)	-	(0.17)	
Net earnings (loss)	$ 0.60	$ 2.07	$ 2.33	$ ((
Earnings (Loss) Per Common Share, Diluted				
Income (Loss) from continuing operations	$ 0.75	$ 2.07	$ 2.46	$ ((
Cumulative effect of accounting change	(0.16)	-	(0.17)	
Net earnings (loss)	$ 0.59	$ 2.07	$ 2.29	$ ((

(1) Interest expense, including amortization of the discount, on the 7.50% Convertible Subordinated Notes for the three and six months ended June 30, 2002, was $232,276, net of incom of $159,724. These notes were issued in connection with the PG&E Corporation's amended and restated credit agreement on June 25, 2002.

(2) The incremental shares associated with PG&E Corporation Warrants, issued in connection with Tranche B of PG&E Corporation's amended and restated credit agreement (see Note the three and six months ended June 30, 2002, were 157,995 and 79,433 shares, respectively.

The diluted share base for the six months ended June 30, 2001, excludes incremental shares of 290,365 related to employee stock options and PG&E Corporation shares held by grantor trusts, due to the antidilutive effect of the loss from continuing operations. PG&E Corporation reflects the preferred dividends of subsidiaries as other expense for computation of both basic and diluted earnings per share.

Stock-Based Compensation

PG&E Corporation accounts for stock-based compensation using the intrinsic value method in accordance with the provisions of Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," as allowed by Statement of Financial Accounting Standards (SFAS) No. 123, "Accounting for Stock-Based Compensation." Under the intrinsic value method, PG&E Corporation does not recognize any compensation expense, as the exercise price of all stock options is equal to the fair market value at the time the options are granted. Had compensation expense been recognized using the fair value-based method under SFAS No. 123, PG&E Corporation's pro-forma consolidated earnings (loss) and earnings (loss) per share would be as follows:

	Three months ended June 30,		Six months ended June 30,	
(in millions, except per share amounts)	**2002**	**2001**	**2002**	**200**
Net Income (loss):				
As reported	$ 218	$ 750	$ 849	$ (
Pro-forma	213	745	839	(
Basic Earnings (loss) per share:				
As reported	0.60	2.07	2.33	(
Pro-forma	0.58	2.05	2.30	(
Diluted earnings (loss) per share:				
As reported	0.59	2.07	2.29	(
Pro-forma	0.57	2.05	2.27	(

Comprehensive Income (Loss)

PG&E Corporation's and the Utility's comprehensive income (loss) consists principally of changes in the market value of certain cash flow hedges under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities."

	PG&E Corporation		Utility	
(in millions)	**2002**	**2001**	**2002**	**2001**
Three months ended June 30				
Net income available for common stock	$ 218	$ 750	$ 463	$ 696
Net gain (loss) in other comprehensive income (OCI) from current period hedging transactions and price changes in accordance with SFAS No. 133	(9)	178	-	(8)
Net reclassification from OCI to earnings	-	31	-	19
Comprehensive income (loss)	$ 209	$ 959	$ 463	$ 707

Six months ended June 30,								
Net income (loss) available for (allocated to) common stock	$	849	$	(201)	$	1,053	$	(304)
Cumulative effect of adoption of SFAS No. 133		-		(243)		-		90
Net gain (loss) in OCI from current period hedging transactions and price changes in accordance with SFAS No. 133		(84)		149		-		(7)
Net reclassification from OCI to earnings		5		(12)		-		(124)
Comprehensive income (loss)	$	770	$	(307)	$	1,053	$	(345)

Significant Accounting Policies

Accounting principles used include those necessary for rate-regulated enterprises, which reflect the ratemaking policies of the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC). Except as disclosed below, PG&E Corporation and the Utility are following the same accounting principles discussed in their 2001 Annual Report on Form 10-K.

Adoption of New Accounting Policies

Accounting for Goodwill and Other Intangible Assets - On January 1, 2002, PG&E Corporation adopted SFAS No. 142, "Goodwill and Other Intangible Assets." This Statement eliminates the amortization of goodwill and requires that goodwill be reviewed at least annually for impairment. Upon implementation of this Statement, the transition impairment test for goodwill was performed as of January 1, 2002, and no impairment loss was recorded. Goodwill amortization expense for the three and six months ended June 30, 2001, was $1 million and $2 million, respectively. Prospective elimination of goodwill amortization will not have a significant impact on the Consolidated Financial Statements. The Utility has no goodwill on its balance sheet at December 31, 2001, or June 30, 2002.

This Statement also requires that the useful lives of previously recognized intangible assets be reassessed and the remaining amortization periods be adjusted accordingly. Adoption of this Statement did not require any adjustments to be made to the useful lives of existing intangible assets and no reclassifications of intangible assets to goodwill were necessary.

Intangible assets other than goodwill are being amortized on a straight-line basis over their estimated useful lives, and are reported under noncurrent assets in the Consolidated Balance Sheets.

The schedule below summarizes the amount of intangible assets by major classes.

	Balance at							
	June 30, 2002				December 31, 2001			
(in millions)		Gross Carrying Amount		Accumulated Amortization		Gross Carrying Amount		Accumulated Amortization
PG&E NEG:								
Service agreements	$	33	$	6	$	33	$	6
Power sale agreements		41		9		44		8
Other agreements		26		7		27		5
Utility:								

Hydro licenses and other agreements		66		15		66	14
PG&E Corporation-Consolidated	$	166	$	37	$	170	$ 33

PG&E NEG's amortization expense on intangible assets for the three and six months ended June 30, 2002, was $2 million and $3 million, respectively, compared to $1 million and $2 million for the same periods in 2001. These amounts do not include amortization expense related to intangibles for certain power sale agreements, which are recorded against the related revenue or expense. The Utility's amortization expense of intangible assets was $1 million for both the three and six months ended June 30, 2002, and also for the same periods in 2001.

The following schedule shows the estimated amortization expenses for intangible assets for full years 2002 through 2006.

(in millions)	2002	2003	2004	2005	2006
PG&E NEG	$ 6	$ 6	$ 6	$ 6	$ 6
Utility	3	3	3	3	3

Accounting for the Impairment or Disposal of Long-Lived Assets - On January 1, 2002, PG&E Corporation adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS No. 144 supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of," but retains its fundamental provision for recognizing and measuring impairment of long-lived assets to be held and used. This Standard requires that all long-lived assets to be disposed of by sale are carried at the lower of carrying amount or fair value less cost to sell, and that depreciation should cease to be recorded on such assets. SFAS No. 144 standardizes the accounting and presentation requirements for all long-lived assets to be disposed of by sale, and supersedes previous guidance for discontinued operations of business segments. The adoption of the Statement did not have any impact on the Consolidated Financial Statements of PG&E Corporation and the Utility.

Changes to Accounting for Certain Derivative Contracts - On April 1, 2002, PG&E Corporation implemented two interpretations issued by the Financial Accounting Standard Board's (FASB) Derivatives Implementation Group (DIG). DIG Issues C15 and C16 changed the definition of normal purchases and sales included in SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities" (collectively, SFAS No. 133). Previously, certain derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business were exempt from the requirements of SFAS No. 133 under the normal purchases and sales exception, and thus were not marked to market and reflected on the balance sheet like other derivatives. Instead, these contracts were recorded on an accrual basis.

DIG C15 changed the definition of normal purchases and sales for certain power contracts. DIG C16 disallowed normal purchases and sales treatment for commodity contracts (other than power contracts) that contain volumetric variability or optionality. PG&E NEG determined that five of its derivative commodity contracts for the physical delivery of power and purchase of fuel no longer qualified for normal purchases and sales treatment under these interpretations. Beginning April 1, 2002, these five contracts were required to be recorded on the balance sheet at fair value and marked to market through earnings. Three of the contracts had positive market values and resulted in pre-tax income of $125 million. The remaining two contracts had negative market values that resulted in a pre-tax charge of $127 million. The cumulative effects of implementation of these accounting changes at April 1, 2002, resulted in PG&E Corporation recording price risk management assets of $37 million, price risk management liabilities of $255 million, and a reduction of out-of-market obligations of $129 million reclassified to net price risk management liabilities.

One of the contracts with a positive market value included above is for a power sales contract at a partnership in which PG&E NEG has a 50% ownership interest. PG&E NEG reflects its investment in this partnership on an equity basis (Investments in Unconsolidated Affiliates). Upon adoption of C15 and C16, PG&E NEG recognized its equity share of the gain from the cumulative change in accounting method and correspondingly increased the book value of its equity investment in the partnership. However, the future net cash flows from the partnership do not support the increased equity investment balance. Therefore, PG&E NEG has recognized an impairment charge of $101 million to reduce its equity-method investment to fair value. The cumulative effect of the change in accounting principle for DIG C15 and C16 was a net charge of $61 million, after-tax, and included the recognition of the fair market value of the five contracts impacted by C15 and C16 and the resultant impairment charge. The Utility was not impacted by these accounting changes.

Implementation of these accounting changes will not impact the timing and amount of cash flows associated with the affected contracts; however, it will impact the timing and magnitude of future earnings. Future earnings will reflect the gradual reversal of the assets and liabilities recorded upon adoption over the contracts' lives, as well as any prospective changes in the market value of the contracts. Prospective changes in the market value of these contracts could result in significant volatility in earnings. However, over the total lives of the contracts, there will be no net impact to total operating results after netting the cumulative effect of adoption against the subsequent years' impacts (assuming that the affected contracts are held to their expiration).

Related Party Transactions

In accordance with various agreements, the Utility and other subsidiaries provide and receive various services to and from their parent, PG&E Corporation. The Utility and PG&E Corporation exchange administrative and professional support services in support of operations. These services are priced either at the fully loaded cost or at the higher of fully loaded cost or fair market value depending on the nature of the services provided. PG&E Corporation also allocates certain other corporate administrative and general costs to the Utility and other subsidiaries using a variety of factors that are based upon the number of employees, operating expenses excluding fuel purchases, total assets, and other cost causal methods. Additionally, the Utility purchases gas commodity and transmission services from, and sells reservation and other ancillary ~~services to~~, PG&E NEG. These services are priced at either tariff rates or fair market value depending on the nature of the services provided. Intercompany transactions are eliminated in consolidation and no profit results from these transactions. The Utility's significant related party transactions were as follows:

	Three months ended June 30,				Six months ended		
(in millions)	2002		2001		2002		
Utility revenues from:							
Administrative services provided to PG&E Corporation	$	2	$	2	$	3	$
Gas reservation services provided to PG&E ET		3		4		6	
Utility expenses from:							
Administrative services received from PG&E Corporation	$	23	$	13	$	50	$
Gas commodity and transmission services received from PG&E ET		9		39		28	
Transmission services received from PG&E GT		10		9		22	

NOTE 2: THE UTILITY CHAPTER 11 FILING

Overview of Electric Industry Restructuring

In 1998, California implemented electric industry restructuring and established a market framework for electric generation in which generators and other power providers were permitted to charge market-based prices for wholesale power. The restructuring of the electric industry was mandated by the California Legislature in Assembly Bill (AB) 1890. The mandate included a rate freeze and a plan for recovery of generation-related costs that were expected to be uneconomic under the new market framework (transition costs). Additionally, the CPUC encouraged the Utility to divest more than 50 percent of its fossil generation facilities and discouraged the Utility from continuing to operate remaining generation facilities by reducing the allowed return on such assets. The new market framework called for the creation of the Power Exchange (PX) and the Independent System Operator (ISO). Before it ceased operating in January 2001, the PX established market-clearing prices for electricity. The ISO's role was to schedule delivery of electricity for all market participants and operate certain markets for electricity. Until December 15, 2000, the Utility was required to sell all of its owned and contracted generation to, and purchase all electricity for its retail customers from, the PX. Customers were given the choice of continuing to buy electricity from the Utility or buying electricity from independent power generators or retail electricity suppliers. Most of the Utility's customers continued to buy electricity through the Utility.

Beginning in June 2000, wholesale spot prices for electricity sold through the PX and ISO began to escalate. While forward and spot prices moderated somewhat in September and October 2000, such prices increased in November and December 2000 to levels substantially higher than during the summer months. The increased cost of the purchased electricity strained the financial resources of the Utility because the CPUC applied the rate freeze in a way which prohibited the Utility from passing on the increases in power costs to its customers. The Utility financed the higher costs of wholesale electric power while interested parties evaluated various solutions to the California energy crisis. Consequently, by December 31, 2000, the Utility had borrowed more than $3 billion under its various credit facilities to finance its wholesale energy purchases.

Because of escalating wholesale electricity costs and the inability to pass on these costs to retail customers, the Utility accumulated approximately $6.9 billion (pre-tax) in under-collected purchased power costs and generation-related transition costs as of December 31, 2000. The under-collected purchased power costs historically were deferred for future recovery as a regulatory asset subject to future collection from customers in rates. However, due to the lack of regulatory, legislative, and judicial relief, the Utility determined that it could no longer conclude that its under-collected purchased power costs and remaining transition costs were probable of recovery in future rates. Therefore, the Utility charged $6.9 billion to expense for its under-collected purchased power costs and its remaining unamortized transition costs at December 31, 2000.

In January 2001, the CPUC increased electric rates, by $0.01 per kilowatt hour (kWh), and in March 2001 by another $0.03 per kWh. In addition, the price of wholesale electricity stabilized. Accordingly, in 2001, the Utility's total generation-related electric revenues were greater than its generation-related costs, resulting in earnings of $458 million (after-tax), which represented a partial recovery of previously written-off under-collected purchased power and transition costs, and included $327 million related to the market value of terminated bilateral contracts. On July 1, 2002, a CPUC Commissioner issued an Assigned Commissioner's Ruling seeking comments on whether the restrictions on applying the $0.01 per kWh and $0.03 per kWh surcharge revenues to "ongoing procurement costs" and "future power purchases" should be modified to allow the surcharge amount to be applied to improve the financial health of the Utility. The ruling suggests that one potentially just and reasonable use of surcharge revenues is any purpose necessary to restore financial health to the Utility. The Utility has filed comments in support of this suggestion. However, other parties have filed comments requesting that the CPUC reduce the Utility's retail electric rates, terminate the surcharges, or change the accounting for the surcharge revenues in a manner which would reduce the Utility's headroom revenues. It is possible that at some future date the CPUC may change the surcharges or the application of the surcharges, either prospectively or retroactively, and any such change could materially affect the Utility's earnings. The CPUC has not set a schedule for deciding these issues, and the Utility cannot predict the outcome of these matters.

During the six months ended June 30, 2002, the Utility's total generation-related revenues exceeded its generation-related costs by $542 million (after-tax). The Utility's previously written-off under-collected purchased power and transition costs amounted to $4.7 billion and $6.2 billion (pre-tax) at June 30, 2002, and December 31, 2001, respectively. The recovery of these remaining under-collected purchased power costs and transition costs is dependent on a number of factors, including but not limited to the ultimate outcome of the Utility's bankruptcy and future regulatory proceedings.

Under AB 1890, the rate freeze was scheduled to end on the earlier of March 31, 2002, or the date the Utility recovered all of its generation-related transition costs as determined by the CPUC. However, on January 2, 2002, the CPUC issued a decision which found that new California legislation, AB 6X, had materially affected the implementation of AB 1890. Therefore, the CPUC scheduled further proceedings to address the impact of AB 6X on the AB 1890 rate freeze for the Utility and to determine the extent and disposition of the Utility's remaining unrecovered transition costs. Additionally, on January 11, 2002, in a court proceeding involving a settlement between Southern California Edison Company (SCE) and the CPUC, the CPUC represented to the court that it has the authority to allow the Utility and SCE to recover their under-collected purchased power and transition costs beyond the end of the AB 1890 rate freeze. In fact, the settlement reached by the CPUC and SCE stipulated that SCE would maintain rates at their current levels (beyond the end of the AB 1890 rate freeze) until the earlier of the date that SCE recovered its previously incurred transition costs or December 31, 2003. To the extent SCE's costs are not recovered by December 31, 2003, they are to be amortized and recovered over a period ending December 31, 2005.

On April 15, 2002, the CPUC filed an alternative plan of reorganization (Alternative Plan) in the Utility's bankruptcy proceeding in U.S. Bankruptcy Court, proposing that the Utility's overall retail electric rates be maintained at current levels through January 31, 2003, in order to generate cash to repay in part the Utility's creditors under the CPUC's plan. The CPUC represented to the Bankruptcy Court that it was authorized to propose and implement its plan under state law. On July 12, 2002, in response to a lawsuit filed in state court by a consumer group challenging the legal authority of the CPUC to propose its plan, the CPUC represented that since utilities are now required under the state law to retain their generating assets, and the CPUC has regained its traditional rate authority over those assets, costs associated with those assets may be recovered by the utilities in the traditional way, under cost-based regulation. In addition, the CPUC represented that its failure to exercise its discretion to change rates to reflect changes in the Utility's costs after the AB 1890 rate freeze does not violate procedural requirements of state law. Based on these CPUC decisions and representations, the Utility believes it can continue to record revenues collected under its existing overall retail rates, subsequent to the statutory end of the rate freeze. However, the CPUC's further proceedings to consider the impact of AB 6X on the AB 1890 rate freeze and the disposition of the Utility's unrecovered transition costs are still pending, and it is possible that at some future date the CPUC may change its interpretation of law or otherwise seek to change the Utility's overall retail electric rates retroactively. Any such change could materially affect the Utility's earnings.

Finally, in one of the March 2001 decisions, the CPUC adopted an accounting proposal by The Utility Reform Network (TURN), which retroactively restates the way in which the Utility's transition costs are recovered. This retroactive change had the effect of extending the AB 1890 rate freeze and reducing the amount of past wholesale power costs that could be eligible for recovery from customers. The CPUC denied the Utility's application for rehearing of this retroactive accounting change. The Utility also filed a petition for a writ of review with the California

Court of Appeal which also was denied. The Utility has filed a petition with the California Supreme Court to review the appellate court action. Further, the Bankruptcy Court denied the Utility's request for an order enjoining the CPUC from enforcing its retroactive order. The Utility has appealed the Bankruptcy Court's denial of injunctive relief to the U.S. District Court for the Northern District of California. The Utility cannot predict the outcome of this matter.

Electricity Purchases

As a result of the Utility's inability to pass through wholesale electricity costs to customers and the resulting impact on the Utility's financial resources, the Utility's credit rating deteriorated to below investment grade in January 2001. This credit downgrade precluded the Utility from access to capital markets. The Utility had no credit under which it could purchase wholesale electricity on behalf of its customers on a continuing basis. Consequently, generators were selling to the Utility only under emergency action taken by the U.S. Secretary of Energy.

In January 2001, the California Legislature and the Governor of California authorized the Department of Water Resources (DWR) to begin purchasing wholesale electric energy on behalf of the Utility's retail customers. On February 1, 2001, the Governor signed into law California AB 1X authorizing the DWR to purchase power to meet the Utility's net open position (the amount of power needed by retail electric customers that cannot be met by utility-owned generation or power under contract to the Utility). The DWR purchased energy on the spot market until it was able to enter into contracts for the supply of electricity. In addition to certain contracts that it has subsequently entered into, the DWR continues to purchase power on the spot market at prevailing market prices.

Initially, the DWR indicated that it intended to buy power only at "reasonable prices" to meet the Utility's net open position, leaving the ISO to purchase the remainder in order to avoid blackouts. The ISO billed the Utility for its costs to purchase power to cover the amount of the Utility's net open position not covered by the DWR. In 2001, the Utility accrued approximately $1 billion for these ISO purchases for the period from January 17, 2001, through April 6, 2001. However, in February, April, and November 2001, the FERC issued a series of orders directing the ISO to buy power only on behalf of creditworthy entities. In its November 2001 order, the FERC directed the ISO to invoice the DWR for all ISO transactions that the ISO entered into on behalf of the Utility. On December 7, 2001, the DWR filed an application for rehearing of the November 7, 2001, FERC order alleging, among other things, that the FERC order was illegal and unconstitutional because it restricted the DWR's unilateral discretion to determine the prices it would pay for the third-party power under the ISO invoices. On March 27, 2002, the FERC denied the DWR's application for rehearing and reaffirmed its previous orders finding that the DWR is responsible for paying such ISO charges.

On February 21, 2002, the CPUC approved a decision adopting rates for the DWR that will allow the DWR to collect power charges and financing charges from ratepayers to pay for the $19 billion in revenues needed by the DWR to procure electricity for the customers of the Utility and other California investor-owned utilities for the two-year period ending December 31, 2002. These revenues needed by the DWR will be financed partially through a DWR bond issuance and partially through the DWR's total statewide revenue requirement, which is allocated among the Utility and the other California investor-owned utilities. Accordingly, the CPUC established a total statewide revenue requirement for power charges of the DWR for the two-year period ending December 31, 2002, of $9 billion and allocated $4.5 billion to the Utility's customers. The February 21, 2002, CPUC order noted that the DWR had been found by the FERC to be responsible for ISO imbalance energy (energy obtained from the market) purchases for 2001, and authorized the DWR to collect rates from the Utility's customers sufficient to reimburse the DWR for these costs. In addition, on February 28, 2002, the DWR and SCE entered into an agreement under which the DWR has assumed financial responsibility for similar imbalance energy costs incurred by SCE.

On March 21, 2002, the CPUC modified its February 21, 2002, revenue requirement decision, effectively lowering the amount allocated to the customers of the Utility to $4.4 billion for the period from January 2001 through December 2002. Based on the March 21, 2002, CPUC decision, the Utility estimates that its total DWR revenue requirement allocation for 2001 is $2.5 billion. The Utility believes that the DWR's revenue requirement incorporates the procurement charges previously billed by the ISO and accrued by the Utility. In light of the March 27, 2002, FERC order and the February 21 and March 21, 2002, CPUC orders, in the first quarter of 2002, the Utility reversed the excess of the ISO accrual (for the period from January 17, 2001, through April 6, 2001) over the amount of the DWR revenue requirement applicable to 2001, for a net reduction of accrued purchased power costs of approximately $595 million, pre-tax.

The February 21, 2002, DWR revenue requirement decision, as modified by the March 21, 2002, decision, requires the DWR to submit true-ups of differences between forecasted and actual data contained in its 2001-2002 revenue requirement when it submits its 2003 revenue requirement. On June 14, 2002, the DWR released its proposed 2003 revenue requirement. In this proposed 2003 revenue requirement, the DWR requested an increase in its revenue requirement for the period from January 17, 2001, through December 31, 2002, to $9.1 billion, a slight increase from the $9.0 billion originally forecast. This revenue requirement reflects actual costs through April 2002 and projected costs for the remainder of 2002. Under AB 1X, the DWR is prohibited from entering into new agreements to purchase power to meet the net open position of the California investor-owned utilities (IOUs) after January 1, 2003. Under current FERC tariffs, in order to purchase power through the ISO, the IOUs must meet the ISO's creditworthiness standards for third party transactions, which require that the IOUs have an investment grade credit rating or meet certain collateral or prepayment requirements. The CPUC has initiated a proceeding which is expected to result in decisions in the second half of 2002 which will address the regulatory obligations and standards under which the IOUs may be required to resume procurement for the net open after January 1, 2003, including whether the IOUs will be required to procure power even if they are not investment grade; the allocation of power and operating responsibility for DWR's existing power contracts among the IOUs; and the reasonableness standards applicable to the IOUs' procurement. In addition, it is possible that the CPUC may seek to compel each IOU to accept assignment of legal and financial responsibility for existing DWR power contracts once the IOU's investment grade credit rating is restored. The Utility believes any such compelled assignment of the DWR contracts would be unlawful, and intends to challenge vigorously any such attempt by the CPUC. If an IOU is unable to meet the ISO's creditworthiness standards, the IOU may be required to post significant collateral or make significant cash prepayments to meet its net open position. It is possible that the Utility will be required to post collateral or make prepayments in order to resume procurement for the net open prior to regaining its investment grade credit rating, and procurement under such conditions could materially affect the Utility's earnings and the amount of cash projected to be available for payment of creditors' bankruptcy claims under the Utility's proposed plan of reorganization or the CPUC's alternative proposed plan of reorganization.

Chapter 11 Filing

On April 6, 2001, as a result of (1) the failure of the DWR to assume the full procurement responsibility for the Utility's net open position, (2) the negative impact of a CPUC decision that created new payment obligations for the Utility and undermined its ability to return to financial viability, (3) the lack of progress in negotiations with the State of California to provide a solution for the energy crisis, and (4) the adoption by the CPUC of a retroactive accounting change that would appear to eliminate the Utility's true under-collected wholesale electricity costs, the Utility filed a voluntary petition for relief under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court for the Northern District of California. Under Chapter 11, the Utility retains control of its assets and is authorized to operate its business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court. Subsidiaries of the Utility, including PG&E Funding LLC (which holds Rate Reduction Bonds) and PG&E Holdings, LLC (which holds stock of the Utility), are not included in the Utility's petition. While the Utility's parent, PG&E Corporation, and PG&E NEG have not filed for relief under Chapter 11 and are not included in the Utility's petition, PG&E Corporation is a co-proponent of the Utility's proposed Plan of Reorganization.

The Utility's Consolidated Financial Statements have been prepared in accordance with the American Institute of Certified Public Accountants' Statement of Position (SOP) 90-7, "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code," and on a going-concern basis, which contemplates continuity of operation, realization of assets, and liquidation of liabilities in the ordinary course of business. However, as a result of the Chapter 11 filing, such realization of assets and liquidation of liabilities are subject to uncertainty.

Certain claims against the Utility in existence prior to its filing for bankruptcy are stayed while the Utility continues business operations as a debtor-in-possession. The Utility has reflected its total estimate of all such valid claims on the June 30, 2002, Consolidated Balance Sheets as $9.2 billion of Liabilities Subject to Compromise and as $3.0 billion of Long-Term Debt. The following schedule summarizes the activity of the Utility's Liabilities Subject to Compromise from the period of December 31, 2001, to June 30, 2002 (in billions):

Liabilities Subject to Compromise at December 31, 2001	$	11.4
Interest accrual for the six months ended June 30, 2002		0.3
Claims paid pursuant to Bankruptcy Court order		(0.9)
Claims authorized by the Bankruptcy Court to be paid (transferred to accounts payable or interest payable)		(0.9)
Reclassification of debt upon liquidation of trust holding solely Utility Subordinated Debentures (Note 5)		0.3
Reversal of first quarter 2001 ISO accrual		(1.0)
Liabilities Subject to Compromise at June 30, 2002	$	9.2

Additional claims or changes to Liabilities Subject to Compromise may subsequently arise from, among other things, resolution of disputed claims and Bankruptcy Court actions. Payment terms for these amounts will be established through the bankruptcy proceedings. Secured claims also are stayed, although the Utility has received authorization from the Bankruptcy Court to make certain principal payments that have matured. Secured claims are secured primarily by liens on substantially all of the Utility's assets and by pledged accounts receivable from natural gas customers. The Bankruptcy Court has approved certain payments and actions necessary for the Utility to carry on its normal business operations (including payment of employee wages and benefits, refunds of certain customer deposits, use of certain bank accounts and cash collateral, assumption of various hydroelectric contracts with water agencies and irrigation districts, certain qualifying facilities (QF) payments, interest on secured debt, and continuation of environmental remediation and capital expenditure programs) and to fulfill certain post-petition obligations to suppliers and creditors. In addition, the Bankruptcy Court has authorized the payment of pre- and post-petition interest and low dollar items on certain claims prior to the Utility's emergence from bankruptcy under a confirmed plan.

Through June 30, 2002, $49.1 billion of claims had been filed. This amount includes claims filed by generators (which the Utility believes have been significantly overstated) and claims filed by certain financial creditors (some of which have been disallowed by the Bankruptcy Court, based on a finding that such claims are duplicative of claims filed by indenture trustees and other claimants or, in the case of commercial paper, claims scheduled by the Utility). This amount also includes governmental claims which include, but are not limited to, contingent environmental claims, claims for federal, state and local taxes, and claims submitted by the DWR for approximately $430 million of energy purchases made on behalf of the Utility's retail customers. The Bankruptcy Court has, at present, disallowed $170 million of DWR energy purchases as duplicative.

Approximately $20.4 billion of claims have been disallowed by the Bankruptcy Court, confirmed as duplicative, or withdrawn. Additional objections to claims have been filed in the Bankruptcy Court which the Utility believes to have merit. These objections will be ruled upon by the court in the future, which the Utility believes will further reduce the amount of the claims.

The claims resolution process in bankruptcy involves the determination by the Bankruptcy Court of the validity of the claim. In addition, it is common to negotiate with creditors to achieve settlement. The Utility intends to explore settlement of claims wherever possible.

On September 20, 2001, the Utility and its parent company, PG&E Corporation, jointly filed with the Bankruptcy Court a proposed plan of reorganization (Plan) of the Utility under the Bankruptcy Code and a related disclosure statement. The Utility and PG&E Corporation filed amendments to the Plan and the disclosure statement on several occasions after the initial filing in an effort to resolve objections filed by various parties, to respond to the Bankruptcy Court's February 7, 2002, decision regarding Federal preemption of state law, and to update the information in the Plan and disclosure statement to reflect other developments with respect to the Utility's business and restructuring efforts. On April 24, 2002, the Bankruptcy Court entered an order approving the Utility's disclosure statement dated April 19, 2002.

On June 7, 2002, PG&E Corporation and the Utility filed a motion with the Bankruptcy Court to extend, until December 2002, the period during which no third parties, other than the CPUC, may submit an alternate proposed plan of reorganization. The exclusivity period was scheduled to end on June 30, 2002, unless extended. On June 24, 2002, the Official Committee of Unsecured Creditors (OCC) requested that the exclusivity period be modified to enable the OCC to formulate and be in a position to file an alternative plan of reorganization if the proponents of the Utility's Plan and the CPUC's Alternative Plan fail to come to terms on a consensual plan and it appears that neither plan as currently proposed is likely to be confirmed by the court or implemented in an expeditious fashion. On July 9, 2002, the Bankruptcy Court issued an order granting the OCC's request and extending the exclusivity period to December 31, 2002, (except as to the CPUC and the OCC).

If the Utility's Plan, as amended, is confirmed and becomes effective, it would allow the Utility to restructure its businesses, refinance the restructured businesses, and use the proceeds from the refinancing to pay all allowed claims, with interest.

The Utility's Plan proposes that all allowed creditor claims would be paid in full with interest, using a combination of cash and long-term notes. Creditors would receive payment as follows:

	On the Effective Date of the Plan, Creditors Would Receive Payment In	
	Cash	**Long-term Notes**
Majority of secured creditors	100%	-
Majority of unsecured creditors with allowed claims of $100,000 or less	100%	-
Unsecured creditors with allowed claims in excess of $100,000	60%	40%

The Utility, through a Bankruptcy Court approved settlement with a group of senior debtholders, has agreed to pay the holders of certain allowed claims pre- and post-petition interest on the principal amount of such claims at rates of interest as follows:

Amount Owed (in millions)	Agreed Upon Rate (per annum)

Commercial Paper claims	$	873	7.466%	
Floating Rate Notes		1,240	7.583%	(Implied yield of 7.690%)
Senior Notes		680	9.625%	
Medium-Term Notes		287	5.810% to 8.450%	
Revolving line of credit claims		938	8.000%	

In addition, if the date on which the Plan becomes effective (Effective Date) does not occur on or before February 15, 2003, these interest rates will be increased by 37.5 basis points. If the Effective Date does not occur on or before September 15, 2003, the agreed rates will be increased by an additional 37.5 basis points. Finally, if the Effective Date does not occur on or before March 15, 2004, the agreed rates will be increased by an additional 37.5 basis points. For other claims, the Utility has recorded the contractual or FERC tariffed interest rate, or when those rates do not apply, the Utility has recorded the Federal Judgment Rate.

Since December 2001, the Bankruptcy Court has approved supplemental agreements entered into between the Utility and many QFs to resolve the issue of the applicable interest rate to be applied to pre-petition amounts owed to QFs. The supplemental agreements (1) set the interest rate for pre-petition payables at 5 percent, (2) provide for a "catch-up payment" of all accrued and unpaid interest through the initial payment date, and (3) depending on the amount owed, either provide for the immediate payment of the principal amount of the pre-petition payables (and interest thereon) or payment in 12 equal monthly payments commencing on the last business day of the month during which Bankruptcy Court approval was granted, and continuing for 11 subsequent months. In the event the Effective Date of the Plan occurs before the last monthly payment is made, the remaining unpaid principal and accrued but unpaid interest thereon shall be paid in full on the Effective Date. Additionally, since January 2002, the Utility has entered into agreements with additional QFs to assume their power purchase agreements, which agreements also contained the same interest and payment terms contained in the supplemental agreements described above. At June 30, 2002, $474 million and $55 million in principal and interest, respectively, have been paid to the QFs. Through June 30, 2002, 253 of 313 active QFs have signed supplemental agreements. The Utility believes that some of the remaining QFs also will wish to enter into similar supplemental agreements.

On March 27, 2002, the Bankruptcy Court authorized payments of pre- and post-petition interest to holders of certain other undisputed claims, including creditors holding certain financial instruments issued by the Utility (including certain senior debtholders, as described above), trade creditors, and other general unsecured creditors, and authorized payment of fees and expenses of indenture trustees and other paying agents (subject to a procedure to permit objections to fees to be made and resolved). Through July 1, 2002, the Utility has paid approximately $562 million in pre- and post-petition interest related to these claims. The Utility estimates that payments pursuant to this authorization could be as much as approximately $700 million, through the third quarter of 2002, based on the claim amounts estimated in the Utility's disclosure statement; however, the Utility has withheld $150 million of this amount because it disputes the underlying claims and will not pay interest on those disputed claims until the disputes are resolved. The actual amount of pre- and post-petition interest eventually payable may be different than the Utility's estimates, depending on the amount of claims ultimately allowed by the Bankruptcy Court. The Utility also repaid advances and interest on advances of $21 million to banks providing letters of credit backing pollution control bonds, which were separately authorized by the Bankruptcy Court.

On March 25, 2002, the Bankruptcy Court authorized the Utility to pay all undisputed creditor claims that are $5,000 or less and undisputed mechanics' liens and reclamation claims, for an aggregate amount of approximately $8 million. These amounts will be paid in the third quarter of 2002.

The Utility's Plan is designed to align the businesses under the regulators that best match the business functions. Retail assets would remain under the retail regulator, the CPUC, and wholesale assets would be placed under wholesale regulators, the FERC and the Nuclear Regulatory Commission (NRC). After this alignment, the retail-focused, state-regulated business would be a gas and electric distribution company (Reorganized Utility) representing approximately 70 percent of the book value of the Utility's assets and having approximately 16,000 employees. The wholesale businesses, which would be federally regulated (as to price, terms, and conditions), would consist of electric transmission (ETrans), interstate gas transmission (GTrans), and generation (Gen).

The Utility's Plan proposes that certain other assets of the Utility deemed not essential to operations would be sold to third parties or transferred to Newco Energy Corporation (Newco), a consolidated subsidiary created by the Utility to hold the investments in ETrans, GTrans, and Gen. Additionally, the Utility would declare and, after the assets are transferred to the newly formed entities, pay a dividend to PG&E Corporation of all of the outstanding common stock of Newco. Each of ETrans, GTrans, and Gen would continue to be an indirect wholly owned subsidiary of PG&E Corporation.

The Utility's 18,500 circuit miles of electric transmission lines and cable would be transferred to ETrans, a California company. ETrans would operate as an independent transmission company selling transmission services to wholesale customers (utilities) and to electric generators.

The Utility's 6,300 miles of gas transmission pipelines and three gas storage facilities would be transferred to GTrans, a California company. GTrans would hold the majority of the land, rights of way, and access rights currently associated with Utility gas transmission pipelines. GTrans also would assume certain continuing contractual obligations currently held by the Utility's gas transmission operation. In addition, the Reorganized Utility would hold a 10- to 15-year transportation and gas storage contract with GTrans.

The Utility's hydroelectric and nuclear generation assets, and associated lands and the power contracts with irrigation districts would be transferred to Gen, a California company. In total, Gen would have approximately 7,100 megawatts (MW) of generation. The facilities would be operated in accordance with all current FERC and NRC licenses. Gen would sell its power back to the Reorganized Utility under a 12-year contract at a stable market-based rate approved by the FERC.

The Utility's Plan relies on the FERC and the Bankruptcy Court to authorize certain actions which are outside of management's control. These actions include allowing a shift in regulatory jurisdiction of certain of the Utility's assets, approving contracts between and among the newly formed entities, and preempting certain state and local laws. Specifically, the Plan asks the Bankruptcy Court to:

- Approve the Utility's Plan, authorizing the Utility to execute, implement, and take all actions necessary or appropriate to give effect to the transactions contemplated by the Plan and the Plan documents;
- Approve the execution of, and find reasonable the terms and conditions of, the proposed service and sales contracts between the Reorganized Utility and one or more of the disaggregated entities;
- Find that the CPUC affiliate transaction rules are not applicable to the restructuring transactions contemplated under the Plan; and
- Find that neither PG&E Corporation nor the Utility is required to comply with certain provisions of the California Corporations Code relating to corporate distributions and the sale of substantially all of a corporation's assets because the Bankruptcy Code preempts such state law.

Further, if the Bankruptcy Court determines that the CPUC and/or the State as a whole have not waived their sovereign immunity with respect to the Plan, PG&E Corporation and the Utility intend to amend the conditions to Plan confirmation to substitute findings of fact or conclusions of law for any declaratory or injunctive relief presently sought against the CPUC or the State.

Finally, the Utility's Plan contemplates that on or as soon as practicable after the Effective Date, PG&E Corporation would distribute the shares of the Reorganized Utility's common stock it holds to the holders of PG&E Corporation common stock on a pro rata basis (Spin-Off). The preferred stock of the Utility that is currently outstanding would remain outstanding preferred stock of the Reorganized Utility. It is contemplated that holders of preferred stock of the Utility would receive in cash on the Effective Date, any dividends unpaid and sinking fund payments accrued in respect of such preferred stock through the last scheduled payment date before the Effective Date. The common stock of the Reorganized Utility would be registered under federal securities laws, and would be freely tradable by the recipients on the Effective Date or as soon as practicable thereafter. The Reorganized Utility would apply to list the common stock of the Reorganized Utility on the New York Stock Exchange.

Key aspects of the Utility's Plan include: (1) the issuance of investment-grade registered debt by ETrans, GTrans, and Gen, the proceeds of which, along with additional notes, would be distributed to the Reorganized Utility so that it could pay creditors, (2) a 12-year bilateral contract whereby Gen would provide the Reorganized Utility firm capacity and energy at an average rate of approximately $50 per megawatt-hour (MWh), and (3) the assumption by the Reorganized Utility of responsibility for the net open position only after certain conditions specified in detail below are met.

In order to ensure the financial viability of the Utility's Plan, the Plan provides that the following conditions must be fulfilled before the Reorganized Utility will reassume the responsibility to purchase power to meet the net open position not already provided through the DWR's power purchase contracts:

1. The Reorganized Utility receives an investment grade credit rating and receives assurances from the rating agencies that its credit rating will not be downgraded as a result of the reassumption of the obligation to meet the net open position;
2. There is an objective retail rate recovery mechanism in place pursuant to which the Reorganized Utility is able to fully recover in a timely manner its wholesale costs of purchasing electricity to satisfy the net open position;
3. There are objective standards in place regarding pre-approval of procurement transactions; and
4. After reassumption of the obligation to meet the net open position, the conditions in clauses (2) and (3) remain in effect.

The CPUC has initiated a proceeding which is intended to address the Utility's resumption of the net open obligation as early as January 1, 2003.

On November 30, 2001, the Utility and PG&E Corporation on behalf of its subsidiaries ETrans, GTrans, and Gen, filed various applications with the FERC seeking approval to implement the proposed reorganization and the securities issuances and debt financings contemplated by the Plan. The FERC also must approve some of the various service agreements to be entered into between the Reorganized Utility and one or more of the disaggregated entities. Additionally, the SEC, as administrator of the Public Utility Holding Company Act (PUHCA), must approve the Plan. An application under PUHCA was filed with the SEC on January 31, 2002.

Also, on November 30, 2001, the Utility filed applications with the NRC for approval to transfer the NRC operating licenses for the Diablo Canyon Nuclear Power Plant (Diablo Canyon) to Gen and one of its subsidiaries, and for the indirect transfer of the Humboldt Bay Nuclear Power Plant, which is in the early stages of decommissioning, to the Reorganized Utility.

Additionally, because the reorganization is intended to qualify as a tax-free reorganization and the Spin-Off is intended to qualify as a tax-free spin-off, PG&E Corporation and the Utility have sought a private letter ruling from the Internal Revenue Service (IRS) confirming the tax-free treatment of these transactions.

The Utility's Plan provides that it will not become effective unless and until the following conditions have been satisfied or waived:

1. The Effective Date shall have occurred on or before January 1, 2003;
2. All actions, documents, and agreements necessary to implement the Plan shall have been effected or executed;
3. PG&E Corporation and the Utility shall have received all authorizations, consents, regulatory approvals, rulings, letters, no-action letters, opinions, or documents that are determined by PG&E Corporation and the Utility to be necessary to implement the Plan;
4. Standard & Poor's (S&P) and Moody's Investors Service (Moody's) shall have established credit ratings for each of the securities to be issued by the Reorganized Utility, ETrans, GTrans, and Gen of not less than BBB- and Baa3, respectively;
5. The Plan shall not have been modified in a material way since the confirmation date; and
6. The registration statements pursuant to which the new securities will be issued shall have been declared effective by the SEC, the Reorganized Utility shall have consummated the sale of its new securities to be sold under the Plan, and the new securities of each of ETrans, GTrans, and Gen shall have been priced and the trade date with respect to each shall have occurred.

If one or more of the conditions described above have not occurred or been waived by January 1, 2003, the confirmation order shall be vacated and the Utility's obligations with respect to claims and equity interests shall remain unchanged.

In a February 7, 2002, decision, the Bankruptcy Court rejected PG&E Corporation's and the Utility's (Proponents) contentions that bankruptcy law permits express preemption of state law in connection with the implementation of a plan of reorganization. The Bankruptcy Court nonetheless held that "the Plan could be confirmed if Proponents are able to establish with particularity the requisite elements of implied preemption." The Bankruptcy Court stated that Proponents must show facts that would lead the Bankruptcy Court to find that the "application of those laws to the facts of the Debtor's proposed reorganization are economic in nature rather than directed at protecting public safety or other non-economic concerns, and that those particular laws stand as an obstacle to the accomplishment and execution of the purposes and objectives of Congress and the Bankruptcy Code." The Bankruptcy Court noted that if the disclosure statement were amended consistent with the court's memorandum decision, the court would approve it and let the Proponents test preemption at confirmation.

On March 18, 2002, the Bankruptcy Court entered an order disapproving the disclosure statement for the reasons set forth in the February 7, 2002, decision. On March 22, 2002, PG&E Corporation and the Utility appealed the Bankruptcy Court's March 18, 2002, order to the United States District Court for the Northern District of California. The CPUC, the City and County of San Francisco (City), and the California Attorney General filed a motion to dismiss the appeal arguing, among other matters, that the District Court lacked appellate jurisdiction because the Bankruptcy Court erred in certifying its March 18, 2002, order as immediately appealable. On June 24, 2002, the District Court issued a ruling finding that the Bankruptcy Court's certification of its preemption order was proper and that the District Court had appellate jurisdiction. The District Court set a hearing for August 16, 2002, to hear arguments regarding the appeal.

The Utility's disclosure statement and Plan were amended consistent with the Bankruptcy Court's February 7, 2002, preemption decision. On April 24, 2002, the Bankruptcy Court approved the Utility's disclosure statement dated April 19, 2002, describing the Utility's Plan. The Bankruptcy Court's approval of the Utility's disclosure statement does not constitute approval of the Plan.

As authorized by the Bankruptcy Court, on April 15, 2002, the CPUC filed its proposed Alternative Plan and disclosure statement with the Bankruptcy Court, followed by an amendment on May 15, 2002. The Bankruptcy Court approved 'the CPUC's disclosure statement on May 17, 2002. The CPUC's Alternative Plan does not call for realignment of the Utility's business, but instead provides for the continued regulation of all of the Utility's current operations by the CPUC. The CPUC's Alternative Plan also includes the following significant components:

- Provides for shareholders to contribute a projected $1.6 billion in cash earned by the Utility from its return on equity for Utility operations during 2001, 2002, and January 2003;

- Proposes to raise $3.9 billion through the issuance of new subordinated debt;

- Proposes to raise $1.75 billion through the sale of Utility common stock;

- Assumes the Utility will satisfy the FERC's creditworthiness requirements and will resume purchasing the net open position no later than January 31, 2003;

- Requires the Utility to dismiss all claims against the state, with prejudice;

- Assumes all valid claims (together with applicable post-petition interest at the lowest non-default contract rate, or if no contract or non-default rate exists, then the Federal Judgment Rate) totaling approximately $13.5 billion will be satisfied in full through a combination of cash (inclusive of the net proceeds from the proposed sale of the new subordinated notes) and reinstatement of certain of the Utility's long-term indebtedness and other obligations (approximately $4.3 billion);

- Becomes effective only if the Utility's new and reinstated debt securities receive investment grade credit ratings; however, the CPUC would retain the right to waive this condition; and

- Assumes the Utility will obtain a $1.9 billion credit facility to fund operating expenses and seasonal fluctuations of capital. A portion of this facility will be used for letters of credit that may be needed to pay collateral for post-petition workers' compensation liabilities.

The CPUC's proposed timeline for its Alternative Plan provides for a confirmation order to be issued on or before October 31, 2002, and for the Alternative Plan to become effective on or before January 31, 2003.

PG&E Corporation and the Utility believe the CPUC's Alternative Plan is not credible or confirmable. PG&E Corporation and the Utility also do not believe the CPUC's Alternative Plan would restore the Utility to investment grade status if the Alternative Plan were to become effective. Additionally, PG&E Corporation and the Utility believe the CPUC's proposal to require the Utility to issue common stock, which would significantly dilute equity and the Alternative Plan component seeking to eliminate any return on equity for a 25-month span violate federal and state law.

Further, on April 22, 2002, the CPUC initiated a regulatory proceeding to consider the rate impacts of its Alternative Plan and the Utility's Plan and invited parties to file comments. The order followed a legal challenge before the California Supreme Court by the Foundation for Taxpayers and Consumer Rights (FTCR) that the CPUC did not have the authority to propose a plan in Bankruptcy Court. Also, on July 17, 2002, the CPUC instituted a proceeding regarding the securities authorization necessary to implement the CPUC Alternative Plan.

On June 17, 2002, solicitations of creditor approval of the competing plans began. Most creditors will have the option of approving one plan, both plans (with an option to indicate a preference for one over the other), or neither plan. Acceptance or rejection of a plan is determined by creditor class. The voting period is scheduled to end on August 12, 2002. In determining whether to confirm either plan, the Bankruptcy Court will consider creditor and equity preference, plan feasibility, distributions to creditors and equity, and the financial viability of the reorganized entities. Various parties have filed objections to confirmation of either or both plans. PG&E Corporation and the Utility filed objections to the CPUC Alternative Plan stating their belief that the Alternative Plan is neither feasible nor confirmable for the reasons discussed above. The CPUC also filed an objection to the Utility's Plan. In May 2002, the OCC issued a report recommending that creditors vote in favor of both plans, but declined to state a preference for either plan.

The Utility and the CPUC each have filed a proposed form of protocol for the parties to follow in conducting discovery in preparation for the confirmation hearings, and they each have requested that the Bankruptcy Court begin the confirmation trial on November 12, 2002. The Bankruptcy Court is expected to address the discovery protocol and scheduling matters at the status conference to be held on August 1, 2002.

Neither the Utility nor PG&E Corporation are able to predict which plan the creditors will approve, or which plan, if any, the Bankruptcy Court will confirm. Whichever plan is confirmed, implementation of the confirmed plan may be delayed due to appeals, CPUC actions or proceedings, or other regulatory hearings that could be required in connection with the regulatory approvals necessary to implement the plan, and other events. Further, neither the Utility nor PG&E Corporation can predict whether the OCC will submit an alternative plan nor what the terms of any such plan would be. Consideration of an alternative plan could cause delays in the current schedule contemplated under the Utility's Plan. The pendency of the bankruptcy proceeding and the related uncertainty around the plan of reorganization that is ultimately adopted and implemented will have a significant impact on the Utility's future liquidity and results of operations. PG&E Corporation and the Utility are not able at this time to predict the outcome of the Utility's bankruptcy case or the effect of the reorganization process on the claims of the Utility's creditors or the interests of the Utility's preferred shareholders. However, the Utility believes, based on information presently available to it, that cash and cash equivalents on hand at June 30, 2002, of $3.8 billion and cash available from operations will provide sufficient liquidity to allow it to continue as a going concern through 2002.

NOTE 3: PRICE RISK MANAGEMENT

PG&E Corporation, primarily through its subsidiaries, engages in price risk management (PRM) activities for both non-trading and trading purposes. Non-trading activities are conducted to optimize and secure the return on risk capital deployed within PG&E NEG's existing asset and contractual portfolio. PG&E Corporation conducts trading activities principally through its unregulated lines of business. Trading activities are conducted to generate profit, create liquidity, and maintain a market presence. Net open positions often exist or are established due to PG&E NEG's assessment of and response to changing market conditions. In addition, non-trading activities existed within the Utility in prior years to hedge against price fluctuations of electricity and natural gas.

Derivative instruments associated with non-trading activities are accounted for in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended (SFAS No. 133) and ongoing interpretations of the FASB's DIG. Derivatives and other financial instruments associated with trading activities in electric power and other energy commodities are accounted for using the mark-to-market method of accounting in accordance with FASB's Emerging Issues Task Force (EITF) Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities."

Non-Trading Activities

At June 30, 2002, PG&E Corporation had cash flow hedges of varying durations associated with commodity price risk, foreign currency risk, and interest rate risk, the longest of which extend through December 2011, December 2004, and March 2014, respectively. The fair value of commodity hedges included in Accumulated Other Comprehensive Income or Loss (OCI), net of taxes, at June 30, 2002, was a gain of $98 million. The fair value of interest rate hedges included in OCI, net of taxes, at June 30, 2002, was a loss of $139 million. The fair value of foreign currency hedges included in OCI, net of taxes, at June 30, 2002, was a loss of $2 million.

PG&E Corporation's ineffective portion of changes in fair values of cash flow hedges was a $2 million gain after taxes for the three and six months ended June 30, 2002, and an immaterial amount for the three and six months ended June 30, 2001. PG&E Corporation's estimated net derivative losses included in OCI at June 30, 2002, are $43 million, of which net losses of $8 million are expected to be reclassified into earnings within the next 12 months. The actual amounts reclassified from accumulated other comprehensive loss to earnings will differ as a result of market price changes. The Utility had no cash flow hedges and therefore no balances in OCI for the three and six months ended June 30, 2002.

The schedule below summarizes the activities affecting accumulated other comprehensive loss net of tax, from derivative instruments:

	Three months ended June 30, 2002		Six months ended June 30, 2002	
(in millions)	PG&E Corporation	Utility	PG&E Corporation	Utility
Derivative gains (losses) included in accumulated other comprehensive income (loss) at beginning of period	$ (34)	$ -	$ 36	$
Net loss of current period hedging transactions and price changes	(9)	-	(84)	
Net reclassification to earnings	-	-	5	
Derivative losses included in accumulated other comprehensive loss at end of period	(43)	-	(43)	
Foreign currency translation adjustment	(2)	-	(2)	

Accumulated other comprehensive loss at end of period	$	(45)	$	-	$	(45)	$	

(in millions)	Three months ended June 30, 2001				Six months ended June 30, 2001			
	PG&E Corporation		Utility		PG&E Corporation		Utility	
Derivative gains (losses) included in accumulated other comprehensive income (loss) at beginning of period	$	(315)	$	(52)	$	-	$	
Cumulative effect of adoption of SFAS No. 133		-		-		(243)		9
Net loss of current period hedging transactions and price changes		178		(8)		149		(
Net reclassification to earnings		31		19		(12)		(12
Derivative losses included in accumulated other comprehensive loss at end of period		(106)		(41)		(106)		(4
Foreign currency translation adjustment		(3)		(1)		(3)		(
Accumulated other comprehensive loss at end of period	$	(109)	$	(42)	$	(109)	$	(4

Trading Activities

PG&E Corporation's net gains (losses) on trading activities, recognized on a fair value basis, were as follows:

(in millions)	Three months ended June 30,				Six months ended June 30,			
	2002		2001		2002		2001	
Trading activities [1]:								
Unrealized gains and losses, net		(48)		62		(53)		16
Realized gains, net		34		31		78		105
Total	$	(14)	$	93	$	25	$	121

[1] The Utility did not engage in trading activities.

Net unrealized gains and losses, including the reversal of unrealized gains and losses previously recognized on contracts that go to settlement or delivery, are presented on a net basis in operating revenues. Realized gains and losses are currently presented on a gross basis in operating income. The realized amounts for sale contracts are presented as operating revenues and the realized amounts for purchase contracts are presented in operating expenses as costs of commodity sales and fuel. The net realized gains of $34 million and $78 million for the three and six months ended June 30, 2002, are composed of operating revenues of $2,387 million and $4,073 million, respectively, and operating expenses of $2,353 million and $3,995 million, respectively. Beginning in the third quarter of 2002, these realized gains and losses on trading activities will be retroactively presented on a net basis in the income statement to comply with the consensus reached by FASB's EITF, Issue on No. 02-03, "Recognition and Reporting of Gains and Losses on Energy Trading Contracts under EITF Issues No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities", and No. 00-17, "Measuring the Fair Value of Energy-Related Contracts in Applying Issue No. 98-10." PG&E Corporation has reviewed its trading activities for 2001 and 2002 for potential instances of so-called "wash trades," and determined that such trades in the aggregate did not have a significant impact on revenues or expenses in any of the quarters in that period.

Gains and losses on trading contracts affect PG&E Corporation's gross margin in the accompanying PG&E Corporation unaudited Consolidated Statements ofOperations on an unrealized mark-to-market basis as the fair value of the forward positions on these contracts fluctuates. Settlement or delivery on a contract is generally not an event that results in incremental net income recognition, as the profit or loss on a contract is recognized in income on an unrealized mark-to-market basis during the periods before settlement occurs.

Gains and losses on trading contracts affect PG&E Corporation's cash flow when these contracts are settled. Net realized gains reported in the table above primarily reflect the net effect of contracts that have been settled in cash. Net realized gains also include certain non-cash items, including amortization of option premiums that were paid or received in cash in earlier periods but are considered realized when the related options are exercised or expire.

Price Risk Management Assets and Liabilities

Price risk management assets and liabilities on the accompanying PG&E Corporation Consolidated Balance Sheets reflect the aggregation of the fair values of outstanding contracts. These fair values are calculated on a mark-to-market basis for contracts that will be settled in future periods. Price risk management assets and liabilities at June 30, 2002, include amounts for trading and non-trading activities, as described below.

	Assets		Liabilities		Net
(in millions)	**Current**	**Noncurrent**	**Current**	**Noncurrent**	**(Liabilitie**
Trading activities	$ 220	$ 193	$ (186)	$ (228)	$
Non-trading activities:					
Cash flow hedges - offset to OCI	283	311	(331)	(286)	
Derivatives marked to market through earnings	5	70	(31)	(237)	(
Total consolidated PRM Assets and Liabilities	$ 508	$ 574	$ (548)	$ (751)	$ (

Non-trading activities include certain long-term contracts that are not included in PG&E Corporation's trading portfolio but that, due to certain pricing provisions and volumetric variability, are unable to receive hedge accounting treatment or the normal purchases and sales exception, as outlined by interpretations of SFAS No. 133. PG&E Corporation has certain other non-trading derivative commodity contracts for the physical delivery of purchases and sales quantities transacted in the normal course of business. These other non-trading activities include contracts that are exempt from SFAS No. 133 fair value requirements under the normal purchases and sales exemption, as described previously. Although the fair value of these other non-trading contracts is not required to be presented on the balance sheet, revenues and expenses are generally recognized in income using the same timing and basis as is used for the non-trading activities accounted for as cash flow hedges. Hence, revenues are recognized as earned and expenses are recognized as incurred.

Credit Risk

Credit risk is the risk of loss that PG&E Corporation and the Utility would incur if counterparties fail to perform their contractual obligations (accounts receivable, notes receivable, and PRM assets reflected on the balance sheets). PG&E Corporation and the Utility conduct business primarily with customers in the energy industry, such as investor-owned and municipal utilities, energy trading companies, financial institutions, and oil and gas production companies, located in the United States and Canada. This concentration of counterparties may impact PG&E Corporation's and the Utility's overall exposure to credit risk in that their counterparties may be similarly affected by changes in economic, regulatory, or other conditions. PG&E Corporation and the Utility mitigate potential credit losses in accordance with established credit approval practices and limits by dealing primarily with creditworthy counterparties (counterparties considered investment grade or higher). PG&E

Corporation and the Utility review credit exposure in relation to specified counterparty limits daily and, to the maximum extent possible, require that all derivative contracts take the form of master agreements that contain credit support provisions that require the counterparty to post security in the form of cash, letters of credit, corporate guarantees of acceptable credit quality, or eligible securities if current net receivables and replacement cost exposure exceed contractually specified limits.

PG&E Corporation and the Utility calculate gross credit exposure as the current fair value (what would be lost if the counterparty defaulted today) plus any outstanding net receivables, prior to the application of credit collateral. In the past year, PG&E Corporation's and the Utility's credit risk has increased partially due to credit rating downgrades of some of the counterparties in the energy industry to below investment grade.

At June 30, 2002, PG&E Corporation had no single counterparty that represented greater than 10 percent of PG&E Corporation's net credit exposure. At June 30, 2002, the Utility had two investment grade counterparties and one below investment grade counterparty that each represented greater than 10 percent of the Utility's net credit exposure.

The schedule below summarizes the exposure to counterparties that are in a net asset position, with the exception of exchange-traded futures (the exchange provides for contract settlement on a daily basis), at June 30, 2002:

(in millions)	Gross Exposure (1)	Credit Collateral (2)	Net Exposure (2)
PG&E Corporation	$ 1,084	$ 183	$ 901
Utility (3)	143	101	42

(1) Gross credit exposure equals fair value (adjusted for appropriate credit reserves), notes receivable, and net (payables) receivables where netting is allowed.

(2) Net exposure is the gross exposure minus credit collateral (cash deposits and letters of credit).

(3) The Utility's gross exposure includes wholesale activity only. Retail activity and payables prior to the Utility's bankruptcy filing are not included. Retail activity at the Utility consists of the accounts receivable from the sale of gas and electricity to millions of residential and small commercial customers. Reserves for uncollectible accounts receivable are calculated for the potential loss from nonpayment by these customers based on historical experience.

At June 30, 2002, approximately $121 million or 13 percent of PG&E Corporation's net credit exposure is to entities that have credit ratings below investment grade. Approximately $17 million or 41 percent of the Utility's net credit exposure is to below investment grade entities. Investment grade is determined using publicly available information including an S&P rating of at least BBB-. Approximately $206 million or 23 percent of PG&E Corporation's net credit exposure at PG&E NEG is not rated Subsequent to June 30, 2002, the credit ratings of two large counterparties (Williams Companies, Inc. and Dynegy Holdings, Inc) were reduced to below investment grade. At June 30, 2002, PG&E Corporation's and the Utility's net credit exposure to these companies was $36 million and $2 million, respectively. By July 29, 2002, the net exposure to these companies was reduced to less than $1 million for both PG&E Corporation and the Utility. PG&E Corporation's regional concentrations of credit exposure are to counterparties that conduct business primarily in the western United States and also to counterparties that conduct business primarily throughout North America. In addition to the Utility's concentration of credit risk due to receivables from residential and small commercial customers in the northern California, the Utility has a net regional concentration of credit exposure totaling $42 million to counterparties that conduct business primarily throughout North America.

NOTE 4: DEBT FINANCING

PG&E Corporation

In November 2001 and March 2002, PG&E Corporation amended its March 1, 2001, Credit Agreement (Old Credit Agreement) with General Electric Capital Corporation (GECC) and Lehman Commercial Paper Inc. (LCP I) and their assignees (Existing Lenders) . The amendments provided PG&E Corporation the option to extend the original $1 billion aggregate term loan credit facility for two one-year periods so that the maturity date could be extended until as late as March 2, 2006, contingent upon PG&E Corporation making a principal repayment of $308 million by June 3, 2002. On June 3, 2002, PG&E Corporation made the principal repayment of $308 million, utilizing current working capital and reducing the principal balance outstanding under the Old Credit Agreement to $692 million.

On June 25, 2002, PG&E Corporation entered into an Amended and Restated Credit Agreement (New Credit Agreement) with GECC (Tranche A Lender) and LCPI and others (collectively, the Tranche B Lenders), which amended and restated the Old Credit Agreement. The New Credit Agreement provides for loans in two tranches. The Tranche A has a principal amount of $ 600 million (Tranche A Loan), representing the $692 million outstanding under the Old Credit Agreement less $92 million that has been converted to a Tranche B Loan. The Tranche B consists of the $92 million converted loan plus $328 million of new borrowings, for a total of $420 million (Tranche B Loan). The Tranche A Loan will continue to have the same maturity date and extension provisions as the Old Credit Agr eement . The Tranche B Loan will mature on the earlier of (1) September 2, 2006, or (2) the date of any spin-off of the shares of PG&E NEG by its indirect parent, PG&E Corporation. The interest rate for the Tranche A Loan is the Eurodollar Rate plus 2.5 percent for the period through August 31, 2002 and will increase to the Eurodollar Rate plus 4.0 percent beginning September 1, 2002. The Tranche B Loan has an interest rate of the Eurodollar Rate plus 4.0 percent. In addition, the Tranche B Loan has a 4.0 percent payment-in-kind interest compounded annually and added to the principal of the note at maturity. The Tranche A Loan and the Tranche B Loan are collectively referred to as the "Loans."

The Tranche A Loan continues to be secured by a first priority lien on (1) PG&E Corporation's equity interest in PG&E National Energy Group, LLC, a Delaware limited liability company (NEG LLC , and together with its direct and indirect subsidiaries, the NEG Group) and (2) NEG LLC's equity interest in PG&E NEG. The Tranche A Loan is also secured by a first priority lien on certain cash interest reserves. The Tranche B Loan is secured by a second priority lien on the equity interests in NEG LLC and PG&E NEG and by a first priority lien on certain other cash interest reserves. In addition, the Tranche B Loan is subordinated to the Tranche A Loan.

PG&E Corporation issued to the Tranche B Lenders warrants to purchase approximately 2.4 million shares of common stock of PG&E Corporation for an exercise price of $0.01 per share (Warrants). The Warrants are recorded at their fair value as an unamortized discount to long-term debt, and as additional paid-in capital on the accompanying PG&E Corporation Consolidated Balance Sheet at June 30, 2002.

In connection with the Old Credit Agreement, affiliates of the Existing Lenders received an option to purchase 3 percent of the shares of PG&E NEG, determined on a fully diluted basis, at an exercise price of $1.00. The option may be exercised at any time until 45 days after the full repayment of the Tranche A Loan. In addition, under the Old Credit Agreement, PG&E Corporation's exercise of each of its one-year extensions of the loan was conditioned upon NEG LLC granting affiliates of the Existing Lenders an additional option to purchase 1 percent of the common stock of PG&E NEG, determined on a fully diluted basis, at an exercise price of $1.00. As a result of the reduction in the principal amount of the Tranche A Loan to $600 million from the $692 million in loans outstanding under the Old Credit Agreement, the 1 percent has been reduced to approximately .87 percent of the common stock of PG&E NEG. The option may be exercised at any time from the relevant extension date until 45 days after full repayment or maturity of the Tranche A Loan. The fair value of the options granted are recorded as a debt issuance cost on the balance sheet and amortized over the expected life of the loans. After the initial recording, the options are marked to market through an increase or decrease in earnings.

NEG LLC has the right to call the option after repayment of the Tranche A Loan in full at a cash purchase price equal to the fair market value of the underlying shares or, at the election of NEG LLC if an initial public offering of the shares of PG&E NEG (IPO) has occurred, by delivering the underlying shares. If an IPO has not occurred prior to repayment of the Tranche A Loan in full, the holders of the option have the right to require NEG LLC or PG&E Corporation to repurchase the option at a purchase price equal to the fair market value of the underlying shares (Put Price), which right is exercisable at any time after the earlier of full repayment of the Tranche A Loan or 45 days before expiration of the option. In addition to the grant of the additional option, PG&E Corporation must pay a fee of 3 percent of the then outstanding balance of the Tranche A Loan as a condition of PG&E Corporation's exercise of each of the one-year extensions.

The New Credit Agreement contains certain limitations on the ability of PG&E Corporation and certain of its subsidiaries to grant liens, consolidate, merge, purchase or sell assets, declare or pay dividends, incur indebtedness, or make advances, loans and investments. However, the New Credit Agreement does not limit (1) PG&E Corporation's ability to spin off its subsidiary, the Utility, substantially in accordance with the Utility's proposed plan of reorganization; (2) the ability of the members of the PG&E NEG Group to grant liens, purchase or sell assets, make investments, and incur indebtedness in accordance with PG&E NEG's business plan or, (3) PG&E Corporation 's ability to make investments in the Utility to the extent required by law or regulatory requirements .

The New Credit Agreement also generally requires mandatory prepayments of the Loans with the net cash proceeds from incurrence of indebtedness, issuance or sale of equity and sales of assets, the receipt of condemnation or insurance proceeds, and distributions or dividends paid to PG&E Corporation; provided, however, that (1) PG&E Corporation may make investments in the Utility with cash proceeds from equity sales or issuances to the extent required by law or regulatory requirements , and (2) the PG&E NEG Group may use such proceeds, or hold such proceeds in cash, to purchase assets or make investments in accordance with PG&E NEG's business plan, except that proceeds from an IPO must be used to the extent required to repay the Tranche A Loan plus $20 million of the Tranche B Loan. Any mandatory prepayments of the Loans will be applied first to the principal amount of the Tranche A Loan, and after the Tranche A Loan is paid in full, to the principal amount of the

Tranche B Loan.

The New Credit Agreement also requires PG&E Corporation to maintain an interest reserve account for each of the Tranche A Loan and the Tranche B Loan in an amount equal to one year's estimated interest. At June 30, 2002, the Tranche A Loan and the Tranche B Loan interest reserve balances, included in restricted cash, were $38 million and $27 million, respectively.

A breach of any covenants would entitle the Lenders to declare the Loans to be due and payable. The covenants include requirements that (1) PG&E NEG's unsecured long-term debt have a credit rating of at least BBB- by S&P's or Baa3 by Moody's, (2) the ratio of the fair market value of PG&E NEG to the aggregate amount of principal then outstanding under the Loans be not less than 2 to 1, and (3) PG&E Corporation maintain cash or cash equivalents (including amounts held in the interest reserves) of either 15 percent or 10 percent (depending upon when applicable) of the total principal amount of the Loans outstanding plus the principal amount of the Notes (as described below).

Concurrent with the refinancing described above, on June 25, 2002, PG&E Corporation issued $ 280 million aggregate principal amount of 7.50% Convertible Subordinated Notes (Notes) due June 30, 2007, in a private offering. The Notes are unsecured and are subordinate to the Loans. PG&E Corporation will pay interest on the Notes semi-annually at a rate of 7.50 percent per year. PG&E Corporation has the right, subject to certain limitations, to pay interest by issuing additional Notes in lieu of paying cash. The New Credit Agreement prohibits PG&E Corporation from paying cash interest on the Notes (1) for 240 days after receipt by the Note trustee of notice delivered by the administrative agent or the Tranche A Lender stating that a default that would permit acceleration has occurred under the New Credit Agreement, or (2) if, after such interest payment, PG&E Corporation's cash and cash equivalents are less than 20 percent of the total principal amount of the Loans outstanding plus the principal amount of the Notes, or 15 percent of such amount upon any extension of the Loans. PG&E Corporation would nevertheless retain its right to issue new Notes in lieu of paying cash interest.

In addition to interest, if PG&E Corporation pays cash dividends to holders of its common stock, Note holders are entitled to receive cash equal to the dividends that would have been paid with respect to the number of shares that the holder would be entitled to receive if the Notes had been converted on the dividend record date. The Notes may be converted by the holders into shares of PG&E Corporation's common stock at a conversion price equal to 119 percent of the volume- weighted average price of the common stock of PG&E Corporation for each of 43 trading days beginning June 28, 2002. The conversion price is subject to adjustment under certain circumstances, including upon consummation of any spin-off transaction of the Utility as proposed in its plan of reorganization or a spin-off of the shares of PG&E NEG. Depending on the value of PG&E Corporation common stock used in the adjustment calculation, such an adjustment could have a material adverse impact on PG&E Corporation's results of operation or financial condition.

The dilutive shares calculations for the three months ended June 30, 2002, include 1,014,332 shares of assumed conversion from the 7.50 percent Convertible Subordinated Notes and 157,995 incremental shares related to warrants issued under the Old Credit Agreement. For the six months ended June 30, 2002, the dilutive shares calculations include 509,968 shares of assumed conversion from the 7.50 percent Convertible Subordinated Notes and 79,433 incremental shares related to warrants issued under the Old Credit Agreement.

PG&E NEG

On April 5, 2002, GenHoldings I, LLC, an indirect subsidiary of PG&E NEG, increased its committed financing from $1.075 billion to $1.460 billion. The outstanding balance at June 30, 2002, was approximately $981 million. The increase in the facility provides for additional borrowing capacity and will provide funding for, and be secured by, an additional project, Covert, which is currently under construction. No other terms of the facility were changed.

On May 2, 2002, PG&E GTN closed on a new $125 million revolving credit facility with a term of three years and an interest rate based on the London Inter-bank Offer Rate (LIBOR) plus a credit spread of initially 0.725 percent. The credit spread percentage corresponds to a rating issued from time to time by Standard and Poor's (S&P) or Moody's on PG&E NEG's senior unsecured long-term debt. This three-year facility replaced a $100 million bank facility that was scheduled to expire. At June 30, 2002, there were no outstanding borrowings under this facility.

On June 6, 2002, PG&E GTN issued $100 million of 6.62 percent senior notes in a private placement. Proceeds were used to repay $90 million of debt on its revolving credit facility and the balance retained to meet general corporate needs.

Interest is capitalized as a component of projects under construction. For the six months ended June 30, 2002, and 2001, PG&E NEG capitalized interest of approximately $86 million and $55 million, respectively.

NOTE 5: UTILITY OBLIGATED MANDATORILY REDEEMABLE PREFERRED SECURITIES OF TRUST HOLDING SOLELY UTILITY SUBORDINATED DEBENTURES

On November 28, 1995, PG&E Capital I (Trust), a wholly owned subsidiary of the Utility, issued 12 million shares of 7.90 percent Cumulative Quarterly Income Preferred Securities (QUIPS) with an aggregate liquidation value of $300 million. Concurrent with the issuance of the QUIPS, the Trust issued to the Utility 371,135 shares of common securities with an aggregate liquidation value of $9 million. The Trust, in turn, used the net proceeds from the QUIPS offering and the proceeds from issuance of the common stock securities to purchase 7.90 percent Deferrable Interest Subordinated Debentures (QUIDS), due 2025, issued by the Utility with a face value of $309 million.

Distribution may be deferred up to 20 consecutive quarters under the terms of the indenture. Pursuant to the indenture, investors will accumulate interest on the unpaid distributions at the rate of 7.90 percent. Upon liquidation or dissolution of the Utility, holders of QUIPS would be entitled to the liquidation preference of $25 per share plus all accrued and unpaid dividends thereon to the date of payment.

On March 16, 2001, the Utility deferred quarterly interest payments on the QUIDS until further notice in accordance with the indenture. The corresponding quarterly payments on the 7.90 percent QUIPS issued by the Trust, due on April 2, 2001, were similarly deferred.

As discussed in Note 2, on March 27, 2002, the Bankruptcy Court issued an order authorizing the Utility to pay pre- and post-petition interest to holders of certain undisputed claims, including QUIPS, within 10 business days after Bankruptcy Court approval of the Utility's disclosure statement. The disclosure statement was approved on April 24, 2002, and on May 6, 2002, the Utility made payments to holders of QUIPS representing interest accrued through February 28, 2002. On May 31, 2002, and July 1, 2002, the Utility also paid interest for the month ended March 31, 2002, and for the three months ended June 30, 2002. Interest payments will continue to be made on a quarterly basis.

On April 12, 2001, Bank One, N.A., as successor-in-interest to The First National Bank of Chicago (Trustee), gave notice that an event of default exists under the Trust Agreement due to the Utility's Chapter 11 filing on April 6, 2001 (see Note 2). As a result of the event of default, the Trust Agreement required the Trust to be liquidated by the Trustee by distributing, after satisfaction of liabilities to creditors of the Trust, the QUIDS to the holders of the QUIPS. Pursuant to the Trustee's notice dated April 24, 2002, the Trust was liquidated on May 24, 2002. Upon liquidation of the Trust, the former holders of QUIPS received a like amount of QUIDS. The terms and interest payments of the QUIDS correspond to the terms and dividend payments of the QUIPS.

The QUIDS are included in financing debt classified as a liability subject to compromise in the accompanying PG&E Corporation's and the Utility's Consolidated Balance Sheets at June 30, 2002.

NOTE 6: COMMITMENTS AND CONTINGENCIES

Commitments

PG&E Corporation has substantial financial commitments in connection with agreements entered into supporting the Utility's and PG&E NEG's operating, construction, and development activities. These commitments are discussed more fully in the PG&E Corporation and Utility combined 2001 Annual Report on Form 10-K. The following summarizes significant changes to commitments since the combined 2001 Annual Report on Form 10-K was filed.

Utility

Natural Gas Supply and Transportation Commitments - Under current CPUC regulations, the Utility purchases natural gas from its various suppliers based on economic considerations, consistent with regulatory, contractual, and operational constraints. The Utility has long-term gas transportation service agreements with various Canadian and interstate pipeline companies. The total demand charges that the Utility will pay each year may change due to changes in tariff rates. These agreements include provisions for payment of fixed demand charges for reserving firm capacity on the pipelines.

The Utility also has long-term gas supply contracts with various Canadian and interstate gas companies. The contracts commit the Utility to purchase gas through May 2003, and total $238 million. On March 6, 2002, the CPUC authorized the Utility to pledge its gas customer accounts receivable and core gas inventory for the purpose of procuring core gas supplies until the earlier of:

- May 1, 2003;
- 15 days after an upgrade of the credit rating of the Utility's mortgage bonds to at least BBB- by S&P or Baa3 by Moody's;

- o the effective date of the Plan of Reorganization; or
- o the dismissal or conversion of the Utility's bankruptcy proceeding.

At June 30, 2002, total gas accounts receivable pledged amounted to $105 million.

At June 30, 2002, the Utility's obligations related to natural gas transportation and supply commitments held pursuant to long-term contracts were as follows (in millions):

2002	$	258
2003		188
2004		88
2005		77
2006		21
Thereafter		5
Total	$	637

The Utility uses a $10 million standby letter of credit to facilitate natural gas purchases in addition to other credit arrangements with natural gas suppliers.

El Paso Capacity Decision - In May 2002, a FERC order directed El Paso Natural Gas Company (El Paso) to change the way it allocates space on its pipeline. The order required El Paso's East of California customers to convert their capacity rights from unlimited "full requirement" to a limited Contract Demand amount of firm capacity. These customers must decide by July 31, 2002, how much El Paso capacity rights they will need in contract demand contracts and how much capacity they will relinquish.

In response, on July 17, 2002, the CPUC issued a decision that requires California IOUs to sign up for El Paso pipeline capacity relinquished by the shippers and not subscribed to by replacement shippers serving California, and pre-approves such costs as just and reasonable. The IOUs are required to purchase a proportionate amount of the released capacity. The decision stated that this requirement would spread El Paso reservation charges over as many ratepayers as possible to minimize the impact on any particular customers. The decision also addressed current capacity issues. The decision ordered that current capacity held by the IOUs on any interstate pipeline cannot be turned back and must be retained for the benefit of California ratepayers. Any capacity in excess of the IOU's need should be released under short-term capacity release arrangements. The IOU's short-term capacity releases ensure that the capacity is not withheld from the California market. The decision also finds that to the extent the IOUs comply with the decision, they shall also receive full cost recovery for their costs associated with existing capacity contracts.

In a future proceeding, the CPUC will address other issues that relate to these proposed rules. Issues to be resolved include cost allocation of turned back capacity among the California IOUs' customers for recovery, capacity releases, and details concerning the guaranteed recovery in rates of the IOUs' costs for subscription to interstate pipeline capacity.

In 1995, the CPUC issued a decision concluding that it was unreasonable for the Utility to commit to purchase gas pipeline capacity from Transwestern Pipeline Company (Transwestern). The decision ordered that costs for the capacity commitments in subsequent years of the contract, be disallowed unless the Utility can demonstrate that the benefits of the capacity commitment outweigh the costs. As discussed below, under the Gas Accord, the Utility could not recover any costs paid to Transwestern through 1997 and would have limited recovery during the period 1998 through 2002. In view of the El Paso decision which directs the utilities to retain their existing capacity contracts and allows for the recovery of the costs of existing capacity contracts, the Utility expects to fully recover its future purchases of gas pipeline capacity. This recovery is expected to result in additional revenues of approximately $90 million over the remaining contract period that ends in March of 2007.

PG&E NEG

Credit Ratings - On July 31, 2002, S&P downgraded PG&E NEG's credit rating to BB+ with CreditWatch with negative implications from BBB with a stable outlook. As a result of this downgrade, PG&E NEG may be required to post replacement collateral or fund cash under those guarantees that either require an investment grade rating or contain more subjective thresholds.

Trading and non-trading hedging guarantees - PG&E NEG and its rated subsidiaries have provided $2.9 billion of guarantees to approximately 250 counterparties in support of its energy trading and non-trading hedging operations. Typically, the overall exposure under these guarantees is only a fraction of the face value of these guarantees, since not all counterparty credit limits are fully utilized at any time. As of July 31, 2002, PG&E NEG and its rated subsidiaries' aggregate exposure under these guarantees was approximately $360 million. Of this exposure, the amounts subject to securitization requirements as a result of a downgrade to below investment grade of PG&E NEG by S&P are $115 million; of PG&E ET are $16 million; and of USGenNE are $1 million. In addition, $37 million of this exposure is under guarantees that have been issued by PG&E GTN with a ratings trigger. However, the ratings trigger for PG&E GTN is not affected by S&P's actions on July 31, 2002. The remaining $191 million could be subject to securitization requirements due to a counterparty's concern with PG&E NEG's or its subsidiary's creditworthiness. As of July 31, 2002, PG&E ET had sufficient cash to cover these obligations.

Equity Commitments and Debt Repayment Guarantees - PG&E NEG has guaranteed debt or equity commitments in connection with the following (in millions):

Lake Road	$ 230
La Paloma	379
Equipment Revolving Credit Facility	230
GenHoldings I	505

PG&E NEG has replaced the ratings triggers in these facilities with financial covenants that are consistent with those contained in PG&E NEG's revolving credit and other loan facilities. These covenants include requirements to exceed a specified cash flow to fixed charges ratio and a specified net worth as well as maintain less than a specified total debt to total capitalization ratio and are set forth in PG&E NEG's revolving credit agreement filed as Exhibit 10.21 to PG&E NEG's Annual Report on Form 10-K filed with the SEC on March 5, 2002. PG&E NEG is in compliance with these covenants.

Not withstanding the above, if PG&E NEG is also downgraded to below investment grade by Moody's, PG&E NEG would be required to fund construction draws under the GenHoldings I financing entirely with equity until the equity commitment is fulfilled. This would result in PG&E NEG being obligated to fund approximately $270 million of additional equity through December 2002 that would have otherwise been funded through June 2003. After December 2002, the lenders would fund the construction draws pursuant to the credit agreement. Failure by PG&E NEG to fund any required equity would result in a default under the GenHoldings I credit facility as well as a default under PG&E NEG's revolving credit facility.

Tolling arrangements - PG&E NEG has entered into five long-term tolling transactions with third parties. Each tolling agreement is supported by a separate guarantee backing the payment obligations of the PG&E NEG affiliate over the term of these long-term contracts (9-25 years). PG&E NEG or its rated subsidiaries has extended approximately $620 million of such guarantees. Of these guarantees, $575 million have been issued by PG&E NEG and contain a ratings trigger that requires PG&E NEG to replace the guarantee or provide alternative collateral as a result of its credit rating dropping below BBB or Baa2. This amount increases by an additional $20 million if PG&E NEG's credit rating is also downgraded to below investment grade by Moody's. In addition, $24 million of these guarantees have been issued by PG&E GTN with a ratings trigger. However, the ratings trigger for PG&E GTN is not affected by S&P's actions on July 31, 2002. The ratings downgrade by S&P on July 31, 2002, has triggered the need for additional guarantees, alternative collateral or other acceptable arrangements under these agreements within a ten to 30 day cure period. In the event that PG&E NEG does not replace the guarantee, provide alternative collateral or agree on other acceptable arrangements as required, the counterparty has the right to terminate the related tolling agreement and seek recovery of damages to be determined in arbitration. It is not known whether the counterparties to the tolling agreement would exercise their rights to terminate the agreements. If a party did exercise its right to terminate a tolling agreement, the agreements generally provide that any damages are to be awarded based upon the difference in the contract price for the power under the agreement and the market price for the power, estimated by PG&E NEG to be $20 million under current conditions. In the event of a dispute over the amount of any termination payment that the parties are unable to resolve by negotiation, the tolling agreements provide for mandatory arbitration, which could take as long as six months to more than a year to complete, depending on the specific procedures detailed in the tolling agreements .

Other Guarantees - PG&E NEG has provided approximately $1.3 billion of guarantees related to other obligations by PG&E NEG companies to counterparties for goods or services. Of this $1.3 billion, the amount subject to securitization requirements as a result of a downgrade to below investment grade of PG&E NEG is $770 million and of PG&E Gen is $9 million. The most significant of these guarantees relate to performance under certain construction and equipment procurement contracts. In the event PG&E NEG is unable to provide the additional or replacement security required in the event of such a downgrade, the counterparty providing the goods or services could suspend performance or terminate the underlying agreement and seek recovery of damages.

These guarantees represent guarantees of subsidiary obligations for transactions entered into in the ordinary course of business. The first is for guarantees related to the construction or development of PG&E NEG's power plants and pipelines. Specifically, these include guarantees for the performance of the contractor building the Harquahala and Covert power projects amounting to $545 million. Any exposure under the guarantees for construction completion is mitigated by guarantees in favor of PG&E NEG from the constructor and equipment vendors related to performance, schedule and cost. Since the constructor and various equipment vendors are performing under their underlying contracts, PG&E NEG does not believe that it has significant exposure under these guarantees. Further, although these guarantees contain ratings triggers, the same lenders who are the beneficiaries of these guarantees are the funding banks for GenHoldings I.

PG&E NEG has provided $343 million in guarantees in favor of the various contractors and equipment vendors for the payment of any cancellation penalties in the event that projects or equipment contracts are cancelled and there remain unpaid amounts. Of this amount, approximately $58 million will be paid to these vendors for cancellation of equipment contracts. In the event that these vendors seek to terminate the contracts sooner, this amount would also represent PG&E NEG's maximum exposure. Included in the above amount is $100 million of guarantees to the constructor of the Harquahala and Covert projects to cover certain separate cost-sharing arrangements. Failure to fund a demand for collateralization would permit the constructor to terminate those separate cost sharing arrangements. This would not have an impact on the constructors' obligations to complete the Harquahala and Covert projects pursuant to the contracts. Therefore, this would not have a financial impact on PG&E NEG or its subsidiaries.

PG&E NEG has provided a $300 million guarantee to support a tolling agreement that a wholly owned subsidiary, Attala Energy Company, has entered into with Attala Generating Company. Attala Generating Company entered into a $340 million sale-lease back transaction. The tolling payments provide the lessee with sufficient cash flows to pay rent under the lease. So long as Attala Energy Company continues to perform under the tolling agreement PG&E NEG does not believe it has any incremental liability or exposure under this guarantee.

The balance of the guarantees are for commitments undertaken by PG&E NEG or subsidiaries in the ordinary course of business for services such as facility and equipment leases, pipe capacity, ash disposal rights, and surety bonds.

Other Commitments - There is a total of $149 million in potential additional liquidity requirements related to other commitments.

In addition to the $360 million in trading exposure that is covered by guarantees and addressed above, there is an additional $73 million of current exposure under trading agreements at July 31, 2002. Some portion of this exposure is related to agreements that contain subjective language requiring additional securitization.

The remaining commitments included in the $149 million, are up to $16 million of surety bonds outstanding on behalf of PG&E NEG that may need to be replaced; transportation and storage agreement tariff provisions that may require an additional $38 million in security; incremental security to power pools that could be as much as $11 million, and; miscellaneous guarantees for land options and other contracts of $11 million.

The summary above identifies the potential demands on PG&E NEG's liquidity as a result of S&P's actions taken on July 31, 2002. As noted above, only the GenHoldings I equity commitment and one additional tolling agreement will be further impacted if Moody's reduces PG&E NEG's credit rating to below investment grade. The actual calls on PG&E NEG's liquidity will depend largely upon counterparties' reactions to the downgrade, the continued performance of PG&E NEG companies under the underlying agreements and the counterparties' other commercial considerations. Therefore, PG&E NEG cannot quantify with any certainty the actual calls on PG&E NEG's liquidity. In the past, PG&E NEG has been able to negotiate acceptable arrangements and reduce its overall exposure to counterparties when PG&E NEG or its counterparties have faced similar situations. However, there can be no assurance that PG&E NEG could negotiate acceptable arrangements in the current circumstances.

As of July 31, 2002, PG&E NEG had $728 million in unrestricted cash and $796 million of unused credit lines and letter of credit facilities. Certain of PG&E NEG's financing instruments are due to mature in the near future. PG&E NEG is currently seeking bank commitments to renew $750 million of revolving credit that expires on August 22, 2002. As of July 31, 2002, PG&E NEG had $431 million outstanding under this facility. PG&E NEG is seeking to replace this short-term facility with a $750 million credit facility containing a $500 million two-year tranche and a $250 million 364-day tranche. In addition, PG&E NEG is seeking to refinance $609 million of debt guaranteed by PG&E NEG in connection with the Lake Road and La Paloma facilities that matures on March 31, 2003. PG&E NEG may be unable to obtain commitments for substantial portions of these financings. If PG&E NEG is unable to do so or otherwise effect acceptable arrangements, PG&E NEG's liquidity position will be materially and adversely impacted, and PG&E NEG may be unable to satisfy demands on its liquidity.

As described above, the downgrade of PG&E NEG's credit ratings impacts certain PG&E NEG's guarantees and financial arrangements that require PG&E NEG to maintain certain credit ratings from S&P and/or Moody's. With respect to certain guarantees issued by PG&E NEG and its affiliates to project lenders and tolling counterparties, the downgrade of PG&E NEG's credit rating to below investment grade by S&P triggers a requirement that PG&E NEG replace the guarantees or provide alternative collateral within a ten to thirty day cure period. The failure of PG&E NEG to do so would entitle the holders of the guarantees to demand payment of the guaranteed amounts, or, in the case of tolling counterparties, to terminate the tolling agreements and seek damage payments to be determined by arbitration. To the extent that PG&E NEG's lenders or counterparties have the right to make such demands on PG&E NEG in an aggregate amount of $100 million or more, this would constitute an event of default under PG&E Corporation's New Credit Agreement with respect to the aggregate $1.02 billion in Tranche A and Tranche B loans outstanding thereunder, as discussed in Note 4 in the Notes to the Consolidated Financial Statements.

Subject to their respective rights as set forth in the Intercreditor and Subordination Agreement, dated as of June 25, 2002, by and between the Tranche A lenders, Tranche B lenders and certain other parties thereto (the Intercreditor Agreement), the Tranche A and Tranche B Lenders (collectively, the Lenders) would, upon notice within three days of the triggering event, have the right to declare all amounts outstanding under the New Credit Agreement to be immediately due and payable. The failure of PG&E Corporation to repay this accelerated indebtedness would entitle the Lenders, subject to the Intercreditor Agreement, to exercise certain remedies, including their rights as secured parties against their collateral, i.e., the pledged interests of PG&E Corporation in NEG, Inc., NEG LLC's pledged interests in NEG Inc., and a pledged interest in an interest reserve account with a current balance of approximately $65 million.

In the event that Moody's Investors Service also downgrades PG&E NEG to below investment grade, the dual downgrade would trigger an event of default under the New Credit Agreement. The occurrence of this default would also entitle the Lenders to exercise the remedies described in the foregoing paragraph.

Further, loss of PG&E NEG's investment grade credit ratings may prevent it from obtaining financing necessary for the funding of various project-related equity commitments. A failure to fund equity commitments in an aggregate amount of $100 million or more would also cause a cross default to the PG&E Corporation New Credit Agreement.

With respect to the $280 million aggregate principal amount of 7.5% Convertible Subordinated Notes issued by PG&E Corporation pursuant to an Indenture dated as of June 25, 2002 by and between PG&E Corporation and U.S. Bank, N.A., as trustee (the Notes), if PG&E Corporation fails to pay the accelerated obligations under the New Credit Agreement as described above and such failure continues for 30 days after receipt of written notice from the trustee or holders of at least 25% of the aggregate principal amount of outstanding Notes, the Notes would also be in default. Thereupon, and subject to the subordination provisions of the Indenture, the trustee or the Note holders would have the right to accelerate the Notes.

If PG&E Corporation's debt obligations become subject to acceleration as described above, PG&E Corporation would attempt to negotiate this situation with its Lenders and Note holders; however, PG&E Corporation cannot predict whether, or to what extent, it would be successful in such efforts. Current PG&E Corporation cash balances are insufficient to repay the full amount of its outstanding debt.

Letters of Credit - Certain of PG&E NEG's commitments are supported by letters of credit. The following table lists the various letters of credit facilities that have the capacity to issue letters of credit (in millions):

Borrower	Maturity	Letter of Credit Capacity	Letters of Credit Outstanding June 30, 2002
PG&E NEG	8/02 & 8/03	$ 650	$ 184
USGenNE	9/03	25	3
PG&E Gen	12/04	10	7
PG&E ET	12/02	25	21
PG&E ET	- (1)	50	25
PG&E ET	11/03	35	31

1. This letter of credit facility provides for up to $50 million of non-domestic letters of credit to be issued, available to PG&E Energy Trading, Canada Corporation, an indirect subsidiary of PG&E NEG, to use to post non-domestic letters of credit to support counterparty trading, for periods no longer than 364 days. There is no term for the facility, but the bank can review for termination each year.

Attala Lease - On May 10, 2002, Attala Generating Company, an indirect subsidiary of PG&E NEG, completed a $340 million sale and leaseback transaction whereby it sold and leased back its facility to a third party special purpose entity. The related lease is being accounted for as an operating lease and will amortize a deferred gain of approximately $5 million from the sale over the lease period, which is 37 years. The payment obligations under this agreement are as follows (in millions):

2002	$	49
2003		38
2004		28
2005		29
2006		27
Thereafter		631
	$	802

Attala Generating Company entered into a tolling agreement with Attala Energy Company, another wholly owned subsidiary of PG&E NEG. Attala Energy Company's obligations under this tolling agreement are guaranteed by a $300 million PG&E NEG guarantee.

Contingencies

PG&E Corporation Guarantees

At June 30, 2002, PG&E Corporation has a $16 million guarantee for an office lease relating to PG&E NEG's San Francisco office, a guarantee related to PG&E NEG's indemnification obligations to the purchaser of PG&E NEG's gas transmission assets in Texas, and a guarantee related to PG&E NEG's indemnification obligations to the purchaser of PG&E Energy Services. PG&E Corporation also has a $.9 million guarantee supporting the Utility's investment in low-income housing projects at June 30, 2002.

Utility

Nuclear Insurance - The Utility has insurance coverage for property damage and business interruption losses as a member of Nuclear Electric Insurance Limited (NEIL). Under this insurance, if a nuclear generating facility suffers a loss due to a prolonged accidental outage, the Utility may be subject to maximum retrospective assessments of $26 million (property damage) and $9 million (business interruption), in each case per policy period, in the event losses exceed the resources of NEIL. The maximum $26 million retrospective assessment can arise if any NEIL member nuclear generating facility suffers a loss.

The Utility has purchased primary insurance of $200 million for public liability claims resulting from a nuclear incident. The Utility has secondary financial protection, which provides an additional $9.3 billion in coverage, which is mandated by the Price-Andersen Act. Under the Price-Andersen Act, secondary financial protection is required for all nuclear reactors having a rated capacity of 100 MW licensed to operate and designed for production of electrical energy. It provides for loss sharing among utilities owning nuclear generating facilities if a costly incident occurs. If a nuclear incident results in claims in excess of $200 million, then the Utility may be assessed up to $176 million per incident, with payments in each year limited to a maximum of $20 million per incident.

Workers' Compensation Security - The Utility must deposit collateral with the State Department of Industrial Relations (DIR) to maintain its status as a self-insurer for workers' compensation claims made against the Utility. Acceptable forms of collateral include surety bonds, letters of credit, cash, or securities. The Utility currently provides collateral in the form of approximately $365 million in surety bonds.

In February 2001, several surety companies provided cancellation notices, citing concerns about the Utility's financial situation. The DIR has not agreed to release the canceling sureties from their obligations for claims occurring prior to the cancellation and has continued to apply the cancelled bond amounts, totaling $185 million, towards the $365 million amount of collateral. The Utility was able to supplement the difference through three additional active surety bonds totaling $180 million. The cancelled bonds have not, to date, impacted the Utility's self-insured status under California law. PG&E Corporation has guaranteed the Utility's reimbursement obligation associated with these surety bonds and the Utility's underlying obligation to pay workers' compensation claims.

Environmental Matters

The Utility may be required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under the Comprehensive Environmental Response Compensation and Liability Act and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites, and sites used by the Utility for the storage or disposal of potentially hazardous materials. Under Federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site.

The Utility records an environmental remediation liability when site assessments indicate remediation is probable and a range of reasonably likely clean-up costs can be estimated. The Utility reviews its remediation liability quarterly for each identified site. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring, and site closure using (1) current technology, (2) enacted laws and regulations, (3) experience gained at similar sites, and (4) the probable level of involvement and financial condition of other potentially responsible parties. Unless there is a better estimate within this range of possible costs, the Utility records the lower end of this range.

The Utility had an environmental remediation liability of $312 million and $295 million (undiscounted) at June 30, 2002, and December 31, 2001, respectively. The $312 million accrued at June 30, 2002, includes (1) $139 million related to the pre-closing remediation liability associated with divested generation facilities, and (2) $173 million related to remediation costs for those generation facilities that the Utility still owns, manufactured gas plant sites, gas gathering sites, and compressor stations. Of the $312 million environmental remediation liability, the Utility has recovered $190 million through rates, and expects to recover the balance in future rates. The Utility also is recovering its costs from insurance carriers and from other third parties as appropriate.

The cost of the hazardous substance remediation ultimately undertaken by the Utility is difficult to estimate. A change in the estimate may occur in the near term due to uncertainty concerning the Utility's responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives. If other potentially responsible parties are not financially able to contribute to these costs or further investigation indicates that the extent of contamination or necessary remediation is greater than anticipated, the Utility's future cost could increase by as much as $449 million. The Utility estimates the upper limit of the range using assumptions least favorable to the Utility, based upon a range of reasonably possible outcomes. Costs may be higher if the Utility is found to be responsible for clean-up costs at additional sites or expected outcomes change.

On June 28, 2001, the Bankruptcy Court authorized the Utility to continue its hazardous waste remediation program and to expend:

- Up to $22 million in each calendar year in which the Chapter 11 case is pending to continue its hazardous substance remediation programs and procedures; and
- Any additional amounts necessary in emergency situations involving post-petition releases or threatened releases of hazardous substances subject to the Bankruptcy Court's specific approval.

The California Attorney General, on behalf of various state environmental agencies, filed claims in the Utility's bankruptcy proceeding for environmental remediation at numerous sites aggregating approximately $770 million. For most if not all of these sites, the Utility is in the process of remediation in cooperation with the relevant agencies and other parties responsible for contributing to the clean-up or would be doing so in the future in the normal course of business. In addition, for the majority of the remediation claims, the State would not be entitled to recover these costs unless it accepts responsibility to clean up the sites, which is unlikely. Since the Utility's proposed plan provides that the Utility intends to respond to these types of claims in the regular course of business, and since the Utility has not argued that the bankruptcy proceeding relieves the Utility of its obligations to respond to valid environmental remediation orders, the Utility believes the claims seeking specific cash recoveries are invalid.

Moss Landing - In December 1999, the Utility was notified by the purchaser of its former Moss Landing power plant that the Utility had violated the plant's National Pollutant Discharge Elimination System (NPDES) permit issued by the Central Coast Regional Water Quality Control Board (Central Coast Board). A tentative settlement has been reached with the Central Coast Board. Under the settlement, the Utility will fund approximately $5 million in environmental projects related to coastal resources. The parties are negotiating the documentation of the settlement. The final agreement will be subject to public comment and will be incorporated in a consent decree to be entered in the California Superior Court. A claim has been filed by the California Attorney General in the Utility's bankruptcy proceeding on behalf of the Central Coast Board seeking unspecified penalties.

Diablo Canyon - In October 2000, the Utility reached a tentative settlement with the Central Coast Board concerning alleged violations under the Utility's NPDES permit. Under the settlement, the Utility will take measures to preserve certain acreage north of the plant and will fund approximately $5 million in environmental projects related to coastal resources. The parties are negotiating the documentation of the settlement. The final agreement will be subject to public comment and will be incorporated in a consent decree to be entered in the California Superior Court. A claim has been filed by the California Attorney General in the Utility's bankruptcy proceeding on behalf of the Central Coast Board seeking unspecified penalties and other relief in connection with Diablo Canyon's operation of its cooling water system.

Additionally, on April 9, 2002, the U.S. Environmental Protection Agency (EPA), proposed regulations under Section 316(b) of the Clean Water

Act for cooling water intake structures. The regulations would affect existing power generation facilities using over 50 million gallons per day (mgd), typically including some form of "once-through" cooling. The Utility's Diablo Canyon, Hunters Point, and Humboldt Bay power plants are among an estimated 539 plans nationwide that would be affected by this rulemaking. The proposed regulations call for a set of performance standards that vary with the type of water body and that are intended to reduce impacts to aquatic organisms. Significant capital investment may be required to achieve the standards if the regulations are adopted as proposed. The final regulations are scheduled to be promulgated in August 2003.

The Utility believes the ultimate outcome of these matters will not have a material impact on its consolidated financial position or results of operations.

PG&E NEG

Environmental Matters

In May 2000, USGen New England (USGenNE), an indirect subsidiary of PG&E NEG, received an Information Request from the EPA, pursuant to Section 114 of the Federal Clean Air Act (CAA). The Information Request asked USGenNE to provide certain information relative to the compliance of its Brayton Point and Salem Harbor plants with the CAA. No enforcement action has been brought by the EPA to date. USGenNE has had preliminary discussions with the EPA to explore a potential settlement of this matter. Management believes that it is not possible to predict at this point whether any such settlement will occur, or in the absence of a settlement, the likelihood of whether the EPA will bring an enforcement action.

As a result of this and related regulatory initiatives by the Commonwealth of Massachusetts, USGenNE is exploring ways to achieve significant reductions of sulfur dioxide and, nitrogen oxide emissions. Additional requirements for the control of mercury and carbon dioxide emissions will also be forthcoming as part of these regulatory initiatives. Management believes that USGenNE would meet these requirements through installation of controls at the Brayton Point and Salem Harbor plants and estimates that capital expenditures on these environmental projects could approximate $332 million over the next five years. These estimates are currently under review and it is possible that actual expenditures may be higher. Based on an emission control plan filed for Brayton Point under the regulations implementing these initiatives, the Massachussetts Department of Environmental Protection (DEP) ruled that Brayton Point is required to meet the newer, more stringent emission limitations for sulfur dioxide and nitrogen oxide by 2006. However, on June 7, 2002, the DEP ruled that Salem Harbor must satisfy these limitations by 2004. USGenNE will not be able to operate Salem Harbor unless it is in compliance with these emission limitations. USGenNE believes it may not be feasible to comply by 2004, and that in any event DEP improperly applied the 2004 deadline to the Salem Harbor emission control plan. USGenNE filed with DEP a revised plan for Salem Harbor in April that it believes meets the DEP requirements for the 2006 compliance date. USGenNE has also filed an administrative appeal of DEP's ruling that Salem Harbor meet the 2004 compliance date.

Various aspects of DEP's regulations allow for public participation in the process through which DEP determines whether the 2004 or 2006 deadline applies and approves the specific activities that USGenNE will undertake to meet the new regulations. A local environmental group has made various filings with DEP requesting such participation.

The EPA is required under the CAA to establish new regulations for controlling hazardous air pollutants from combustion turbines and reciprocating internal combustion engines. Although the EPA has yet to propose the regulations, the CAA required that they be promulgated by November 2000. Another provision in the CAA requires companies to submit case-by-case Maximum Achievable Control Technology (MACT) determinations for individual plants, if the EPA fails to finalize regulations within 18 months past the deadline. On April 5, 2002, the EPA promulgated a regulation that extends this deadline for the case-by-case permits until May 2004. The EPA intends to finalize the MACT regulations before this date, thus eliminating the need for the plant-specific permits. PG&E NEG will not be able to accurately quantify the economic impact of the future regulations until more details are available through the rulemaking process.

PG&E NEG's existing power plants are subject to federal and state water quality standards with respect to discharge constituents and thermal effluents. Three of the fossil-fueled plants owned and operated by USGenNE (Salem Harbor, Manchester Street, and Brayton Point) are operating pursuant to NPDES permits that have expired. For the facilities whose NPDES permits have expired, permit renewal applications are pending, and all three facilities are continuing to operate under existing terms and conditions until new permits are issued. On July 22, 2002, the EPA and the DEP issued a draft NPDES permit for Brayton Point that, among other things, substantially limits the discharge of heat by Brayton Point into Mount Hope Bay. Based on its initial review of the draft permit, USGenNE believes that the draft permit is excessively stringent. It is estimated that USGenNE's cost to comply with the new permit conditions could be as much as $248 million through 2005, but this is a preliminary estimate. There are various administrative and judicial proceedings that must be completed before the draft NPDES permit for Brayton Point becomes final and these proceedings are not expected to be completed during 2002. In addition, it is possible that the new permits for Salem Harbor and Manchester Street may also contain more stringent limitations than prior permits, and that the cost to comply with the new permit conditions could be greater than the current estimate of $4 million. In addition, the issuance of any final NPDES permits may be affected by the EPA's proposed regulations under Section 316(b) of the Clean Water Act, which are discussed below.

On March 27, 2002, Rhode Island Attorney General, Sheldon Whitehouse, notified USGenNE of his belief that 'Brayton Point "is in violation of applicable statutory and regulatory provisions governing its operations...," including "protections accorded by common law" respecting discharges from the facility into Mt. Hope Bay. He stated that he intended to seek judicial relief "to abate these environmental law violations and to recover damages..." within the next 30 days. The notice purportedly was provided pursuant to section 7A of chapter 214 of Massachusetts General Laws. PG&E NEG believes that Brayton Point Station is in full compliance with all applicable permits, laws, and regulations. The complaint has not yet been filed or served. In early May 2002, the Rhode Island Attorney General stated that he did not plan to file the action until the EPA issues a draft Clean Water Act NPDES permit for Brayton Point. The EPA issued its draft permit on July 22, 2002, and the Rhode Island Attorney General has since stated that he has no intention of pursuing this matter until he reviews USGenNE's response to the draft permit. Management is unable to predict whether he will pursue this matter and, if he does, the extent to which it will have a material adverse effect on PG&E NEG's financial condition or results of operations.

On April 9, 2002, the EPA proposed regulations under Section 316(b) of the Clean Water Act for cooling water intake structures. The regulations would affect existing power generation facilities using more than 50 mgd typically including some form of "once-through" cooling. Brayton Point, Salem Harbor, and Manchester Street generating facilities are among an estimated 539 plants nationwide that would be affected by this rulemaking. The proposed regulations call for a set of performance standards that vary with the type of water body and that are intended to reduce impacts to aquatic organisms. The final regulations are scheduled to be promulgated in August 2003. The extent to which they may require additional capital investment will depend on the timing of the NPDES permit proceedings for the affected facilities. It is possible that the regulations may allow greater flexibility in achieving specified permit limits and thereby reduce the cost of compliance.

During April 2000, an environmental group served USGenNE and other PG&E NEG's subsidiaries with a notice of its intent to file a citizen's suit under the Resource Conservation and Recovery Act (RCRA). In September 2000, PG&E NEG signed a series of agreements with the DEP and the environmental group to resolve these matters that require PG&E NEG to alter its existing wastewater treatment facilities at its Brayton Point and Salem Harbor generating facilities.

PG&E NEG began the activities during 2000, and is expected to complete them in 2002. PG&E NEG incurred expenditures related to these agreements of approximately $5.8 million in 2000, $2.4 million in 2001, and $2.0 million through June 2002. In addition to the costs previously incurred in 2000 and 2001, PG&E NEG maintains a reserve in the amount of $8 million relating to its estimate of the remaining environmental expenditures to fulfill its obligations under these agreements. PG&E NEG has deferred costs associated with capital expenditures and has set up a receivable for amounts it believes are probable of recovery from insurance proceeds.

PG&E NEG believes that it may be required to spend up to approximately $592 million, excluding insurance proceeds, through 2008 for environmental compliance to continue operating these facilities. This amount may change, however, and the timing of any necessary capital expenditures could be accelerated in the event of a change in environmental regulations or the commencement of any enforcement proceeding against PG&E NEG. In the event PG&E NEG does not spend required amounts as of each facility's compliance deadline to maintain environmental compliance, PG&E NEG may not be able to continue to operate one or all of these facilities.

Legal Matters

In the normal course of business, PG&E Corporation, the Utility, and PG&E NEG are named as parties in a number of claims and lawsuits. The most significant of these are discussed below. The Utility's Chapter 11 bankruptcy filing on April 6, 2001, discussed in Note 2 of the Notes to the Consolidated Financial Statements, automatically stayed the litigation described below against the Utility, except as otherwise noted.

Chromium Litigation - There are 15 civil suits pending against the Utility in several California state courts. One of these suits also name PG&E Corporation as a defendant. One additional civil suit filed against the Utility and PG&E Corporation after the Utility's bankruptcy filing was dismissed without prejudice while the plaintiffs seek the right to file and pursue late claims in the Bankruptcy Court. The suits seek an unspecified amount of compensatory and punitive damages for alleged personal injuries resulting from alleged exposure to chromium in the vicinity of the Utility's gas compressor stations at Hinkley, Kettleman, and Topock, California. Currently, there are claims pending on behalf of approximately 1,290 individuals.

The Utility is responding to the suits in which it has been served and is asserting affirmative defenses. The Utility will pursue appropriate legal defenses, including statute of limitations, exclusivity of workers' compensation laws, and factual defenses, including lack of exposure to chromium and the inability of chromium to cause certain of the illnesses alleged.

There have been approximately 1,260 claims filed with the Bankruptcy Court (by most of the plaintiffs in the 15 cases and other individuals) alleging that exposure to chromium in soil, air, or water near the Utility's compressor stations at Hinkley, Kettleman, or Topock, California, caused personal injuries, wrongful death, or other injuries. Approximately 1,035 of these claimants have filed proofs of claim requesting an approximate aggregate amount of $580 million and approximately another 225 claimants have filed claims for an "unknown amount." On November 14, 2001, the Utility filed objections to these claims and requested the Bankruptcy Court to transfer the chromium claims to the federal District Court. On January 8, 2002, the Bankruptcy Court denied the Utility's request to transfer the chromium claims and granted certain claimants' motion for relief from stay so that the state court lawsuits pending before the Utility filed its bankruptcy petition can proceed.

The Utility has recorded a reserve in its financial statements in the amount of $160 million for these matters. PG&E Corporation and the Utility believe that, after taking into account the reserves recorded at June 30, 2002, the ultimate outcome of this matter will not have a material adverse impact on PG&E Corporation's or the Utility's financial condition or future results of operations.

Natural Gas Royalties Litigation - This litigation involves the consolidation of approximately 77 False Claims Act cases filed in various federal district courts by Jack J. Grynberg (called a relator in the parlance of the False Claims Act) on behalf of the United States of America, against more than 330 defendants, including the Utility and PG&E GTN. The cases were consolidated for pretrial purposes in the District of Wyoming. The current case grows out of prior litigation brought by the same relator in 1995 that was dismissed in 1998.

Under procedures established by the False Claims Act, the United States acting through the Department of Justice (DOJ), is given an opportunity to investigate the allegations and to intervene in the case and take over its prosecution if it chooses to do so. In April 1999, the U.S. DOJ declined to intervene in any of the cases.

The complaints allege that the various defendants (most of which are pipeline companies or their affiliates) incorrectly measured the volume and heat content of natural gas produced from federal or Indian leases. As a result, it is alleged that the defendants underpaid, or caused others to underpay, the royalties that were due to the United States for the production of natural gas from those leases. The complaints do not seek a specific dollar amount or quantify the royalties claim. The complaints seek unspecified treble damages, civil penalties, and expenses associated with the litigation.

The relator has filed a claim in the Utility's bankruptcy case for $2.5 billion, $2 billion of which is based upon the plaintiff's calculation of penalties sought against the Utility.

PG&E Corporation and the Utility believe the allegations to be without merit and intend to present a vigorous defense. PG&E Corporation and the Utility believe that the ultimate outcome of the litigation will not have a material adverse effect on their financial condition or results of operations.

Federal Securities Lawsuit - A complaint, *Gillam, et al. v. PG&E Corporation, et al*., is pending in the U.S. District Court for the Northern District of California. An executive officer of PG&E Corporation has also been named as a defendant. The first amended complaint, purportedly brought on behalf of all persons who purchased PG&E Corporation common stock or certain shares of the Utility's preferred stock between July 20, 2000, and April 9, 2001, claimed that the defendants caused PG&E Corporation's Consolidated Financial Statements for the second and third quarters of 2000 to be materially misleading in violation of federal securities laws as a result of recording as a deferred cost and capitalizing as a regulatory asset the under-collections that resulted when escalating wholesale energy prices caused the Utility to pay far more to purchase electricity than it was permitted to collect from customers. On January 14, 2002, the District Court granted the defendants' motion to dismiss the plaintiffs' first amended complaint, finding that the complaint failed to state a claim in light of the public disclosures by PG&E Corporation, the Utility, and others regarding the under-collections, the risk that they might not be recoverable, the financial consequences of non-recovery, and other information from which analysts and investors could assess for themselves the probability of recovery.

On February 4, 2002, the plaintiffs filed a second amended complaint that, in addition to containing many of the same allegations as appeared in the first amended complaint, contains many of the same allegations that appear in the California Attorney General's complaint discussed below. The plaintiffs seek an unspecified amount of compensatory damages, plus costs and attorneys' fees. On March 11, 2002, the defendants filed a motion to dismiss the second amended complaint. After a hearing held on June 24, 2002, the District Court issued an order on June 25, 2002, dismissing the second amended complaint with prejudice. Plaintiffs have filed a notice of appeal of the District Court's order with the appellate court.

PG&E Corporation believes the allegations to be without merit and intends to present a vigorous defense. PG&E Corporation believes that the ultimate outcome of the litigation will not have a material adverse effect on its financial condition or results of operations.

Order Instituting Investigation (OII) into Holding Company Activities and Related Litigation - On April 3, 2001, the CPUC issued an OII into whether the California investor-owned utilities, including the Utility, have complied with past CPUC decisions, rules, or orders authorizing their holding company formations and/or governing affiliate transactions, as well as applicable statutes. The order states that the CPUC will investigate (1) the utilities' transfer of money to their holding companies since deregulation of the electric industry commenced, including during times when their utility subsidiaries were experiencing financial difficulties, (2) the failure of the holding companies to financially assist the utilities when needed, (3) the transfer by the holding companies of assets to unregulated subsidiaries, and (4) the holding companies' action to "ringfence" their unregulated subsidiaries. The CPUC will also determine whether additional rules, conditions, or changes are needed to adequately protect ratepayers and the public from dangers of abuse stemming from the holding company structure. The CPUC will investigate whether it should modify, change, or add conditions to the holding company decisions, make further changes to the holding company structure, alter the standards under which the CPUC determines whether to authorize the formation of holding companies, otherwise modify the decisions, or recommend statutory changes to the California Legislature. As a result of the investigation, the CPUC may impose remedies, prospective rules, or conditions, as appropriate.

On January 9, 2002, the CPUC issued an interim decision and order interpreting the "first priority condition" adopted in the CPUC's holding company decision. This condition requires that the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner, be given first priority by the board of directors of the holding company. In the interim order, the CPUC stated, "the first priority condition does not preclude the requirement that the holding company infuse all types of 'capital' into their respective utility subsidiaries where necessary to fulfill the Utility's obligation to serve." The three major California investor-owned energy utilities and their parent holding companies had opposed the broader interpretation, first contained in a proposed decision released for comment on December 26, 2001, as being inconsistent with the prior 15 years' understanding of that condition as applying more narrowly to a priority on capital needed for investment purposes. The CPUC also interpreted the first priority condition as prohibiting a holding company from: (1) acquiring assets of its utility subsidiary for inadequate consideration, and (2) acquiring assets of its utility subsidiary at any price, if such acquisition would impair the utility's ability to fulfill its obligation to serve or to operate in a prudent and efficient manner. The utilities' applications for rehearing were denied on July 17, 2002.

In a related decision, the CPUC denied the motions filed by the California utility holding companies to dismiss the holding companies from the pending investigation on the basis that the CPUC lacks jurisdiction over the holding companies. However, in the interim decision interpreting the first priority condition discussed above, the CPUC separately dismissed PG&E Corporation (but no other utility holding company) as a respondent to the proceeding. In its written decision adopted on January 9, 2002, the CPUC stated that PG&E Corporation was being dismissed so that an appropriate legal forum could decide expeditiously whether adoption of the Utility's proposed Plan of Reorganization would violate the first priority condition. The utilities' applications for rehearing were denied on July 17, 2002.

On January 10, 2002, the California Attorney General filed a complaint in the San Francisco Superior Court against PG&E Corporation and its directors, as well as against the directors of the Utility, alleging PG&E Corporation violated various conditions established by the CPUC in decisions approving the holding company formation among other allegations. The Attorney General also alleges that the December 2000 and January and February 2001 ringfencing transactions by which PG&E Corporation subsidiaries complied with credit rating agency criteria to establish independent credit ratings violated the holding company conditions.

Among other allegations, the Attorney General alleges that, through the Utility's bankruptcy proceedings, PG&E Corporation and the Utility engaged in unlawful, unfair, and fraudulent business practices in alleged violation of California Business and Professions Code Section 17200 by seeking to implement the transactions contemplated in the proposed Plan of Reorganization filed in the Utility's bankruptcy proceeding. The complaint also seeks restitution of assets allegedly wrongfully transferred to PG&E Corporation from the Utility. On February 8, 2002, PG&E Corporation filed a notice of removal in the Bankruptcy Court to transfer the Attorney General's complaint to the Bankruptcy Court. On February 15, 2002, a motion to dismiss the lawsuit or in the alternative to stay the suit, was filed. Subsequently, the Attorney General filed a motion to remand the action to state court. The Bankruptcy Court held a hearing on April 24, 2002, to consider the remand motion. On June 14, 2002, the court issued a memorandum decision rejecting the Attorney General's claim of sovereign immunity, and ordered the Attorney General to amend its complaint to drop or at least separate its plan of reorganization-related claims from its other claims by July 14, 2002. The court indicated that it would then remand to state court the Attorney General's Section 17200 claims that did not relate to the plan of reorganization. The Attorney General dropped the plan of reorganization claims in the amended complaint filed with the Bankruptcy Court on July 22, 2002.

On February 11, 2002, a complaint entitled *City and County of San Francisco; People of the State of California v. PG&E Corporation, and Does 1-150* was filed in San Francisco Superior Court. The complaint contains some of the same allegations contained in the Attorney General's complaint, including allegations of unfair competition. In addition, the complaint alleges causes of action for conversion, claiming that PG&E Corporation "took at least $5.2 billion from the Utility," and for unjust enrichment. The City seeks injunctive relief, the appointment of a receiver, payment to ratepayers, disgorgement, the imposition of a constructive trust, civil penalties, and costs of suit.

On March 4, 2002, PG&E Corporation filed a notice of removal in the Bankruptcy Court to transfer the City's complaint to the Bankruptcy Court. Subsequently, the City filed a motion to remand the action to state court. The Bankruptcy Court held a hearing on April 24, 2002, to consider the remand motion. On June 14, 2002, the court rejected the City's claim of sovereign immunity and its request for remand as to the unjust enrichment and conversion claims. In the same ruling, the court remanded to the state court the City's Section 17200 claims. PG&E Corporation filed a notice of appeal regarding the remand decision in the City's case, the only one of the three Section 17200 cases that is ripe for appeal at this time.

In addition, a third case, entitled *Cynthia Behr v. PG&E Corporation, et al*., has been filed by a private plaintiff (who has also filed a claim in bankruptcy) in Santa Clara Superior Court also alleging a violation of California Business and Professions Code Section 17200. The Behr complaint also names the directors of the Utility as defendants. The allegations of the complaint are similar to the allegations contained in the Attorney General's complaint but adds allegations of fraudulent transfer and violation of the California bulk sales laws. Plaintiff requests the same remedies as the Attorney General's case and in addition requests damages, attachment, and restraints upon the transfer of defendants' property. On March 8, 2002, PG&E Corporation filed a notice of removal in the Bankruptcy Court to transfer the complaint to the Bankruptcy Court.

Subsequently, the plaintiff filed a motion to remand the action to state court. The Bankruptcy Court held a hearing on April 24, 2002, to consider the remand motion. In its June 14, 2002 ruling mentioned above as to the Attorney General's and the City's cases, the court rejected Behr's claim for remand on her fraudulent conveyances and bulk sales claims but remanded to state court the Section 17200 claims. By amended complaint, Behr has dropped her fraudulent conveyance and bulk sales claims.

PG&E Corporation and the Utility believe that they have complied with applicable statutes, CPUC decisions, rules, and orders. Neither the Utility nor PG&E Corporation, however, can predict what the outcome of the CPUC's investigation will be or whether the outcome will have a material adverse effect on their results of operations or financial condition. PG&E Corporation will vigorously respond to and defend the litigation. PG&E Corporation cannot predict whether the outcome of the litigation will have a material adverse effect on its results of operations or financial condition.

William Ahern, et al. v. Pacific Gas and Electric Company - On February 27, 2002, a group of 25 ratepayers filed a complaint against the Utility at the CPUC demanding an immediate reduction of approximately $0.035 per kilowatt-hour (kWh) in allegedly excessive electric rates and a refund of alleged recent overcollections in electric revenue since June 1, 2001. The complaint claims that electric rate surcharges adopted in the first quarter of 2001 due to the high cost of wholesale power, surcharges that increased the average electric rate by $0.04 per kWh, became excessive later in 2001. (In January 2001, the CPUC authorized a $0.01 per kWh increase to pay for energy procurement costs. In March 2001, the CPUC authorized an additional $0.03 per kWh electric rate increase as of March 27, 2001, to pay for energy procurement costs, which the Utility began to collect in June 2001.) The only alleged over-collection amount calculated in the complaint is approximately $400 million during the last quarter of 2001. On April 2, 2002, the Utility filed an answer, arguing that the complaint should be denied and dismissed immediately as an impermissible collateral action and on the basis that the alleged facts, even if assumed to be true, do not establish that currently authorized electric rates are not reasonable. On May 10, 2002, the Utility filed a motion to dismiss the complaint. The CPUC has not yet issued a decision. PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material adverse effect on their financial condition or results of operation.

Recorded Liability for Legal Contingencies

In accordance with SFAS No. 5, "Accounting for Contingencies," PG&E Corporation makes a provision for a liability when it is both probable that a liability has been incurred and the amount of the loss can be reasonably estimated. These provisions are reviewed quarterly and adjusted to reflect the impacts of negotiations, settlements, rulings, advice of legal counsel, and other information and events pertaining to a particular case. The following table reflects the current year's activity to the recorded liability for legal matters for PG&E Corporation and the Utility:

(in millions)	2002
Beginning balance, January 1,	$ 209
Provision for liabilities	17
Adjustments	(5)
Ending balance, June 30,	$ 221

NOTE 7: SEGMENT INFORMATION

PG&E Corporation has identified three reportable operating segments, which were determined based on similarities in economic characteristics, products and services, types of customers, methods of distributions, the regulatory environment, and how information is reported to PG&E Corporation's key decision makers. In accordance with accounting principles generally accepted in the United States of America, prior year segment information has been restated to conform to the current segment presentation. The Utility is one reportable operating segment and the other two are part of PG&E NEG. These three reportable operating segments provide different products and services and are subject to different forms of regulation or jurisdictions. PG&E Corporation's reportable segments are described below.

Segment information for the three and six months ended June 30, 2002 and 2001 was as follows:

PG&E National Energy Group

(in millions)	Utility	Total PG&E NEG	Integrated Energy & Marketing	Interstate Pipeline Operations	PG&E NEG Eliminations	PG&E Corporation & Other Eliminations (2)	Total
Three months ended June 30, 2002							
Operating revenues	$ 2,711	$ 3,041	$ 3,002	$ 44	$ (5)	$ -	$ 5,752
Intersegment revenues (1)	3	19	9	10	-	(22)	-
Total operating revenues	2,714	3,060	3,011	54	(5)	(22)	5,752
Income (loss) from continuing operations	463	(180)	(190)	17	(7)	(4)	279
Net income (loss)	463	(241)	(251)	17	(7)	(4)	218
Three months ended June 30, 2001							
Operating revenues	2,305	2,705	2,637	55	13	-	5,010
Intersegment revenues (1)	4	48	39	9	-	(52)	-
Total operating revenues	2,309	2,753	2,676	64	13	(52)	5,010
Income (loss) from continuing operations	696	71	53	19	(1)	(17)	750
Net income (loss)	696	71	53	19	(1)	(17)	750
Six months ended June 30, 2002							
Operating revenues	5,161	5,358	5,276	91	(9)	-	10,519
Intersegment revenues (1)	6	50	28	22	-	(56)	-
Total operating revenues	5,167	5,408	5,304	113	(9)	(56)	10,519
Income (loss) from continuing operations	1,053	(143)	(164)	35	(14)	-	910
Net income (loss)	1,053	(204)	(225)	35	(14)	-	849
Six months ended June 30, 2001							
Operating revenues	4,865	6,818	6,703	111	4	-	11,683
Intersegment revenues (1)	6	141	123	18	-	(147)	-
Total operating revenues	4,871	6,959	6,826	129	4	(147)	11,683
Income (loss) from continuing operations	(304)	125	88	38	(1)	(22)	(201)
Net income (loss)	(304)	125	88	38	(1)	(22)	(201)
Total assets at June 30, 2002 (3)	24,648	11,422	9,953	1,355	114	709	36,779
Total assets at June 30, 2001 (3)	23,216	12,990	11,343	1,172	475	223	36,429

(1) Intersegment electric and gas revenues are recorded at market prices, which for the Utility and PG&E NEG's Interstate Pipeline Operations business segment are tariffed rates prescribed by the CPUC and the FERC, respectively.

(2) Includes PG&E Corporation, PG&E Ventures LLC, and elimination entries.

(3) Assets of PG&E Corporation are included in amounts under the "PG&E Corporation & Other Eliminations" column exclusive of investment in its subsidiaries.

NOTE 8: IMPAIRMENT OF PROJECT DEVELOPMENT, TURBINES, AND OTHER RELATED EQUIPMENT COSTS

PG&E NEG has reviewed its growth plans for its electric generating business in light of the recent changes in the energy and equity markets as well as the slowdown of the U.S. economy. Further, energy prices, electric generating industry fundamentals and financial market's support for competitive energy companies have significantly declined, thereby constraining access to funds at acceptable terms to PG&E NEG. Over supply of electric generation in the current and near future has significantly decreased the value of planned future development projects. In response to these market changes and considering the expected level of future electric generating supply, PG&E NEG has reconsidered the extent of and reduced its planned investment activities in electric generating development projects. PG&E NEG has analyzed the potential cash flow from those projects that it no longer anticipates pursuing and has recognized an impairment of the asset value it is carrying for those development projects. The aggregate pre-tax impairment charge recorded by PG&E NEG for its development assets (excluding associated equipment costs discussed below) is $19 million. The remaining asset value (recorded in Other Non Current Assets) that PG&E NEG has retained as of June 30, 2002 for its portfolio of development projects is $48 million. PG&E NEG anticipates continuing to develop these projects to completion or for future disposal and believes that their unique characteristics provide value that will enable recovery of the capitalized costs over the useful lives of the projects. PG&E NEG has no material commitments (excluding equipment costs discussed below) for the projects under continuing development.

To support PG&E NEG's electric generating development program, PG&E NEG had contractual commitments and options to purchase a significant number of combustion turbines and related equipment. PG&E NEG's commitment to purchase combustion turbines and related equipment exceeds the new planned development activities discussed above. The current electric generating market is faced with an over supply of facilities in operation and in construction. The current and future market for combustion turbines and related equipment has also seen an over supply and large cancellation of turbine orders. The net realizability of PG&E NEG's investment in and future committed payments for its excess combustion turbine and related equipment portfolio, in light of current development plans, is doubtful. Based upon PG&E NEG's current development plans and analysis of future market prices for combustion turbines and related equipment, PG&E NEG has recognized a charge of $246 million. The charge consists of the impairment of previously capitalized costs associated with prior payments made under the terms of the turbine and equipment contracts in the amount of $188 million and the accrual of $58 million for future termination payments required under the turbine and related equipment contracts. Although PG&E NEG has impaired the value of these turbines and related equipment, it has not terminated its commitments or options with respect to this equipment. The remaining asset value (recorded in Other Non Current Assets) that PG&E NEG has retained as of June 30, 2002, for its investment in turbines and related equipment is approximately $33 million. These turbine and equipment commitments have been retained to support the equipment needs for PG&E NEG's current portfolio of advanced development projects discussed above. PG&E NEG and its equipment vendors have agreed to suspend any PG&E NEG payment obligations, except for $19 million, for at least the next twelve months. Thereafter, PG&E NEG must either restart equipment payments or terminate such commitments and pay the associated termination costs.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

PG&E Corporation is an energy-based holding company headquartered in San Francisco, California. PG&E Corporation's energy utility subsidiary, Pacific Gas and Electric Company (the Utility), delivers electric service to approximately 4.8 million customers and natural gas service to approximately 4.0 million customers. On April 6, 2001, the Utility filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code (Bankruptcy Code) in the United States Bankruptcy Court for the Northern District of California (Bankruptcy Court). Under Chapter 11, the Utility retains control of its assets and is authorized to operate its business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court. The factors causing the Utility to take this action are discussed in this Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) and in Note 2 of the Notes to the Consolidated Financial Statements.

PG&E Corporation's other significant subsidiary is PG&E National Energy Group, Inc. (PG&E NEG), headquartered in Bethesda, Maryland. PG&E NEG is an integrated energy company with a strategic focus on power generation, power plant development, natural gas transmission, and wholesale energy marketing and trading in North America. PG&E NEG and its subsidiaries have integrated their generation, development, and energy marketing and trading activities in an effort to create energy products in response to customer needs, increase the returns from their operations, and identify and capitalize on opportunities to increase their generating and pipeline capacity. PG&E NEG was incorporated on December 18, 1998, as a wholly owned subsidiary of PG&E Corporation. Shortly thereafter, PG&E Corporation contributed various subsidiaries to PG&E NEG. PG&E NEG's principal subsidiaries include: PG&E Generating Company, LLC and its subsidiaries (collectively, PG&E Gen), PG&E Energy Trading Holdings Corporation and its subsidiaries (collectively, PG&E Energy Trading or PG&E ET), PG&E Gas Transmission Corporation and its subsidiaries (collectively, PG&E GTC), which include PG&E Gas Transmission, Northwest Corporation and its subsidiaries (collectively, PG&E GTN) and North Baja Pipeline, LLC (NBP). PG&E NEG also has other less significant subsidiaries.

PG&E Corporation has identified three reportable operating segments, which were determined based on similarities in economic characteristics, products and services, types of customers, methods of distribution, the regulatory environment, and how information is reported to PG&E Corporation's key decision makers. The Utility is one reportable operating segment. The other two reportable operating segments are the Integrated Energy and Marketing (PG&E Energy) and the Interstate Pipeline Operations (PG&E Pipeline) segments of PG&E Corporation's subsidiary, PG&E NEG. These three reportable operating segments provide different products and services and are subject to different forms of regulation or jurisdictions. Financial information about each reportable operating segment is provided in this MD&A and in Note 7 of the Notes to the Consolidated Financial Statements.

This Quarterly Report on Form 10-Q is a combined report of PG&E Corporation and the Utility. It includes separate Consolidated Financial Statements for each entity. The Consolidated Financial Statements of PG&E Corporation reflect the accounts of PG&E Corporation, the Utility, and PG&E Corporation's wholly owned and controlled subsidiaries. This MD&A should be read in conjunction with the Consolidated Financial Statements and Notes to the Consolidated Financial Statements included herein. Further, this combined Quarterly Report on Form 10-Q should be read in conjunction with PG&E Corporation's and the Utility's Consolidated Financial Statements and Notes to the Consolidated Financial Statements incorporated by reference in their combined 2001 Annual Report on Form 10-K.

This combined Quarterly Report on Form 10-Q, including this MD&A, contains forward-looking statements, including statements regarding management's guidance regarding 2002 earnings per share, that are necessarily subject to various risks and uncertainties. These statements are based on current expectations and assumptions which management believes are reasonable and on information currently available to management. These forward-looking statements are identified by words such as "estimates," "expects," "anticipates," "plans," "believes," and other similar expressions. Actual results could differ materially from those contemplated by the forward-looking statements.

Although PG&E Corporation and the Utility are not able to predict all of the factors that may affect future results, some of the factors that could cause future results to differ materially from historical results or those expressed or implied by the forward-looking statements include:

- the quarterly amount of "headroom" (the current recovery in the Utility's existing electric rates of prior uncollected costs previously written off according to accounting principles generally accepted in the United States) recognized by the Utility, which can fluctuate materially due to many factors, including the outcome of regulatory proceedings and other regulatory actions, sales volatility, the impact of the end of the rate freeze period and post-rate freeze ratemaking, and changes in the application of the surcharge revenues accrued by the Utility under rate increases approved by the California Public Utilities Commission (CPUC) in January and March 2001, and the impact of the proceedings to determine the level of revenue requirements for the California Department of Water Resources' (DWR) power procurement costs

- the pace and outcome of the Utility's bankruptcy case, which will be affected by:

- whether the Bankruptcy Court confirms the Utility's proposed plan of reorganization (Utility Plan) or the CPUC's competing alternative proposed plan of reorganization (Alternative Plan);

- whether regulatory or governmental approvals required to implement either plan are obtained and the timing of such approvals;

    - the impact of any delays in implementation of a plan due to litigation related to regulatory, governmental, or Bankruptcy Court orders;

    - future equity or debt market conditions, future interest rates, future credit ratings, and other factors that may affect the ability to implement either plan or affect the amount and value of the securities proposed to be issued under either plan;

    - whether the Official Committee of Unsecured Creditors (OCC) submits a proposed alternative plan of reorganization and the terms and conditions of any such plan;

- whether the Utility is required to re-assume the obligation to purchase power for its retail customers under circumstances that threaten to undermine the Utility's creditworthiness, financial condition, or results of operation;

- whether the Utility is required to accept assignment or operational responsibility of the DWR's power purchase contracts and any ratemaking associated with that obligation;

- the outcome of the CPUC's pending investigation into whether the California investor-owned utilities, including the Utility, have complied with past CPUC decisions, rules, or orders authorizing their holding company formations, the outcomes of the lawsuits brought by the California Attorney General and the City and County of San Francisco (City) against PG&E Corporation alleging unfair or fraudulent business acts or practices based on alleged violations of conditions established in the CPUC's holding company decisions, and the outcome of the California Attorney General's petition requesting revocation of PG&E Corporation's exemption from the Public Utility Holding Company Act of 1935, and the effect of such outcomes, if any, on PG&E Corporation, the Utility, and PG&E NEG;
- the outcome of the Utility's various regulatory proceedings pending at the CPUC and at the Federal Energy Regulatory Commission (FERC);

- whether the Utility will be successful in its filed rate doctrine litigation and other claims against the CPUC and the State of California for recovery of costs that were not collected from retail ratepayers;

- the CPUC's determination of the end of the rate freeze and the amount of under-collected power procurement and transition costs the Utility is allowed to collect from its customers after the end of the rate freeze;

- legislative or regulatory changes affecting the electric and natural gas industries in the United States, including the pace and extent of efforts to restructure the electric and natural gas industries and changes to rules and tariffs applicable to energy marketing and trading transactions, the market in which PG&E NEG operates, and changes in the accounting treatment of such transactions;

- the volatility of commodity fuel and electricity prices and the spread between them (which may result from a variety of factors, including: weather; the supply and demand for energy commodities; the availability of competitively priced alternative energy sources; the level of production and availability of natural gas, crude oil, and coal; transmission or transportation constraints; federal and state energy and environmental regulation and legislation; the degree of market liquidity; and natural disasters, wars, embargoes, and other catastrophic events); any resulting increases in the cost of producing power and decreases in prices of power sold; and whether the Utility's and PG&E NEG's strategies to manage and respond to such volatility are successful;

- the extent to which the ability of PG&E Corporation to obtain financing or capital on reasonable terms is affected by conditions in the general economy, the energy or capital markets, by restrictions imposed on PG&E Corporation under its credit agreement, by changes in PG&E NEG's credit ratings, and by the interpretation of the CPUC's holding company conditions;

- PG&E NEG's ability to obtain financing from third parties or from PG&E Corporation while preserving PG&E NEG's credit quality, which ability could be negatively affected by conditions in the general economy, the energy markets, or the capital markets; and the market's perceptions of the energy industry;

- the extent to which PG&E NEG's current or planned construction of generation, pipeline, and storage facilities are completed and the pace and cost of that completion, including the extent to which commercial operations of these construction projects are delayed or prevented because of various development and construction risks such as PG&E NEG's failure to obtain necessary permits or equipment, the failure of third-party contractors to perform their contractual obligations, or the failure of necessary equipment to perform as anticipated and the potential loss of permits or other rights in connection with PG&E NEG's decision to delay or defer construction;

- the extent to which PG&E NEG's development plans and strategies are affected by changes in the national energy markets and by the timing of generating, pipeline, and storage capacity expansion and retirements by others;

- whether market conditions will require further impairment or write-off of PG&E NEG assets, which may cause PG&E NEG to fail to comply with the net worth requirements of its loan agreements or which may cause PG&E Corporation to fail to comply with the debt covenant in its term loan agreement requiring PG&E NEG to maintain a certain loan to value ratio;

- restrictions imposed upon PG&E Corporation and PG&E NEG under certain term loans of PG&E Corporation, including requirements for PG&E Corporation to comply with debt covenants regarding cash reserves, loan to value ratios, and investment grade credit ratings, among others;
- future sales levels which are affected by general economic and financial market conditions, changes in interest rates, weather, conservation efforts, outages, and in the case of the Utility, the level of exit fees that may be imposed on direct access customers;
- volatility in income resulting from mark-to-market accounting, changes in mark-to-market methodologies, and the extent to which the assumptions underlying PG&E NEG's and the Utility's mark-to-market accounting and risk management programs are not realized;
- the effectiveness of PG&E NEG's and the Utility's risk management policies and procedures;
- the ability of PG&E NEG's and the Utility's counterparties to satisfy their financial commitments to PG&E NEG and the Utility, respectively, and the impact of counterparties' nonperformance on PG&E NEG's and the Utility's liquidity position;
- the effect of compliance with existing and future environmental laws, regulations, and policies, the cost of which could be significant;
- the impact of the recent or future downgrades in credit ratings of PG&E NEG and other subsidiaries on PG&E NEG's and PG&E Corporation's financial condition which will be affected by the extent to which PG&E NEG and its subsidiaries can meet liquidity calls which may be made in connection with trading activities, meet obligations to fund various equity commitments, provide other collateral to replace PG&E NEG guarantees, or obtain financing for planned development projects, whether PG&E NEG is able to renew a substantial portion of its revolving credit lines otherwise due to expire on August 22, 2002; and whether a default occurs under PG&E Corporation's credit agreement;
- the extent to which counterparties seek damages based upon credit downgrades and their ability to recover such damages;
- the effect of new accounting pronouncements; and
- the outcome of pending litigation and environmental matters.

As the ultimate impact of these and other factors is uncertain, these and other factors may cause future earnings to differ materially from results or outcomes currently sought or expected.

In this MD&A, we first discuss our earnings guidance, we then discuss the impact of the California energy crisis and the Utility's bankruptcy on our liquidity, and then PG&E NEG's liquidity. We then discuss statements of cash flows and financial resources, and our results of operations for the six months ended June 30, 2002, and 2001. Finally, we discuss our competitive and regulatory environment, our risk management activities, and various uncertainties that could affect future earnings. Our MD&A applies to both PG&E Corporation and the Utility.

2002 Guidance

PG&E Corporation expects 2002 corporate earnings from operations, excluding headroom, to be in the range of $2.25 to $2.35 per share on a fully diluted basis. Earnings from operations, including headroom, are expected to exceed $4.75 per share for 2002. Earnings from operations with and without headroom exclude items impacting comparability, and should not be considered an alternative to net income as prescribed by accounting principles generally accepted in the United States.

STATE OF INDUSTRY

Utility

The California energy crisis described in Note 2 of the Notes to the Consolidated Financial Statements has had a significant negative impact on the liquidity and capital resources of the Utility. Beginning in June 2000, the wholesale price of electric power in California steadily increased to an average cost of $0.182 per kilowatt-hour (kWh) for the seven-month period June 2000 through December 2000, as compared to an average cost of $0.042 per kWh for the same period in 1999. During this period, retail electric rates were frozen. The Utility was only permitted to collect approximately $0.054 per kWh in frozen retail rates from its customers to pay for the Utility's generation-related costs. While seeking rate relief from the CPUC, the Utility financed the difference between its wholesale electricity costs and the amount collected through frozen retail rates. By December 31, 2000, the Utility had borrowed more than $3 billion. At December 31, 2000, the Utility had accumulated a total of approximately $6.9 billion in under-collected purchased power costs and generation-related transition costs. This amount was charged to earnings at December 31, 2000, because the Utility could no longer conclude that such costs were probable of collection through regulated rates.

In January 2001, the CPUC granted an interim rate increase of $0.010 per kWh. This increase, which could not be used to recover past procurement costs, was not sufficient to cover the ongoing high wholesale electricity costs then being experienced. As a result of the higher energy prices and the insufficient rate increase, PG&E Corporation's and the Utility's credit ratings deteriorated to below investment grade. These credit downgrades, which occurred on January 16 and 17, 2001, were events of default under one of the Utility's revolving credit facilities and precluded PG&E Corporation's and the Utility's access to the capital markets. Accordingly, the banks stopped funding under the Utility's revolving credit facility. On January 17, 2001, the Utility began to default on maturing commercial paper obligations. In addition, the Utility was no longer able to meet its obligations to generators, qualifying facilities (QF), the Independent System Operator (ISO), and the Power Exchange (PX), and began making partial payments of amounts owed.

As of January 19, 2001, the Utility had no credit under which it could purchase power for its customers, and generators were only selling to the Utility under emergency actions taken by the U.S. Secretary of Energy. As a result, the State of California authorized the DWR to purchase electricity for the Utility's customers. California Assembly Bill (AB) 1X was passed on February 1, 2001, authorizing the DWR to enter into contracts for the supply of electricity and to issue revenue bonds to finance electricity purchases, although the DWR indicated that it intended to buy power only at reasonable prices to meet the Utility's net open position, leaving the ISO to purchase the remainder in order to avoid blackouts. (The net open position is the amount of power needed by retail electric customers that cannot be met by utility-owned generation or power under contract to the Utility).

Throughout the energy crisis, the Utility sought relief through various regulatory proceedings and through efforts to reach a negotiated solution with the State of California (State). In late March and early April 2001, the CPUC issued a series of decisions that increased the Utility's inability to recover past debts and increased its exposure to significant additional costs. On March 27, 2001, the CPUC ruled on the Utility's November 20, 2000, request for rate relief. This decision made permanent the $0.010 per kWh interim increase authorized in January 2001 and granted an additional $0.030 per kWh (on average) energy surcharge that would be effective immediately, but that would not be included in customer bills until June 2001. The revenue generated by the rate increase was to be used only for electric power procurement costs incurred after March 27, 2001. This decision ordered the Utility to pay the DWR the full generation-related portion of retail rates for every kWh of electricity sold by the DWR without regard to whether overall retail rates were adequate to recover the remainder of the Utility's cost of service. In the same decision, the CPUC adopted an accounting proposal by The Utility Reform Network (TURN), which retroactively restates the way in which transition costs are recovered. This retroactive change had the effect of extending the rate freeze and reducing the amount of past wholesale power costs that could be eligible for recovery from customers. The CPUC denied the Utility's application for rehearing of this retroactive accounting change. The Utility also filed a petition for a writ of review with the California Court of Appeal, which also was denied. The Utility has filed a petition with the California Supreme Court to review the appellate court action. The Utility's request filed with the Bankruptcy Court for an order enjoining the CPUC from enforcing its order was denied by the Bankruptcy Court. The Utility has appealed the Bankruptcy Court's denial of injunctive relief to the U.S. District Court for the Northern District of California.

On July 1, 2002, a CPUC Commissioner issued an Assigned Commissioner's Ruling seeking comments on whether the restrictions of applying the $0.010 per kWh and $0.030 per kWh surcharge revenues only to "ongoing procurement costs" and "future power purchases" should be modified to allow the surcharge amount to be applied to improve the financial health of the Utility. See further discussion in the Regulatory Matters section of this MD&A.

Also on March 27, 2001, the CPUC issued a ruling that required the Utility to begin paying the QFs in full and within 15 days of the end of the QF's billing cycle. On April 3, 2001, the CPUC issued a ruling which adopted a methodology for the Utility to reimburse the DWR for power purchases made to meet the Utility's net open position. The Utility believes that these actions taken by the CPUC were illegal and the Utility filed for rehearings and appeals with the CPUC, in federal court, and with the Bankruptcy Court. The status of these proceedings is discussed later in this MD&A.

As a result of (1) the failure of the DWR to assume the full procurement responsibility for the Utility's net open position, (2) the negative impact of a CPUC decision that created new payment obligations for the Utility and undermined its ability to return to financial viability, (3) a lack of progress in negotiations with the State of California to provide a solution for the energy crisis, and (4) the adoption by the CPUC of an illegal and retroactive accounting change that would appear to eliminate the Utility's true under-collected purchased power costs, the Utility filed a voluntary petition for relief under Chapter 11 of the Bankruptcy Code on April 6, 2001. See Note 2 of the Notes to the Consolidated Financial Statements for further discussion of the energy crisis, the Utility's voluntary petition for relief under Chapter 11 of the Bankruptcy Code, and the status of the proceedings.

Under AB 1X, the DWR is prohibited from entering into new agreements after January 1, 2003, to purchase power to meet the net open position of the California investor-owned utilities (IOUs). The CPUC has initiated a proceeding to address the regulatory obligations and standards under which the IOUs may be required to resume procurement for the net open after January 1, 2003, including whether the IOUs can be required to procure power even if they are not investment grade; the allocation of power and operating responsibility for DWR's existing power contracts among the IOUs; and the reasonableness standards applicable to the IOUs' procurement. This proceeding is further discussed below under the Regulatory Matters sections of this MD&A.

PG&E NEG

The national markets in which PG&E NEG participates are experiencing the first sustained downturn in the electric power commodity business cycle since electric deregulation began in the mid 1990's. Price spikes beginning in 1997 and 1998 culminated in peak prices in 2000 and early 2001. New supply additions begun during the high-price period combined with a softening economy and reduced load growth have resulted in excess energy supply in many regions. The excess supply conditions have put downward pressure on the price of electricity minus the cost of fuel, or spark spread, available in most regional wholesale energy markets. Furthermore, the economic slowdown and a number of regulatory events, many of which were consequences of the California energy crisis and the Enron bankruptcy, have increased uncertainty in the energy sector.

Conditions in the national energy markets will constrain PG&E NEG's near-term profitability and growth. The excess supply conditions reduce operating margins for electric generators and lower price volatility for energy products, potentially reducing profits from energy trading activities. In response to these market changes, PG&E NEG has reconsidered the extent of and reduced its planned investment activities in electric generating development projects. PG&E NEG has analyzed the potential cash flow from those projects that no longer anticipates pursuing and has recognized an impairment of the carrying value of those development projects and the associated turbine and equipment assets. This impairment, described under "Investing Activities" below, reflects PG&E NEG's judgment that the market viability of these development projects is uncertain. PG&E NEG is continuing to seek purchasers or partners for these development projects and the equipment associated with them. PG&E NEG also initiated a program to reduce administrative, general and other operating costs, with a targeted annual reduction of a minimum of $40 million.

In addition, a series of events and disclosures have created a more difficult financial and regulatory climate for the energy industry and its participants, including PG&E NEG. S&P announced that it has changed its methodology to review energy industry participants, and has recently issued several downgrades. On July 31, 2002, S&P downgraded PG&E NEG to BB+ from BBB. See "Credit Ratings and Liquidity Uses" below.

In addition, investigations are underway by state and federal authorities into energy trading matters. In response to a data request order from FERC, PG&E NEG conducted an investigation into certain activities of its subsidiaries in the U.S. portion of the Western Systems Coordinating Council ("WSCC") during the years 2000 and 2001. FERC requested information regarding transactions in which energy traders simultaneously engaged in any purchase and sale of the same product at the same price with the same counterparty in the WSCC during the years 2000 and 2001. As a result of its investigation, PG&E NEG identified 12 such instances. In addition, PG&E NEG has reviewed its activities including those in other regions during the period January 2000 through May 2002 using the FERC criteria and has identified 32 additional instances. These instances had no material effect on PG&E NEG's reported revenues or financial results. Revenues associated with these instances represent approximately 0.14 percent of PG&E NEG's revenues during the same period. PG&E Corporation has adopted a policy prohibiting participation in this type of transaction.

PG&E NEG maintains an insurance program including coverage for power plant construction and operating risks. Recent events have adversely affected the insurance industry generally and the machinery and equipment segment in particular. This effect is especially acute for insurance covering advanced gas turbine technology; including many of those PG&E NEG has in construction. As a result, PG&E NEG expects that its insurance coverages will be at lower levels than PG&E NEG has historically procured, certain coverages (for example, terrorism insurance) may no longer be available on commercially reasonable terms, deductibles will increase in size and premiums will be significantly higher. Therefore, PG&E NEG will likely carry a greater percentage of self-insurance at potential risk of greater losses than in prior periods.

LIQUIDITY AND FINANCIAL RESOURCES

In November 2001 and March 2002, PG&E Corporation amended its March 1, 2001, Credit Agreement (Old Credit Agreement) with General Electric Capital Corporation (GECC) and Lehman Commercial Paper Inc. (LCPI) and their assignees (Existing Lenders). The amendments provided PG&E Corporation the option to extend the original $1 billion aggregate term loan credit facility for two one-year periods so that the maturity date could be extended until as late as March 2, 2006, contingent upon PG&E Corporation making a principal repayment of $308 million by June 3, 2002. On June 3, 2002, PG&E Corporation made the principal repayment of $308 million, utilizing current working capital and reducing the principal balance outstanding under the Old Credit Agreement to $692 million.

On June 25, 2002, PG&E Corporation entered into an Amended and Restated Credit Agreement (New Credit Agreement) with GECC (Tranche A Lender) and LCPI and others (collectively, the Tranche B Lenders) which amended and restated the Old Credit Agreement. The New Credit

Agreement provides for loans in two tranches. The Tranche A has a principal amount of $600 million (Tranche A Loan), representing the $692 million outstanding under the Old Credit Agreement less $92 million that has been converted to a Tranche B Loan. The Tranche B consists of the $92 million converted loan plus $328 million of new borrowings, for a total of $420 million (Tranche B Loan). The Tranche A Loan will continue to have the same maturity date and extension provisions as the Old Credit Agreement. The Tranche B Loan will mature on the earlier of (1) September 2, 2006, or (2) the date of any spin-off of the shares of PG&E NEG by its indirect parent, PG&E Corporation. The interest rate for the Tranche A Loan is the Eurodollar Rate plus 2.5 percent for the period through August 31, 2002, and will increase to the Eurodollar Rate plus 4.0 percent beginning September 1, 2002. The Tranche B Loan has an interest rate of the Eurodollar Rate plus 4.0 percent. In addition, the Tranche B Loan has a 4.0 percent payment-in-kind interest compounded annually and added to the principal of the note at maturity. The Tranche A Loan and the Tranche B Loan are collectively referred to as the "Loans."

The Tranche A Loan continues to be secured by a first priority lien on (1) PG&E Corporation's equity interest in PG&E National Energy Group, LLC, a Delaware limited liability company (NEG LLC, and together with its direct and indirect subsidiaries, the NEG Group), and (2) NEG LLC's equity interest in PG&E NEG. The Tranche A Loan is also secured by the first priority lien on certain cash interest reserves. The Tranche B Loan is secured by a second priority lien on the equity interests in NEG LLC and PG&E NEG and by a first priority lien on certain other cash interest reserves. In addition, the Tranche B Loan is subordinated to the Tranche A Loan.

PG&E Corporation issued to the Tranche B Lenders warrants to purchase approximately 2.4 million shares of common stock of PG&E Corporation for an exercise price of $0.01 per share (Warrants). The Warrants are recorded at their fair value as an unamortized discount to long-term debt, and as additional paid-in capital on the PG&E Corporation Consolidated Balance Sheets at June 30, 2002.

In connection with the Old Credit Agreement, affiliates of the Existing Lenders received an option to purchase 3 percent of the shares of PG&E NEG, determined on a fully diluted basis, at an exercise price of $1.00. The option may be exercised at any time until 45 days after the full repayment of the Tranche A Loan. In addition, under the Old Credit Agreement, PG&E Corporation's exercise of each of its one-year extensions of the loan was conditioned upon NEG LLC granting affiliates of the Existing Lenders an additional option to purchase 1 percent of the common stock of PG&E NEG, determined on a fully diluted basis, at an exercise price of $1.00. As a result of the reduction in the principal amount of the Tranche A Loan to $600 million from the $692 million in loans outstanding under the Old Credit Agreement, the 1 percent has been reduced to approximately 0.87 percent of the common stock of PG&E NEG. The option may be exercised at any time from the relevant extension date until 45 days after full repayment or maturity of the Tranche A Loan. The fair value of the options granted are recorded as a debt issuance cost and amortized over the expected life of the loans. After the initial recording, the options are marked to market through an increase or decrease in earnings.

NEG LLC has the right to call the option after repayment of the Tranche A Loan in full at a cash purchase price equal to the fair market value of the underlying shares or, at the election of NEG LLC if an initial public offering of the shares of PG&E NEG (IPO) has occurred, by delivering the underlying shares. If an IPO has not occurred prior to repayment of the Tranche A Loan in full, the holders of the option have the right to require NEG LLC or PG&E Corporation to repurchase the option at a purchase price equal to the fair market value of the underlying shares (Put Price), which right is exercisable at any time after the earlier of full repayment of the Tranche A Loan or 45 days before expiration of the option. In addition to the grant of the additional option, PG&E Corporation must pay a fee of 3 percent of the then outstanding balance of the Tranche A Loan as a condition of PG&E Corporation's exercise of each of the one-year extensions.

The New Credit Agreement contains certain limitations on the ability of PG&E Corporation and certain of its subsidiaries to grant liens, consolidate, merge, purchase or sell assets, declare or pay dividends, incur indebtedness, or make advances, loans and investments. However, the New Credit Agreement does not limit (1) PG&E Corporation's ability to spin-off its subsidiary, the Utility, substantially in accordance with the Utility's proposed plan of reorganization, and (2) the ability of the members of the PG&E NEG Group to grant liens, purchase or sell assets, make investments, and incur indebtedness in accordance with PG&E NEG's business plan, or (3) PG&E Corporation's ability to make investments in the Utility to the extent required by law or regulatory requirements.

The New Credit Agreement also generally requires mandatory prepayments of the Loans with the net cash proceeds from incurrence of indebtedness, issuance or sale of equity and sales of assets, the receipt of condemnation or insurance proceeds, and distributions or dividends paid to PG&E Corporation; provided however, that (1) PG&E Corporation may make investments in the Utility with cash proceeds from equity sales or issuances to the extent required by law or regulatory requirements, (2) the PG&E NEG Group may use such proceeds, or hold such proceeds in cash, to purchase assets or make investments in accordance with PG&E NEG's business plan, except that proceeds from an IPO must be used to the extent required to repay the Tranche A Loan, plus $20 million of the Tranche B Loan. Any mandatory prepayments of the Loans will be applied first to the principal amount of the Tranche A Loan and, after the Tranche A Loan is paid in full, to the principal amount of the Tranche B Loan.

The New Credit Agreement also requires PG&E Corporation to maintain an interest reserve account for each of the Tranche A Loan and the Tranche B Loan in an amount equal to one year's estimated interest. At June 30, 2002, the Tranche A Loan and the Tranche B Loan interest reserve balances, included in restricted cash, were $38 million and $27 million, respectively.

A breach of any covenants would entitle the Lenders to declare the Loans to be due and payable. The covenants include requirements that (1) PG&E NEG's unsecured long-term debt have a credit rating of at least BBB - by Standard & Poor's (S&P) or Baa3 by Moody's Investors Service, Inc. (Moody's), (2) the ratio of fair market value of PG&E NEG to the aggregate amount of principal then outstanding under the Loans be not less than 2 to 1, and (3) PG&E Corporation maintain cash or cash equivalents (including amounts held in the interest reserves) of either 15 percent or 10 percent (depending upon when applicable) of the total principal amount of the Loans outstanding plus the principal amount of the Notes (as described below).

Concurrent with the refinancing described above, on June 25, 2002, PG&E Corporation issued $280 million aggregate principal amount of 7.50% Convertible Subordinated Notes (Notes) due June 30, 2007, in a private offering. The Notes are unsecured and are subordinate to the Loans. PG&E Corporation will pay interest on the Notes semi-annually at a rate of 7.50 percent per year. PG&E Corporation has the right, subject to certain limitations, to pay interest by issuing additional Notes in lieu of paying cash. The New Credit Agreement prohibits PG&E Corporation from paying cash interest on the Notes (1) for 240 days after receipt by the Note trustee of notice delivered by the administrative agent or the Tranche A Lender stating that a default that would permit acceleration has occurred under the New Credit Agreement, or (2) if, after such interest payment, PG&E Corporation's cash and cash equivalents are less than 20 percent of the total principal amount of the Loans outstanding plus the principal amount of the Notes, or 15 percent of such amount upon any extension of the Loans. PG&E Corporation would nevertheless retain its right to issue new Notes in lieu of paying cash interest.

In addition to interest, if PG&E Corporation pays cash dividends to holders of its common stock, Note holders are entitled to receive cash equal to the dividends that would have been paid with respect to the number of shares that the holder would be entitled to receive if the Notes had been converted on the dividend record date. The Notes may be converted by the holders into shares of PG&E Corporation's common stock at a conversion price equal to 119 percent of the volume-weighted average price of the common stock of PG&E Corporation for each of 43 trading days beginning June 28, 2002. The conversion price is subject to adjustment under certain circumstances, including upon consummation of any spin-off transaction of the Utility as proposed in its plan of reorganization or a spin-off of the shares of PG&E NEG. Depending on the value of PG&E Corporation common stock used in the adjustment calculation, such adjustment could have a material adverse impact on PG&E Corporation's results of operation or financial condition.

Credit Ratings

As discussed below, the California energy crisis has impacted the credit ratings of various debt and equity instruments. The credit ratings at July 31, 2002, of the various debt and equity instruments of PG&E Corporation, the Utility, and PG&E NEG are summarized in the table below:

	Credit Rating	
	Standard & Poor's	**Moody's Investors Service**
PG&E Corporation		
GECC/LCPI Loans	Not Rated	B2
Convertible Subordinated Notes	Not Rated	Not Rated
Utility		
Mortgage Bonds	CCC	B3
Pollution Control Bonds-Bond Insurance	AAA	Aaa
Pollution Control Bonds-Letters of Credit	AA to AA-/A-1+	Not Rated
Medium-Term Notes	D	Caa2
San Joaquin Valley Power Authority Bond	Not Rated	Rating Withdrawn
DWR Loan	Not Rated	Not Rated
Senior 5-Year Note	D	Caa2
Revolving Credit Line	Not Rated	Not Rated
Floating Rate Notes	D	Not Rated
Matured Commercial Paper	D	Not Prime
Redeemed Pollution Control Bonds-Bank Loans	Not Rated	Not Rated
Deferrable Interest Subordinated Debentures (QUIDS)	Rating Pending	Caa3

Preferred Stock	D	Ca
PG&E NEG		
Senior Unsecured Notes due 2011 (PG&E NEG)	BB+	Baa2
Senior Unsecured Notes due 2005 (PG&E GTN)	BBB+	Baa1
Senior Unsecured Debentures due 2025 (PG&E GTN)	BBB+	Baa1
Medium-Term Notes (nonrecourse) (PG&E GTN)	BBB+	Baa1
Outstanding Credit Facilities	Various	Various
Term Loans-Gen Holdings I LLC	BBB-	Baa3
Mortgage Loans and Others	Not Rated	Not Rated

PG&E NEG

The PG&E Energy and PG&E Pipeline business segments require substantial amounts of liquidity and capital resources to support construction, working capital, and counterparty credit requirements. PG&E NEG's strategy has been to finance PG&E NEG operations using a combination of funds from operations, equity, long-term debt (secured directly by those assets without recourse to other entities), long-term corporate borrowings in the capital markets, and short and medium term bank facilities that provide working capital, letters of credit and other liquidity needs. PG&E NEG's credit ratings have been important to PG&E NEG's ability to provide counterparty guarantees and to obtain capital.

On July 31, 2002, S&P downgraded PG&E NEG to BB+ from BBB. On the same date S&P downgraded PG&E ET to BB+ from BBB+, PG&E GTN to BBB+ from A-, PG&E Gen to BB+ from BBB, and USGenNE to BB+ from BBB-. All of the rated companies have also been placed on CreditWatch with negative implications. In April 2002, Moody's affirmed PG&E NEG's Baa2 rating, but changed the outlook for PG&E NEG to negative from stable. The downgrade of PG&E NEG's credit ratings impacts certain guarantees and financial arrangements that require PG&E NEG to maintain certain credit ratings from S&P and/or Moody's. These provisions are referred to as "ratings triggers." Generally, the ratings triggers are linked to one or more investment grade ratings. PG&E NEG's counterparties generally hold guarantees from PG&E NEG or a rated subsidiary of PG&E NEG, usually PG&E ET or PG&E GTN.

In addition to agreements containing ratings triggers, other agreements allow counterparties to seek additional security for performance whenever such counterparty becomes concerned about PG&E NEG's or its subsidiaries' creditworthiness. The downgrades could give rise to such concerns. As a result of the rating triggers or other demand for security, PG&E NEG may be required to provide additional collateral in the form of cash, letters of credit or replacement guarantees or to fund obligations in advance of their expected schedules. The amount of this additional security or funding varies depending upon PG&E NEG's current exposure under its agreements and the reactions to the downgrades of counterparties holding PG&E NEG's guarantees. This funding or provision of additional collateral may significantly deplete or exceed PG&E NEG's liquidity resources.

Ratings triggers and additional security obligations are generally a feature of five categories of PG&E NEG agreements: (1) trading and non-trading hedging agreements and related guarantees, (2) tolling agreement guarantees, (3) debt repayment or equity commitments in connection with asset-specific debt arrangements, (4) guarantees related to other obligations by PG&E NEG companies to counterparties for goods or services, and (5) other contractual commitments to third parties.

Trading and non-trading hedging guarantees- PG&E NEG and its rated subsidiaries have provided $2.9 billion of guarantees to approximately 250 counterparties in support of its energy trading and non-trading hedging operations. Typically, the overall exposure under these guarantees is only a fraction of the face value of these guarantees, since not all counterparty credit limits are fully utilized at any time. As of July 31, 2002, PG&E NEG and its rated subsidiaries' aggregate exposure under these guarantees was approximately $360 million. Of this exposure, the amounts subject to securitization requirements as a result of a downgrade to below investment grade of PG&E NEG by S&P are $115 million; of PG&E ET are $16 million; and of USGenNE are $1 million. In addition, $37 million of this exposure is under guarantees that have been issued by PG&E GTN with a ratings trigger. However, the ratings trigger for PG&E GTN is not affected by S&P's actions on July 31, 2002. The remaining $191 million could be subject to securitization requirements due to a counterparty's concern with PG&E NEG's or its subsidiary's creditworthiness. As of July 31, 2002, PG&E ET had sufficient cash to cover these obligations.

Equity Commitments and Debt Repayment Guarantees- PG&E NEG has guaranteed debt or equity commitments in connection with the following (in millions):

Lake Road	$	230
La Paloma		379
Equipment Revolving Credit Facility		230
GenHoldings I		505

PG&E NEG has replaced the ratings triggers in these facilities with financial covenants that are consistent with those contained in PG&E NEG's revolving credit and other loan facilities. These covenants include requirements to exceed a specified cash flow to fixed charges ratio and a specified net worth as well as maintain less than a specified total debt to total capitalization ratio and are set forth in PG&E NEG's revolving credit agreement filed as Exhibit 10.21 to PG&E NEG's Annual Report on Form 10-K filed with the SEC on March 5, 2002. PG&E NEG is in compliance with these covenants.

Not withstanding the above, if PG&E NEG is also downgraded to below investment grade by Moody's, PG&E NEG would be required to fund construction draws under the GenHoldings I financing entirely with equity until the equity commitment is fulfilled. This would result in PG&E NEG being obligated to fund approximately $270 million of additional equity through December 2002 that would have otherwise been funded through June 2003. After December 2002, the lenders would fund the construction draws pursuant to the credit agreement. Failure by PG&E NEG to fund any required equity would result in a default under the GenHoldings I credit facility as well as a default under PG&E NEG's revolving credit facility.

Tolling arrangement - PG&E NEG has entered into five long-term tolling transactions with third parties. Each tolling agreement is supported by a separate guarantee backing the payment obligations of the PG&E NEG affiliate over the term of these long-term contracts (9-25 years). PG&E NEG or its rated subsidiaries has extended approximately $620 million of such guarantees. Of these guarantees, $575 million have been issued by PG&E NEG and contain a ratings trigger that requires PG&E NEG to replace the guarantee or provide alternative collateral as a result of its credit rating dropping below BBB or Baa2. This amount increases by an additional $20 million if PG&E NEG's credit rating is also downgraded to below investment grade by Moody's. In addition, $24 million of these guarantees have been issued by PG&E GTN with a ratings trigger. However, the ratings trigger for PG&E GTN is not affected by S&P's actions on July 31, 2002. The ratings downgrade by S&P on July 31, 2002, has triggered the need for additional guarantees, alternative collateral or other acceptable arrangements under these agreements within a ten to 30 day cure period. In the event that PG&E NEG does not replace the guarantee, provide alternative collateral or agree on other acceptable arrangements as required, the counterparty has the right to terminate the related tolling agreement and seek recovery of damages to be determined in arbitration. It is not known whether the counterparties to the tolling agreement would exercise their rights to terminate the agreements. If a party did exercise its right to terminate a tolling agreement, the agreements generally provide that any damages are to be awarded based upon the difference in the contract price for the power under the agreement and the market price for the power, estimated by PG&E NEG to be $20 million under current conditions. In the event of a dispute over the amount of any termination payment that the parties are unable to resolve by negotiation, the tolling agreements provide for mandatory arbitration, which could take as long as six months to more than a year to complete, depending on the specific procedures detailed in the tolling agreements .

Other Guarantees - PG&E NEG has provided approximately $1.3 billion of guarantees related to other obligations by PG&E NEG companies to counterparties for goods or services. Of this $1.3 billion, the amount subject to securitization requirements as a result of a downgrade to below investment grade of PG&E NEG is $770 million and PG&E Gen is $9 million. The most significant of these guarantees relate to performance under certain construction and equipment procurement contracts. In the event PG&E NEG is unable to provide the additional or replacement security required in the event of such a downgrade, the counterparty providing the goods or services could suspend performance or terminate the underlying agreement and seek recovery of damages.

These guarantees represent guarantees of subsidiary obligations for transactions entered into in the ordinary course of business. The first is for guarantees related to the construction or development of PG&E NEG's power plants and pipelines. Specifically, these include guarantees for the performance of the contractor building the Harquahala and Covert power projects amounting to $545 million. Any exposure under the guarantees for construction completion is mitigated by guarantees in favor of PG&E NEG from the constructor and equipment vendors related to performance, schedule and cost. Since the constructor and various equipment vendors are performing under their underlying contracts, PG&E NEG does not believe that it has significant exposure under these guarantees. Further, although these guarantees contain ratings triggers, the same lenders who are the beneficiaries of these guarantees are the funding banks for GenHoldings I.

PG&E NEG has provided $343 million in guarantees in favor of the various contractors and equipment vendors for the payment of any cancellation penalties in the event that projects or equipment contracts are cancelled and there remain unpaid amounts. Of this amount, approximately $58 million will be paid to these vendors for cancellation of equipment contracts. In the event that these vendors seek to terminate the contracts sooner, this amount would also represent PG&E NEG's maximum exposure. Included in the above amount is $100 million of guarantees to the constructor of the Harquahala and Covert projects to cover certain separate cost-sharing arrangements. Failure to fund a demand for collateralization would permit the constructor to terminate those separate cost sharing arrangements. This would not have an impact on the constructors' obligations to complete the Harquahala and Covert projects pursuant to the contracts. Therefore, this would not have a financial impact on PG&E NEG or its subsidiaries.

PG&E NEG has provided a $300 million guarantee to support a tolling agreement that a wholly owned subsidiary, Attala Energy Company, has entered into with Attala Generating Company. Attala Generating Company entered into a $340 million sale-lease back transaction. The tolling payments provide the lessee with sufficient cash flows to pay rent under the lease. So long as Attala Energy Company continues to perform under the tolling agreement PG&E NEG does not believe it has any incremental liability or exposure under this guarantee.

The balance of the guarantees are for commitments undertaken by PG&E NEG or subsidiaries in the ordinary course of business for services such as facility and equipment leases, pipe capacity, ash disposal rights, and surety bonds.

Other Commitments- There is a total of $149 million in potential additional liquidity requirements related to other commitments.

In addition to the $360 million in trading exposure that is covered by guarantees and addressed above, there is an additional $73 million of current exposure under trading agreements at July 31, 2002. Some portion of this exposure is related to agreements that contain subjective language requiring additional securitization.

The remaining commitments included in the $149 million, are up to $16 million of surety bonds outstanding on behalf of the PG&E NEG that may need to be replaced; transportation and storage agreement tariff provisions that may require an additional $38 million in security; incremental security to power pools that could be as much as $11 million, and; miscellaneous guarantees for land options and other contracts of $11 million.

Liquidity Resources

The summary above identifies the potential demands on PG&E NEG's liquidity as a result of S&P's actions taken on July 31, 2002. As noted above, only the GenHoldings I equity commitment and one additional tolling agreement guarantee will be further impacted if Moody's reduces PG&E NEG's credit rating to below investment grade. The actual calls on PG&E NEG's liquidity will depend largely upon counterparties' reactions to the downgrade, the continued performance of PG&E NEG companies under the underlying agreements and the counterparties' other commercial considerations. PG&E NEG has reviewed its anticipated sources and uses of liquidity in light of the impact of the S&P downgrade and current market conditions. The following table provides an estimate of PG&E NEG's potential sources and uses of cash for the next twelve months and is based upon the assumptions regarding exposure and negotiations with and payments to counterparties and calls on PG&E NEG's liquidity set forth above (in millions):

Potential sources of cash	
Cash on hand, July 31, 2002	$ 728
Estimated operating cash flow (1)	500
Financings	
Available capacity under two-year $500 million revolver	310
Available capacity under one-year $750 million revolver to be renewed August 22, 2002 (2)	319
Available capacity under USGenNE $100 million credit facility	22
Available capacity under PG&E GTN $125 million facility (3)	125
Available capacity under other facilities with $120 million capacity	20
Facility financing on GenHoldings I for construction costs (4)	266
Refinancing of Lake Road/La Paloma required by March 31, 2003	609
Other non-recourse financings in progress (5)	125
Other sources of cash	65
Total potential sources of cash	3,089
Potential uses of cash	
Operating and debt service cost	141
Capital requirements for current construction program	910

Payment for equipment termination and repayment of equipment revolver	126
Potential collateral requirements for asset business (6)	76
Maximum cash collateral requirements on trading (7)	323
Lake Road/La Paloma loan maturity	609
Total potential uses of cash	2,185
Net potential surplus liquidity	$ 904

(1) Distributions and dividends from PG&E NEG subsidiaries.

(2) One year revolver facility due for renewal on August 22, 2002: $431 million outstanding at July 31, 2002.

(3) PG&E GTN debt capacity is only available for affiliated entities to the extent PG&E NEG can meet certain ringfencing restrictions.

(4) Five year facility, net of letters of credit and working capital to support underlying projects.

(5) Non-recourse financing for operating projects with cash to be available to PG&E NEG under current conditions.

(6) Covers pipeline transport, gas storage, and power pool collateral requirements.

(7) Exposure for all trading agreements having financial covenants for subinvestment grade entities.

PG&E NEG cannot predict with certainty the actual calls on PG&E NEG's liquidity. In the past, PG&E NEG has been able to negotiate acceptable arrangements and reduce its overall exposure to counterparties when PG&E NEG or its counterparties have faced similar situations. However, there can be no assurance that PG&E NEG could negotiate acceptable arrangements in the current circumstances.

As the table above indicates, as of July 31, 2002, PG&E NEG had $728 million in unrestricted cash and $796 million of unused credit lines and letter of credit facilities. Certain of PG&E NEG's financing instruments are due to mature in the near future. PG&E NEG is currently seeking bank commitments to renew $750 million of revolving credit that expires on August 22, 2002. As of July 31, 2002, PG&E NEG had $431 million outstanding under this facility. PG&E NEG is seeking to replace this short-term facility with a $750 million credit facility containing a $500 million two-year tranche and a $250 million 364-day tranche. In addition, PG&E NEG is seeking to refinance $609 million of debt guaranteed by PG&E NEG in connection with the Lake Road and La Paloma facilities that matures on March 31, 2003. PG&E NEG may be unable to obtain commitments for substantial portions of these financings. If PG&E NEG is unable to do so or otherwise effect acceptable arrangements, PG&E NEG's liquidity position will be materially and adversely impacted, and PG&E NEG may be unable to satisfy demands on its liquidity.

As described above, the downgrade of PG&E NEG's credit ratings impacts certain PG&E NEG's guarantees and financial arrangements that require PG&E NEG to maintain certain credit ratings from S&P and/or Moody's. With respect to certain guarantees issued by PG&E NEG and its affiliates to project lenders and tolling counterparties, the downgrade of PG&E NEG's credit rating to below investment grade by S&P triggers a requirement that PG&E NEG replace the guarantees or provide alternative collateral within a 10 to 30 day cure period. The failure of PG&E NEG to do so would entitle the holders of the guarantees to demand payment of the guaranteed amounts, or, in the case of tolling counterparties, to terminate the tolling agreements and seek damage payments to be determined by arbitration. To the extent that PG&E NEG's lenders or counterparties have the right to make such demands on PG&E NEG in an aggregate amount of $100 million or more, this would constitute an event of default under PG&E Corporation's New Credit Agreement with respect to the aggregate $1.02 billion in Tranche A and Tranche B loans outstanding thereunder, as discussed in Note 4 of the Notes to the Consolidated Financial Statements.

Subject to their respective rights as set forth in the Intercreditor and Subordination Agreement, dated as of June 25, 2002, by and between the Tranche A lenders, Tranche B lenders and certain other parties thereto (the Intercreditor Agreement), the Tranche A and Tranche B Lenders (collectively, the Lenders) would, upon notice within three days of the triggering event, have the right to declare all amounts outstanding under the New Credit Agreement to be immediately due and payable. The failure of PG&E Corporation to repay this accelerated indebtedness would entitle the Lenders, subject to the Intercreditor Agreement, to exercise certain remedies, including their rights as secured parties against their collateral, i.e., the pledged interests of PG&E Corporation in NEG, Inc., NEG LLC's pledged interests in NEG Inc., and a pledged interest in an interest reserve account with a current balance of approximately $65 million.

In the event that Moody's also downgrades PG&E NEG to below investment grade, the dual downgrade would trigger an event of default under the New Credit Agreement. The occurrence of this default would also entitle the Lenders to exercise the remedies described in the foregoing paragraph.

Further, loss of PG&E NEG's investment grade credit ratings may prevent it from obtaining financing necessary for the funding of various project-related equity commitments. A failure to fund equity commitments in an aggregate amount of $100 million or more would also cause a cross default to the PG&E Corporation New Credit Agreement.

With respect to the $280 million aggregate principal amount of 7.5% Convertible Subordinated Notes issued by PG&E Corporation pursuant to an Indenture dated as of June 25, 2002 by and between PG&E Corporation and U.S. Bank, N.A., as trustee (the Notes), if PG&E Corporation fails to pay the accelerated obligations under the New Credit Agreement as described above and such failure continues for 30 days after receipt of written notice from the trustee or holders of at least 25 percent of the aggregate principal amount of outstanding Notes, the Notes would also be in default. Thereupon, and subject to the subordination provisions of the Indenture, the trustee or the Note holders would have the right to accelerate the Notes.

If PG&E Corporation's debt obligations become subject to acceleration as described above, PG&E Corporation would attempt to negotiate this situation with its Lenders and Note holders; however, PG&E Corporation cannot predict whether, or to what extent, it would be successful in such efforts. Current PG&E Corporation cash balances are insufficient to repay the full amount of its outstanding debt.

PG&E Corporation

Operating Activities

Net cash provided by operating activities totaled $394 million and $2,852 million for the six months ended June 30, 2002, and 2001, respectively. The decrease of $2,458 million between 2002 and 2001 was partially due to the $1.1 billion income tax refund received in the six months ended June 30, 2001, with no such refund received in 2002. In 2002, PG&E NEG recorded a loss on impairment of assets of $265 million. In addition, the Utility made payments in satisfaction of certain obligations classified as liabilities subject to compromise in the six months ended June 30, 2002.

Investing Activities

Net cash used in investing activities was $1.3 billion and $1.2 billion for the six months ended June 30, 2002, and 2001, respectively. The increase of approximately $.1 billion between 2002 and 2001 was primarily due to increased capital expenditures in 2002 for improvement of the Utility's electric and gas transmission and distribution networks, along with construction on PG&E NEG's generation facilities and pipelines. Offsetting this increase in capital expenditures were proceeds of $340 million received from a sales/leaseback and a decrease in PG&E NEG's development costs and turbine prepayments in 2002.

Financing Activities

Cash generated through financing activities was $540 million and $289 million for the six months ended June 30, 2002, and 2001, respectively. Activity for 2002 resulted from the Utility's repayment of long-term debt, offset by PG&E NEG's increased borrowings under new and existing credit facilities and the proceeds that PG&E Corporation received from the refinancing of its Old Credit Agreement. See Note 4 of the Notes to the Consolidated Financial Statements for more information on PG&E NEG's new credit facilities and PG&E Corporation's refinancing of its Old Credit Agreement. A loan by PG&E Corporation in 2001 netted $906 million in proceeds, which was used with cash on hand to repay defaulted commercial paper, other loans, and dividends. In addition, the Utility and PG&E NEG paid down long-term balances in 2001.

Utility

The Utility is currently operating as a debtor-in-possession under Chapter 11 of the Bankruptcy Code. While certain pre-petition debts are stayed, the Utility does not have access to external funding from the capital markets. Additionally, the Utility is in default under its credit facilities, commercial paper, floating rate notes, senior notes, pollution control reimbursement agreements, and medium-term notes resulting from its failure to pay certain of its obligations. The event of default under each security has been stayed in accordance with the bankruptcy proceedings. The Utility has been making the capital investment in its infrastructure out of cash on hand under supervision of the Bankruptcy Court. It is uncertain whether the Utility will be able to continue to make such necessary capital investment in the future. See Note 2 of the Notes to the Consolidated Financial Statements for a discussion of the Chapter 11 bankruptcy filing.

On March 27, 2002, the Bankruptcy Court issued an order authorizing the Utility to pay pre- and post-petition interest to holders of certain undisputed claims, including commercial paper, senior notes, floating rate notes, medium-term notes, Cumulative Quarterly Income Preferred Securities (QUIPS), prior bond claims, revolving line of credit claims, trade creditors, and certain other general unsecured creditors. Pursuant to the court's order, the Utility was required to make an initial payment of pre- and post-petition interest to holders of financial debt (excluding trade creditors and certain other general unsecured creditors) within 10 business days after the Bankruptcy Court approval of the disclosure statement related to the Utility's proposed Plan of Reorganization. The Bankruptcy Court approved the disclosure statement on April 24, 2002.

In the second quarter of 2002, the Utility paid approximately $460 million in pre- and post-petition interest related to these claims. An interest payment of $102 million also was made to holders of financial debt on July 1, 2002, for interest accrued through June 30, 2002. Interest payments will be made on a quarterly basis in the future, on October 1, January 1, April 1, and July 1, of each year. The Utility also repaid advances and interest on advances of $21 million to banks providing letters of credit backing pollution control bonds, which repayment was separately authorized by the Bankruptcy Court.

The Utility estimates that payments made to the creditors pursuant to the Bankruptcy Court's authorization could be as much as approximately $700 million through the third quarter of 2002 based on the claim amounts estimated in the Utility's disclosure statement; however, the Utility has withheld approximately $150 million of this amount because it disputes the underlying claims and will not pay interest on these disputed claims until the disputes are resolved. The actual amount of pre- and post-petition interest eventually paid may be different, depending on the amount of claims ultimately allowed by the Bankruptcy Court.

As the Utility has been accruing interest on its pre- and post-petition debt at the approved rates, the payment of such interest ~~is not expected to~~ have an adverse material impact on its financial condition or results of operation.

Additionally, since January 2002, the Utility has entered into agreements with additional QFs to assume their power purchase agreements, which also contained the same interest and payment terms contained in the supplemental agreements described above. At June 30, 2002, $474 million and $55 million in principal and interest, respectively, have been paid to the QFs.

As of June 30, 2002, the Utility had cash and short-term investments of $3.8 billion. The Utility believes that these funds will be adequate to maintain its continuing operations through 2002.

The following section discusses the Utility's significant cash flows from operating, investing, and financing activities for the six months ended June 30, 2002, and 2001.

Operating Activities

Net cash provided by operating activities decreased to $630 million for the six months ended June 30, 2002, from $2,664 million for the same period in the prior year. The decrease is primarily due to payments made in the six months ended June 30, 2002, pursuant to Bankruptcy Court orders, which primarily consisted of principal and interest payments to QFs and interest on financial debt and other general unsecured and secured debt. See discussion of payment of liabilities subject to compromise in Note 2 of the Notes to the Consolidated Financial Statements. Additionally, the 2000 income tax refund of $1.1 billion was received in the first quarter of 2001, with no comparable refund received in the six months ended June 30, 2002.

Investing Activities

The primary uses of cash from investing activities were additions to property, plant and equipment. While the Utility is in Chapter 11, these expenditures will be funded from cash provided by operating activities. Capital expenditures were $743 million and $575 million for the six months ended June 30, 2002, and 2001, respectively, and were primarily attributable to the improvement of the distribution and transmission networks for electric and gas operations. Planned expenditures for 2002 are $1.6 billion, and mainly include projects designed to upgrade and improve the Utility's gas and electric transmission and distribution system

Financing Activities

Net cash used by financing activities in the six months ended June 30, 2002, was $475 million, reflecting mainly the repayment of long-term debt. Repayment of matured long-term debt consisted of $333 million related to mortgage bonds, pursuant to a Bankruptcy Court order, and $141 million related to the Rate Reduction Bonds, which are held by PG&E Funding LLC, a wholly owned subsidiary of the Utility.

Except as discussed in Note 2 of the Notes to the Consolidated Financial Statements, the Utility has no plans to seek external financing alternatives as a source of funding. In addition, until its financial condition is restored, the Utility is precluded from paying dividends to its shareholders. Dividends on preferred stock are cumulative. Until cumulative dividends on preferred stock are paid, the Utility may not pay any dividends on its common stock.

Net cash used by financing activities in the six months ended June 30, 2001, was $281 million, reflecting mainly the net repayment under credit facilities and short-term borrowings of $28 million and repayment of long-term debt of $252 million. Repayment of long-term debt consisted of payments of $93 million and $18 million made prior to the filing for Chapter 11 related to maturities of mortgage bonds and medium-term notes, respectively, and payments totaling $141 million related to the Utility's Rate Reduction Bonds.

Other Commitments and Contingencies

The Utility has substantial financial commitments and contingencies in connection with its operating, investing, and financing activities. See Note 6 of the Notes to the Consolidated Financial Statements for further discussion of commitments and contingencies.

PG&E NEG

Operating Activities

PG&E NEG's funds from operations come from distributions from PG&E NEG's subsidiary companies. Cash flow distributions from subsidiaries are subject to various debt covenants, organizational by-laws, and partner approvals that can restrict these entities from distributing cash to PG&E NEG unless, among other things, debt service, lease obligations, and any applicable preferred payments are current, the applicable subsidiary or project affiliate meets certain debt service coverage ratios, a majority of the participants approve the distribution, and there are no events of default. In addition, PG&E GTN and the subsidiaries that own PG&E NEG's energy trading businesses cannot pay dividends unless the subsidiary's board of directors or board of control, including its independent director, unanimously approves the dividend payment and the subsidiary has either a specified investment grade credit rating or meets a consolidated interest coverage ratio of greater than or equal to 2.25 to 1.00 and a consolidated leverage ratio of less than or equal to 0.70 to 1.00.

During the six months ended June 30, 2002, PG&E NEG generated net cash from operations of $18 million compared to net cash from operations of $34 million for the same period in 2001, or decrease of $16 million. Increases in net income including adjustments to reconcile net income to net cash provided in operations activities, improved operating cash flow by $69 million period to period. The increase from period to period was primarily due to net price risk management activities. Offsetting this increase in cash flow from operations was a decrease due to the net effect of changes in operating assets and liabilities of $85 million period to period. Included in investing activities is a cash flow of $42 million related to the long-term receivable from New England Power Company associated with the assumption of power purchase agreements. These cash flows offset cash payments made to New England Power Company, which are reflected in operating activities.

Investing Activities

PG&E NEG's cash outflows from investing activities are primarily attributable to capital expenditures on generating and pipeline assets in construction and advanced development and turbine prepayments. During the six months ended June 30, 2002, PG&E NEG used net cash of $530 million in investing activities compared to $673 million for the same period in 2001, or a decrease of $143 million. The decrease in investing activities from period to period was primarily due to proceeds from the Attala Generating Company sale/leaseback transaction providing $340 million in the second quarter of 2002. Offsetting the sale/leaseback proceeds were increased construction expenditures of $900 million for the six months ended June 30, 2002, versus $473 million for the six months ended June 30, 2001. Advanced development and turbine prepayments were $6 million and $173 million for the six months ended June 30, 2002, and 2001, respectively. Other net expenditures were $39 million and $27 million for the six months ended June 30, 2002, and 2001, respectively. To date, PG&E NEG has made a number of commitments associated with the planned growth of owned and controlled generating facilities and pipelines. These include commitments for projects under construction, commitments for the acquisition and maintenance of equipment needed for the projects under development, payment commitments for tolling arrangements, and forward sale and purchase commitments associated with PG&E NEG's energy marketing and trading activities.

Generating Projects in Construction

PG&E NEG currently owns five generating facilities under construction. The table below outlines the expected dates that these projects will be completed.

Projects	Location	Percentage Completion	Projected In-Service Date
Athens	New York	53%	3rd Quarter 2003
Covert	Michigan	41	3rd Quarter 2003
Harquahala	Arizona	45	3rd Quarter 2003

La Paloma	California	98	4th Quarter 2002
Mantua Creek	New Jersey	18	Undetermined

A local intervenor group has contested in federal court the issuance of a U.S. Army Corps of Engineers (ACOE) permit for the Athens facility alleging, among other things, that the ACOE violated the National Environmental Policy Act. The intervenor group sought preliminary and permanent injunctive relief. The court denied the preliminary relief and the intervenor group has appealed.

PG&E NEG has entered into a construction contract for the Mantua Creek project and released the contractor to perform early construction activities; however, full mobilization of the construction contractor has not taken place and unrestricted construction has been delayed. As of June 30, 2002, PG&E NEG had recorded assets of $244 million for Mantua Creek, representing equipment payments, construction activities, and development costs. The interconnection arrangements for the Mantua Creek project currently require that Mantua Creek achieve commercial operation by June 2004. PG&E NEG is seeking an extension of this deadline. If PG&E NEG is unable to obtain such an extension, PG&E NEG may be required to accelerate current construction activities and increase expenditures accordingly in order to preserve its investment in Mantua Creek. This acceleration of costs could put additional pressure on PG&E NEG's liquidity position. PG&E NEG continues to explore its options to find a partner for, or to finance or sell, the project.

PG&E NEG has executed construction contracts, excluded from above, for its Smithland and Cannelton projects for up to 163 megawatts (MW) at two hydroelectric facilities on the Ohio River in Kentucky. PG&E NEG had commenced construction of the first 16 MW of turbines for the Smithland project, but has suspended construction because recently stated seismic requirements caused a re-evaluation of the project's design in connection with the ACOE permit. PG&E NEG believes that satisfying the new seismic criteria will not require any design changes and the ACOE will concur. Pending such concurrence, PG&E NEG has not restarted construction.

Generating Projects in Development - PG&E NEG has reviewed its growth plans for its electric generating business in light of the recent changes in the energy and equity markets as well as the slowdown of the U.S. economy. Further, energy prices, electric generating industry fundamentals, and financial market's support for competitive energy companies have significantly declined, thereby constraining access to funds at acceptable terms to PG&E NEG. Over supply of electric generation in the current and near future has significantly decreased the value of planned future development projects. In response to these market changes and considering the expected level of future electric generating supply, PG&E NEG has reconsidered the extent of and reduced its planned investment activities in electric generating development projects. PG&E NEG has analyzed the potential cash flow from those projects that it no longer anticipates pursuing and has recognized an impairment of the asset value it is carrying for those development projects. The aggregate pre-tax impairment charge recorded by PG&E NEG for its development assets (excluding associated equipment costs discussed below) is $19 million. The remaining asset value (recorded in Other Non Current Assets) that PG&E NEG has retained as of June 30, 2002, for its portfolio of development projects is $48 million. PG&E NEG anticipates continuing to develop these projects to completion or for future disposal and believes that their unique characteristics provide value that will enable recovery of the capitalized costs over the useful lives of the projects. PG&E NEG has no material commitments (excluding equipment costs discussed below) for the projects under continuing development.

Turbine Purchase Commitments - To support its electric generating development program, PG&E NEG had contractual commitments and options to purchase a significant number of combustion turbines and related equipment. PG&E NEG's commitment to purchase combustion turbines and related equipment exceeds the new planned development activities discussed above. The current electric generating market is faced with an over supply of facilities in operation and in construction. The current and future market for combustion turbines and related equipment has also seen an over supply and large cancellation of turbine orders. The net realizability of PG&E NEG's investment in and future committed payments for its excess combustion turbine and related equipment portfolio, in light of current development plans, is doubtful. Based upon PG&E NEG's current development plans and analysis of future market prices for combustion turbines and related equipment, PG&E NEG has recognized a charge of $246 million. The charge consists of the impairment of previously capitalized costs associated with prior payments made under the terms of the turbine and equipment contracts in the amount of $188 million and the accrual of $58 million for future termination payments required under the turbines and related equipment contracts. Although PG&E NEG has impaired the value of these turbines and related equipment, it has not terminated its commitments or options with respect to this equipment. The remaining asset value (recorded in Other Non Current Assets) that PG&E NEG has retained as of June 30, 2002, for its investment in turbines and related equipment is approximately $33 million. These turbine and equipment commitments have been retained to support the equipment needs for PG&E NEG's current portfolio of advanced development projects discussed above. PG&E NEG and its equipment vendors have agreed to suspend any PG&E NEG payment obligations, except for $19 million, for at least the next 12 months. Thereafter, PG&E NEG must either restart equipment payments or terminate such commitments and pay the associated termination costs, if any. PG&E NEG's recorded liability reflects these termination costs.

PG&E GTN Pipeline Expansion - PG&E GTN is in the process of completing its 2002 Expansion Project, which when completed will expand its system by approximately 217 million cubic feet (MMcf) per day. Approximately 40 MMcf per day of that expansion capacity was placed in service in November 2001 and the remaining capacity is scheduled to be placed in service by the end of 2002. The total cost of the expansion is estimated to be $122 million of which $118 million has been spent through June 30, 2002. FERC has issued a preliminary determination on non-environmental matters authorizing PG&E GTN to complete a second expansion of approximately 150 MMcf per day of additional capacity, at a cost of approximately $111 million. PG&E GTN is evaluating plans for the timing of the second expansion and may defer its construction. PG&E GTN expects to fund these expansions from cash provided by operations, external financing, and capital contributions from PG&E NEG.

PG&E GTN regularly solicits expressions of interest for the acquisition or development of additional pipeline capacity and may develop additional firm transportation capacity as sufficient demand is demonstrated. PG&E GTN has also initiated a preliminary assessment of a Washington lateral pipeline that would originate at the PG&E GTN mainline system and extend to metropolitan areas in the Pacific Northwest.

North Baja Pipeline - PG&E NEG has begun construction of a new 500 MMcf per day gas pipeline, North Baja, to deliver natural gas to Northern Mexico and Southern California. The North Baja project is expected to be completed by the end of 2002. At June 30, 2002, PG&E NEG had spent approximately $100 million on this project. PG&E NEG owns all of the United States section of this cross-border project. PG&E NEG's share of the costs to develop this project will be approximately $140 million.

The California State Lands Commission is a defendant and, along with North Baja, is a real party in interest in an action brought by the County of Imperial and the City of El Centro alleging that the environmental impact report prepared for the North Baja pipeline in California failed to address environmental justice and other issues as required by the California Environmental Quality Act (CEQA). The claim seeks an injunction restraining construction of the pipeline, but no request for a temporary restraining order was filed. Therefore, construction of the project is underway. PG&E NEG intends to vigorously participate in the lawsuit. A hearing on the merits of the case is scheduled for August 30, 2002.

Financing Activities

PG&E NEG's cash outflows from financing activities were primarily attributable to increases in borrowings under PG&E NEG's credit facilities relating to the continuing completion of PG&E NEG's construction facilities and borrowings under construction financing. For the six months ended June 30, 2002, and 2001, PG&E NEG provided net cash flows from financing activities of $553 million and $702 million, respectively. This decrease is primarily related to the timing of construction funding needed for the Athens, La Paloma, Covert, and Harquahala projects.

RISK MANAGEMENT ACTIVITIES

PG&E Corporation and the Utility have established risk management policies that allow the use of energy, financial, and weather derivative instruments (a derivative is a contract whose value is dependent on or derived from the value of some underlying asset) and other instruments and agreements to be used to manage its exposure to market, credit, volumetric, regulatory, and operational risks. Such derivatives include forward contracts, futures, swaps, options, and other contracts.

- Forward contracts are commitments to purchase or sell energy commodities in the future.
- Futures contracts are standardized commitments to purchase or sell an energy commodity or financial instrument at a specific price and future date.
- Swap agreements require payments to or from counterparties for a quantity based upon the difference between agreed upon prices, at least one of which is an index.
- Option contracts provide the right to buy or sell energy or a financial instrument at a price.

PG&E Corporation uses derivatives for both trading (for profit) and non-trading purposes. Trading activities may be done for purposes of generating profit, gathering market intelligence, creating liquidity, maintaining a market presence, and taking a market view. Non-trading activities may be done for purposes of hedging the risks associated with an asset, liability, committed transaction, or probable forecasted transaction.

The activities affecting the estimated fair value of trading activities and the non-trading activities balance, included in net price risk management assets and liabilities, are presented below:

	Three Months Ended	Six Months E

(in millions)	June 30, 2002 [1]	June 30, 200:
Fair values of trading contracts at beginning of period	$ 31	$
Net gain on contracts settled during the period	34	
Changes in fair values attributable to changes in valuation techniques and assumptions	-	
Other changes in fair values	(66)	
Fair values of trading contracts outstanding at end of period	(1)	
Fair value of non-trading contracts at the end of the period	(216)	-
Net Price Risk Management Asset at end of period	$ (217)	$

[1] For the three and six months ended June 30, 2002, the fair value of all new contracts when entered into was zero.

PG&E Corporation estimated the fair value of its trading contracts at June 30, 2002, using the midpoint of quoted bid and ask prices, where available, and other valuation techniques when market data was not available (e.g., illiquid markets or products). When market data is not available, PG&E Corporation utilizes alternative pricing methodologies, including, but not limited to, third-party pricing curves, the extrapolation of forward pricing curves using historically reported data, or interpolating between existing data points. Most of PG&E Corporation's risk management models are reviewed by or purchased from third-party experts with extensive experience in specific derivative applications. The fair value of trading contracts also includes deductions for time value, credit, model, and other reserves necessary to determine fair value.

The weighted average maturity of the entire portfolio of trading contracts was approximately one year as of June 30, 2002. The following table shows the fair value of PG&E Corporation's trading contracts by maturity at June 30, 2002.

	Fair Value of Trading Contracts [2]				
Source of Prices Used in Estimating Fair Value	Maturity Less than One Year	Maturity One-Three Years	Maturity Four-Five Years	Maturity in Excess of Five Years	Total Fair Value
(in millions)					
Actively quoted markets	$ 59	$ (38)	$ (7)	$ (4)	$ 10
Provided by other external sources	-	-	(43)	66	23
Based on models and other valuation methods [1]	(21)	(29)	1	15	(34)
Total Mark-to-Market	$ 38	$ (67)	$ (49)	$ 77	$ (1)

(1) In many cases, these prices are an input into option models that calculate a gross mark-to-market value from which fair value is derived.

(2) Excludes all non-trading contracts including non-trading contracts that receive mark-to-market accounting treatment.

The amounts disclosed above are not indicative of likely future cash flows, as these positions may be impacted by changes in underlying valuations, new transactions in the trading portfolio in response to changing market conditions, market liquidity, and PG&E Corporation's risk management portfolio needs and strategies.

Market Risk

Market risk is the risk that changes in market conditions will adversely affect earnings or cash flow. Such risks include price risk, credit risk, interest rate risk, and foreign currency risk and may impact PG&E Corporation and its subsidiaries' assets and trading portfolios.

Commodity Price Risk

Commodity price risk is the risk that changes in market prices of a commodity for physical delivery will adversely affect earnings and cash flows.

Utility Electric Commodity Price Risk

In compliance with regulatory requirements, the Utility manages commodity price risk independently from the activities in PG&E Corporation's unregulated businesses. The Utility reports its commodity price risk separately for its electricity and natural gas businesses. Since January 2001, the DWR has been responsible for purchasing wholesale power for the Utility's retail electric customers on behalf of the State of California. The Utility is currently passing through revenues to the DWR based on the amount of power supplied by the DWR to cover the Utility's net open position and the per kWh rate established by the CPUC's March 21, 2002, revenue requirement decision. Future revisions to the DWR's revenue requirement as a result of, among other things, changes in the market price of electric energy, may impact the amount of revenues allocated from the Utility to the DWR. Because the Utility's electric rates are frozen, the Utility is exposed to commodity price risk as changes in the amount of revenues allocated to the DWR as pass through revenues impact the amount of remaining revenues the Utility has available to recover its generation, transmission, and distribution costs.

Under AB 1X, the DWR is prohibited from entering into new power purchase contracts and from purchasing power on the spot market after January 1, 2003. The CPUC has opened a rulemaking proceeding to consider the ratemaking mechanisms that will apply to the California IOUs' power procurement costs incurred to meet their net open position after January 1, 2003. See discussion of the Generation Procurement OIR in the Regulatory Matters section of this MD&A.

Utility Natural Gas Commodity Price Risk

Under a ratemaking method called the Core Procurement Incentive Mechanism (CPIM), the Utility recovers in retail rates the cost of procuring natural gas for its customers as long as the costs are within 99 percent to 102 percent "dead-band" of a benchmark price. The CPIM benchmark price reflects a weighting of prescribed daily and monthly gas price indices that are representative of Utility gas purchases. Ratepayers and shareholders share costs or savings outside the "dead-band" equally. In addition, the Utility has contracts for capacity on various gas pipelines. Although the Utility recovers most of the cost of the capacity contracts in retail rates, there is price risk related to the unused portions of the pipeline capacity to the extent that it is brokered at floating rates, which are reset monthly to reflect changes in commodity prices.

Under a ratemaking pact called the Gas Accord, currently scheduled to be in effect through December 2002, shareholders are at risk for any revenues from the sale of capacity on the Utility's pipelines and gas storage fields. According to the terms of the Gas Accord, a portion of the pipeline and storage capacity is sold at competitive market-based rates. The Utility is generally exposed to reduced revenues when the price spreads between two delivery points narrow. In addition, the Utility is generally exposed to reduced revenues when throughput volumes are lower than expected, primarily caused by temperature and precipitation effects or by economy-driven impacts. On October 9, 2001, the Utility filed another Gas Accord application with the CPUC requesting a two-year extension without modification to existing terms and conditions of the existing Gas Accord. In return, the Utility will maintain gas transmission and storage rates at year 2002 levels during the two-year period.

On February 26, 2002, the CPUC issued a ruling that set an expedited schedule of hearings. On May 20, 2002, on behalf of itself and a wide cross-section of parties, the Utility filed a joint motion for approval of a "Gas Accord II Settlement Agreement." If approved, the Settlement Agreement would extend terms and conditions of the existing Gas Accord for one year. The Settlement Agreement also would provide an open season for any new or relinquished Utility transmission and storage capacity for the first year of the Gas Accord II period. The Settlement Agreement would postpone until 2004 any changes that might result from litigation of issues raised by individual parties in response to the Utility's October 2001 application. On July 23, 2002, the ALJ issued a draft decision that would approve the Settlement Agreement. A decision is expected in late August 2002. The Utility cannot predict what the outcome of the final decision in this proceeding will be, or whether the outcome will have a material adverse effect on its results of operations or financial condition.

PG&E NEG Commodity Price Risk

PG&E NEG is exposed to commodity price risk for its portfolio of electric generation assets and supply contracts that serve wholesale and industrial customers, and with respect to various merchant plants currently in development and construction. PG&E NEG manages such risks using a risk management program that primarily includes the buying and selling of fixed-price commodity commitments to lock in future cash flows of its forecasted generation. PG&E NEG is also exposed to commodity price risk for net open positions within its trading portfolio due to the assessment of and response to changing market conditions.

Value-at-Risk

PG&E Corporation and the Utility measure commodity price risk exposure using value-at-risk and other methodologies that simulate future price movements in the energy markets to estimate the size and probability of future potential losses. Market risk is quantified using a variance/co-variance value-at-risk model that provides a consistent measure of risk across diverse energy markets and products. The use of this methodology requires a number of important assumptions, including the selection of a confidence level for losses, volatility of prices, market liquidity, and a holding period.

PG&E Corporation uses historical data for calculating the price volatility of its contractual positions and how likely the prices of those positions will move together. The model includes all derivatives and commodity instruments over the entire length of the terms of the transaction in the trading and non-trading portfolios. PG&E Corporation and the Utility express value-at-risk as a dollar amount of the potential loss in the fair value of their portfolios based on a 95 percent confidence level using a one-day holding period. Therefore, there is a 5 percent probability that PG&E Corporation and its subsidiaries' portfolios will incur a loss in one day greater than their value-at-risk. For example, if the value-at-risk is calculated at $5 million, there is a 95 percent confidence level that if prices moved against current positions, the reduction in the value of the portfolio resulting from such one-day price movements would not exceed $5 million.

The following table illustrates the daily value-at-risk exposure for commodity price risk at June 30, 2002.

(in millions)	
Utility	
Non-Trading Activities (1)	$ 3.5
PG&E NEG	
Trading Activities	3.8
Non-Trading Activities:	
Non-Trading Contracts that Receive Mark-to-Market Accounting Treatment (2)	3.9
Non-Trading Contracts Accounted for as Hedges (3)	13.9

(1) Includes the Utility's gas portfolio only.

(2) Includes derivative power and fuels contracts that do not qualify to be accounted for as cash flow hedges, due to certain pricing provisions, or exempted from SFAS No. 133 as normal purchases and sales.

(3) Includes only the risk related to the financial instruments that serve as hedges and does not include the related underlying hedged item.

Value-at-risk has several limitations as a measure of portfolio risk, including, but not limited to, underestimation of the risk of a portfolio with significant options exposure, inadequate indication of the exposure of a portfolio to extreme price movements, and the inability to address the risk resulting from intra-day trading activities. Value-at-risk also does not reflect the significant regulatory, legislative, and legal risks currently facing the Utility or the risks relating to the Utility's bankruptcy proceedings.

Interest Rate Risk

Interest rate risk is the risk that changes in interest rates could adversely affect earnings and cash flows. Specific interest rate risks for PG&E Corporation and the Utility include the risk of increasing interest rates on short-term and long-term debt, the risk of decreasing rates on floating rate assets which have been financed with fixed rate debt, the risk of increasing interest rates for planned new fixed long-term financings, and the risk of increasing interest rates for planned refinancing using long-term fixed rate debt. In addition, the Utility is exposed to changes in interest rates on interest accruing on loan payments and trade payables currently in default.

PG&E Corporation uses the following interest rate instruments to manage its interest rate exposure: interest rate swaps, interest rate caps, floors, or collars, swaptions, or interest rate forward and futures contracts. Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At June 30, 2002, if interest rates change by 1 percent for all variable rate debt at PG&E Corporation and the Utility, the change would affect net income by approximately $30 million and $29 million, respectively, based on variable rate debt and derivatives and other interest rate sensitive instruments outstanding.

Foreign Currency Risk

Foreign currency risk is the risk of changes in value of pending financial obligations in foreign currencies that could occur prior to the settlement of the obligation due to a change in the value of that foreign currency in relation to the U.S. dollar. The Utility and PG&E Corporation are exposed to foreign currency risk associated with foreign currency exchange variations related to Canadian denominated purchase and swap agreements. However, for the Utility changes in gas purchase costs due to fluctuations in the value of the Canadian dollar would be passed through to customers in rates. In addition, PG&E Corporation has translation exposure resulting from the need to translate Canadian-denominated financial statements of its affiliate PG&E Energy Trading Canada Corporation into U.S. dollars for PG&E NEG's Consolidated Financial Statements. PG&E Corporation and the Utility use forwards, swaps, and options to hedge foreign currency exposure.

PG&E Corporation and the Utility use sensitivity analysis to measure their foreign currency exchange rate exposure to the Canadian dollar. Based on a sensitivity analysis at June 30, 2002, a 10 percent devaluation of the Canadian dollar would be immaterial to PG&E Corporation's and the Utility's Consolidated Financial Statements.

Credit Risk

Credit risk is the risk of loss that PG&E Corporation and the Utility would incur if counterparties fail to perform their contractual obligations (accounts receivable, notes receivable and price risk management assets reflected on the balance sheet). PG&E Corporation and the Utility conduct business primarily with customers in the energy industry, and this concentration of counterparties may impact the overall exposure to credit risk in that its counterparties may be similarly affected by changes in economic, regulatory, or other conditions. PG&E Corporation and the Utility manage credit risk pursuant to their Risk Management Policies, which provide processes by which counterparties are assigned credit limits in advance of entering into significant exposure. These procedures include an evaluation of a potential counterparty's financial condition, net worth, credit rating, and other credit criteria as deemed appropriate, and are performed at least annually. Credit exposure is calculated daily and, in the event that exposure exceeds the established limits, PG&E Corporation and the Utility take immediate action to reduce exposure and/or obtain additional collateral. Further, PG&E Corporation and the Utility rely heavily on master agreements that allow for the netting of positive and negative exposures associated with a counterparty, under certain circumstances.

At June 30, 2002, PG&E Corporation had no single counterparty that represented greater than 10 percent of PG&E Corporation's net credit exposure. At June 30, 2002, the Utility had two investment grade counterparties and one below investment grade counterparty that each represented greater than 10 percent of the Utility's net credit exposure.

The schedule below summarizes the exposure to counterparties that are in a net asset position, with the exception of exchange-traded futures (the exchange provides for contract settlement on a daily basis), at June 30, 2002:

(in millions)	Gross Exposure (1)	Credit Collateral (2)	Net Exposure (2)
PG&E Corporation	$ 1,084	$ 183	$ 901
Utility (3)	143	101	42

(1) Gross credit exposure equals fair value (adjusted for appropriate credit reserves), notes receivable, and net receivables (payables) where netting is allowed.

(2) Net exposure is the gross exposure minus credit collateral (cash deposits and letters of credit).

(3) The Utility's gross exposure includes wholesale activity only. Retail activity and payables prior to the Utility's bankruptcy filing are not included. Retail activity at the Utility consists of the accounts receivable from the sale of gas and electricity to residential and small commercial customers. Reserves for uncollectible accounts receivable from these customers exist and are based on their historical experience of nonpayment.

At June 30, 2002, approximately $121 million or 13 percent of PG&E Corporation's net credit exposure is to entities that have credit ratings below investment grade. Approximately $17 million or 41 percent of the Utility's net credit exposure is to below investment grade entities. Investment grade is determined using publicly available information, including S&P's rating of at least BBB-. Approximately $206 million or 23 percent of PG&E Corporation's net credit exposure at PG&E NEG is not rated. Subsequent to June 30, 2002, the credit ratings of two large counterparties (Williams Companies, Inc. and Dynegy Holdings, Inc.) were reduced to below investment grade. At June 30, 2002, PG&E Corporation's and the Utility's net exposure to these companies was $36 million and $2 million, respectively. By July 29, 2002, the net exposure to these companies was reduced to less than $1 million for both PG&E Corporation and the Utility. PG&E Corporation has regional concentrations of credit exposure to counterparties that conduct business primarily in the western United States and also to counterparties that conduct business primarily throughout North America. In addition to the Utility's concentration of credit risk due to receivables from residential and small commercial customers in northern California, the Utility has a net regional concentration of credit exposure totaling $42 million to counterparties that conduct business primarily throughout North America.

RESULTS OF OPERATIONS

The following table shows for the three months and six months ended June 30, 2002 and 2001, certain items from the accompanying Consolidated Statements of Operations detailed by Utility and PG&E NEG operations of PG&E Corporation. (In the "Total" column, the table shows the combined results of operations for those items.) The information for PG&E Corporation (the "Total" column) includes the appropriate intercompany elimination. Results of operations are discussed following this table.

		PG&E National Energy Group					
(in millions)	Utility	Total PG&E NEG	Integrated Energy & Marketing	Interstate Pipeline Operations	PG&E NEG Eliminations	PG&E Corporation & Other Eliminations (1)	Total
Three months ended June 30, 2002							
Operating revenues	$ 2,714	$ 3,060	$ 3,011	$ 54	$ (5)	$ (22)	$ 5,752
Operating expenses	1,655	3,340	3,320	25	(5)	(17)	4,978
Operating income (loss)	1,059	(280)	(309)	29	-	(5)	774
Interest income							43
Interest expense							(361)
Other income (expenses), net							(21)
Income taxes							156
Income from continuing operations							279
Net income							218
Net cash used by operating activities							(837)
Net cash used by investing activities							(518)

Net cash provided by financing activities							668
EBITDA (2)	1,346	(245)	(285)	44	(4)	(12)	1,089
Three months ended June 30, 2001							
Operating revenues	2,309	2,753	2,676	64	13	(52)	5,010
Operating expenses	973	2,628	2,595	25	8	(38)	3,563
Operating income (loss)	1,336	125	81	39	5	(14)	1,447
Interest income							74
Interest expense							(312)
Other income (expenses), net							4
Income taxes							463
Income from continuing operations							750
Net income							750
Net cash provided by operating activities							

ATTACHMENT G

November 30, 2001

PG&E Letter DCL-01-119

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Power Plant, Units 1 and 2
Application for License Transfers and Conforming Administrative License Amendments

Dear Commissioners and Staff:

Pursuant to Section 184 of the Atomic Energy Act and 10 CFR 50.80, Pacific Gas and Electric Company (PG&E) herein requests Nuclear Regulatory Commission (NRC) consent to the transfer of the NRC operating licenses for the Diablo Canyon Power Plant, Units 1 and 2 (DCPP). PG&E is requesting these transfers in connection with a comprehensive Plan of Reorganization (Plan) for PG&E filed under Chapter 11 of the United States Bankruptcy Code.

On April 6, 2001, PG&E filed a Chapter 11 petition for relief. PG&E's goal was to halt the deterioration of its financial position, restore the company to financial health, and continue supplying electricity and gas in the normal course of business. On September 20, 2001, PG&E filed with the Bankruptcy Court the comprehensive Plan and Disclosure Statement. Under the Plan, operating authority for DCPP will be transferred to a new generating company named Electric Generation LLC (Gen) and ownership of the two-unit generating asset will be assigned to a wholly-owned subsidiary of Gen named Diablo Canyon LLC (Nuclear).

PG&E also requests, pursuant to 10 CFR 50.90, conforming amendments to the two facility operating licenses. Gen would become the licensee authorized to possess, use, and operate the units and Nuclear would be licensed only to possess (own) the plant. The enclosed application includes mark-ups of the facility operating licenses to reflect the conforming license amendments associated with the proposed transfers.

As discussed in this application, the Plan involves a complete restructuring of PG&E's businesses and operations. Through the proposed restructuring, PG&E anticipates that value realized will provide necessary cash and increased debt capacity to enable it to repay creditors, restructure existing debt, and emerge from the Chapter 11 bankruptcy case. PG&E anticipates that the restructuring will create new businesses, including Gen, that will be financially sound going forward.

Pursuant to the Plan, PG&E will disaggregate and restructure its current businesses and divide its operations and assets among four separate operating companies. PG&E will contribute certain assets to each of the entities. The majority of the assets and liabilities associated with the current electric transmission business of PG&E will be contributed to ETrans LLC (ETrans); the majority of PG&E's gas transmission assets and liabilities will be contributed to GTrans LLC (GTrans); and the majority of the assets and liabilities associated with the current generation business of PG&E, including DCPP, will be contributed to Gen or its subsidiaries. In addition, PG&E has created a separate corporation called Newco Energy Corporation (Newco) to hold the membership interests of each of ETrans, GTrans and Gen. PG&E is the sole shareholder of Newco. After the assets and liabilities are transferred to the newly-formed entities, PG&E will declare and pay a dividend of the outstanding common stock of Newco to PG&E Corporation (PG&E's parent corporation), and each of ETrans, GTrans and Gen will thereafter be an indirect wholly-owned subsidiary of PG&E Corporation, which will change its name.

PG&E has also created subsidiaries of Gen to hold specific assets and project-specific liabilities. For example, Nuclear is a subsidiary of Gen created to hold the ownership interest in DCPP. In addition to DCPP, PG&E will transfer to Nuclear the beneficial interest in the Nuclear Decommissioning Trust associated with DCPP. Gen will lease DCPP from Nuclear and operate DCPP.

While certain other assets will be sold and some assets not needed in the utility businesses may be transferred to one or more special purpose entities, the remaining assets will be retained by PG&E. PG&E, as a reorganized company, will continue to conduct local electric and gas distribution operations and associated customer services. Upon consummation of the disaggregation of PG&E's businesses as described above, PG&E Corporation will declare a dividend and distribute the common stock of PG&E to its public shareholders, separating PG&E from PG&E Corporation.[1]

In connection with the proposed restructuring and the transfer of the DCPP assets, no physical changes will be made to DCPP and there will be no significant changes to management of the nuclear station (including to the key management employees currently responsible for operation of DCPP). The existing onsite nuclear organizations at DCPP will be transferred to Gen and the current nuclear personnel will become employees of Gen and continue to operate the plant. Operation will continue to be in accordance with the terms and conditions of the present licenses and in accordance with the present licensing bases.

[1] Reorganized PG&E will retain ownership of and responsibility for the shutdown Humboldt Bay Power Plant, Unit 3. By separate application, PG&E is seeking NRC approval, if necessary, of an indirect transfer of the NRC license for Humboldt Bay Power Plant, Unit 3.

Additional information pertaining to the proposed license transfers and administrative license amendments is included in the enclosed application and supporting attachments. This information demonstrates that: (1) the reorganization and license transfers will not adversely impact the operation of DCPP or adversely impact the managerial or technical qualifications of the licensed operator; (2) the licensees will be financially qualified to own, operate, and maintain the units; (3) the provisions of the Plan related to transfer of the beneficial interest in the Nuclear Decommissioning Trust assure that there will be no adverse impact on the existing assurance of adequate decommissioning funding for DCPP; and (4) the license transfers will not result in foreign ownership, control, or domination over the licensee.

Additionally, under the proposed license amendments, provisions are made for continuing the existing antitrust operating license conditions such that no further antitrust review is required in connection with the proposed license transfers.

With regard to the conforming amendments to the licenses, these changes fall within the NRC's generic finding of no significant hazards considerations under 10 CFR 2.1315(a). Information supporting categorical exclusion from environmental review under 10 CFR 51.22 is also provided.

PG&E is notifying the State of California of the request for conforming license amendments by transmitting a copy of this letter and application to the designated state officials.

As explained in the attached application, pursuant to the Bankruptcy Code, the Plan must be approved by the Bankruptcy Court. A number of filings, approvals, or rulings are also required or desirable at the Federal Energy Regulatory Commission, the Securities and Exchange Commission, and the Internal Revenue Service. PG&E will make the necessary filings and expects to obtain all the necessary approvals or rulings in order to effectuate the Plan by the end of 2002.

Accordingly, PG&E requests NRC consent to the license transfers and approval of the conforming administrative license amendments as promptly as possible, but no later than July 31, 2002. Such NRC consent should be immediately effective upon issuance and, consistent with NRC practice, should authorize the transfers occurring at any time through twelve months following the date of approval or such later date as may be permitted by the NRC. This schedule will allow sufficient time for other approvals needed prior to closing on the reorganization, for arrangement of financing and completion of administrative actions necessary to complete the transactions, and for contingencies. PG&E will keep the NRC informed if there are any significant changes in the status of the other required approvals or other developments that have an impact on the schedule.

This application includes Enclosure 8 that contains confidential commercial or financial information. PG&E requests that the information be withheld from public disclosure pursuant to 10 CFR 9.17(a)(4) and 10 CFR 2.790. The proprietary nature of this enclosure is described in the attached Affidavit. A non-proprietary version of Enclosure 8, suitable for public disclosure, is also provided with this application.

If you have any questions about this matter, please contact Terry Grebel at (805) 595-6382. Service upon the applicant of comments, hearing requests, intervention petitions, or other pleadings should be made to the undersigned, and to Richard F. Locke, Esq., Pacific Gas and Electric Company, 77 Beale Street, B30A, San Francisco, California 94105, and to David A. Repka, Esq., Winston & Strawn, 1400 L Street, N.W., Washington, DC 20005. Additional service should be made to Earle O'Donnell, Esq., Dewey Ballantine LLP, 1775 Pennsylvania Avenue, N.W., Washington, DC 20006.

Sincerely,

Gregory M. Rueger
Senior Vice President -
Generation and Chief Nuclear Officer

cc: Edgar Bailey, DHS (w/o enclosures)
Ellis W. Merschoff (w/proprietary enclosures)
David L. Proulx (w/proprietary enclosures)
Girija S. Shukla (w/proprietary enclosures)
Diablo Distribution (w/o enclosures)

Enclosures

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of PACIFIC GAS AND ELECTRIC COMPANY	)	Docket No. 50-275 Facility Operating License No. DPR-80
Diablo Canyon Power Plant Units 1 and 2	)	Docket No. 50-323 Facility Operating License No. DPR-82

AFFIDAVIT

I, Gregory M. Rueger, first being duly sworn, depose and say: that I am Senior Vice President - Generation and Chief Nuclear Officer of Pacific Gas and Electric Company, the licensee herein; that I have full power and authority to sign and file this Application with the Nuclear Regulatory Commission on behalf of said company; that I am familiar with the contents thereof; and that the facts stated therein are true and correct to the best of my knowledge, information, and belief.

____
Gregory M. Rueger
Senior Vice President -
Generation and Chief Nuclear Officer

Subscribed and sworn to before me, this ____ day of ________________, _____.

State of California
County of San Francisco

____
Notary Public

AFFIDAVIT OF GREGORY M. RUEGER

I, Gregory M. Rueger, am Senior Vice President Generation and Chief Nuclear Officer of Pacific Gas and Electric Company (PG&E), and do hereby affirm and state:

1. I am authorized to execute this affidavit on behalf of PG&E and PG&E's sole common shareholder, PG&E Corporation.

2. PG&E is providing information in support of its Application for License Transfers and Conforming Administrative License Amendments (NRC Facility Operating License Nos. DPR-80 and DPR-82) (Diablo Canyon Power Plant, Units 1 and 2). The information specifically being provided in Enclosure 8 includes financial projections related to the plan of reorganization for ~~PG&E~~ as filed with the United States Bankruptcy Court and related to the continued operation of Diablo Canyon Units 1 and 2. While some of the information in Enclosure 8 has been publicly disclosed in the bankruptcy proceeding, Enclosure 8 includes other proprietary commercial and financial information not previously disclosed that should be held in confidence by the NRC pursuant to the policy reflected in 10 CFR 2.790(a)(4) and 9.17(a)(4), because:

   i. This information is and has been held in confidence by PG&E and its affiliated companies.

   ii. This information is of a type that is held in confidence by PG&E and its affiliates, and there is a rational basis for doing so because the information contains sensitive financial information concerning assets, projected revenues and operating expenses.

   iii. This information is being transmitted to the NRC in confidence.

   iv. Other than the information included in the bankruptcy filing, this information is not available in public sources and could not be gathered readily from other publicly available information.

   v. Public disclosure of this information would create substantial harm to the competitive position of PG&E and its successors by disclosing internal financial projections.

AFFIDAVIT OF GREGORY M. RUEGER (Continued)

3. Accordingly, PG&E requests, on behalf of itself, PG&E Corporation, Electric Generation LLC, and Diablo Canyon LLC, that the designated information be withheld from public disclosure pursuant to the policy reflected in 10 CFR 2.790(a)(4) and 9.17(a)(4).

____
Gregory M. Rueger
Senior Vice President –
Generation and Chief Nuclear Officer

Subscribed and sworn to before me, this ____ day of ________________, _____.

State of California
County of San Francisco

____
Notary Public

APPLICATION FOR CONSENT TO LICENSE TRANSFERS AND CONFORMING LICENSE AMENDMENTS FOR DIABLO CANYON POWER PLANT, UNITS 1 AND 2

TABLE OF CONTENTS

Application for Consent to License Transfers and Conforming License Amendments For Diablo Canyon Power Plant, Units 1 and 2

LIST OF ENCLOSURES

Enclosure 1:	Plan of Reorganization and Disclosure Statement
Enclosure 2:	Proposed Corporate Structure of PG&E Corporation and Principal Subsidiaries
Enclosure 3:	Form of Diablo Canyon Facility Lease By and Between Diablo Canyon LLC, as Lessor, and Electric Generation LLC, as Lessee
Enclosure 4:	Marked-up Pages of Operating License for Proposed Conforming Changes Related to DCPP Unit 1
Enclosure 5:	Marked-up Pages of Operating License for Proposed Conforming Changes Related to DCPP Unit 2
Enclosure 6:	No Significant Hazards Considerations Determination
Enclosure 7:	Form of Bilateral Power Sales Agreement By and Between Electric Generation LLC and Reorganized PG&E
Enclosure 8:	Financial Qualifications Information: Financial Statement and Related Information
Enclosure 9:	Decommissioning Funding Assurance: Calculation Demonstrating Adequacy of "Prepayment Amount"

Application For Consent To License Transfers And Conforming License Amendments For Diablo Canyon Power Plant, Units 1 And 2

I. Introduction/Overview

Pacific Gas and Electric Company (PG&E) submits the following information and requests, pursuant to 10 CFR 50.80, Nuclear Regulatory Commission (NRC) consent to the transfer of the operating licenses for the Diablo Canyon Power Plant, Units 1 and 2 (DCPP). This request is being made in support of a comprehensive reorganization and restructuring of the businesses and operations of PG&E, including its nuclear and non-nuclear generation, transmission, and electricity distribution businesses, as is described further below.

On April 6, 2001, PG&E filed a petition for relief under Chapter 11 of the United States Bankruptcy Code. PG&E's goal was to halt the deterioration of its financial position, restore the company to financial health, and continue supplying electricity and gas in the normal course of business. On September 20, 2001, PG&E and its parent corporation, PG&E Corporation, filed with the Bankruptcy Court a comprehensive Plan of Reorganization (Plan) for PG&E and a Disclosure Statement. Under the Plan, operating authority for DCPP will be transferred to a new limited liability company named Electric Generation LLC (Gen) and ownership of the two-unit generating asset will be assigned to a wholly-owned subsidiary of Gen named Diablo Canyon LLC (Nuclear).

This transfer request specifically relates to the transfer of the authorities to "possess, use, and operate" the facilities under the following Facility Operating Licenses:

- Diablo Canyon Unit 1 DPR- 80
- Diablo Canyon Unit 2 DPR- 82

A copy of the Plan and Disclosure Statement filed with the Bankruptcy Court is provided as Enclosure 1.[2] The proposed reorganization as it relates to PG&E and DCPP is summarized and illustrated in Enclosure 2.

In essence, under the Plan, the current businesses of PG&E will be disaggregated and restructured. PG&E will divide its operations and the assets of its business lines among four separate operating companies. The majority of the assets and liabilities associated with the current electric transmission business of PG&E will be contributed to ETrans LLC (ETrans); the majority of

2 The Plan will likely be amended from time to time in ways that are not material to this application to the NRC and PG&E expects to file an amended Plan and Disclosure Statement with the Bankruptcy Court in the future.

PG&E's gas transmission assets and liabilities will be contributed to GTrans LLC (GTrans); and the majority of the assets and liabilities associated with the current generation business, including DCPP, will be contributed to Gen or its subsidiaries. In addition, PG&E has created a separate corporation called Newco Energy Corporation (Newco) to hold the membership interests of each of ETrans, GTrans and Gen. PG&E is the sole shareholder of Newco. After the assets are transferred to the newly-formed entities, PG&E will declare and pay a dividend of the outstanding common stock of Newco to PG&E Corporation, and each of ETrans, GTrans and Gen will thereafter be an indirect wholly-owned subsidiary of PG&E Corporation. PG&E Corporation will also change its name.

PG&E, as a reorganized company, will retain most of the remaining assets and liabilities, and will continue to conduct local electric and gas distribution operations and associated customer services. (PG&E will also retain ownership of and responsibility for the shutdown Humboldt Bay Power Plant, Unit 3.) Upon consummation of the disaggregation of PG&E's businesses, PG&E Corporation will declare a dividend and distribute the common stock of PG&E to its public shareholders, separating PG&E from PG&E Corporation.

PG&E has also created subsidiaries of Gen to hold specific assets and project-specific liabilities related to Gen's line of business. Nuclear is a subsidiary of Gen created to hold the ownership in DCPP. Gen will also have multiple subsidiaries formed to hold its hydroelectric assets.

Because Nuclear will hold the ownership interest in DCPP, Nuclear will need to become a licensed owner. Nuclear will lease DCPP to Gen under lease terms that assign to Gen the entitlement to the output and capacity of DCPP and that make Gen responsible for all costs of plant operation. A copy of the form of the facility lease for DCPP between Nuclear and Gen is provided as Enclosure 3.

Gen will operate DCPP and will accordingly need to become the operating licensee. Gen will operate the units under the same terms and conditions included in the present licenses. No physical changes will be made to the plant as a result of the license transfers, and there will be no significant changes in the day-to-day management of, and operating procedures for, the plant.

The present onsite nuclear organizations at DCPP will not change following the transfer to Gen. The onsite nuclear employees of PG&E will become employees of Gen and will continue to operate the units. Offsite corporate resources will continue to be provided, either as a result of transfers to Gen or by service agreements. The technical qualifications of Gen will be equivalent to those of PG&E presently, and specific personnel qualification requirements established in plant Technical Specifications, plant procedures, and applicable industry standards will continue to be met.

As discussed further below, the licensees will be viable businesses and have the financial qualifications to own and operate DCPP. Gen will operate as an electricity generation company, with diversified generation assets. Substantially all of Gen's output will be sold to the reorganized PG&E pursuant to a bilateral contract described below. Gen's financial projections provided in accordance with NRC regulations demonstrate that Gen will, in the aggregate, fully recover its costs by the sale of electricity generated by its generation capacity and its power purchase agreements.

As also discussed further below, decommissioning funding assurance for DCPP will be preserved. The beneficial interest in the Nuclear Decommissioning Trust associated with DCPP will be transferred to Nuclear. Although Nuclear will not be a rate-regulated electric utility, PG&E anticipates that the net cash value (after tax) of the interest transferred will meet the NRC decommissioning funding requirements established by 10 CFR 50.75(c).

Because the proposed restructuring and license transfers affect the named licensees under the NRC operating licenses, PG&E also requests, in accordance with 10 CFR 50.90, NRC approval of certain administrative amendments to conform the operating licenses. Mark-ups showing the proposed changes are provided in Enclosures 4 and 5. In the license markups, with respect to ongoing operational matters Gen succeeds and replaces PG&E as the operator of DCPP. Nuclear is identified and authorized as the facility owner. References to PG&E as the initial licensed operator are retained for certain historical license conditions. And, with respect to the existing antitrust license conditions, Gen, ETrans, and PG&E are reflected as the responsible licensees, in effect jointly and severally obligated to meet those conditions. ETrans and PG&E will be licensees solely for purposes of the antitrust conditions.[3]

In Enclosure 6, PG&E is providing an evaluation confirming the NRC's generic determination in 10 CFR 2.1315(a) that the proposed conforming license changes involve no significant hazards considerations.

Administrative changes to documents other than the plant operating licenses and Technical Specifications may be necessary upon completing the transfers to reflect Gen as the new operator and Nuclear as the owner. Any changes to documents such as the Updated Final Safety Analysis Report, the Physical Security Plan, the Quality Assurance Manual, and the Emergency Plan will be made in a timely fashion after the transfers during routine updates and as required by regulations such as 10 CFR 50.71(e) and 50.54. Changes to other documents such as procedures and drawings will be made, where necessary, in accordance with routine or periodic internal update processes as applicable to those documents.

---

3 With the exception of Diablo Canyon LLC (Nuclear), which will be the licensed owner of DCPP, the names of Gen, ETrans, and the other newly-created entities may be changed prior to implementation of the Plan. Prior to issuance of the conforming license amendments, PG&E will provide the NRC with the final names of the entities that will be licensees.

II. Statement of Purpose of the Transfers and the Nature of the Transaction Making the Transfers Desirable

As stated above, PG&E is requesting the proposed license transfers as part of a reorganization of PG&E's businesses and operations in support of the reorganization plan filed with the United States Bankruptcy Court. Through the proposed restructuring, PG&E anticipates that the value realized will provide necessary cash and increased debt capacity to enable it to repay all valid creditor claims in full, restructure existing debt, and emerge from the Chapter 11 bankruptcy case. PG&E anticipates that the restructuring will create new businesses, including Gen and Nuclear, that will be financially sound going forward.

After the transfer Gen will operate, maintain, and manage DCPP in accordance with the operating licenses and NRC requirements, and with the same regard for public and personnel safety exemplified to date by PG&E. The license transfers will not affect ongoing operational enhancements and improvement initiatives. Key managers now responsible for the safe operation of DCPP will remain responsible for its operation after the reorganization.

III. General Corporate Information Regarding Gen and Nuclear

The information required to be included in an application for the transfer of a license pursuant to 10 CFR 50.80 is set forth below. This information demonstrates that the requested transfers are consistent with the Atomic Energy Act and applicable NRC regulations.

A. *Name and Address*[4]

The licensed operator and the licensed owner of DCPP will be, respectively:

- Electric Generation LLC
  77 Beale Street
  32nd Floor
  San Francisco, California 94105

[4] In addition to Gen and Nuclear, as discussed below in Section III.G and as shown in the license mark-ups in Enclosures 4 and 5, ETrans will become a licensee, as a successor to PG&E with respect to the transmission system, and reorganized PG&E, which will be the distribution entity, will remain a licensee — each for the limited purpose of retaining responsibility for the existing antitrust license conditions. Presently, the addresses of these entities are: Pacific Gas and Electric Company, 77 Beale Street, P.O. Box 770000, San Francisco, California 94177; and ETrans LLC, 77 Beale Street, 32nd Floor, San Francisco, California 94105.

- Diablo Canyon LLC
  77 Beale Street
  32nd Floor
  San Francisco, California 94105

B. *Description of Business*

Gen is a California limited liability company wholly-owned by Newco. PG&E is the sole shareholder of Newco. However, as part of implementation of the Plan, PG&E will declare and pay a dividend of the outstanding common stock of Newco to PG&E Corporation, and Gen will thereafter be an indirect wholly-owned subsidiary of PG&E Corporation, which will be renamed.

Gen will operate as a separate electricity generation company. PG&E's conventional hydroelectric generations facilities, the Helms Pumped Storage Facility, Irrigation District contracts, and DCPP all will be transferred to Gen or subsidiaries of Gen. Upon implementation of the Plan, Gen, as distinct from PG&E, will have responsibility for, and control over, operation of DCPP, including the presently proposed DCPP Independent Spent Fuel Storage Installation (ISFSI).

Nuclear is a California limited liability company and a wholly-owned subsidiary of Gen. Nuclear's business will be to own the DCPP assets and to lease these assets to Gen. PG&E's beneficial interest in the Nuclear Decommissioning Trust associated with DCPP will also be transferred to Nuclear, as described herein.

C. *Organization and Management*

1. Electric Generation LLC

The business of Gen will be conducted under the direction of a two person board of control (a limited liability company's equivalent to a corporation's board of directors). The members of the board of control, and their addresses, are as follows:

- Peter A. Darbee
  PG&E Corporation
  One Market Street
  San Francisco, California 94105

- Bruce R. Worthington
  PG&E Corporation
  One Market Street
  San Francisco, California 94105

The identity of any additional members of the board of control will be provided when available, and it is expected that all members will be citizens of the United States.

The principal officers of Gen, and their addresses, are as follows:

- Bruce R. Worthington
  President and Treasurer
  PG&E Corporation
  One Market Street
  San Francisco, California 94105

- Gregory M. Rueger
  Chief Nuclear Officer
  Pacific Gas & Electric Company
  77 Beale Street
  San Francisco, California 94120

- Linda Y.H. Cheng
  Corporate Secretary
  PG&E Corporation
  One Market Street
  San Francisco, California 94105

The identity of any additional officers will be provided when available, and it is expected that all officers will be citizens of the United States.[5]

2. <u>Diablo Canyon LLC</u>

Nuclear will not have a board of control. The business of Nuclear will be conducted under the direction of its sole member, Gen.

Presently there are no officers of Nuclear and none are currently contemplated. The identity of any officers will be provided if appointed, and it is expected that any officers would be citizens of the United States.

D. <u>No Foreign Ownership or Control</u>

Neither Gen, Nuclear, nor Newco Energy Corporation, as indirect wholly-owned subsidiaries of re-named PG&E Corporation, will be owned, controlled, or dominated by foreign interests. As discussed above, all of the principal directors and officers of Gen and Nuclear are expected to be

5 The members of the board of directors or board of control, as appropriate, and the officers, of Newco Energy Corporation and ETrans presently are the same as for Gen, except that Mr. Rueger is an officer of Gen only.

citizens of the United States. PG&E Corporation is incorporated under the laws of the State of California. The shares of PG&E Corporation are publicly and widely held and are traded on the New York Stock Exchange.

ETrans and PG&E will be licensees only with respect to antitrust conditions. They will not own or control DCPP in any way that would implicate foreign ownership restrictions.

E. ***Technical Qualifications***

As discussed above, Gen will lease DCPP from Nuclear and operate DCPP on its own behalf. Under the lease, Gen will have all the necessary authority and responsibility for operation of the units and for maintaining public health and safety and regulatory compliance.

The technical qualifications of Gen to carry out its operational responsibilities under the DCPP operating licenses will be equivalent to the present technical qualifications of PG&E. The management team from PG&E's present nuclear organization, from the Senior Vice President-Generation and Chief Nuclear Officer position down, will be transferred to Gen. These individuals have substantial nuclear experience and a proven record in nuclear plant operations. They will continue to meet the applicable industry qualifications standards.

The management and technical support functions will continue to conform to the pertinent provisions in the plant Technical Specifications and the DCPP Updated Final Safety Analysis Report. Concurrent with the license transfers, the current on-site organizations at DCPP will be transferred intact to Gen. The existing structure is shown in the DCPP Updated Final Safety Analysis Report, Figures 13.1-1 and 13.1-2 (Revision 14, November 2001), and will be unchanged. The existing organizational structure provides for clear lines of authority and responsibility for management of the plants.

In addition, it is expected that substantially all PG&E nuclear personnel in the existing DCPP nuclear organizations will become employees of Gen and will continue to be assigned to DCPP. These employees will take direction through the Gen management chain of command and their responsibilities will continue to be clear and unambiguous. The qualifications of the nuclear personnel generally will not change as a result of the restructuring and license transfers. The personnel qualification requirements presently defined in the respective plant Technical Specifications and DCPP Updated Final Safety Analysis Report will not be changed and will continue to be met.

Other corporate service or support functions (*e.g.,* information technology, human resources, certain technical support functions) presently provided from PG&E's off-site corporate offices in San Francisco will be reorganized, but will continue to be provided. It is expected that some of these functions will be transferred to Gen; others may be provided by service agreements with affiliates. The structure and mechanism for providing these support functions is currently under evaluation.

PG&E will also transfer to Gen or Nuclear all of the assets necessary for the operation of DCPP. Among these assets are an extensive list of documents, including books, operating records, manuals, blue-prints, specifications, engineering design plans, procedures, etc. These documents include the official copies of records which the NRC requires a licensee to maintain. The vast majority of these documents are located at DCPP; however, to the extent that other such documents are maintained at offices located elsewhere, custody and control of these documents will be assured as part of the transfer.

Further, as necessary, contracts with the Nuclear Steam Supply System supplier and other major vendors will be transferred to Gen or appropriate other contracts will be obtained in a timely manner. Other contracts and contractor relationships relating to the units will be transferred to Gen as appropriate.

In total, the technical qualifications of the Gen management, site, and support organizations will be equivalent to those of the existing PG&E nuclear organization. Sufficient qualified technical resources will be provided to support safe operation and maintenance of the units, and the plants will continue to be operated in accordance with the licenses, NRC requirements, licensing bases, and other NRC commitments.

F. Financial Qualifications

1. Operating Costs

Gen and Nuclear will have the financial qualifications to be the NRC licensees for DCPP. Neither licensee will be a regulated "electric utility" as defined by the NRC, selling to traditional retail ratepayers with cost-of-service rates, but their ability to cover DCPP operating, maintenance, fuel and other expenses will be established.

First, Nuclear, as the asset owner, will lease DCPP to Gen under a lease agreement that will require Gen to cover all the operating and capital costs of DCPP.

Second, Gen will operate as an electricity generation company that controls substantial generation assets, including DCPP and hydroelectric generating stations. Pursuant to the Plan, Gen and the reorganized PG&E will enter into a long-term bilateral power sales agreement whereby Gen's output and the power produced under its power purchase agreements will be sold at wholesale to reorganized PG&E. Pursuant to the bilateral contract, these sales will be in accordance with a rate approved by the Federal Energy Regulatory Commission (FERC) as just and reasonable. A copy of a form of the bilateral power sales agreement between Gen and reorganized PG&E is provided as Enclosure 7.[6]

Under the bilateral contract, reorganized PG&E will be entitled to purchase substantially all of the output of Gen's facilities and Gen's power purchase agreements, but electricity from DCPP and certain hydroelectric facilities will be purchased on a must-take basis. As currently contemplated, the contract will have a term of 12 years.

Under the NRC's regulations, 10 CFR 50.33(f)(2), a non-electric utility applicant for an operating license (or a transferee) must demonstrate that it has reasonable assurance of obtaining the funds necessary to cover the plant's estimated operating costs by submitting "estimates for total annual operating costs for each of the first five years of operation of the facility" as well as the "source(s) of funds to cover these costs." This showing is also referenced in the NRC's Standard Review Plan (SRP) on financial qualifications.[7]

Following the proposed restructuring and license transfers, the financing and financial reporting relevant to the generation businesses will occur at the Gen level of the organization. Gen will be a financially robust entity due to its diversified generation portfolio and the power sales contract with PG&E. The projected revenues from sales of electricity and capacity, the capitalization, and the extent and diversity of Gen's assets together provide the assurance that Gen will meet its financial obligations under the lease with Nuclear.

Enclosure 8 provides financial qualifications information at the Gen level. In accordance with 10 CFR 50.33(f)(2) and the SRP, Enclosure 8 includes a Projected Income Statement for Gen for the first five years of operation following the license transfer.[8] The

---

6 The form of the bilateral contract provided in Enclosure 7 is subject to FERC approval and is subject to change before it is executed.

7 NUREG-1577, Rev. 1, "Standard Review Plan on Power Reactor License Financial Qualifications and Decommissioning Funding Assurance" (March 1999).

8 The financial information in Enclosure 8 represents an update of the financial information originally included in the September filing with the Bankruptcy Court in the Plan and Disclosure Statement. The information in the Plan and Disclosure Statement will be amended.

Projected Income Statement shows Gen's total annual operating costs. The source of funds to cover these costs will be operating revenues. The Projected Income Statement shows that the anticipated revenues from the sales of capacity and energy by Gen provide reasonable assurance of adequate funds to meet Gen's ongoing operating expenses. Enclosure 8 also includes certain key assumptions utilized in the Projected Income Statement, including the contract price for power under the bilateral power sales agreement and the assumed capacity factor for DCPP.

Gen's projected assets and revenue streams will also be more than sufficient to cover operating and maintenance costs that might be associated with a six-month shutdown of one of the DCPP units. Enclosure 8 includes a Projected Opening Balance Sheet demonstrating that Gen will have total assets exceeding $2.5 billion. The total estimated operating costs attributable to DCPP are also shown in Enclosure 8. These costs include plant operations and maintenance costs, non-fuel capital additions, and nuclear fuel. The fixed operating costs of the units in the case of an extended shutdown would exclude the fuel costs, the non-fuel capital additions, as well as certain operation and maintenance costs. The projected assets of Gen, along with its substantial projected non-nuclear generation revenues, will provide reasonable assurance of Gen's financial capability to fund an extended shutdown.

Accordingly, Gen will fully meet or exceed the financial qualifications requirements of 10 CFR 50.33(f) and the guidelines of the SRP.

2. <u>Decommissioning Funding Assurance</u>

Decommissioning funding assurance for DCPP is presently provided by an external Nuclear Decommissioning Trust as authorized by 10 CFR 50.75(e)(1)(ii). In accordance with 10 CFR 50.75(f)(1), PG&E reported on the status of this fund on March 30, 2001.[9]

As discussed above, PG&E will transfer to Nuclear the beneficial interest in the Nuclear Decommissioning Trust associated with DCPP. The funds associated with the beneficial interest will be segregated from the licensees' assets and outside its administrative control. The trustee will continue to manage investment of the funds in accordance with a master trust

---

9 PG&E Letter DCL-01-026, HBL-01-005, from L.F. Womack, "Decommissioning Funding Reports for Diablo Canyon Power Plant Units 1 and 2 and Humboldt Bay Power Plant Unit 3" (March 30, 2001).

agreement and applicable NRC requirements and license conditions. The funds will be used only in a manner consistent with the terms of the trust agreements.

Presently, as it pertains to DCPP, the Nuclear Decommissioning Trust includes a California Public Utilities Commission (CPUC) jurisdictional qualified trust and a Federal Energy Regulatory Commission (FERC) jurisdictional qualified trust. The liquidation value of the DCPP component of the CPUC and FERC trusts, as of September 30, 2001, was approximately $473.5 million for Unit 1 and $627.5 million for Unit 2 (approximately $1.101 billion combined). The transfer to Nuclear of PG&E's beneficial interest in the Trust associated with DCPP is subject to the approval of Bankruptcy Court as part of confirmation of the Plan. The transfer of the beneficial interest is also subject to the approval of the FERC and, accordingly, PG&E will seek in its application for approvals associated with the transaction under Section 203 of the Federal Power Act the FERC's consent to the transfer of the Trust.[10]

PG&E also expects to seek a private letter ruling from the Internal Revenue Service (IRS) to assure that the beneficial interest in the qualified decommissioning funds can be transferred to Nuclear on a tax-free basis.

Enclosure 9 demonstrates the sufficiency of the current level of decommissioning funding for each of the two DCPP units. Enclosure 9 shows that, assuming the present value of the DCPP funds, plus credit for a contribution to the funds in 2002 as already approved through the CPUC ratemaking process, and no further contributions, the decommissioning trusts are adequately funded to meet the NRC-mandated decommissioning obligations. With credit for a 0.84 percent annual real rate of return through the present terms of the licenses, which is an assumed rate of return significantly less than the 2.0 percent allowed by NRC regulations, the value of the prepaid fund will provide the level of funding assurance required by 10 CFR 50.75(c), NRC Regulatory Guide 1.159, and NUREG-1307, Rev. 8.

[10] The CPUC jurisdictional qualified trust and the FERC jurisdictional qualified trust also include money associated with the Humboldt Bay Power Plant, Unit 3. PG&E also maintains a CPUC jurisdictional non-qualified trust for the Humboldt Bay Power Plant, Unit 3. PG&E will retain its beneficial interests in the trusts for the purpose of decommissioning the Humboldt Bay Power Plant, Unit 3. All of the funds in the trusts associated with the Humboldt Bay Power Plant, Unit 3 will be segregated from the DCPP components as part of the reorganization and separation process.

For NRC decommissioning purposes, the minimum amount as of December 31, 2001, that would need to be transferred, as a condition of the NRC license transfer, in order to meet NRC requirements, would be approximately $347.9 million for Unit 1 and $487.7 million for Unit 2. These amounts would satisfy NRC requirements for financial assurance for decommissioning in the form of prepayment in accordance with 10 CFR 50.75(e)(1)(i).[11] Additional amounts, beyond the NRC minimum and up to the total amount in the Nuclear Decommissioning Trust associated with DCPP at the time of the transfer, will be included in the beneficial interest transferred to Nuclear if and to the extent such transfer is approved by FERC and the Bankruptcy Court, as required.

3. <u>Nuclear Insurance</u>

Gen will, upon transfer of the assets and assumption of the licenses, assume the responsibility for providing the financial protection as required by 10 CFR Part 140, and for continuing site insurance coverage as required by Price-Anderson 10 CFR 50.54(w).[12]

Gen's obligations will include the responsibilities with respect to retrospective liability required in accordance with 10 CFR 140.21. Based upon the financial information provided in Enclosure 8, Gen will have the financial ability to meet this obligation.

G. *Antitrust Considerations*

The NRC has determined that antitrust reviews of post-operating license transfer applications are neither required nor authorized by the Atomic Energy Act, and therefore no antitrust information is required to be submitted with this post-operating license transfer application.[13]

---

11 The NRC formulas in 10 CFR 50.75(c) include only those decommissioning costs incurred by licensees to remove a facility or site safely from service and reduce residual radioactivity to levels that permit: (1) release of the property for unrestricted use and termination of the license; or (2) release of the property under restricted conditions and termination of the license. The cost of dismantling or demolishing nonradiological systems and structures is not included in the NRC decommissioning cost estimates. The costs of managing and storing spent fuel on site until transfer to DOE are not included in the cost formulas. The Nuclear Decommissioning Trust for DCPP currently includes funds for non-NRC decommissioning costs.

12 PG&E and/or Gen will in due course request modified Price-Anderson indemnity agreements and will make changes to nuclear liability and property coverages to reflect Gen as the operator and Nuclear as the owner, and each as an additional named insured.

13 Final Rule, Antitrust Review Authority: Clarification, 65 Fed. Reg. 44,649 (July 19, 2000); <u>see also</u> <u>Kansas Gas and Electric Co</u>. (Wolf Creek Generating Station, Unit 1), CLI-99-19, 49 NRC 441 (June 18, 1999).

However, because the Plan calls for a restructuring that would split generation assets from the transmission and distribution businesses, the antitrust conditions currently included in Appendix C of the DCPP licenses would not and could not apply directly to Gen or Nuclear. The conditions also could not apply solely to PG&E.

Under the Plan, reorganized PG&E will be a local electric and gas distribution company serving retail customers in Northern and Central California. The company will have a service territory that covers 70,000 square miles. PG&E will contribute its approximately 18,500 circuit miles of electric transmission lines and cables located in California to ETrans. This will include approximately 1,300 circuit miles of 500 kV lines, 5,300 circuit miles of 230 kV lines, 6,000 circuit miles of 115kV lines and 4,000 circuit miles of 70 and 60 kV lines, and the towers, poles and underground conduit used to support the lines and cables. In addition, ETrans and its subsidiaries will receive all transmission substations, transmission control centers and associated operations systems, junctions and transmission switching stations and associated equipment necessary to support the lines and cables and all of the other land, entitlements, rights of way, access rights, personal, real and intellectual property and the business records necessary to operate the electric transmission business.

Currently, PG&E is a participating transmission owner in the California Independent System Operator (ISO), the entity that operates and controls most of the electric transmission facilities owned by the State's three major investor-owned utilities and provides open access to electric transmission services on a non-discriminatory basis. The ISO uses PG&E's transmission facilities to provide open access transmission service. As part of the restructuring, PG&E will assign to ETrans its contractual obligations as a participating transmission owner in the ISO.[14]

Accordingly, with respect to the existing antitrust license conditions, PG&E proposes to retain those conditions at this time. In order to preserve as nearly as possible the current antitrust obligations, PG&E proposes to retain reorganized PG&E on the license with respect to antitrust conditions and to add ETrans as a licensee for those conditions, as PG&E's successor with respect to the transmission system. PG&E and ETrans would be licensees for the limited purpose of the antitrust license

[14] In December 1999, the FERC issued its final rule on Regional Transmission Organizations (RTOs) and encouraged utilities that own transmission systems to form RTOs on a voluntary basis. In several orders issued on July 12, 2001, the FERC indicated its strong preference for a single RTO that encompasses most of the Western United States, including California, and potentially Canadian provinces as well, that are interconnected in the region encompassed by the Western Systems Coordinating Council. No RTO is operational in the Western United States at this time. ETrans intends to join a FERC-approved Western RTO at such time as one is established and approved by FERC.

conditions. Along with Gen, PG&E and ETrans will be jointly and severally responsible for those conditions. This arrangement is reflected in the proposed license mark-ups provided in Enclosures 4 and 5.

H. Restricted Data

This application does not contain any Restricted Data or other classified defense information, and it is not expected that any such information will become involved. However, Gen and Nuclear will appropriately safeguard such information if any such information does become involved and will not permit any individual to have access to any such information until the Office of Personnel Management (the successor to the Civil Service Commission) shall have made an investigation and report to the NRC on the character, associations, and loyalty of such individual, and the NRC shall have determined that permitting such person to have access to Restricted Data will not endanger the common defense and security of the United States.

I. No Environmental Impact

The proposed license transfers and conforming license amendments meet the categorical exclusion criteria of 10 CFR 51.22(c)(21), in that this application does no more than request the approval of a direct transfer of the NRC licenses and the associated conforming amendments to the licenses.

The proposed license transfers and conforming license amendments do not involve any changes to the physical operation of the plants and, accordingly, do not involve any increase in the amount or type of radiological effluents that may be allowed to be released offsite. The proposed transfers and license amendments also do not involve any increase in the amount or type of any non-radiological effluents that may be released offsite. Further, the proposed transfers and license amendments do not involve any increase in individual or cumulative occupational radiation exposure. In sum, the proposed actions will have no environmental impact. Accordingly, if necessary, PG&E requests that the NRC issue and publish a finding of no significant environmental impact pursuant to 10 CFR 51.32 and 51.35.

IV. Additional Information on Regulatory Issues

A. Design and Licensing Bases/Updates to FSAR

The proposed license transfers and conforming license amendments will designate Gen as the licensee authorized to possess, use, and operate the DCPP nuclear units. The transfers and amendments will not affect the physical configuration of the facilities or alter any substantive Technical Specification requirements under which the units operate. Gen will control or have access to the design and licensing basis documents to the same extent as PG&E does now, and the proposed transfers and conforming amendments will not affect the design and licensing bases. Changes to the Updated Final Safety Analysis Report necessary to reflect the change in responsible licensee will be incorporated on a schedule that complies with 10 CFR 50.71(e) following NRC approval of the transfers.

B. ***Emergency Planning***

Concurrent with the transfers of operating authority, Gen will assume authority and responsibility for functions necessary to fulfill the emergency planning and preparedness requirements of 10 CFR 50.47(b) and Part 50, Appendix E. No changes will be made that reduce the effectiveness of the emergency plans or that adversely impact compliance with the NRC's emergency planning requirements.

Prior to implementation of the reorganization, the emergency plans will be reviewed in detail and any needed changes to the plans or implementing procedures will be made in accordance with 10 CFR 50.54(q) and Part 50, Appendix E, Section V, as appropriate. No major substantive changes to the existing emergency plans presently implemented by PG&E are anticipated as a result of the transfer. Likewise, no substantive changes are anticipated to the existing emergency planning organization. Generally, the current emergency facilities, equipment, and organizations will be transferred to Gen or Nuclear. As necessary, ownership of off-site emergency sirens will be transferred to Gen or Nuclear and provisions will be made, as needed, for the sirens to continue to be located on poles owned by the distribution company.

As part of the transition process, PG&E will evaluate offsite corporate support for the emergency plan and will make provisions for continued offsite corporate support, if needed. Existing agreements for support from outside organizations and agencies also will be reviewed such that appropriate actions can be taken, at an appropriate time prior to the transfers, to notify the parties to such agreements of the Plan and Gen's anticipated responsibility for management and operation of DCPP. Support agreements will be assigned to Gen, if necessary.

C. ***Offsite Power***

Offsite power is currently provided to DCPP over transmission facilities owned by PG&E and operated by the ISO. As a result of the disaggregation of assets, certain transmission assets will be transferred to ETrans. However, the physical facilities will not change as a result of the change in ownership of and operating authority for DCPP. Independent sources of offsite power will continue to be provided to the stations in compliance with 10 CFR Part 50, Appendix A, General Design Criterion 17.

Gen will establish an interconnection agreement with ETrans and will have power for DCPP pursuant to the bilateral contract between Gen and PG&E. Additionally, certain nuclear protocols related to the operation of the transmission system are already established by agreement between PG&E and the ISO, and these nuclear protocols will remain in place. Under an agreement between Gen and ETrans, ETrans will be responsible for the relationship with the ISO. Also, the agreements with ETrans will address continued maintenance of the transmission equipment that ETrans will own.

D. ***<u>Exclusion Area Control</u>***

As the current owner and plant operator of DCPP, PG&E has the authority to determine and control activities within the exclusion areas for the DCPP plant site at least to the extent required by 10 CFR Part 100. As a result of the transfer of ownership of DCPP and related assets to Nuclear, and the lease agreement between Nuclear and Gen, Gen will have the required exclusion area control. Nuclear will own, and lease to Gen, essentially the same property as PG&E presently owns and controls, with the exception of certain transmission facilities. With respect to the transmission facilities, maintenance and switchyard agreements with ETrans will provide Gen with the right to determine activities in the exclusion area to the extent necessary to meet Part 100. This authority will extend to any activities of ETrans or other authorized entity with respect to maintenance of the switchyard and transmission facilities.

With respect to other activities unrelated to plant operations that will occur within the exclusion area previously identified in the DCPP Updated Final Safety Analysis Reports, there will be no changes. Gen will assume responsibility for the emergency plans as discussed above.

E. ***<u>Security</u>***

Concurrent with the transfer of ownership and operating authority, Gen will assume authority and responsibility for the functions necessary to fulfill the security requirements of 10 CFR Part 73. No material changes are expected to the existing physical security organization, guard training and qualifications, safeguards contingency plans, or equipment. Accordingly, the proposed license transfers will not impact compliance with the NRC's security requirements.

Existing agreements for support from outside organizations and agencies will be reviewed such that appropriate actions can be taken prior to the transfers to notify parties to such agreements of Gen's relationship with PG&E, the plan of reorganization, and Gen's anticipated responsibility for management and operation of DCPP. Support agreements will be assigned to Gen, if necessary.

Any changes to the security plans to reflect the transfer of responsibility will not decrease the effectiveness of the plans and will be made in accordance with 10 CFR 50.54(p).

F. *Quality Assurance*

The proposed transfers will not impact compliance with the quality assurance requirements of 10 CFR Part 50, Appendix B, nor will they reduce the commitments in the NRC-accepted quality assurance programs for DCPP. Concurrent with the transfers of ownership and operating authority, Gen will assume authority and ultimate responsibility for present functions associated with the quality assurance programs. The transfers of the licenses to Gen will not degrade the effectiveness of these functions. Any changes to the Quality Assurance Program to reflect the transition will not reduce the commitments in the quality assurance program description and will be handled in accordance with 10 CFR 50.54(a).

G. *Training*

The proposed license transfer will not impact compliance with the operator re-qualification program requirements of 10 CFR Part 50.54 and related sections, nor maintenance of the Institute of Nuclear Power Operations accreditation for licensed and non-licensed personnel training. Concurrent with the license transfers, Gen will assume responsibility for implementation of the present operator training programs. Changes to the programs to reflect the transition will not decrease the scope of the approved operator requalification program and will be made in accordance with 10 CFR 50.54(i).

H. *Spent Fuel Storage*

Upon transfer of ownership and operating responsibility, Gen will assume responsibility for safe storage of the fuel as one of its DCPP operational responsibilities. Nuclear will assume title to spent nuclear fuel located at DCPP. PG&E will assign to Nuclear its rights and obligations under the Standard Contract with the Department of Energy, as well as related claims.

By separate license and amendment applications, PG&E in the near future will request a site-specific Part 72 license for the proposed DCPP ISFSI and will request related amendments to the DCPP Part 50 license. PG&E anticipates that, given the current anticipated schedules, the Part 72 ISFSI license will be issued after the license transfers requested herein and after the implementation of the proposed reorganization. Accordingly, PG&E anticipates that Gen will become the initial ISFSI licensee as operator of that facility.

V. Other Approvals

The Plan must be approved by the Bankruptcy Court pursuant to Section 1129 of the Bankruptcy Code, 11 USC 1129. As discussed above, PG&E has filed the Plan and Disclosure Statement. The Bankruptcy Court will hold a hearing to consider approving the Disclosure Statement. That hearing is now scheduled for December 19, 2001. The Bankruptcy Code further requires the Bankruptcy Court, after notice, to hold a confirmation hearing. PG&E expects the confirmation hearing to be held and the Plan to be confirmed in the next 6 months.

Pursuant to Section 1123 of the Bankruptcy Code, 11 USC 1123, the Bankruptcy Court has broad authority to authorize a debtor to dispose of assets in connection with implementation of a reorganization without approvals that might otherwise be required under applicable law. PG&E has requested the approval of the Bankruptcy Court to undertake the proposed transactions without further review or approval of California state and local government agencies.

In addition to the approval from the NRC, PG&E will seek the approval of the Securities and Exchange Commission (SEC) under Section 9(a)(2) of the Public Utility Holding Company Act of 1935, 15 USC 79i(a)(2) (because the transactions will result in the ownership by PG&E Corporation of more than one public utility company). PG&E will also need to make several notifications to, and file requests for approval from, the FERC, including, among other filings, a Federal Power Act (FPA) Section 203 application related to transfers of FERC jurisdictional transmission assets, an FPA Section 205 application for approval of the Gen-PG&E bilateral contract for sales of electricity and capacity, a filing under Section 205 of the FPA of generation interconnection agreements and other agreements, applications under Sections 204 and 305(a) of the FPA relating to issuance of securities for several of the businesses, and filings related to the hydroelectric stations and the gas transmission business. PG&E expects to make these filings by November 30, 2001, and to receive all of the necessary SEC and FERC approvals before the end of 2002.

As discussed above, PG&E also expects to seek a private letter ruling from the IRS related to the transfer of the beneficial interest in the qualified Nuclear Decommissioning Trust. Applications to transfer environmental permits, rights of way, and minor licenses and permits necessary for implementation of the transaction will be made to other federal, state, and local agencies, as required.

VI. Schedule

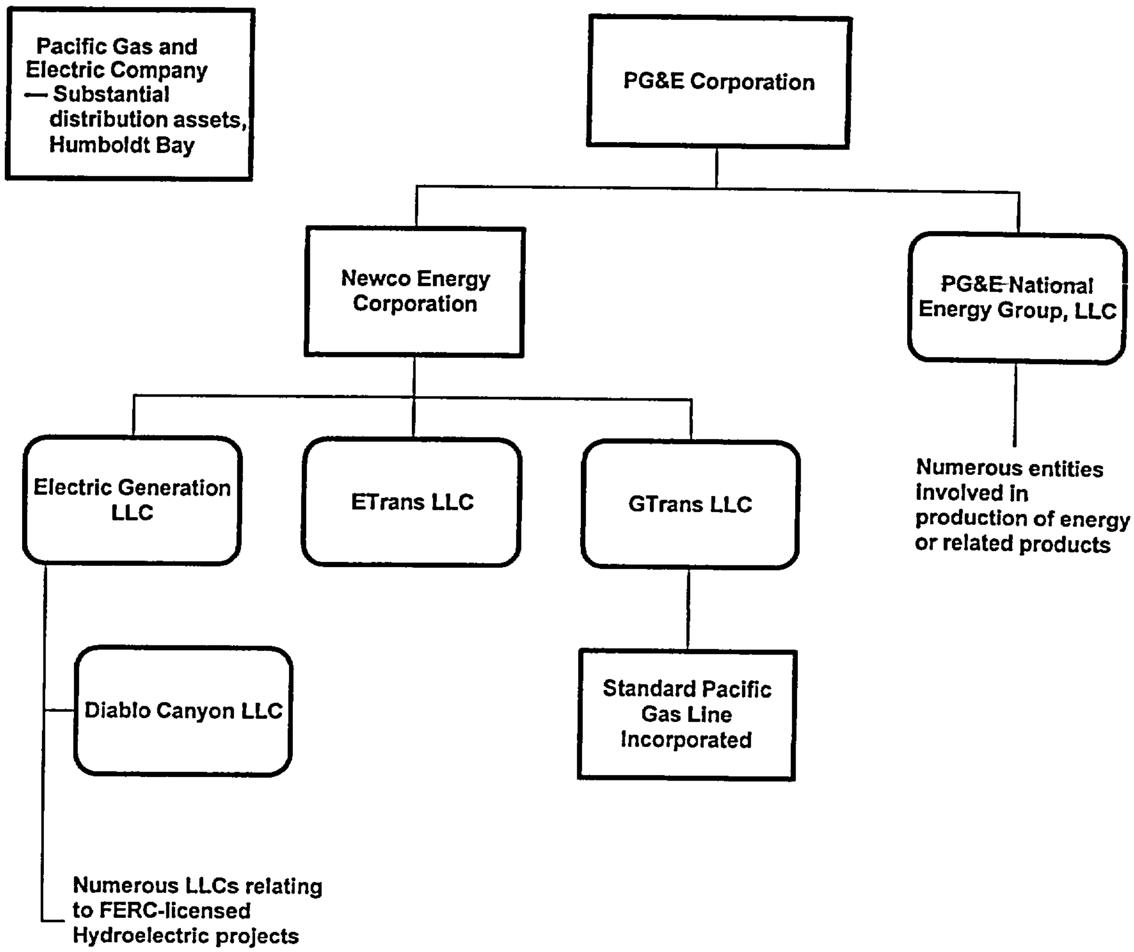
PG&E requests that the NRC consent to the proposed transfers as promptly as possible, but no later than July 31, 2002.

The NRC's consent should be made immediately effective upon issuance and, consistent with NRC practice, should authorize the transfers occurring at any time through twelve months following the date of the consent or through such later date as may be permitted by the NRC. This schedule will allow sufficient time for other approvals needed prior to closing on the reorganization, for arrangement of financing and completion of administrative actions necessary to complete the transactions, and for contingencies.

Plan of Reorganization and Disclosure Statement

Proposed Corporate Structure of PG&E Corporation and Principal Subsidiaries After Implementation of Plan of Reorganization

Proposed Corporate Structure of PG&E Corporation and Principal Subsidiaries After Implementation of Plan of Reorganization



Note: PG&E Corporation and PG&E National Energy Group to be renamed.

Form of Diablo Canyon Facility Lease By and Between Diablo Canyon LLC, as Lessor, and Electric Generation LLC, as Lessee

Marked-up Pages of Operating License for Proposed Conforming Changes Related to DCPP Unit 1

Marked-up Pages of Operating License for Proposed Conforming Changes Related to DCPP Unit 2

No Significant Hazards Considerations Determination

No Significant Hazards Considerations Determination

Description of the Change

The transfers of ownership of and operating responsibility for Diablo Canyon Power Plant, Units 1 and 2, involve a number of conforming changes to the operating licenses for the units to reflect the new generating company, Electric Generation LLC (Gen), as the operator of the two units, and to reflect that the ownership of the assets will be assigned to Diablo Canyon LLC (Nuclear), a wholly-owned subsidiary of Gen. In addition, these conforming changes to the licenses include changes that are necessary to reflect additional entities responsible for compliance with the existing antitrust licenses conditions. Consistent with the generic determination in 10 CFR Part 2.1315(a), which became effective December 3, 1998, these administrative license amendments involve no significant hazards considerations.

Basis for Proposed No Significant Hazards Considerations Determination

1. The conforming amendments do not involve a significant increase in the probability or consequences of an accident previously evaluated.

   The proposed amendments do not involve a significant increase in the probability or consequences of an accident previously evaluated because of the following:

   - The amendments do not involve any change in the design, configuration, or operation of the nuclear plant. All Limiting Conditions for Operation, Limiting Safety System Settings and Safety Limits specified in the Technical Specifications remain unchanged. Also, the Physical Security Plan, the Operator Training and Requalification Program, the Quality Assurance Program, and the Emergency Plan are not being substantively changed by the proposed transfer and amendment.

   - The technical qualifications of Gen to carry out its responsibilities under the operating licenses, as amended, will be equivalent to the present technical qualifications of PG&E. Upon the effective date of the transfer of the licenses, Gen will operate, manage, and maintain the nuclear plant in accordance with the conditions and requirements established by the NRC as defined in the current operating licenses. The organization and the qualifications of the personnel engaged in the operation, maintenance, engineering, assessment, training, and other related services will be essentially unchanged as a result of the transfer. The key executives currently responsible for the overall safe operation of the nuclear plant as designated in plant Technical Specifications will continue to be responsible, although their titles may change.

   Therefore, the proposed amendments do not involve an increase in the probability or consequences of an accident previously analyzed.

2. <u>The conforming amendments do not create the possibility of a new or different kind of accident from any accident previously evaluated.</u>

The proposed amendments do not create the possibility of a new or different kind of accident from any accident previously evaluated because of the following:

- The amendments do not involve any change in the design, configuration, or operation of the nuclear plant. The current plant design and design bases will remain the same. The current plant safety analyses, therefore, remain complete and accurate in addressing the design basis events and in analyzing plant response and consequences.

- The Limiting Conditions for Operations, Limiting Safety System Settings and Safety Limits specified in the Technical Specifications are not affected by the change. As such, the plant conditions for which the design basis accident analyses were performed remain valid.

- The amendments do not introduce a new mode of plant operation or new accident precursors, does not involve any physical alterations to plant configurations, or make changes to system set points that could initiate a new or different kind of accident.

Therefore, the proposed amendments do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. <u>The conforming amendments do not involve a significant reduction in a margin of safety.</u>

The proposed amendments do not involve a significant reduction in a margin of safety because of the following:

- The amendments do not involve a change in the design, configuration, or operation of the nuclear plant. The change does not affect either the way in which the plant structures, systems, and components perform their safety function or their design and licensing bases.

- Plant safety margins are established through Limiting Conditions for Operation, Limiting Safety System Settings and Safety Limits specified in the Technical Specifications. Because there is no change to the physical design of the plant, there is no change to any of these margins.

Therefore, the proposed amendments do not involve a significant reduction in a margin of safety.

Form of Bilateral Power Sales Agreement By and Between Electric Generation LLC and Reorganized PG&E

Financial Qualifications Information: Financial Statement and Related Information

GEN
PROJECTED INCOME STATEMENT
($ Millions)

	Year 1[15]	Year 2	Year 3	Year 4	Year 5
Operating Revenues					
Nuclear					
Other Generation					
Total Operating Revenues	1473	1492	1510		
Operating Expenses					
Purchased Power	76	72	62		
Fuel	96	90	94		
Operation & Maintenance	365	401	354		
Depreciation & Amortization	49	53	62		
Administrative & Other	81	82	84		
Total Operating Expenses	667	697	657		
Operating Income (Loss)	805	795	853		
Other Non-Operating Income (Deductions)	(195)	(191)	(185)		
Income Before Income Taxes	611	605	668		
Income Taxes	247	245	271		
Net Income (Loss)	363	360	397		

15 Year 1 is the first 12 month period following closing on the transaction and implementation of the license transfers.

GEN
PROJECTED OPENING BALANCE SHEET
($ Millions)

ASSETS		LIABILITIES	
Current Assets		**Current Liabilities**	
Cash and Temporary Cash Investments	0	Accounts Payable	72
Accounts Receivable	200	Other Current Liabilities	0
Inventories	66	Total Current Liabilities	72
Other Current Assets	0		
Total Current Assets	266		
Fixed Assets		**Non-Current Liabilities**	
Plant	874	DOE Decontamination & Decommissioning Assessment	6
Fuel	170	Funded Decommissioning Liability	1,219
Total Fixed Assets	1,044	Unfunded Decommissioning Liability	0
		Other Long Term Liabilities	16
		Total Non-Current Liabilities	1,242
Other Long Term Assets		**Capitalization**	
Decommissioning Funds	1,219	Debt	2,400
Goodwill	0	Equity	(1,183)
Other Long Term Assets	1	Total Capitalization	1,217
Total Other Assets	1,220		
Total Assets	2,530	**Total Liabilities & Capitalization**	2,530

GEN
KEY ASSUMPTIONS

	Year 1	Year 2	Year 3	Year 4	Year 5
Generation (GWh)[16]					
Nuclear					
Non-Nuclear					
Purchases					
Total Supply (GWh)					
Market Sales (GWh)					
Average Market Price ($/MWh)[17]					
Total Generation Revenues ($ Millions)					
Nuclear Capacity Factor					

16 Net of transmission line losses.

17 Average Market Price is derived from the proposed bilateral power sales agreement rather than forward market price projections. The Average Market Price is calculated as total revenue divided by total electric output.

GEN
ESTIMATED NUCLEAR COSTS

AGGREGATE: TWO DCPP UNITS

($ Millions)

Year	Operating and Maintenance Expenses	Fuel Capital Expenses	Additional Capital Expenses		Total[18]
			Base Capital	Major Projects[19]	
1					
2					
3					
4					
5					

[18] These totals exclude approximately _____ per year of Administrative and General expenses attributed to DCPP.

[19] Major Projects in Years 1 through 3 include ______________________. Major Projects in Years 4 through 5 include partial cost of ______________________________. DCPP Independent Spent Fuel Storage Installation (dry cask storage) is reflected as an operating expense, not a capital expense.

Decommissioning Funding Assurance: Calculation Demonstrating Adequacy of "Prepayment Amount"

Diablo Canyon Power Plant, Unit 1
License Expires September 22, 2021

Funding Status Assuming 0.84% Net After-Tax Earnings[20]
($ Millions)

Calendar Year	Contribution	Earnings	Balance	NRC Minimum (2002)	NRC Minimum Status
2001	1.92	-	482.75[21]	347.88	Fully Funded
2002	7.68	30.61	521.04	367.01	Fully Funded
2003	-	33.03	554.07	387.20	Fully Funded
2004	-	35.13	589.20	408.50	Fully Funded
2005	-	37.36	626.56	430.96	Fully Funded
2006	-	39.72	666.28	454.67	Fully Funded
2007	-	42.24	708.52	479.67	Fully Funded
2008	-	44.92	753.44	506.06	Fully Funded
2009	-	47.77	801.21	533.89	Fully Funded
2010	-	50.80	852.01	563.25	Fully Funded
2011	-	54.02	906.03	594.23	Fully Funded
2012	-	57.44	963.47	626.91	Fully Funded
2013	-	61.08	1,024.55	661.39	Fully Funded
2014	-	64.96	1,089.51	697.77	Fully Funded
2015	-	69.07	1,158.58	736.15	Fully Funded
2016	-	73.45	1,232.04	776.64	Fully Funded
2017	-	78.11	1,310.15	819.35	Fully Funded
2018	-	83.06	1,393.21	864.42	Fully Funded
2019	-	88.33	1,481.54	911.96	Fully Funded
2020	-	93.93	1,575.47	962.12	Fully Funded
2021	-	72.05	1,647.53	1,000.33	Fully Funded

20 The assumption is based upon the current California Public Utilities Commission authorized after-tax earnings rate.

21 Reflects projected end-of-year 2001 balance, including contributions made in 2001. Liquidation value as of September 30, 2001, was $473.5 million.

Calculation Notes for DCPP Unit 1

Contribution: PG&E is currently authorized to contribute a total of $24.003 million per year to the Diablo Canyon Nuclear Decommissioning Master Trusts. Unit 1's portion of the total contribution is $7.68 million. For 2001, only the 4th Quarter contribution, to be made December 28, 2001, is shown as a contribution. Contributions for the first three Quarters are included in the end-of-year 2001 balance.

Earnings: PG&E has assumed after-tax earnings to the trust of 6.34 percent per year. (The liability (cost estimate) is grown at 5.5 percent per year, resulting in a 0.84 percent after-tax real growth rate on the trust.) Earnings are calculated each year by multiplying the prior year's balance by 6.34 percent. Year 2021 earnings are calculated on a partial-year basis.

Balance: The end-of-year 2002 balance is determined as follows —

PG&E used the liquidation value of the Unit 1 trust ($473.5 million) as of September 30, 2001 and determined an end-of-year 2001 balance by escalating the trust asset at 6.34 percent per annum for the remaining 3 months of 2001. After adding in the 4th Quarter 2001 contribution, the resulting end-of-year 2001 balance was $482.75 million. ($473.5 * (1.0634^(3/12)) + $1.92)

Contributions of $7.68 million and earnings of $30.61 million (calculated at 6.34 percent of the year 2001 balance) are then added to the year end 2001 balance of $482.75 million to derive the end-of-year 2002 balance of $521.04 million.

Current year end balances are calculated by adding prior end-of-year balances to the current year's earnings and contributions.

Year 2021 balances are calculated on a partial-year basis.

NRC Minimum: The Calendar Year 2002 NRC Minimum for Unit 1 of $367.01 million is calculated as follows —

PG&E's March 2001 letter to the NRC (DCL-01-026) indicated the total NRC decommissioning fund estimate in January 2001 dollars, based on preliminary October 2000 through January 2001 data, was $793.4 million. That number represents the combined Unit 1 and Unit 2 NRC decommissioning fund estimate.

PG&E updated the January 2001 estimate to reflect actual October 2000 through January 2001 data. The January 2001 actual combined Unit 1 and Unit 2 NRC decommissioning fund estimate is $795.6 million.

To determine the end-of-year 2001 total decommissioning fund estimate, PG&E escalated the balance at 5.5 percent per annum for the remaining 11 months of

2001. The resulting end-of-year 2001 balance was $835.6 million. ($795.6 * (1.055^(11/12)).

The $835.6 million was allocated to Units 1 and 2 using site-specific decommissioning cost estimates prepared for PG&E by TLG, Inc. By Unit, the NRC amount is as follows:

	TLG Estimate	Percent of Total	NRC Decom
Unit 1	436.6	41.6 %	$347.88 (41.6% * $835.6)
Unit 2	612.1	58.4 %	$487.72 (58.4% * $835.6)
Total	1,048.7	100.0 %	$835.6

Years 2002 forward, are determined by multiplying the end-of-year 2001 amount by an escalation factor of 5.5 percent.

Diablo Canyon Power Plant, Unit 2
License Expires April 26, 2025

Funding Status Assuming 0.84% Net After-Tax Earnings[22]
($ Millions)

Calendar Year	Contribution	Earnings	Balance	NRC Minimum (2002)	NRC Minimum Status
2001	4.08	-	641.28[23]	487.72	Fully Funded
2002	16.32	40.66	698.26	514.54	Fully Funded
2003	0.00	44.27	742.53	542.84	Fully Funded
2004	0.00	47.08	789.60	572.70	Fully Funded
2005	0.00	50.06	839.67	604.20	Fully Funded
2006	0.00	53.23	892.90	637.43	Fully Funded
2007	0.00	56.61	949.51	672.49	Fully Funded
2008	0.00	60.20	1,009.71	709.47	Fully Funded
2009	0.00	64.02	1,073.72	748.50	Fully Funded
2010	0.00	68.07	1,141.80	789.66	Fully Funded
2011	0.00	72.39	1,214.19	833.09	Fully Funded
2012	0.00	76.98	1,291.17	878.91	Fully Funded
2013	0.00	81.86	1,373.03	927.25	Fully Funded
2014	0.00	87.05	1,460.08	978.25	Fully Funded
2015	0.00	92.57	1,552.65	1,032.06	Fully Funded
2016	0.00	98.44	1,651.09	1,088.82	Fully Funded
2017	0.00	104.68	1,755.76	1,148.71	Fully Funded
2018	0.00	111.32	1,867.08	1,211.88	Fully Funded
2019	0.00	118.37	1,985.45	1,278.54	Fully Funded
2020	0.00	125.88	2,111.33	1,348.86	Fully Funded
2021	0.00	133.86	2,245.19	1,423.05	Fully Funded
2022	0.00	142.34	2,387.53	1,501.31	Fully Funded
2023	0.00	151.37	2,538.90	1,583.89	Fully Funded
2024	0.00	160.97	2,699.87	1,671.00	Fully Funded
2025	0.00	55.89	2,755.76	1,701.09	Fully Funded

22 The assumption is based upon the current California Public Utilities Commission authorized after-tax earnings rate.

23 Reflects projected end-of-year 2001 balance, including contributions made in 2001. Liquidation value as of September 30, 2001, was $627.5 million.

Calculation Notes for DCPP Unit 2

Contribution: PG&E is currently authorized to contribute a total of $24.003 million per year to the Diablo Canyon Nuclear Decommissioning Master Trusts. Unit 2's portion of the total contribution is $16.32 million. For 2001, only the 4th Quarter contribution, to be made December 28, 2001, is shown as a contribution. Contributions for the first three Quarters are included in the end-of-year 2001 balance.

Earnings: PG&E has assumed after-tax earnings to the trust of 6.34 percent per year. (The liability (cost estimate) is grown at 5.5 percent per year, resulting in a 0.84 percent after-tax real growth rate on the trust.) Earnings are calculated each year by multiplying the prior year's balance by 6.34 percent. Year 2025 earnings are calculated on a partial-year basis.

Balance: The end-of-year 2002 balance is determined as follows —

> PG&E used the liquidation value of the Unit 2 trust ($627.48 million) as of September 30, 2001 and determined an end-of-year 2001 balance by escalating the trust asset at 6.34 percent per annum for the remaining 3 months of 2001. After adding in the 4th Quarter 2001 contribution, the resulting end-of-year 2001 balance was $641.28 million. ($627.48 * (1.0634^(3/12)) + $4.08)
>
> Contributions of $16.32 million and earnings of $40.66 million (calculated at 6.34 percent of the year 2001 balance) are then added to the year end 2001 balance of $641.28 million to derive the end-of-year 2002 balance of $698.26 million.
>
> Current year end balances are calculated by adding prior end-of-year balances to the current year's earnings and contributions.
>
> Year 2025 balances are calculated on a partial-year basis.

NRC Minimum: The Calendar Year 2002 NRC Minimum for Unit 2 of $514.54 million is calculated as follows —

> PG&E's March 2001 letter to the NRC (DCL-01-026) indicated the total NRC decommissioning fund estimate in January 2001 dollars, based on preliminary October 2000 through January 2001 data, was $793.4 million. That number represents the combined Unit 1 and Unit 2 NRC decommissioning fund estimate.
>
> PG&E updated the January 2001 estimate to reflect actual October 2000 through January 2001 data. The January 2001 actual combined Unit 1 and Unit 2 NRC decommissioning fund estimate is $795.6 million.
>
> To determine the end-of-year 2001 total decommissioning fund estimate, PG&E escalated the balance at 5.5 percent per annum for the remaining 11 months of

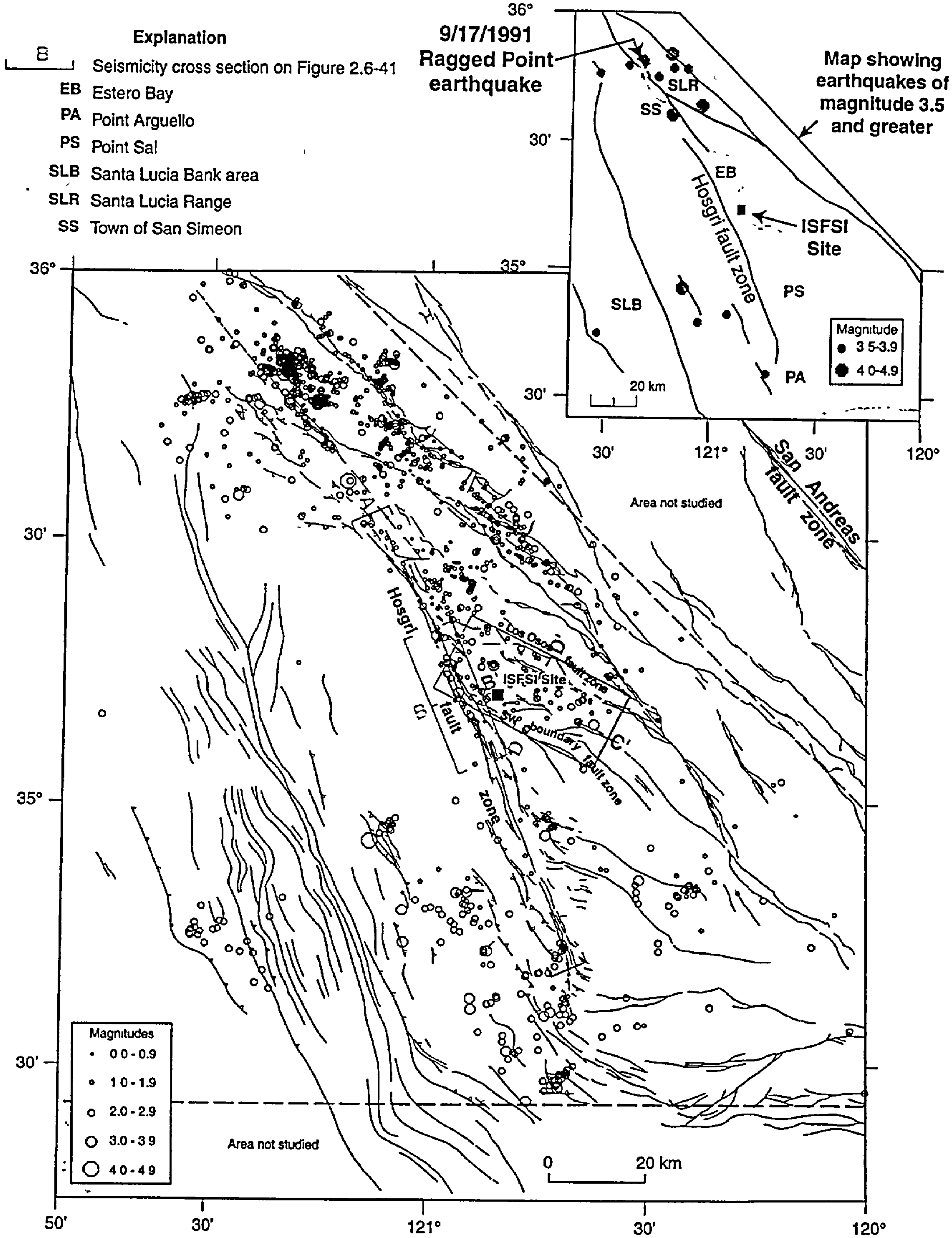
2001. The resulting end-of-year 2001 balance was $835.6 million. ($795.6 * (1.055^(11/12)).

The $835.6 million was allocated to Units 1 and 2 using site-specific decommissioning cost estimates prepared for PG&E by TLG, Inc. By Unit, the NRC amount is as follows:

	TLG Estimate	Percent of Total	NRC Decom
Unit 1	436.6	41.6 %	$347.88 (41.6% * $835.6)
Unit 2	612.1	58.4 %	$487.72 (58.4% * $835.6)
Total	1,048.7	100.0 %	$835.6

Years 2002 forward, are determined by multiplying the end-of-year 2001 amount by an escalation factor of 5.5 percent.

ATTACHMENT H

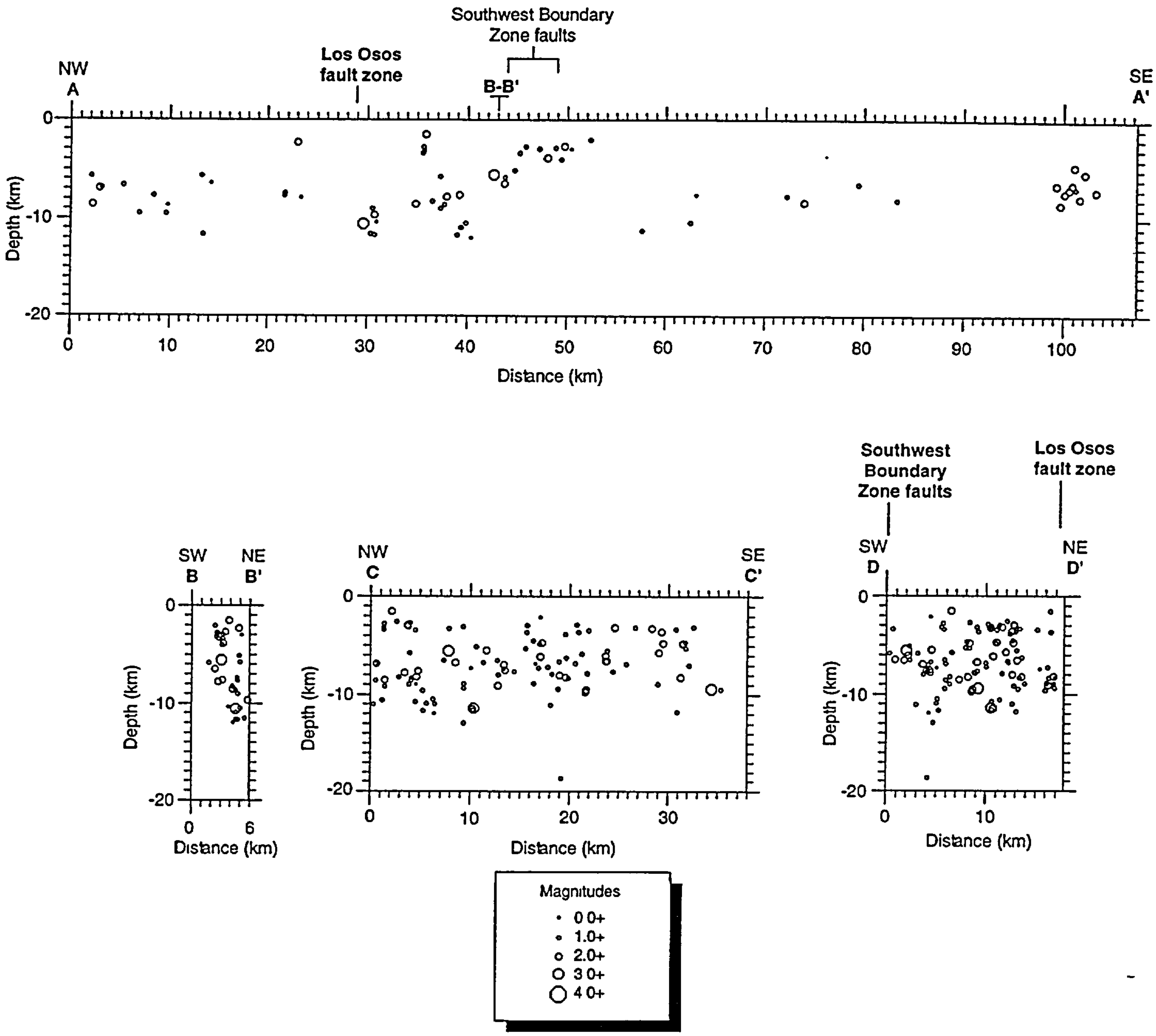


(From M K Mc Laren and W U. Savage, Seismicity of south-central coastal California, October 1987 through January 1997, Bulletin of the Seismological Society of America, in press)

SAFETY ANALYSIS REPORT

DIABLO CANYON ISFSI

FIGURE 2.6-40
QUATERNARY FAULTS AND SEISMICITY FROM OCTOBER 1987 THROUGH JANUARY, 1997

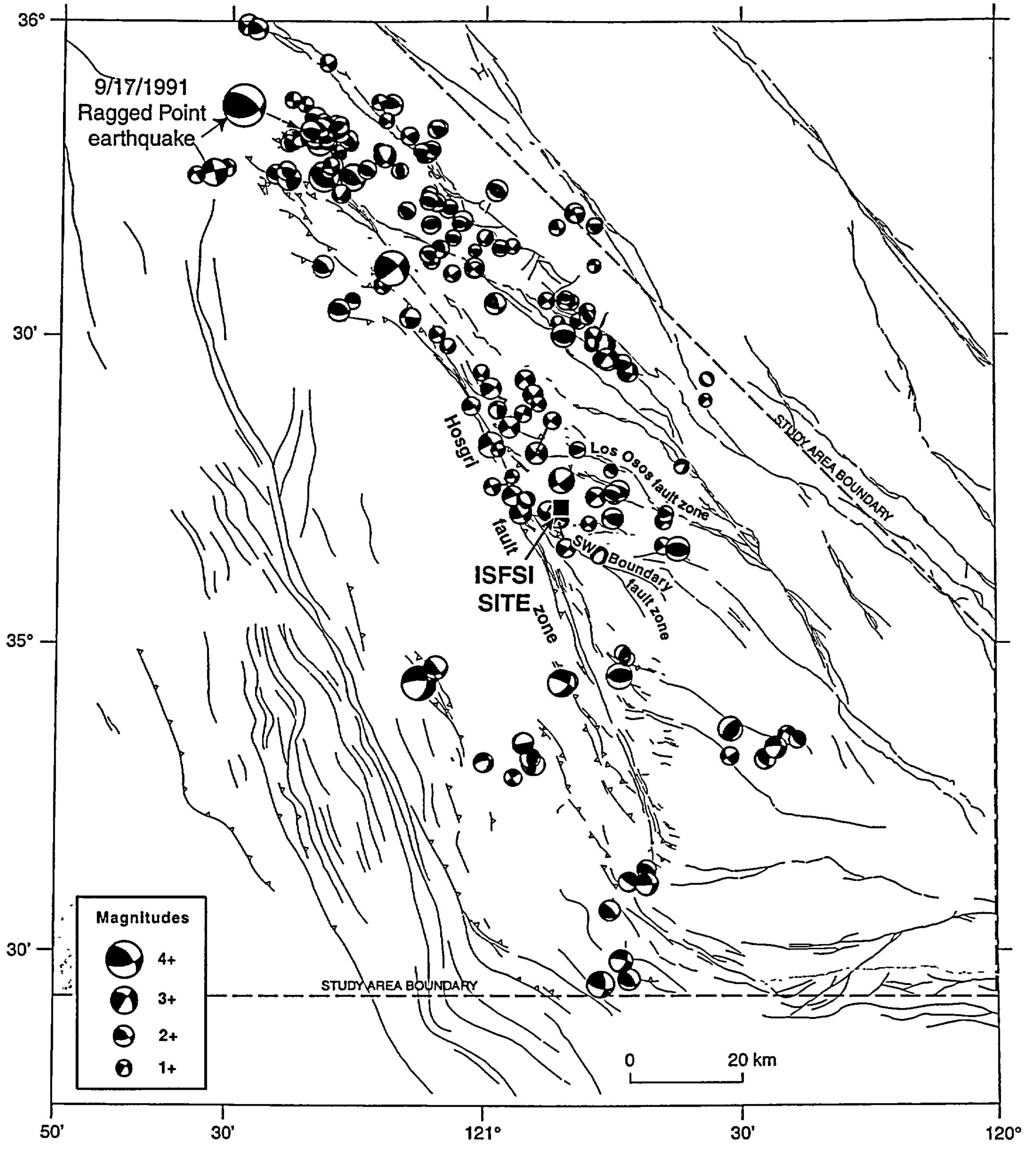


(From M K. Mc Laren and W U. Savage, Seismicity of south-central coastal California, October 1987 through January 1997, Bulletin of the Seismological Society of America, in press)

SAFETY ANALYSIS REPORT

DIABLO CANYON ISFSI

FIGURE 2.6-41
SEISMICITY CROSS SECTION A-A' THROUGH D-D' FOR EARTHQUAKES FROM OCTOBER 1987 THROUGH JANUARY 1997



(From M K Mc Laren and W.U Savage, Seismicity of south-central coastal California, October 1987 through January 1997, Bulletin of the Seismological Society of America, In press)

SAFETY ANALYSIS REPORT
DIABLO CANYON ISFSI
FIGURE 2.6-42 LOWER HEMISPHERE, P-WAVE FIRST-MOTION FOCAL MECHANISM PLOTS OF EARTHQUAKES FROM OCTOBER 1987 THROUGH JANUARY 1997