December 21, 2001

PG&E Letter DIL-01-002

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Docket No. 72-26
Diablo Canyon Independent Spent Fuel Storage Installation
License Application for Diablo Canyon Independent Spent Fuel Storage Installation

Dear Commissioners and Staff:

In accordance with 10 CFR 72, Subpart B, Pacific Gas and Electric Company (PG&E) hereby submits an application to the Nuclear Regulatory Commission (NRC) requesting a site-specific license for an Independent Spent Fuel Storage Installation (ISFSI) at the Diablo Canyon Power Plant (DCPP).

An ISFSI at Diablo Canyon is part of PG&E's plan to provide storage capacity for spent fuel generated by DCPP through the remainder of the term of the respective NRC operating licenses (DPL 80 and 82). A permanent repository is not yet available and is not expected to be available on a schedule to meet DCPP operational needs. The ISFSI that is the subject of this 10 CFR 72 application is required beginning in 2006. This plan for handling and storing spent fuel meets PG&E's statutory obligations and will allow for continuing operation of DCPP.

PG&E is submitting: (a) calculation packages (PG&E Letters DIL-01-004, dated December 21, 2001 and DIL-01-007, dated December 21, 2001); (b) proprietary and non-proprietary Holtec drawing packages (PG&E Letter DIL-01-008, dated December 21, 2001); (c) geologic data reports (PG&E Letter DIL-01-005, dated December 21, 2001); and (d) DCPP Security Program Revisions and Exemption Requests (PG&E Letter DIL-01-003, dated December 21, 2001) as supplemental information to support NRC review of the ISFSI license application.

In connection with this submittal, PG&E previously submitted a 10 CFR 50 license amendment request (LAR) (DCL-01-096, dated September 13, 2001) seeking NRC approval to take credit for soluble boron in the spent fuel pools in order to maximally use the existing storage capacity and thus provide spent fuel storage with full core offload capability through approximately 2006. PG&E will also submit a 10 CFR 50

LAR to permit cask handling activities in the DCPP fuel handling building/auxiliary building.

The Diablo Canyon ISFSI will use the Holtec dry cask storage system, which has previously been certified by the NRC. This license application and supporting materials demonstrate that the Diablo Canyon ISFSI will be built and operated in a safe manner, will have no impact on the operation of the power plant, and will have no significant environmental impacts. While additional amendments will be required for the 10 CFR 50 licenses for the power plant, as discussed below, they will involve no undue public health and safety risks.

Background

DCPP consists of two nuclear generation units located approximately 6 miles northwest of Avila Beach, California. The two units are essentially identical pressurized water reactors (PWRs), each rated at a nominal 1100 megawatts-electric (MWe). The two units share a common auxiliary building as well as certain components of auxiliary systems. The reactors, including their nuclear steam supply systems, were furnished by Westinghouse Electric Corporation. Each reactor has a dedicated fuel handling system and spent fuel storage pool. Both units and the plant site are owned and operated by PG&E.

Unit 1 began commercial operation in May 1985 and Unit 2 in March 1986. The operating licenses expire in September 2021 for Unit 1 and April 2025 for Unit 2. In general, the operating and spent fuel storage histories of DCPP Unit 1 and Unit 2 are similar to those of other PWRs. The spent fuel storage racks were initially of low-density design, capable of accommodating only one and one-third cores of spent fuel assemblies. These low-density racks were replaced in the late 1980s with the high-density racks that are currently in use.

The spent fuel pool for each unit presently has sufficient capacity for the storage of 1,324 fuel assemblies. Each reactor core contains 193 fuel assemblies, and both units are currently operating on 18 to 21-month refueling cycles. Typically, 76-96 spent fuel assemblies are permanently discharged from each unit after a refueling. Each unit has operated for 10 fuel cycles and each is presently operating in its 11th cycle. Based on the existing inventory and the expected generation of spent fuel, each spent fuel pool can accommodate the concurrent storage of a full core of irradiated fuel and the anticipated quantity of spent fuel generated from prior refueling operations until 2006. After that time, an alternative means of spent fuel storage at DCPP must be provided unless the spent fuel can be shipped offsite.

The Nuclear Waste Policy Act (NWPA) of 1982 as amended, mandated that the Department of Energy (DOE) assume responsibility for the permanent disposal of spent nuclear fuel from the nation's commercial nuclear power plants beginning in January 1998 pending the availability of a permanent DOE repository. Nuclear power plant operators such as PG&E have been given the responsibility under the NWPA to provide for the interim onsite storage of spent fuel until it is accepted by DOE. As noted above, DOE has not complied with its NWPA mandate to have a repository in operation commencing in January 1998, and no interim spent fuel storage facility has been established. Moreover, no such DOE facility is expected to become operational in a timeframe to meet DCPP's spent fuel storage needs. Thus, spent fuel generated by DCPP will need to remain at DCPP until a DOE or other facility is available. Consequently, additional spent fuel storage capacity is needed at DCPP beginning no later than 2006.

The additional capacity to accommodate discharged spent fuel, as proposed herein, will allow DCPP to continue to generate electricity. Any interruption in the availability of this capacity would almost certainly have a negative impact on the domestic sector power supply in California. Given the existing power supply situation in California and in the western United States as well as uncertainties about future power supplies, any loss of power from DCPP could have significant adverse impacts on the population, the infrastructure, and the economy. Expansion of the onsite spent fuel storage capacity at DCPP as planned by PG&E is necessary to avoid these potential significant negative impacts.

PG&E has considered several alternative means for accommodating the additional spent fuel that will be generated at DCPP through the licensed operating life of each unit. The onsite alternatives include a second reracking of the spent fuel pools to replace the existing high-density racks with racks of higher-density design and building an onsite ISFSI using dry cask storage technology. PG&E has also considered the possibility of participating in the Private Fuel Storage venture, which has an application pending before the NRC for a license to independently store spent fuel from nuclear power plants. Based on an overall assessment of operational and safety considerations, the amount of spent fuel to be generated, the transportation requirements associated with the alternatives, resources needed, and scheduling restraints, PG&E has concluded that dry cask storage of spent fuel at DCPP is the optimum alternative at this time for providing the necessary storage capacity. However, as discussed below, increasing the spent fuel pool storage capacity through a second reracking with higher density racks remains a viable option if it appears that the ISFSI cannot be licensed on a schedule that meets PG&E's storage requirements.

The expanded storage capacity provided by the use of dry casks at the ISFSI will be used to store aged spent fuel that has been stored for 5 years or longer in the DCPP spent fuel pools. The storage spaces in the respective spent fuel pools that become available following this transfer of the aged spent fuel into dry cask storage then can be used to store future discharged spent fuel from the reactor core. Storage casks will be acquired as needed to accommodate the spent fuel generated until shipment offsite occurs.

Dry Cask Storage: Licensing Considerations

The Diablo Canyon ISFSI will consist of: the ISFSI storage pad, the cask transfer facility (CTF), the onsite cask transporter, and the dry cask storage system. The dry cask storage system that has been selected by PG&E for the Diablo Canyon ISFSI is the Holtec International (Holtec) HI-STORM 100 System. The HI-STORM 100 System is comprised of a multi-purpose canister (MPC), the storage overpack, and the HI-TRAC transfer cask. The HI-STORM 100 System is certified by the NRC for use by general licensees as well as site-specific licensees, presently with a 24 PWR fuel assembly MPC and storage overpack (see NRC 10 CFR 72 Certificate of Compliance [CoC] No. 1014).

Holtec has proposed a number of changes to the certified HI-STORM 100 System in LAR 1014-1, submitted to the NRC on August 31, 2000. These proposed changes include a HI-STORM 100SA storage overpack, a higher-capacity MPC-32 design (for storage of 32 PWR spent fuel assemblies), and MPC designs with different fuel storage capabilities (e.g., high burnup fuel, certain damaged fuel). As discussed below, several of these proposed changes are desirable for the Diablo Canyon ISFSI. PG&E understands, however, that several of the proposed changes in LAR 1014-1, such as the designs to accommodate high burnup fuel, may involve extensive NRC review. As discussed below, issuance of a revised Certificate of Compliance No. 1014-1 may not necessarily be required to support the plant-specific Diablo Canyon ISFSI license.

The Diablo Canyon ISFSI is designed to hold up to 140 storage casks (138 casks plus 2 spare locations). Because of its higher capacity, the principal MPC to be used will be the MPC-32. Based on the current fuel strategy and use of the MPC-32, the ISFSI with a storage pad capacity of 140 casks will be capable of storing the spent fuel generated by DCPP Units 1 and 2 over the term of the current operating licenses (2021 and 2025, respectively). In addition, to accommodate spent fuel generated during the licensed period, as well as any damaged fuel assemblies, debris, and nonfuel hardware, PG&E may use three other MPC designs from the HI-STORM 100 System: the MPC-24, MPC-24E, and MPC-24EF. All four MPC designs use the same storage overpack and are either licensed by current CoC No. 1014 or will be licensed by future revisions to CoC No. 1014. These MPC designs will accommodate most of the DCPP-specific fuel characteristics.

PG&E's application incorporates these designs in a preferred cask system licensing approach as follows:

- The initial Diablo Canyon ISFSI site-specific license would incorporate the MPC capabilities as specified in CoC No. 1014, as proposed to be amended in the Holtec LAR 1014-1. The NRC is anticipated to issue a final technical review on LAR 1014-1 and a preliminary Safety Evaluation Report (SER) in late December 2001 or early 2002. Rulemaking is expected to be completed in mid-2002. While the MPC capabilities covered by the Holtec CoC No. 1014 and LAR 1014-1 will not completely envelope all of the spent fuel characteristics eventually needed for DCPP fuel, they will cover most of the current spent fuel pool inventory and will permit the storage of nearly all spent fuel and associated nonfuel hardware generated through the license terms.

- MPC designs needed for the balance of DCPP's spent fuel characteristics will be addressed in future revisions to the CoC. As these changes are submitted by Holtec and approved by the NRC, PG&E will amend the Diablo Canyon ISFSI site-specific license to incorporate these changes. The resulting capability will provide PG&E with the flexibility to store onsite all the spent fuel and nonfuel hardware from DCPP Units 1 and 2 generated during the term of its current operating licenses.

- In a Federal Register Notice dated October 11, 2001 (66 FR 51823), NRC issued the final rule change regarding greater than Class C (GTCC) waste (e.g., split pins and thimble tubes). The rule change applies only to the interim storage of GTCC waste generated or used by commercial nuclear power plants. The rule change allows interim storage of reactor-related GTCC wastes under a 10 CFR 72 site-specific license. In accordance with the guidance of ISG-17, PG&E plans to request a modification to its proposed site-specific license at a future date to allow interim storage of GTCC wastes at the Diablo Canyon ISFSI. These wastes are currently stored in the DCPP spent fuel storage pool.

Licensing of the Diablo Canyon ISFSI also involves NRC review of a number of site-specific issues. These include the site-specific environmental review, geotechnical issues related to the site, natural phenomena, and other site-specific matters. Holtec LAR 1041-1 includes a high-seismic capability for the storage overpack (the HI-STORM 100SA). However, LAR 1014-1 does not incorporate some Diablo Canyon specific information (e.g., the pad design, the overpack seismic anchorage design, the cask transporter seismic design, and the CTF design). PG&E is submitting information on these matters as part of this site-specific application and intends that these issues be reviewed and licensed as part of the PG&E site-specific 10 CFR 72 license.

In order to expedite the determination of the feasibility of licensing a dry cask storage facility at DCPP on a schedule that would support PG&E's spent fuel storage needs, PG&E requests that the NRC:

- Initiate a review of the site-related and unique design aspects of PG&E's 10 CFR 72 license application immediately following completion of the 10 CFR 72 application acceptance review

- Continue review of Holtec LAR 1014-1, in parallel with the 10 CFR 72 review of Diablo Canyon site-related issues

- Following issuance of a preliminary safety evaluation for Holtec LAR 1014-1 (currently scheduled for late December 2001 or early 2002), initiate a review of the remaining Diablo Canyon cask-related issues.

If the schedule for issuance of a CoC for Holtec LAR 1014-1 extends significantly beyond the currently scheduled mid-2002, PG&E requests that the NRC consider issuing an SER for use of the MPC-24 (which is already certified in CoC No. 1014) at Diablo Canyon. While the MPC-32 is the preferred MPC due to its larger storage capacity, licensing the MPC-24 for use at Diablo Canyon would allow PG&E to begin dry cask storage to meet initial spent fuel storage needs.

Schedule

In order to support the operational needs for continued Diablo Canyon operation, PG&E requests that the Diablo Canyon ISFSI license be issued by December 2003. PG&E's schedule for constructing and operating the Diablo Canyon ISFSI is dependent upon the timely completion of the NRC environmental review process and timely technical reviews of the site-specific license application. With the submittal of the ISFSI license application in 2001, based on a review of other licensee schedules, PG&E believes that the review process at the NRC can be completed in approximately 2 years. Assuming no delays in the review process, and NRC issuance of the Diablo Canyon ISFSI license in 2003, PG&E plans to have the Diablo Canyon ISFSI in full operational status with initial placement of fuel in storage casks in 2005. This schedule provides a contingency period to ensure the Diablo Canyon ISFSI operation by 2006.

PG&E emphasizes that meeting the storage needs by 2006 is essential for continued DCPP operation. If the licensing schedule for the Diablo Canyon ISFSI cannot support that need with assurance, PG&E will need to re-evaluate other alternatives for spent fuel storage. As noted above, PG&E is presently maintaining the option of reracking the spent fuel pools to provide additional storage with full core offload capability past 2006. However, the lead time to implement this alternative is significant. Accordingly, PG&E needs to promptly determine the feasibility of licensing the Diablo Canyon ISFSI on the required schedule, and therefore requests an expedited NRC decision on the feasibility of the licensing approach and schedule outlined above.

Although initial site characterization and storage system design activities have been conducted for the Diablo Canyon ISFSI, PG&E does not plan to initiate extensive facility construction activities until the NRC environmental review is completed, and the Diablo Canyon ISFSI license has been issued or the necessary environmental findings made. Thus, Diablo Canyon ISFSI construction work is not expected to begin until 2004 at the earliest. Nonetheless, pending NRC approval of the Diablo Canyon ISFSI license application, PG&E intends to proceed with relatively minor site preparation activities such as infrastructure development and access road work, and is in the process of obtaining the appropriate permits from other agencies.

Application Overview

In support of this 10 CFR 72 license application, PG&E is submitting the following:

- One original License Application signed under oath
- Fifteen copies of the License Application
- Fifteen copies of the Safety Analysis Report
- Fifteen copies of the Environmental Report

In accordance with Regulatory Guide 3.50, the Emergency Plan, proposed Technical Specifications, Training Program, Quality Assurance (QA) Program, and Preliminary Decommissioning Plan are included as attachments to the License Application.

With respect to the QA program required by 10 CFR 72, Subpart G, the DCPP QA Program (Chapter 17 of the DCPP Final Safety Analysis Report Update) was revised to include the Diablo Canyon ISFSI requirements and is included as Attachment E to the License Application. PG&E intends to apply this revised QA Program to its Diablo Canyon ISFSI activities, and is submitting the revised QA Program to allow the NRC to make a finding that the QA Program complies with 10 CFR 72, Subpart G.

The DCPP Security Program, which includes the Security Training and Qualification Plan and Safeguards Contingency Plan, has been revised, as applicable to include the Diablo Canyon ISFSI requirements and is being submitted under separate cover (reference PG&E Letter DIL-01-003, dated December 21, 2001).

Other Matters

The information contained in this License Application is not considered to be proprietary.

In addition to the approval from the NRC under 10 CFR 72, other state and local permits and licenses will be required to support the construction and operation of the Diablo Canyon ISFSI, as discussed in detail in Chapter 9 of the Environmental Report. With respect to the State of California, PG&E applied for a Coastal Development Permit (CDP) in November 2001. The CDP application will require an environmental determination in accordance with state law. The County of San Luis Obispo acts as the lead agency on behalf of the state. PG&E encourages NRC coordination with the County during the environmental review process.

If you have any questions regarding this application or require additional information, please contact Mr. Terence Grebel at (805) 595-6382.

Sincerely,

Lawrence F. Womack

cc: Timothy J. Kobetz
Ellis W. Merschoff
David L. Proulx
Girija S. Shukla
David A. Repka
Brian Gutherman
Thomas A. Moulia
Roy B. Willis
Diablo Distribution w/o Enclosures

Enclosures

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of PACIFIC GAS AND ELECTRIC COMPANY)	Docket No. 72-26
Diablo Canyon Independent Spent Fuel Storage Installation)	

AFFIDAVIT

Lawrence F. Womack, of lawful age, first being duly sworn upon oath says that he is Vice President, Nuclear Services of Pacific Gas and Electric Company; that he has executed PG&E Letter DIL-01-002 (License Application for the Diablo Canyon ISFSI) on behalf of said company with full power and authority to do so; that he is familiar with the content thereof; and that the facts stated therein are true and correct to the best of his knowledge, information, and belief.

Lawrence F. Womack
Vice President, Nuclear Services

Subscribed and sworn to before me this 15 th day of December, 2001.

Amy J. Calloway
Notary Public
County of San Luis Obispo
State of California

AMY J. CALLOWAY
Commission # 1275128
Notary Public - California
San Luis Obispo County
My Comm. Expires Aug 26, 2004

Diablo Canyon Power Plant

Independent Spent Fuel Storage Installation

License Application

Pacific Gas and Electric Company
Avila Beach, California

Table of Contents

1.0 General and Financial Information

1.1 Application for License

In accordance with the requirements of 10 CFR 72, Pacific Gas and Electric Company (PG&E) hereby submits a site-specific license application to construct and operate an Independent Spent Fuel Storage Installation (ISFSI) located at the site of the Diablo Canyon Power Plant (DCPP) in Avila Beach, California. The proposed facility is named the Diablo Canyon ISFSI.

This application for the proposed ISFSI contains information required by the provisions of 10 CFR 72, Subpart B and was prepared using the guidance of Regulatory Guide 3.50, Revision 1. The application consists of the following:

a. The license application.
b. The technical information and safety analysis report required by 10 CFR 72.24 is provided as a separate document titled "Diablo Canyon Independent Spent Fuel Storage Installation Safety Analysis Report".
c. The Emergency Plan required by 10 CFR 72.32 is provided as a revision of the DCPP Emergency Plan. (Attachment B)
d. The proposed technical specifications are provided as a separate document titled, "Diablo Canyon ISFSI Technical Specifications." (Attachment C)
e. The environmental report required by 10 CFR 72.34 is provided in a separate document titled, "Diablo Canyon Independent Spent Fuel Storage Installation Environmental Report."
f. Security information as required by 10 CFR 72, Subpart H, is being submitted under separate cover as a revision to the DCPP Security Plan. (Reference PG&E Letter DIL-01-003 dated December 21, 2001.)
g. A training program as required by 10 CFR 72.192 is provided as a separate document, "Diablo Canyon ISFSI Training Program." (Attachment D)
h. A description of the quality assurance program required by 10 CFR 72.24(n) is provided as a revision to DCPP Quality Assurance Program contained in the DCPP Final Safety Analysis Report Update. (Attachment E)

1.2 Applicant

Pacific Gas and Electric Company is a wholly owned subsidiary of PG&E Corporation and is the owner of the Diablo Canyon Independent Spent Fuel Storage Installation.

The address for PG&E at Diablo Canyon is:

Pacific Gas and Electric Company
PO Box 56
Avila Beach, CA 93424

1.3 Description of Business of Applicant

Pacific Gas and Electric Company, including its subsidiaries, is a wholly owned subsidiary of PG&E Corporation, which was incorporated in 1995. PG&E Corporation is a holding company based in San Francisco, California, which provides energy services throughout North America.

Pacific Gas and Electric Company is an operating public utility primarily regulated by the California Public Utilities Commission and engaged principally in the business of providing electric and natural gas services throughout most of Northern and Central California. The principal executive offices of PG&E Corporation are located at One Market, Spear Tower, Suite 2400, San Francisco, California 94105. The principal executive offices of Pacific Gas and Electric Company are located at 77 Beale Street, P.O. Box 770000, San Francisco, California, 94177.

As of December 31, 2000, PG&E Corporation had $35.3 billion in assets. PG&E Corporation generated $26.2 billion in operating revenues for 2000. As of December 31, 2000, PG&E Corporation and its subsidiaries and affiliates had approximately 23,300 employees. As of December 31, 2000, Pacific Gas and Electric Company had $22 billion in assets. Pacific Gas and Electric Company generated $9.6 billion in operating revenues for 2000.

As of December 31, 2000, Pacific Gas and Electric Company had approximately 19,800 employees. PG&E is the sole owner and operator of DCPP.

In addition to the regulated utility business of Pacific Gas and Electric Company, PG&E Corporation's other affiliated businesses include the ownership and operation of natural gas pipelines, natural gas storage facilities, and natural gas processing plants, primarily in the Pacific Northwest, through various subsidiaries of PG&E Corporation PG&E Gas Transmission; development, construction, operation, ownership, and management of independent power generation facilities through its National Energy Group; the purchase and sale of energy commodities and financial instruments to PG&E Corporation's other businesses, unaffiliated utilities, marketers, municipalities, cooperatives, independent power producers, and large end-use customers through PG&E Energy Trading Corporation and its affiliates (PG&E Energy Trading). On September 1, 1998, PG&E Corporation through its indirect subsidiary, USGen New England, completed the acquisition of a portfolio of electric generating assets and power supply contracts from the New England Electric System.

1.4 Legal Status and Organization

PG&E is a corporation organized and existing under the laws of the State of California and its principal office is located in San Francisco, California at the address stated above. PG&E is not foreign owned, controlled or dominated and makes this application on its own behalf. PG&E is not acting as an agent or representative of any other person. A list of officers is provided in the PG&E Corporation 2000 Annual Report. This report is included as Attachment A.

1.5 Financial Qualifications

PG&E will have the financial qualifications to construct and operate the DCPP ISFSI. The total cost of building and operating the Diablo Canyon ISFSI for the first period, from now to 2025, is estimated to be $132 million. The cost assumes 50 storage casks are loaded to maintain full offload capability until the end of license with room in the spent fuel pool to completely offload the cores at end of license. The costs to completely offload the spent fuel pools, an additional 88 storage casks, and operate the ISFSI in the second period from 2026 until 2040, is estimated to be an additional $107 million. Additional costs, beyond 2040, are estimated to be $1.5 million per year. All costs are in year 2001 dollars. The funds necessary to cover the costs in the first period will be derived from electric rates and from electric operating revenues. The costs for the second period, and continuing costs until all the fuel is removed from the site, will be derived from the DCPP Decommissioning Fund.

Presently, PG&E is an electric utility subject to rates established by the California Public Utilities Commission (CPUC). As long as PG&E remains the licensee, both capital expenditures and operation and maintenance costs will be covered by revenues derived from electric rates. PG&E's assets and revenues are discussed above. On April 6, 2001, PG&E filed a petition for relief under Chapter 11 of the United States Bankruptcy Code. Since that time, PG&E's contracts have been under the jurisdiction of the Bankruptcy Court. PG&E's contract with Holtec related to the ISFSI, including the dry cask storage system, has been approved by the Bankruptcy Court and costs under the contract have been authorized.

On September 20, 2001, PG&E filed with the Bankruptcy Court a comprehensive plan of reorganization for PG&E. The plan of reorganization involves a complete restructuring of PG&E's businesses and operations. Under the plan, PG&E's generating assets, including Diablo Canyon and the proposed ISFSI, will be transferred to a new generating company named Electric Generation LLC ("Gen"). Gen will be a subsidiary of PG&E Corporation (presently PG&E's parent corporation), and PG&E will be separated from PG&E Corporation. The plan of reorganization is subject to confirmation by the Bankruptcy Court, but is intended to restore PG&E to financial health and to create financially sound companies, such as Gen, going forward.

On November 30, 2001, PG&E filed with the NRC a request for NRC consent to a transfer of the Part 50 operating license for DCPP to Gen. (In addition, the application requests approval of a transfer of ownership of the asset to a subsidiary of Gen, Diablo Canyon LLC.) The license transfer application includes financial data for the first five years of operation of Diablo Canyon by Gen, beginning with the assumed implementation of the reorganization plan by the end of 2002. Upon implementation, costs related to the ISFSI will be treated as Diablo Canyon operating expenses. The source of funds to cover these costs will be operating revenues. The financial data included with the license transfer application shows the estimated Diablo Canyon costs for five years, including costs associated with the ISFSI. The data also shows the substantial projected revenues and income of Gen based upon both nuclear and hydroelectric electricity generation, as well as the substantial assets of the company. In total, this data demonstrates the financial qualifications of Gen to construct and operate the Diablo Canyon ISFSI, and to become the site-specific Part 72 licensee for that facility once the Part 50 license transfer is approved by the NRC and the reorganization plan is implemented.

The funds necessary for decommissioning of the proposed ISFSI are estimated to be approximately $13.9 million when escalated to 2001 dollars, for the DECON alternative. The detailed cost estimate was reflected in PG&E's March 2001 Decommissioning Funding Report to the NRC as required by 10 CFR 50.75 (f)(1). This estimate covers only the costs for decontamination and disposal of low level waste; it does not cover the costs of demolition and disposal of non-contaminated material, which costs for the Diablo Canyon ISFSI are estimated to be $7.3 million in 2001 dollars. PG&E has established an external sinking fund account for decommissioning DCPP Units 1 and 2, as discussed in the March 2001 Decommissioning Funding Report to the NRC. This account contains monies for decommissioning the Diablo Canyon ISFSI.

1.6 Site Location and Completion Dates

The ISFSI will be located at the Diablo Canyon Power Plant within the existing owner-controlled area in San Luis Obispo County, California.

The projected spent fuel storage requirements for DCPP necessitate operation of the ISFSI beginning in 2006. To meet this schedule, PG&E requests that the 10 CFR 72 license and associated 10 CFR 50 license amendment be issued by the end of 2003.

1.7 Communications

It is requested that communications pertaining to this application be sent to:

Gregory M. Rueger
Senior Vice President
Generation and Chief Nuclear Officer
77 Beale Street, MC B32
San Francisco, CA 94105

Copies should also be sent to:

Terence L. Grebel
Manager, Regulatory Projects
Diablo Canyon Power Plant
P.O. Box 56
Avila Beach, CA 93424

Richard F. Locke
Pacific Gas and Electric
Law Department
77 Beale Street, MC B30A
San Francisco, CA 94105

2.0 Technical Qualifications

The technical qualifications of the PG&E staff for managing the design, construction and operation of the Diablo Canyon ISFSI are contained in Chapter 9 of the Diablo Canyon ISFSI Safety Analysis Report. Due to the passive nature of the ISFSI and its relatively infrequent demand on operations personnel, it is expected that ISFSI operations can be scheduled so the normal station organization can accommodate the ISFSI storage-related responsibilities without the need for obtaining additional personnel. Qualified contractor personnel may be used for cask handling activities at the Cask Transfer Facility and cask transport activities onsite. PG&E will maintain an adequate staff of trained and certified personnel for the conduct of all ISFSI operations.

3.0 Technical Information – Safety Analysis Report

The Diablo Canyon ISFSI will use sealed multi-purpose canisters (MPCs) placed inside storage overpacks to store spent fuel and other approved contents from the Diablo Canyon Power Plant Units 1 and 2. The spent fuel assemblies and nonfuel hardware that meet the Diablo Canyon Technical Specification and Diablo Canyon ISFSI Safety Analysis Report Chapter 10 requirements will be placed into the MPCs under water in the Diablo Canyon Power Plant spent fuel pool. The loaded MPCs and associated transfer cask will then be lifted out of the water. The lid will then be welded and the outer surface decontaminated. The water in the MPC fuel cavity will be removed, any remaining water in the cavity dried, and the vent and drain ports in the lid welded closed. The transfer cask will then be placed onto a transporter and transported to the CTF. At the CTF, the MPC will be transferred to a storage overpack and then transported to the ISFSI storage pad for storage. The storage overpack and MPC are totally passive systems with natural convection cooling sufficient to maintain safe fuel cladding temperatures. The storage cask provides shielding, and no radioactive materials are anticipated to be released under normal operating conditions.

The Diablo Canyon ISFSI is designed to store all of the spent fuel and associated nonfuel hardware resulting from the operation of the Diablo Canyon Power Plant Units 1 and 2 through 2021 and 2025 respectively. The total spent fuel storage design capacity of the facility is 4400 spent fuel assemblies or up to 140 casks (138 casks with two spare locations).

The Safety Analysis Report (SAR) filed with this application describes the design criteria for the dry cask storage system, transporter, storage pad, cask transfer facility and all related matters pertaining to operation of the ISFSI. The Holtec International HI-STORM 100 System Final Safety Analysis report and the related LAR 1014-1 contain detailed descriptions of the dry cask storage system and how it meets the prescribed criteria. This documentation has been previously filed with the Nuclear Regulatory Commission and is specifically relied upon in this Application, as referenced herein. The NRC has previously issued Certificate of Compliance 1014 for the HI-STORM 100 system. The combination of the Diablo Canyon ISFSI SAR and the Holtec Reports listed in the Diablo Canyon SAR Section 1.5 provide all the information required by 10 CFR 72.

The Diablo Canyon ISFSI SAR follows the format specified in Regulatory Guide 3.62, "Standard Format and Content for the Safety Analysis Report for Onsite Storage of Spent Nuclear Fuel Storage Casks," dated February 1989. The Topical Safety Analysis Reports describing the vendor dry cask storage system follow the format specified in Regulatory Guide 3.61, "Standard Format and Content for a Topical Safety Analysis Report for a Spent Fuel Dry Storage Cask", Revision 1, February 1989.

4.0 Conformity with General Design Criteria

Subpart F of 10 CFR 72 provides the general design criteria for an ISFSI. The Diablo Canyon ISFSI complies with all the applicable 10 CFR 72 design criteria. The specific conformance of the Diablo Canyon ISFSI to the 10 CFR 72 general design criteria is addressed in detail in the SAR and other documents attached thereto. A detailed cross-reference of the design criteria to the applicable sections of the SAR and other documents is provided in SAR Table 4.2-4.

5.0 Operating Procedures-Administrative and Management Controls

The Diablo Canyon ISFSI will be operated under the same management organization responsible for operation of the Diablo Canyon Power Plant Units 1 and 2. This organization is described in Chapter 9 of the Diablo Canyon ISFSI SAR.

Procedures for operation of the Diablo Canyon ISFSI will be developed by PG&E and incorporated into existing station procedures. Operation of the Diablo Canyon ISFSI will consist of loading spent fuel and associated nonfuel hardware fuel into MPCs, sealing the MPCs, transporting the MPC in a transfer cask to the CTF, transferring the MPCs into storage overpacks, and placing the loaded storage overpacks at the ISFSI.

Administrative controls and operating procedures which will be in effect for operation of the ISFSI are described in Chapter 9 of the SAR. Operating controls and limits are addressed in Chapter 10 of the SAR.

6.0 Quality Assurance Program

All activities associated with the Diablo Canyon ISFSI that are considered important to safety will be conducted in accordance with the NRC-approved 10 CFR 50 Appendix B DCPP Quality Assurance Program. Adherence to this program ensures that, as required by Subpart G to 10 CFR 72, an adequate quality assurance program will be implemented. A description of the Quality Assurance Program is provided in Chapter 11 of the SAR and the proposed program is included as Attachment E.

7.0 Training Program

As discussed in Section 9.3 of the Diablo Canyon ISFSI SAR, and in Attachment E, personnel working at the Diablo Canyon ISFSI will receive training to provide and maintain a well-qualified work force for safe operation of the ISFSI. The existing Diablo Canyon Power Plant training program is accredited by INPO, is directly applicable to the Diablo Canyon ISFSI, and will be used to provide this training. Additional training program elements will be developed to address training requirements specific to the ISFSI.

The additional training elements will address the following subjects.

1. ISFSI licensing basis and Technical Specifications
2. ISFSI layout and function
3. ISFSI security
4. ISFSI communications

5. ISFSI operation, emergency, maintenance, and administrative procedures
6. Storage system loading and unloading, handling and onsite transportation
7. Storage system decontamination techniques

Following completion of the ISFSI training program, trainees will be given a written and practical exam to ensure they understand the important aspects of the information described above. Retention of the training records and certifications of proficiency will be consistent with that for personnel involved in fuel handling operations at the Diablo Canyon Power Plant.

ISFSI retraining will be consistent with the retraining requirements in effect at the Diablo Canyon Power Plant for personnel involved in fuel handling operations.

8.0 Inventory and Records Requirements

The inventory and records system for the stored spent fuel, associated nonfuel hardware, and overall operation of the ISFSI are described in Section 5.3 of the Diablo Canyon ISFSI SAR. This system will meet the requirements of 10 CFR 72.72.

9.0 Physical Protection

The physical security program for the Diablo Canyon ISFSI is provided in the DCPP Physical Security Plan, the Safeguards Contingency Plan, and the Security Training and Qualification Plan. These documents contain safeguards information and are protected and controlled in accordance with 10 CFR 2.790(d) and 10 CR 73.21. Revisions to these documents to incorporate the requirements for the Diablo Canyon ISFSI are being submitted under separate cover. (Reference PG&E Letter DIL-01-003 dated December 21, 2001.)

10.0 Decommissioning Plan

The dry cask storage system design concept used at the Diablo Canyon ISFSI features inherent ease and simplicity for decommissioning. At the end of its service lifetime, decommissioning of the Diablo Canyon ISFSI will be accomplished by removing the MPCs containing the spent fuel and associated nonfuel hardware from the storage overpacks, transferring the MPCs to a transport cask for transportation offsite, decontaminating as required exposed surfaces by conventional means, releasing materials for either re-use or disposal, and finally releasing the site for unrestricted use.

It is estimated that the storage overpack materials will be only slightly activated as a result of their long-term exposure to the relatively low neutron flux emanating from the spent fuel. After decontamination, the storage overpacks could either be: a) released for use at another nuclear facility; b) cut up for scrap or partially scrapped and any remaining contaminated or c) activated portions shipped as low-level radioactive waste to a disposal facility.

Due to the zero-leakage design of the MPC, no residual contamination is expected to be left behind on the concrete storage pads. The storage pads, fences, and peripheral utility structures require no decontamination or special handling after the last MPC is removed.

The cost of decommissioning the Diablo Canyon ISFSI is expected to be a small fraction of the total decommissioning costs of the Diablo Canyon Power Plant. As noted above, PG&E has established an external sinking trust fund account for decommissioning DCPP Units 1 and 2. As discussed in the Preliminary Decommissioning Plan and the March 30, 2001 Decommissioning Funding Report to the NRC, this account contains designated monies for decommissioning the Diablo Canyon ISFSI. This is in accordance with 10 CFR 50.75(bb), where the NRC requires a separate plan and fund for spent fuel management.

A preliminary decommissioning plan is provided in Attachment F.

11.0 Emergency Plan

The DCPP Emergency Plan will be used to provide the necessary guidelines concerning responsibilities, authorities, actions and resources required to cope with the range of occurrences that may arise at the Diablo Canyon ISFSI. To provide these guidelines, the Diablo Canyon Power Plant Emergency Plan has been modified to reflect the actions to be taken during postulated events described in Chapter 8 of the SAR.

The revised Diablo Canyon Power Plant Emergency Plan is included as Attachment B.

12.0 Environmental Report

The environmental impacts of all aspects of the Diablo Canyon ISFSI have been evaluated in the Environmental Report enclosed with the License Application. The Environmental Report has been prepared to meet the requirements of Subpart A of 10 CFR 51 and Subpart E of 10 CFR 72. The environmental impacts will not be significant. This conclusion is consistent with the NRC's generic finding in NUREG-0575, Final Generic Environmental Impact Statement (FGEIS) on Handling and Storage of Spent Light-Water Power Reactor Fuel" issued in 1979 that storage of light water spent fuel has an insignificant impact on the environment.

13.0 Proposed License Conditions

The proposed license conditions are submitted as Attachment C to this License Application.

ATTACHMENT A

PG&E YEAR IN REVIEW & FINANCIAL STATISTICAL REPORT

PG&E Corporation™

2000 Annual Report

Corporate Overview

PG&E Corporation is a national energy-based holding company with 2000 revenues exceeding $26 billion and approximately $35 billion in assets. It markets energy services and products throughout North America through its National Energy Group and is the parent company of Pacific Gas and Electric Company, the Northern and Central California utility that delivers natural gas and electricity service to one in every 20 Americans.

Financial Highlights
PG&E Corporation

(unaudited, dollars in millions, except per share amounts)	2000	1999
Operating Revenues	$ 26,232	$ 20,820
Net loss		
Net income from operations	925	826
Items impacting comparability(1)	(4,289)	(899)
Reported net loss	$ (3,364)	$ (73)
Loss per Common Share		
Net income from operations	$ 2.54	$ 2.24
Items impacting comparability(1)	(11.83)	(2.44)
Reported net loss per common share	$ (9.29)	$ (.20)
Dividends per Common Share	$ 1.20	$ 1.20
Total Assets	$ 35,291	$ 29,470
Number of common shareholders at December 31	138,467	151,000
Number of common shares outstanding at December 31	387,193,727(2)	384,406,113(2)

(1) Items impacting comparability in 2000 include the write-off of regulatory assets at the Utility of $4,111 million ($11.36 per share); impact of an inability to fully utilize tax benefits of losses in California of $79 million ($0.22 per share); adjustments to the estimated loss on disposal of the retail energy services unit of $40 million ($0.11 per share); a favorable actualization of $20 million ($0.06 per share) on the sale of the Texas natural gas liquids and natural gas pipeline business unit, which closed on December 22, 2000; an $83 million charge ($0.23 per share) related to an adjustment to legal reserves at the Utility; $4 million ($0.01 per share) of other items; and $0.02 per share of dilution. Items impacting comparability in 1999 include the following: write-down of assets related to sale of the Texas natural gas liquids and natural gas pipeline business of $890 million ($2.42 per share); provision for loss on the sale of the retail energy services unit of $58 million ($0.16 per share); decrease in legal reserves of $35 million ($0.10 per share); income from change in accounting principle of $12 million ($0.03 per share); and other items of $2 million ($0.01 per share).

(2) The common shares outstanding include 23,815,500 shares held by a wholly owned subsidiary of PG&E Corporation. These shares are treated as treasury stock in the Consolidated Financial Statements.

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To Our Shareholders:

The year 2000 and the first few months of 2001 have been tumultuous for California and for your Company.*

This letter describes the energy crisis in California; its impacts on us, including a large write-off and the Chapter 11 filing by our Pacific Gas and Electric Company subsidiary; as well as financial results, changes in our Board, our stock price and dividends, and some thoughts about the future.

California Energy Crisis

For several years, driven by increases in customer electricity consumption and strong economic growth in California and surrounding states, and by the failure of new power plant construction to keep pace with the growth, demand for power has begun to outstrip supply. Beginning in 2000 and increasing so far this year, California consumers have been subjected to rolling blackouts when their consumption exceeded all available generating supplies. This situation will require several years to fully resolve as new plants are constructed in California and neighboring states, and as customers act to use less electricity. During 2001, and potentially beyond, electric consumers will face the risk of continued supply interruptions.

The rules California chose to govern its deregulated electricity industry, exacerbated by the supply shortage, have resulted in extraordinarily high wholesale electricity prices. By year-end 2000, wholesale prices were almost 10 times higher than the year before, and they have continued to increase into 2001. At times, 2000's wholesale prices peaked at 100 times the prior year's.

The heart of this crisis for our Company is that unregulated wholesale electric prices are far higher than retail consumer rates, which remain frozen by state regulators. This means that customers' electric bills have not reflected the true cost of the power we have bought for them. When this imbalance arose, we requested rate relief, making it clear that no business can afford to sell a product for less than it costs. That's common sense. When no rate relief was forthcoming, we sued the California Public Utilities Commission (CPUC) in Federal District Court, asking them to follow established federal rate doctrine requiring that prudently incurred wholesale electricity costs be allowed in retail rates. This lawsuit is in progress.

To continue buying the electricity our customers were consuming, the utility used its available cash and credit to finance the shortfall between customer rates and our wholesale costs. By October 2000, we reported that this shortfall had climbed to $3.4 billion. By November, it was $4.5 billion, and by the end of December, $6.6 billion.

By January 2001, we had exhausted the utility's ability to continue financing its customers' energy purchases. Our credit rating fell to below investment grade and subsequently to default, and we were no longer able to buy power in the wholesale market. At that point, the state of California began buying some wholesale power directly for retail consumers, and the state's Independent System Operator continued to buy some power for which it billed us. The price of other power that we purchased directly from qualifying facilities also increased beyond the amount provided in retail rates, driven mainly by extraordinary increases in winter natural gas prices. At the end of the first quarter of 2001, we have accumulated about $9 billion in wholesale energy costs not covered by customer rates.

The bottom line for our Company in this crisis is the need to record a charge against earnings of $4.1 billion, after tax, for unrecovered wholesale power and transition costs at year-end. This is required under the accounting rules that govern our financial reporting. Taking this charge does not diminish our conviction that the utility is entitled under law to recover these costs, nor does it diminish our ongoing lawsuit in Federal District Court.

Also, this crisis led us to conclude that Pacific Gas and Electric Company should file for Chapter 11 protection under the U.S. Bankruptcy Code.

The write-off and the Chapter 11 filing are discussed in more detail below.

Pacific Gas and Electric Company Chapter 11 Filing

Our utility unit, Pacific Gas and Electric Company, on April 6, 2001, filed for reorganization under Chapter 11 of the U.S. Bankruptcy Code in San Francisco Bankruptcy Court. We took this action because of the following: (1) our unreimbursed wholesale electricity costs were increasing at an estimated $300 million per month, or more; (2) continuing CPUC decisions, some of which we believe are illegal, were economically disadvantaging the utility; and (3) negotiations with California's governor and his staff were no longer making progress.

Neither PG&E Corporation nor any of its other subsidiaries, including the National Energy Group, have filed for Chapter 11 reorganization.

We chose to file for Chapter 11 reorganization affirmatively because we expect the court will provide the venue needed to reach a solution, which thus far the state and the state's regulators have been unable to achieve.

Our objective is to proceed through the Chapter 11 process as quickly as possible, without disruption to our operations or inconvenience to our customers, and to emerge and rebuild value for our shareholders.

Financial Results for 2000

PG&E Corporation's results for 2000 include Pacific Gas and Electric Company taking an after-tax charge of $4.1 billion against its income for the year, as it can no longer meet the financial reporting standards that require our uncollected wholesale power and transition costs to be probable of recovery in order for us to carry them forward on our balance sheet.

Excluding the wholesale electricity write-off and other non-recurring items, PG&E Corporation reported net income from operations for the year of $925 million, or $2.54 per share on a diluted basis, compared with net income from operations in 1999 of $826 million, or $2.24 per share on a diluted basis, a 13 percent increase.

We are proud of the solid operating results achieved by both Pacific Gas and Electric and the National Energy Group.

Pacific Gas and Electric Company

While the energy crisis was certainly the biggest story of last year, it was not the only story. On an operating basis, the utility contributed $769 million, or $2.11 per share, to net income from operations for PG&E Corporation in 2000, compared with $763 million, or $2.07 share, in net income from operations for 1999.

The utility also had the following accomplishments last year:

- Pacific Gas and Electric Company's supplier diversity program exceeded its goals by increasing its 2000 purchases nine percent over 1999 results. The utility purchased $180 million worth of products and services from businesses owned and operated by women, minorities, and disabled veterans. The utility's efforts were recognized by the Northern California Supplier Development Council, which named utility personnel as Buyer of the Year, Corporate Coordinator of the Year, and Executive of the Year. The council also named the utility as Corporation of the Year.
- We implemented an Internet-based program that allows customers to schedule appointments, make payment arrangements, and review their accounts on line. They also now have the ability to conduct a web-based home energy efficiency analysis. This gives more than 16 million callers each year to our customer service centers a second option.
- We initiated a new "pricing responsive" bidding program for customers. It works by giving large commercial and industrial customers financial incentives to use less power when demand on the system peaks and electric prices are at their highest.
- We teamed with local, regional, and state organizations to bring more businesses to California by providing an attractive economic development package.
- Our team continued its long track record of excellent operations at our Diablo Canyon Nuclear Power Plant. The plant again received a Number 1 rating from the Institute of Nuclear Power Operations. No other plant has received as many consecutive Number 1 ratings as Diablo Canyon, a testament to the excellence of our operations team at the plant.

National Energy Group

The National Energy Group earned, on an operating basis, $162 million and contributed $0.45 per share to PG&E Corporation's overall net income from operations, representing a 165 percent increase over 1999 results.

The National Energy Group's accomplishments in 2000 included:

- The signing of contracts for 50 turbines to support the development of new power plants capable of generating approximately 16,000 megawatts of electric power.
- An agreement to acquire Duke Energy North America's 500-megawatt Attala power plant in Mississippi.
- The initiation of construction of the 1,048-megawatt La Paloma power plant near Bakersfield, California. The plant is expected to enter service in summer 2002.

- Completion of an 810-megawatt long-term tolling agreement with Southhaven Power, LLC, that provides the NEG with marketing control of the power from a third-party-owned generation asset in the Southern U.S. market.
- Completion of a 10-year 160-megawatt tolling agreement with DTE Energy Services that provides the NEG with control of its first generating asset in the Midwest market.
- The filing for permits to build the 550-megawatt Umatilla Power Plant in Oregon, which will be adjacent to the National Energy Group's existing 474-megawatt Hermiston facility. The plant is expected to begin operation in 2003.
- The announcement that the NEG has joined with Mexico's Próxima Gas, S.A. de C.V., and Sempra Energy International to construct the 212-mile North Baja Pipeline project, which will begin at an interconnection with El Paso Natural Gas Co. near Ehrenberg, Arizona, traverse southeastern California and northern Baja California, Mexico, and terminate at an interconnection with the Rosarito Pipeline south of Tijuana.

  The NEG will direct development of the 77-mile U.S. segment of the pipeline, while Sempra Energy International and Próxima Gas will direct development of the 135-mile Mexico segment. The project is expected to be in service as early as January 2003.

Changes to our Boards of Directors

This year we welcomed David R. Andrews to our Boards. Dave is a partner and former chairman of the law firm of McCutchen, Doyle, Brown & Enersen. He recently served for three years as the legal adviser to the U.S. Department of State and Secretary Madeleine Albright.

Two members of our Boards reached mandatory retirement age in February 2001. Richard A. Clarke, former Chairman and CEO, retired after 15 years as a director and a PG&E career that spanned more than 35 years. Harry M. Conger, former Chairman and CEO of Homestake Mining, retired from our Boards after almost 20 years as a director. We thank them for their long and dedicated service.

John Sawhill, who served as a director since 1990, passed away in May 2000. We will miss his contribution to our Boards and his friendship.

Stock Price and Dividends

The uncertainty surrounding recovery of our utility unit's uncollected wholesale power costs, and most recently its Chapter 11 filing, have severely reduced our stock price. That fact is a huge disappointment.

Under the terms of PG&E Corporation's recent refinancing of its defaulted debt, dividends cannot be resumed until repayment of that $1 billion. Following that repayment, the Board of Directors will evaluate if and when resumption of dividends is in the best interest of the Company.

The Future

The California energy crisis will be resolved, and the underlying operating earnings of the Company will re-emerge from the uncertainty that currently overshadows them.

I am also confident that the underlying operational and financial performance will be recognized in the future stock price of the Company, and I, with you, look forward to accomplishing that objective.

Sincerely,

Robert D. Glynn, Jr.
Chairman of the Board, Chief Executive Officer, and President
April 9, 2001

PG&E Corporation At A Glance

PG&E National Energy Group

	2000	1999
Operating revenues	$16.6 billion	$11.6 billion
Earnings from operations per common share*	$0.45	$0.17

Products and services	Power generation Electricity and natural gas commodity supply Natural gas transportation Energy commodity trading and risk management services Electricity and natural gas for industrial, commercial, and institutional customers nationwide
Operating power plants (gross MW)	7,234 megawatts of capacity
Power plants in development or construction	19,993 megawatts
Power controlled through contracts	518 megawatts in operation; 3,722 megawatts under development
Energy trading volume in 2000:	
Natural gas	5.5 billion cubic feet per day
Power	289 million megawatt-hours
Natural gas pipelines in operation	612 miles in the Pacific Northwest
Natural gas pipelines in development	77 miles in Southern California and Arizona
Average daily natural gas throughput	2.75 billion cubic feet

Pacific Gas and Electric Company

	2000	1999
Operating revenues	$9.6 billion	$9.2 billion
Earnings from operations per common share*	$2.11	$2.07

Service area	70,000 square miles in Northern and Central California, with a population of 13 million, about one in 20 Americans
Delivery systems	131,000 circuit miles of electric transmission and distribution lines, 43,000 miles of natural gas transmission and distribution pipelines
Recent investments in infrastructure	$1.2 billion in 1999 and $1.2 billion in 2000
A few of the customers served by Pacific Gas and Electric Company	3,372 high-tech companies, 1,977 wineries, 26 gold mines, 2,534 bakeries, 1,052 shoe stores, 1,482 video rental stores, 411 golf courses, 1,191 florists, and 986 car washes
Estimated energy savings through customer energy efficiency programs	441 million kilowatt-hours of electricity, or the equivalent to supply 65,000 households 9.5 million therms of natural gas, or the equivalent to supply 15,200 homes

* Earnings from operations per common share exclude items impacting comparability and should not be considered as an alternative to net income as an indicator of the Companies' operating performance.

SELECTED FINANCIAL DATA

(in millions, except per share amounts)	2000	1999	1998	1997	1996
PG&E Corporation[1]					
For the Year					
Operating revenues	$26,232	$20,820	$19,577	$15,255	$ 9,610
Operating income (loss)	(4,807)	878	2,098	1,762	1,896
Income (Loss) from continuing operations	(3,324)	13	771	745	722
Earnings (Loss) per common share from continuing operations, basic and diluted	(9.18)	0.04	2.02	1.82	1.75
Dividends declared per common share	1.20	1.20	1.20	1.20	1.77
At Year-End					
Book value per common share	$ 8.76	$ 19.13	$ 21.08	$ 21.30	$ 20.73
Common stock price per share	20.00	20.50	31.50	30.31	21.00
Total assets	35,291	29,470	33,234	31,115	26,237
Long-term debt (excluding current portions)	4,736	6,682	7,422	7,659	7,770
Rate reduction bonds (excluding current portions)	1,740	2,031	2,321	2,611	—
Redeemable preferred stock and securities of subsidiaries (excluding current portion)	635	635	635	750	694
Pacific Gas and Electric Company					
For the Year					
Operating revenues	$ 9,637	$ 9,228	$ 8,924	$ 9,495	$ 9,610
Operating income (loss)	(5,201)	1,993	1,876	1,820	1,896
Income (Loss) available for common stock	(3,508)	763	702	735	722
At Year-End					
Total assets	$21,988	$21,470	$22,950	$25,147	$26,237
Long-term debt (excluding current portion)	3,342	4,877	5,444	6,218	7,770
Rate reduction bonds (excluding current portion)	1,740	2,031	2,321	2,611	—
Redeemable preferred stock and securities (excluding current portion)	586	586	586	694	694

(1) PG&E Corporation became the holding company for Pacific Gas and Electric Company on January 1, 1997. The Selected Financial Data of PG&E Corporation and Pacific Gas and Electric Company (the Utility) for 1996 are identical because they reflect the accounts of the Utility as the predecessor of PG&E Corporation. Matters relating to certain data above, including the provision for loss on generation-related regulatory assets and undercollected purchased power costs, discontinued operations, and the cumulative effect of a change in accounting principle, are discussed in Management's Discussion and Analysis and in the Notes to the Consolidated Financial Statements.

MANAGEMENT'S DISCUSSION AND ANALYSIS

PG&E Corporation is an energy-based holding company headquartered in San Francisco, California. PG&E Corporation's Northern and Central California energy utility subsidiary, Pacific Gas and Electric Company (the Utility), delivers electric service to approximately 4.6 million customers and natural gas service to approximately 3.8 million customers. On April 6, 2001, the Utility filed a voluntary petition for relief under the provisions of Chapter 11 of the U.S. Bankruptcy Code. Pursuant to Chapter 11 of the U.S. Bankruptcy Code, 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 (MD&A) and in Notes 2 and 3 of the Notes to the Consolidated Financial Statements.

PG&E Corporation's National Energy Group, Inc. (the NEG) is an integrated energy company with a strategic focus on power generation, new power plant development, natural gas transmission, and wholesale energy marketing and trading in North America. The NEG businesses include its power plant development and generation unit, PG&E Generating Company, LLC and its affiliates (collectively, PG&E Gen); its natural gas transmission unit, PG&E Gas Transmission Corporation (PG&E GT); and its wholesale energy and marketing trading unit, PG&E Energy Trading Holdings Corporation, which owns PG&E Energy Trading—Gas Corporation, and PG&E Energy Trading—Power, L.P. (collectively, PG&E Energy Trading or PG&E ET). During 2000, the NEG sold its energy services unit, PG&E Energy Services Corporation (PG&E ES). Also, during the fourth quarter of 2000, the NEG sold its Texas natural gas and natural gas liquids business carried on through PG&E Gas Transmission, Texas Corporation and PG&E Gas Transmission Teco, Inc. and their subsidiaries (PG&E GTT). For more information about the NEG's businesses, see "PG&E National Energy Group, Inc." below.

PG&E Corporation has identified five reportable operating segments. The Utility is one reportable operating segment and the other four are part of the NEG (PG&E Gen, PG&E Gas Transmission, Northwest Corporation (PG&E GTN), PG&E GTT, and PG&E ET). During 2000, the NEG has been integrating these lines of business into two lines of business: (1) an integrated power generation and energy trading and marketing business, and (2) a natural gas transmission business. Financial information about each reportable operating segment is provided in this MD&A and in Note 16 of the Notes to the Consolidated Financial Statements.

This is a combined annual 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. The consolidated financial statements of the Utility reflect the accounts of the Utility and its wholly owned and controlled subsidiaries. This MD&A should be read in conjunction with the consolidated financial statements included herein.

This combined annual report, including our Letter to Shareholders and this MD&A, contains forward-looking statements about the future 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 those expressed or implied by the forward-looking statements or historical results include:

- the reorganization plan that is ultimately adopted by the Bankruptcy Court;
- the regulatory, judicial, or legislative actions (including ballot initiatives) that may be taken to meet future power needs in California, mitigate the higher wholesale power prices, provide refunds for prior power costs, or address the Utility's financial condition;
- the extent to which the Utility's undercollected wholesale power purchase costs may be collected from customers;
- any changes in the amount of transition costs the Utility is allowed to collect from its customers, and the timing of the completion of the Utility's transition cost recovery;

- future market prices for electricity and future fuel prices, which in part, are influenced by future weather conditions, the availability of hydroelectric power, and the development of competitive markets;
- the method and timing of valuation of the Utility's hydroelectric generation assets;
- future operating performance at the Diablo Canyon Nuclear Power Plant (Diablo Canyon) and the future ratemaking applicable to Diablo Canyon;
- legislative or regulatory changes, including the pace and extent of the ongoing restructuring of the electric and natural gas industries across the United States;
- future sales levels and economic conditions;
- the extent to which our current or planned generation development projects are completed and the pace and cost of such completion;
- generating capacity expansion and retirements by others;
- the outcome of the Utility's various regulatory proceedings;
- fluctuations in commodity gas, natural gas liquids, and electric prices and the ability to successfully manage such price fluctuations;
- the effect of compliance with existing and future environmental laws, regulations, and policies, the cost of which could be significant; and
- the outcome of pending litigation.

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 we currently seek or expect. Each of these factors is discussed in greater detail in this MD&A.

In this MD&A, we first discuss the California energy crisis and its impact on our liquidity. We then discuss statements of cash flows and financial resources, and our results of operations for 2000, 1999, and 1998. 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.

LIQUIDITY AND FINANCIAL RESOURCES

The California Energy Crisis

The state of California is in the midst of an energy crisis. The cost of wholesale power has risen to levels almost ten times greater than those in 1999. Rolling blackouts have occurred as a result of a broken deregulated electricity market. Because of this crisis, PG&E Corporation and the Utility have experienced a significant deterioration in their liquidity and consolidated financial position. The Utility's credit rating has deteriorated to below investment grade level. As of March 29, 2001, the Utility is in default or has not paid amounts due under various bank agreements, commercial paper, and payments to the California Power Exchange (PX), the California Independent System Operator (ISO), qualifying facilities (QFs), and energy service providers totaling over $4 billion. In addition, PG&E Corporation and the Utility recognized a fourth quarter charge to earnings of $6.9 billion ($4.1 billion after tax) to reflect the fact that the Utility could no longer conclude that its generation-related regulatory assets and undercollected purchased power costs were probable of recovery from ratepayers. This charge resulted in accumulated deficits at December 31, 2000, of $2.0 billion and $2.1 billion for the Utility and PG&E Corporation, respectively.

As more fully discussed herein, the Utility has been working with regulators and state and federal legislators and California leaders in an effort to seek an overall solution to the California energy crisis. However, the ongoing uncertainty as to the timing and extent of any solution, in addition to increasing debt and regulatory changes, caused the Utility to seek protection from its creditors through a Chapter 11 Bankruptcy Filing. The filing for bankruptcy protection and the related uncertainty around any reorganization plan, that is ultimately adopted, will have a significant impact on the Utility's future liquidity and results of operations. In addition to the $4 billion of defaults and amounts not paid mentioned above, the Utility anticipates an aggregate of approximately $1.5 billion of additional obligations that will become due and payable in April 2001. As of March 29, 2001, the Utility had $2.6 billion of cash available to fund operations.

See Notes 2 and 3 of the Notes to the Consolidated Financial Statements for a detailed discussion of the California energy crisis and the events leading up to the charge incurred by PG&E Corporation and the Utility. A discussion of the current and future liquidity and financial resources, and mitigation efforts undertaken by the Utility and PG&E Corporation follows.

Pacific Gas and Electric Company

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 financial resources of the Utility. Beginning in June 2000, the wholesale price of electric power in California steadily increased to an average cost of 18.16 cents per kilowatt-hour (kWh) for the seven month period of June 2000 through December 2000, as compared to an average cost of 4.23 cents per kWh for the same period in 1999. Under California Assemby Bill 1890 (AB 1890), the Utility's electric rates were frozen at levels that allowed approximately 5.4 cents per kWh to be charged to the Utility's customers as reimbursement for power costs incurred by the Utility on behalf of its retail customers. The excess of wholesale electricity costs above the generation-related cost component available in frozen rates resulted in an undercollection at December 31, 2000, of approximately $6.6 billion, and rose to approximately $8.9 billion by February 28, 2001.

The difference between the actual costs incurred to purchase power and the amount recovered from customers was funded through a series of borrowings. In October 2000, the Utility fully utilized its existing $1 billion revolving credit facility to support the Utility's commercial paper program and other liquidity requirements. On October 18, 2000, the Utility obtained an additional $1 billion, 364-day revolving credit facility. On November 1, 2000, the Utility issued $1 billion of short-term floating rate notes and $680 million of five-year notes. On November 22, 2000, the Utility issued an additional $240 million of short-term floating rate notes. On December 1, 2000, the bank group reduced the size of the $1 billion, 364-day revolving credit facility to $850 million. At December 31, 2000, the Utility had borrowed $614 million against its five-year revolving credit agreement, had issued $1,225 million of commercial paper, and had issued $1,240 million of floating rate notes.

In late 2000, the Utility began to implement cash conservation measures that included layoffs of 1,000 temporary workers, suspension of dividend payments, and deferral of merit increases and incentive compensation for employees. Also, federal and state legislators and regulators recognized that the wholesale power market was seriously flawed and they began seeking solutions to the California energy crisis.

In response to the growing crisis, on January 4, 2001, the California Public Utilities Commission (CPUC) approved an interim one-cent per kWh rate increase, which would raise approximately $70 million in cash per month for three months. Even if all this cash had been available to the Utility immediately, $210 million represented approximately one week's worth of net power purchases at the then current prices. Thus, the rate increase did not raise enough cash for the Utility to pay its ongoing wholesale electric energy procurement bills or make further borrowing possible.

On January 10, 2001, the Board of Directors of the Utility suspended the payment of its fourth quarter 2000 common stock dividend in an aggregate amount of $110 million payable on January 15, 2001, to PG&E Corporation and PG&E Holdings, Inc., a wholly-owned subsidiary of the Utility. In addition, the Utility's Board of Directors decided not to declare the regular preferred stock dividends for the three-month period ending January 31, 2001, normally payable on February 15, 2001. Dividends on all Utility preferred stock are cumulative. Until cumulative dividends on preferred stock are paid, the Utility may not pay any dividends on its common stock, nor may the Utility repurchase any of its common stock.

On January 16 and 17, 2001, the outstanding bonds of the Utility were downgraded to below investment grade status. Standard and Poor's (S&P) stated that the downgrade reflected the heightened probability of the Utility's imminent insolvency and the resulting negative financial implications for PG&E Corporation and affiliated companies because, among other reasons, (1) some of the Utility's principal trade creditors were demanding that sizeable cash payments be made as a pre-condition to the purchase of natural gas and electric power necessary for on-going business operations; (2) neither legislative nor negotiated solutions to the California utilities' financial situation appeared to be forthcoming in a timely manner, which continued to impede access to financial markets for the working capital needed to avoid insolvency; and (3) Southern California Edison's (SCE) decision to default on its obligation to pay principal and interest due on January 16, 2001, diminished the prospects for the Utility's access to capital markets.

This downgrade to below investment grade status was an event of default under one of the Utility's revolving credit facilities and precluded the Utility from access to the capital markets. As a result, the banks stopped funding under the 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, QFs, the ISO, and PX, and began making partial payments of amounts owed.

The Utility's credit ratings as of March 29, 2001, are as follows:

Corporate credit rating: D/D
Commercial paper: D
Senior secured debt: CCC
Senior unsecured debt: CC
Preferred stock: D
Shelf senior secured/unsecured subordinated debt: CCC/CC
Shelf debt preferred stock: D

After the downgrade, the PX notified the Utility that the ratings downgrade required the Utility to post collateral for all transactions in the PX day-ahead market. Since the Utility was unable to post such collateral, the PX suspended the Utility's trading privileges effective January 19, 2001, in the day-ahead market. The PX also sought to liquidate the Utility's block-forward contracts for the purchase of power. On January 25, 2001, a California Superior Court judge granted the Utility's application for a temporary restraining order, which thereby restrained and enjoined the PX and its agents from liquidating the Utility's contracts in the block-forward market, pending hearing on a preliminary injunction on February 5, 2001. Immediately before the hearing on the preliminary injunction, California Governor Gray Davis, acting under California's Emergency Services Act, commandeered the contracts for the benefit of the state. Under the Act, the state must pay the Utility the reasonable value of the contracts, although the PX may seek to recover the monies that the Utility owes to the PX from any proceeds realized from those contracts. Discussions and negotiations on this issue are currently ongoing between the state and the Utility.

On January 19, 2001, the Utility was no longer able to continue purchasing power for its customers because of a lack of creditworthiness and the state of California authorized the California Department of Water Resources (DWR) to purchase electricity for the Utility's customers. Assembly Bill 1X (AB1X) was passed on February 1, 2001, authorizing the DWR to enter into contracts for the purchase and sale of electric power and to issue revenue bonds to finance electricity purchases. The DWR has entered into long-term contracts with several generators for the supply of electricity. However it continues to purchase significant amounts of power on the spot market at prevailing market prices. The DWR is not purchasing electricity for the Utility's entire net open position (the amount of power that cannot be met by the Utility's own or contracted-for generation). To the extent that the DWR is not purchasing electricity for the entire net open position, the remainder is being procured by the ISO. To that extent, the ISO may attempt to charge the Utility for those purchases.

As a result of (1) the failure by the state to assume the full procurement responsibility for the Utility's net open position, as was provided under AB1X, (2) the negative impact of recent actions by the CPUC 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 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 undercollected purchased power costs, the Utility filed a voluntary petition for relief under provisions of Chapter 11 of the U.S. Bankruptcy Code on April 6, 2001.

As of March 29, 2001, the Utility was in default and had not paid the following:

Description	Amount (in millions)
Items not paid	
PX/ISO—real time market deliveries	$1,448
Qualifying facilities	643
Direct access credits due to energy service providers	503
Commercial paper	861
Bank loans	939*
Other	26
Total Items Not Paid	$4,420
Items coming due through April 30, 2001	
PX/ISO—real time market deliveries	$ 550
Qualifying facilities	340
Gas suppliers	470
Other	140
Total coming due	$1,500
Total cash on hand at March 29, 2001	$2,600

*Loans that lenders have agreed to forbear through April 13, 2001.

Additionally, the Utility may be required by the CPUC to pay the DWR for purchases that it has made on behalf of the Utility's customers. As discussed further in Note 2 of the Notes to the Consolidated Financial Statements, there is a dispute over how much the Utility must pay the DWR. Also, the DWR has indicated that it intends to purchase power only at "reasonable prices." The ISO has continued to purchase power at prices in excess of the DWR's as yet undisclosed ceiling and has been billing the Utility for the differential. The Utility does not yet know what the total expected billing is for these purchases.

Subject to certain qualifications, the banks under the Utility's $1 billion revolving credit agreement agreed to forbear from exercising any remedies with respect to the Utility's default under that agreement until April 13, 2001.

Subject to the approval by the Bankruptcy Court, the Utility's intent is to pay its ongoing costs of doing business while seeking resolution of the wholesale energy crisis. It is the Utility's intention to continue to pay employees, vendors, suppliers, and other creditors to maintain essential distribution and transmission services. However, the Utility is not in a position to pay maturing or accelerated obligations, nor is the Utility in a position to pay the ISO, PX, and the QFs the amounts due for the Utility's power purchases above the amount included in rates for power purchase costs. The Utility's current actions are intended to allow the Utility to continue to operate while efforts to reach a regulatory or legislative solution continue. The Utility's plans will be subject to approval of the Bankrupcy Court.

The Utility has also deferred quarterly interest payments on the Utility's 7.90% Deferrable Interest Subordinated Debentures, Series A, due 2025, until further notice in accordance with the indenture. The corresponding quarterly payments on the 7.90% Cumulative Quarterly Income Preferred Securities, Series A, (QUIPS) issued by PG&E Capital I, due on April 2, 2001, have been similarly deferred. Distributions can be deferred up to a period of five years per the indenture. Investors will accumulate interest on the unpaid distributions at the rate of 7.90%.

The weakened financial condition of the Utility also has impacted its ability to supply natural gas to its natural gas customers. In December 2000 and January 2001, several gas suppliers demanded prepayment, cash on delivery, or other forms of payment assurance before they would deliver gas, instead of the normal payment terms, under which the Utility would pay for the gas after delivery. As the Utility was unable to meet such demands at that time, several gas suppliers refused to supply gas, accelerating the depletion of the Utility's gas storage reserves and potentially exacerbating the electric power crisis if the Utility were required to divert gas from industrial users, including natural gas fired power plant operators.

The U.S. Secretary of Energy issued a temporary order on January 19, 2001, requiring the gas suppliers to continue to make deliveries to avoid a worsening natural gas shortage emergency. However, this order expired on February 7, 2001, and certain companies, representing about 10% of the Utility's natural gas suppliers, terminated deliveries after the order expired.

The Utility tried to mitigate the worsening supply situation by withdrawing more gas from storage and, when able, purchasing additional gas on the spot market. Additionally, on January 31, 2001, the CPUC authorized the Utility to pledge its gas account receivables and its gas inventories for up to 90 days (extended to 180 days in a CPUC draft decision issued on February 15, 2001) to secure gas for its core customers. At March 29, 2001, the amount of gas accounts receivables pledged was approximately $900 million. As of March 29, 2001, approximately 30% of the Utility's suppliers of natural gas had signed security agreements with the Utility and discussions were continuing with the Utility's other suppliers. Additionally, the Utility is currently implementing a program to obtain longer-term summer and winter supplies and daily spot supplies.

PG&E Corporation

The liquidity and financial condition crisis faced by the Utility also negatively impacted PG&E Corporation. Through December 31, 2000, PG&E Corporation funded its working capital needs primarily by drawing down on available lines of credit and other short-term credit facilities. At December 31, 2000, PG&E Corporation had borrowed $185 million against its five-year revolving credit agreement and had issued $746 million of commercial paper. Due to the credit ratings downgrades of PG&E Corporation, the banks refused any additional borrowing requests and terminated their remaining commitments under existing credit facilities. Commencing January 17, 2001, PG&E Corporation began to default on its maturing commercial paper obligations.

Commencing on March 2, 2001, PG&E Corporation refinanced its debt obligations with $1 billion in aggregate proceeds of two term loans under a common credit agreement with General Electric Capital Corporation and Lehman Commercial Paper Inc. In accordance with the credit agreement, the proceeds, together with other PG&E Corporation cash, were used to pay $501 million in commercial paper (including $457 million of commercial paper on which PG&E Corporation had defaulted), $434 million in borrowings under PG&E Corporation's long-term revolving credit facility, and $116 million to PG&E Corporation shareholders of record as of December 15, 2000, in satisfaction of a defaulted fourth quarter 2000 dividend. Further, approximately $85 million was used to pre-pay the first year's interest under the credit agreement and to pay transaction expenses associated with the debt restructuring. See Note 3 of the Notes to the Consolidated Financial Statements for a detailed description of the loan.

On March 15, 2001, PG&E Corporation's corporate credit rating was withdrawn by S&P due to the March 2, 2001, refinancing of its obligations and the fact that PG&E Corporation had no more public debt to be rated.

PG&E Corporation itself had cash of $297 million at March 29, 2001, and believes that the funds will be adequate to maintain its continuing operations throughout 2001. In addition, PG&E Corporation believes that the holding company and its non-CPUC regulated subsidiaries are protected from the bankruptcy of the Utility.

PG&E National Energy Group

In December 2000, and in January and February 2001, PG&E Corporation and the NEG undertook a corporate restructuring of NEG, known as a "ringfencing" transaction. The ringfencing complied with credit rating agency criteria, enabling the NEG, PG&E GTN, and PG&E ET to receive or retain their own credit ratings based on their own creditworthiness. The ringfencing involved the creation or use of special purpose entities (SPEs) as intermediate owners between PG&E Corporation and its non-CPUC regulated subsidiaries. These SPEs are: PG&E National Energy Group, LLC, which owns 100% of the stock of the NEG; PG&E GTN Holdings LLC which owns 100% of the stock of PG&E GTN; and PG&E Energy Trading Holdings LLC, which owns 100% of the stock of PG&E Corporation's energy trading subsidiaries, PG&E Energy Trading–Gas Corporation, PG&E Energy Trading Holdings Corporation, and PG&E Energy Trading-Power, L.P. In addition, the NEG's organizational documents were modified to include the same structural elements as the SPEs to meet credit rating agency criteria. Ringfencing is intended to reduce the likelihood that the assets of the ringfenced companies would be substantively consolidated in a bankruptcy proceeding involving such companies' ultimate parent, and to thereby preserve the value of the "protected" entities as a whole. The SPEs require unanimous approval of their respective boards of directors, including an independent director, before they can (a) consolidate or merge with any entity, (b) transfer substantially all of their assets to any entity, or (c) institute or consent to bankruptcy, insolvency, or similar proceedings or actions. The SPEs may not declare or pay dividends unless the respective board of directors has unanimously approved such action and the company meets specified financial requirements.

STATEMENTS OF CASH FLOWS FOR 2000, 1999, AND 1998

PG&E Corporation normally funds investing activities from cash provided by operations after capital requirements and, to the extent necessary, external financing. Our policy is to finance our investments with a capital structure that minimizes financing costs, maintains financial flexibility, and, with regard to the Utility, complies with regulatory guidelines.

PG&E Corporation Consolidated

Cash Flows from Operating Activities

Net cash (used) provided by PG&E Corporation's operating activities totaled $(776) million, $2,155 million, and $3,388 million in 2000, 1999, and 1998, respectively. The decrease of $2,931 million between 1999 and 2000 is attributable to the California energy crisis previously discussed.

Cash Flows from Investing Activities

During 2000, 1999, and 1998, PG&E Corporation used $1.8 billion, $1.6 billion, and $1.6 billion, respectively, for upgrades and expansion of its facilities in operation or under construction. These capital expenditures were partially offset by the 1999 and 1998 divestitures of generation facilities at the Utility and by the completed sales of the PG&E ES and PG&E GTT business units in 2000. In 2000, PG&E Corporation sold its Energy Services retail business for $85 million and its value-added-services business and various other assets for $18 million. The NEG received $306 million, which included a working capital adjustment for the sale of PG&E GTT. The sale also included the assumption of liabilities associated with PG&E GTT and debt having a book value of $564 million. In 1999 and 1998, the Utility received proceeds of $1,014 million and $501 million, respectively, from the sale of generation facilities. In 1998, PG&E Corporation sold its Australian energy holdings for proceeds of approximately $126 million, and the NEG sold its Bear Swamp facility for $479 million.

Cash Flows from Financing Activities

As of March 29, 2001, PG&E Corporation, itself, had $297 million in cash on hand and had successfully refinanced its obligations that were in default. (See previous discussion of PG&E Corporation's refinancing.) Net cash provided by financing activities in 2000 totaled $2.4 billion, principally through borrowings under credit facilities and issuances of short-term and long-term debt needed to fund energy purchases. Net cash used by financing activities in 1999 and 1998 totaled $2.0 billion and $1.1 billion, respectively, and was used principally to retire debt, repurchase outstanding common stock, and pay dividends.

During 2000, 1999, and 1998, PG&E Corporation issued $65 million, $54 million, and $63 million of common stock, respectively, primarily through the Dividend Reinvestment Plan and the stock option plan component of the Long-Term Incentive Program. During 2000, 1999, and 1998, PG&E Corporation declared dividends on its common stock of $434 million, $460 million, and $466 million, respectively.

During 2000, 1999, and 1998, PG&E Corporation repurchased $2 million, $693 million, and $1,158 million of its common stock, respectively, primarily through separate, accelerated share repurchase programs. As of December 31, 1997, the Board of Directors had authorized the repurchase of up to $1.7 billion of PG&E Corporation's common stock on the open market or in negotiated transactions. As part of this authorization, in January 1998, PG&E Corporation repurchased in a specific transaction 37 million shares of common stock. As of December 31, 1998, approximately $570 million remained available under this repurchase authorization. In February 1999, PG&E Corporation used this remaining authorization to purchase 16.6 million shares at a total cost of $531 million. A subsidiary of PG&E Corporation made this repurchase, along with subsequent stock repurchases. The stock held by the subsidiary is treated as treasury stock and reflected as Stock Held by Subsidiary on the Consolidated Balance Sheet of PG&E Corporation.

In October 1999, the Board of Directors of PG&E Corporation authorized an additional $500 million for the purpose of repurchasing shares of PG&E Corporation's common stock on the open market. This authorization supplemented the approximately $40 million remaining from the amount previously authorized by the Board of Directors on December 17, 1997. The authorization for share repurchase extends through September 30, 2001. As of December 31, 1999, through its wholly owned subsidiary, PG&E Corporation repurchased an additional 7.2 million shares, at a cost of $159 million under this authorization. At December 31, 2000, the remainder under the share repurchase authorization is approximately $380 million. PG&E Corporation is precluded by its

March 2, 2001, loan agreement with General Electric Capital Corporation and Lehman Commercial Paper Inc. from repurchasing its common stock until the loan is repaid.

Utility

The following section discusses the Utility's significant cash flows from operating, investing, and financing activities for the three year period ended December 31, 2000.

Cash Flows from Operating Activities

Net cash (used) provided by the Utility's operating activities totaled $(699) million, $2,196 million, and $3,736 million in 2000, 1999, and 1998, respectively. The decrease of $2,895 million between 1999 and 2000 is attributable to the California energy crisis and the significant deterioration of the Utility's financial condition reflected by the deferred electric procurement costs of $6,465 million which have not yet been recovered from ratepayers and which were determined not to be probable of recovery through regulated rates and recognized as a charge to earnings in the fourth quarter 2000.

Cash Flows from Investing Activities

The primary uses of cash for investing activities are additions to property, plant, and equipment. The Utility's capital expenditures were $1,245 million, $1,181 million, and $1,382 million, for the years ended December 31, 2000, 1999, and 1998, respectively.

During 1999, the Utility sold three fossil-fueled generation facilities and its geothermal generation facilities. These sales closed in April and May 1999, respectively, and generated proceeds of $1,014 million. In 1998, the Utility had proceeds of $501 million from the sale of three fossil-fueled generation plants.

Cash Flows from Financing Activities

In April 2000, a subsidiary of the Utility repurchased from PG&E Corporation 11.9 million shares of its common stock at a cost of $275 million. In December 1999, 7.6 million shares of the Utility's common stock, with an aggregate purchase price of $200 million, was purchased by a subsidiary of the Utility. These repurchases are reflected as stock held by subsidiary in the Consolidated Balance Sheet of the Utility. Earlier in 1999, the Utility repurchased from PG&E Corporation, and cancelled 20 million shares of its common stock from PG&E Corporation for an aggregate purchase price of $726 million to maintain its authorized capital structure. In 2000, 1999, and 1998, the Utility paid dividends on its common and preferred stock of $475 million, $440 million, and $444 million, respectively.

The Utility's long-term debt that either matured, was redeemed, or was repurchased during 2000 totaled $597 million. Of this amount, (1) $110 million related to the maturity of its 6.63%, and 6.75% mortgage bonds due June 1, and December 1, 2000, (2) $81 million related to the Utility's repurchase of various pollution control loan agreements, (3) $113 million related to the maturity of the Utility's various medium term notes, (4) $3 million related to the other scheduled maturities of long-term debt, and (5) $290 million related to maturity of rate reduction bonds.

The Utility's long-term debt that either matured, was redeemed, or was repurchased during 1999 totaled $672 million. Of this amount, (1) $290 million related to the Utility's rate reduction bonds maturing, (2) $135 million related to the Utility's repurchase of mortgage and various other bonds, (3) $147 million related to maturity of various utility mortgage bonds, and (4) $100 million related to the maturities and redemption of various of the Utility's medium-term notes and other debt. During 2000 and 1999, the Utility did not redeem or repurchase any of its preferred stock.

On November 1, 2000, the Utility issued $680 million of five-year, fixed-rate notes and $1,000 million of 364-day floating rate notes. On November 22, 2000, the Utility issued $240 million in floating rate notes.

PG&E National Energy Group

The California energy crisis has impacted the funding available for new projects at the NEG. The NEG undertook a ringfencing strategy to facilitate access to capital markets and insulate the NEG's assets from the risk of bankruptcy at the Utility. The refinancing of PG&E Corporation's debts on March 2, 2001, further insulates NEG from the risk of bankruptcy at the Utility.

General

Historically, the NEG has obtained cash from operations, borrowings under credit facilities, non-recourse project financing and other issuances of debt, issuances of commercial paper, and borrowings and capital contributions from PG&E Corporation. These funds have been used to finance operations, service debt obligations, fund the acquisition, development, and/or construction of generating facilities, and to start-up other businesses, finance capital expenditures, and meet other cash and liquidity needs.

The projects that the NEG develops typically require substantial capital investment. Some of the projects in which the NEG has an interest have been financed primarily with non-recourse debt that is repaid from the project's cash flows. This debt is often secured by interests in the physical assets, major project contracts and agreements, cash accounts, and, in some cases, the ownership interest in that project subsidiary. These financing structures are designed to ensure that the NEG is not contractually obligated to repay the project subsidiary's debt; that is, they are "non-recourse" to the NEG and to its subsidiaries not involved in the project. However, the NEG has agreed to undertake financial support for some of its project subsidiaries in the form of limited obligations and contingent liabilities such as guarantees of specified obligations. To the extent the NEG becomes liable under these guarantees or other agreements in respect of a particular project, it may have to use distributions it receives from other projects to satisfy these obligations.

Cash Flows from Operating Activities

Cash flow (used by) generated from operations totaled $(77) million, $(41) million, and $(348) million for the years ended December 31, 2000, 1999, and 1998, respectively. The decrease in cash flows for 2000 compared to 1999 of $36 million is attributable to increases in working capital required to support the expanded energy trading operations and a decrease in depreciation expense as a result of the impairment of PG&E GTT assets in 1999. The increase in cash flows generated from operations in 1999 as compared to 1998 of $307 million is due principally to the increase in earnings, excluding the non-cash charge to reflect impairment of the investment in PG&E GTT; an increase in working capital balances of approximately $53 million; realization of gains in energy contracts accounted for on a mark-to-market basis; and increases in the non-cash charges, such as depreciation and the deferred tax provision, partially offset by the increase in the amortization of out-of-market contractual obligations and an increase in capitalized development costs.

Cash Flows from Investing Activities

The NEG recognized $65 million, $63 million, and $113 million in earnings on investments, which are accounted for using the equity method for 2000, 1999 and 1998, respectively. The NEG received cash distributions from these investments totaling approximately $104 million, $66 million and $69 million during 2000, 1999 and 1998, respectively.

Four natural gas-fueled combined-cycle power plants are currently under construction, which when completed will be owned or leased by the NEG. These power plants, referred to as "merchant power plants," will sell power as a commodity in the competitive marketplace. The electricity generated by these plants will be sold on a wholesale basis to local utilities and power marketers, including PG&E ET, which, in turn, will sell it to industrial, commercial, and other electricity customers.

Millennium Power, a 360-megawatt (MW) power plant located in Massachusetts, is scheduled to begin commercial service in 2001. Lake Road Generating Plant (Lake Road), an approximately 780-MW power plant located in Connecticut, is scheduled to begin commercial service in 2001. La Paloma Generating Plant, an approximately 1,050-MW power plant, is located in California, and is scheduled to begin commercial service in 2002. Lake Road and La Paloma are being financed through a synthetic lease with a third-party owner. PG&E Gen will operate the plant under operating leases. See Note 14 of the Notes to the Consolidated Financial Statements. The estimated cost to construct these plants is approximately $1.4 billion.

In October 2000, the NEG completed construction on an 11.5 MW wind project that is the largest wind generating facility in the Eastern United States for a total cost of $16 million.

In September 2000, the NEG purchased the Attala Generating Plant for $311 million. The seller is obligated to deliver a fully operating facility by July 1, 2001. Attala is a 500 MW natural gas-fired combined-cycle project, located in Mississippi.

The NEG used $1.3 billion in cash for its investing activities in 1998. During 1998, through its indirect subsidiary USGenNE, the NEG completed the acquisition of a portfolio of electric generating assets and power supply contracts from New England Electric System (NEES). The funding requirements for this acquisition were $1,746 million and included the acquisition of (1) electric generating assets classified as property, plant, and equipment; (2) receivable for support payments of approximately $800 million; and (3) approximately $1,300 million of contractual obligations.

The NEES assets include hydroelectric, coal, oil, and natural gas-fueled generation facilities with a combined generating capacity of 4,000 MW. In addition USGenNE assumed 23 multi-year power-purchase agreements representing an additional 800 MW of production capacity. USGenNE entered into agreements with NEES as part of the acquisition, which (1) provide that NEES shall make support payments over the next ten years to USGenNE for the purchase power agreements, and (2) require that USGenNE provide electricity to NEES under contracts that expire over the next six to eleven years.

In 1998, the NEG spent approximately $220 million on development and construction activities. Also in 1998, the NEG entered into a sale/leaseback transaction whereby it sold and leased back its Bear Swamp facility, comprised of the Bear Swamp pumped storage station and the Fife Brook station, to a third party. This transaction generated cash proceeds of $479 million. Finally in 1998, the NEG completed the sale of its Australian energy holdings for proceeds of approximately $126 million, and executed some portfolio management transactions, which generated cash proceeds of approximately $22 million.

Cash Flows from Financing Activities

The NEG maintains $1,350 million in five revolving credit facilities, which support commercial paper and Eurodollar borrowing arrangements. At December 31, 2000 and 1999, the NEG had total outstanding balances related to such borrowings of $1,181 million and $1,173 million, respectively. In addition, certain letters of credit held by the NEG reduce the available outstanding facility commitments. At December 31, 2000, approximately $36 million of letters of credit were outstanding under these facilities. Since the NEG has the ability and intent to refinance certain borrowings, $661 million and $649 million of such borrowings are classified as long-term debt as of December 31, 2000 and 1999, respectively. The remaining outstanding balances are classified as short-term borrowings in the Consolidated Balance Sheets of PG&E Corporation.

Capital Requirements

The table below provides information about PG&E Corporation's capital requirements at December 31, 2000:

Expected maturity date	2001	2002	2003	2004	2005	Thereafter
			(dollars in millions)			
Utility:						
Capital spending	$1,505					
Long-term debt						
Variable rate obligations	$ 120	$697	$350	$ 40	$ 40	$ 20
Fixed rate obligations	$ 274	$379	$354	$392	$1,012	$2,038
Average interest rate	8.0%	7.8%	6.3%	6.4%	6.9%	7.3%
Rate reductions bonds	$ 290	$290	$290	$290	$ 290	$ 580
Average interest rate	6.2%	6.3%	6.4%	6.4%	6.4%	6.4%
National Energy Group:						
Capital spending	$2,445					
Long-term debt						
Variable rate obligations	$ 16	$ 94	$584	$ 9	$ 9	$ 80
Fixed rate obligations	$ 1	$ 34	$ 7	$ 1	$ 251	$ 325
Average interest rate	9.4%	6.9%	7.0%	9.4%	7.1%	8.9%

RESULTS OF OPERATIONS

In this section, we discuss the operations of the NEG and present the components of our results of operations for 2000, 1999, and 1998. The table below shows for 2000, 1999, and 1998, certain items from our Statement of Consolidated Operations detailed by Utility and the NEG operations of PG&E Corporation. (In the "Total" column, the table shows the combined results of operations for these groups.) The information for PG&E Corporation (the

"Total" column) includes the appropriate intercompany elimination. Following this table we discuss our results of operations.

National Energy Group

The NEG has been formed to pursue opportunities created by the gradual restructuring of the energy industry across the nation. The NEG integrates our national power generation, gas transmission, and energy trading businesses. The NEG contemplates increasing PG&E Corporation's national market presence through a balanced program of development, acquisition, and contractual control of energy assets and businesses, while at the same time undertaking ongoing portfolio management of its assets and businesses. The NEG's ability to anticipate and capture profitable business opportunities created by industry restructuring will have a significant impact on PG&E Corporation's future operating results.

Power Generation

We participate in the development, operation, ownership, and management of non-utility electric generating facilities that compete in the United States power generation market. In September 1998, PG&E Corporation, through its indirect subsidiary USGen New England, Inc. (USGenNE), completed the acquisition of a portfolio of electric generation assets and power supply contracts from NEES. The purchased assets include hydroelectric, coal, oil, and natural gas-fueled generation facilities with a combined generating capacity of about 4,000 MW.

As part of the New England electric industry restructuring, the local utility companies were required to offer Standard Offer Service (SOS) to their retail customers. Retail customers may select alternative suppliers at any time. The SOS is intended to provide customers with a price benefit (the commodity electric price offered to the retail customer is expected to be less than the market price) for the first several years, followed by a price disincentive that is intended to stimulate the retail market.

Retail customers may continue to receive SOS through December 31, 2004, in Massachusetts, and through December 31, 2009, in Rhode Island. However, if customers choose an alternate supplier, they are precluded from going back to the SOS.

In connection with the purchase of the generation assets, USGenNE entered into wholesale agreements with certain of the retail companies of NEES to supply at specified prices the electric capacity and energy requirements necessary for their retail companies to meet their SOS obligations. These companies are responsible for passing on the revenues generated from the SOS. USGenNE currently is indirectly serving a large portion of the SOS electric capacity and energy requirements for these companies. For the years ended December 31, 2000 and 1999, the SOS price paid to generators was $0.043 and $0.035 per kWh for generation, respectively.

Like other utilities, New England utilities previously entered into agreements with unregulated companies (e.g., qualifying facilities under Public Utilities Regulatory Policies Act (PURPA)) to provide energy and capacity at prices that are anticipated to be in excess of market prices. The NEG assumed NEES' contractual rights and duties under several of these power purchase agreements. At December 31, 2000, these agreements provided for an aggregate 470 MW of capacity. NEES will make support payments to us toward the cost of these agreements. The remaining support payments by NEES total $0.8 billion in the aggregate (undiscounted) and are due in monthly installments through January 2008. In certain circumstances, with our consent, NEES may make a full or partial lump sum accelerated payment.

Currently, approximately 60% to 70% of the capacity is dedicated to serving SOS customers. To the extent that customers eligible to receive SOS choose alternate suppliers, or as these obligations are sold to other parties, this percentage will continue to decrease. As customers choose alternate suppliers, or the SOS obligations are sold, a greater proportion of the output of the acquired operating capacity will be subject to market prices.

Gas Transmission Operations

The NEG, through PG&E GTN, owns and operates gas transmission pipelines and associated facilities, subject to regulation by the Federal Energy Regulatory Commission (FERC). The pipeline and associated facilities extend over 612 miles from the Canada-U.S. border to the Oregon-California border. PG&E GTN provides firm and interruptible transportation services to third-party shippers on an open-access basis. Its customers are principally retail gas distribution utilities, electric generators that use natural gas to generate electricity, natural gas marketing companies that purchase and resell natural gas to utilities and end-use customers, natural gas producers, and industrial consumers.

On January 27, 2000, PG&E Corporation signed a definitive agreement with El Paso Field Services Company (El Paso) providing for the sale to El Paso, a subsidiary of El Paso Energy Corporation, of the stock of PG&E GTT. Given the terms of the sales agreement, in 1999, PG&E Corporation recognized a charge against pre-tax earnings* of $1,275 million, to reflect PG&E GTT's assets at their fair value.

On December 22, 2000, after receipt of governmental approvals, PG&E Corporation completed the stock sale. The sales agreement had a provision, which included a sales price adjustment for changes in working capital from December 31, 1999 to closing. The total consideration received was $456 million, which includes the working capital adjustment, less $150 million used to retire the PG&E GTT short-term debt, and the assumption by El Paso of PG&E GTT long-term debt having a book value of $565 million. In December 2000, PG&E Corporation recorded income of approximately $20 million reflecting the sales price true-up.

Energy Trading

The NEG's trading businesses purchase bulk volumes of power and natural gas from the NEG's affiliates and the wholesale market. The NEG then transports and resells these commodities, either directly to third parties or to other PG&E Corporation affiliates. The NEG also provides risk management services to other NEG businesses and to wholesale customers. (See "Price Risk Management Activities" below; and Note 4 of the Notes to the Consolidated Financial Statements.)

Energy Services

In December 1999, PG&E Corporation's Board of Directors approved a plan to dispose of PG&E ES, its wholly owned subsidiary, through a sale. The disposal has been accounted for as a discontinued operation, and PG&E Corporation's investment in PG&E ES was written down to its then estimated net realizable value. In addition, PG&E Corporation provided a reserve for anticipated losses through the anticipated date of sale. The total provision for discontinued operations was $58 million, net of income taxes of $36 million. Of this amount, $33 million (net of taxes) was allocated toward operating losses for the period leading up to the intended disposal date. In 2000, $31 million (net of taxes) of actual operating losses were charged against this reserve. During the second quarter of 2000, the NEG finalized the disposal of the energy commodity portion of PG&E ES for $20 million, plus net working capital of approximately $65 million, for a total of $85 million. In addition, the sale of the Value-Added Services business and various other assets was completed on July 21, 2000, for a total consideration of $18 million. For the year ended December 31, 2000, an additional estimated loss of $40 million (or $0.11 per share), net of income tax of $36 million, was recorded. The additional loss was greater than the amount originally provided for several reasons: (1) the sale was originally contemplated to be a sale of the entity as a whole; (2) it was ultimately sold in various pieces; (3) several assets were not sold and were subsequently abandoned; and (4) wind-down costs associated with abandoned assets were greater than originally contemplated. In addition, the worsening energy situation in California also contributed to the additional loss incurred.

		PG&E National Energy Group					
			PG&E GT				
(in millions)	Utility	PG&EGen	NW	Texas	PG&E ET	Eliminations & Other[1]	Total
2000:							
Operating revenues	$ 9,637	$1,211	$239	$ 873	$16,054	$(1,782)	$26,232
Operating expenses	14,838	1,073	105	869	15,974	(1,820)	31,039
Operating loss							(4,807)
Interest income							266
Interest expense							(788)
Other income (expense), net							(23)
Income taxes							(2,028)
Loss from continuing operations							(3,324)
Net loss							(3,364)
Net cash used by operating activities							(776)
Net cash used by investing activities							(970)
Net cash provided by financing activities							2,364
EBITDA[2]	$(1,244)	$ 227	$176	$ 108	$ 91	$ (55)	$ (697)
1999:							
Operating revenues	$ 9,228	$1,122	$224	$ 1,148	$10,521	$(1,423)	$20,820
Operating expenses	7,235	1,007	104	2,446	10,582	(1,432)	19,942
Operating income							878
Interest income							118
Interest expense							(772)
Other income (expense), net							37
Income taxes							248
Income from continuing operations							13
Net loss							(73)
Net cash provided by operating activities							2,155
Net cash used by investing activities							(117)
Net cash used by financing activities							(2,043)
EBITDA[2]	$ 3,523	$ 203	$181	$(1,178)	$ (53)	$ 19	$ 2,695
1998:							
Operating revenues	$ 8,924	$ 649	$237	$ 1,941	$ 8,509	$ (683)	$19,577
Operating expenses	7,048	489	101	1,996	8,528	(683)	17,479
Operating income							2,098
Interest income							101
Interest expense							(781)
Other income (expense), net							(36)
Income taxes							611
Income from continuing operations							771
Net income							719
Net cash provided by operating activities							3,388
Net cash used by investing activities							(2,226)
Net cash used by financing activities							(1,113)
EBITDA[2]	$ 3,294	$ 200	$177	$ 15	$ (15)	$ (7)	$ 3,664

(1) Net income on intercompany positions recognized by segments using mark-to-market accounting is eliminated. Intercompany transactions are also eliminated.

(2) EBITDA is defined as income before provision for income taxes, interest expense, interest income, deferred electric procurement costs, depreciation and amortization, provision for loss on generation-related assets and undercollected purchased power costs. EBITDA is not intended to represent cash flows from operations and should not be considered as an alternative to net income as an indicator of the PG&E Corporation's operating performance or to cash flows as a measure of liquidity. Refer to the Statement of Cash Flows for the U.S. GAAP basis cash flows. PG&E Corporation believes that EBITDA is a standard measure commonly reported

and widely used by analysts, investors, and other interested parties. However, EBITDA as presented herein may not be comparable to similarly titled measures reported by other companies.

Overall Results

PG&E Corporation's financial position and results of operations are impacted by the ongoing California energy crisis. Please see the Liquidity and Financial Resources section and Note 2 of the Notes to the Consolidated Financial Statements for more information on the California energy crisis.

Net loss for the year ended December 31, 2000 increased to $3,364 million from a net loss of $73 million for the same period in 1999. Of the $3,291 million increase, the Utility's net loss allocated to common stock for the year ended December 31, 2000 accounted for $4,271 million of the increase, partially offset by an increase in the NEG net income of $980 million.

The decrease in performance of 2000 compared to 1999 results of operations is attributable to the following factors:

- The Utility's earnings were impacted as a result of the write-off of its remaining generation related regulatory assets and undercollected purchased power costs ($4.1 billion, after taxes). Because of the substantial uncertainty created by the California energy crisis, the Utility can no longer conclude that energy costs, which had been deferred on its balance sheets, are probable of recovery. Under Statement of Financial Accounting Standard (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulations," if a rate mechanism provided by legislation or other regulatory authority were subsequently established that made recovery from regulated rates probable as to all or a portion of the undercollection that was previously charged against earnings, a regulatory asset would be reinstated with a corresponding increase in earnings.
- As a result of the high cost of power, with no offsetting revenues, the Utility and PG&E Corporation had a net loss for California tax purposes. California law does not permit carrybacks of such losses and only permits carryforwards of 55% of such losses. As a result, PG&E Corporation was unable to recognize $79 million of state tax benefits because of California law. Income tax expense was also higher due to depreciation adjustments and a reduction in investment tax credits.
- In 2000, the Utility recorded a provision ($83 million, after tax) for potential losses associated with litigation discussed in Note 15 of the Notes to the Consolidated Financial Statements.
- At the end of 1999, PG&E Corporation announced its plans to dispose of PG&E GTT, and these assets were written down to estimated fair value resulting in a charge of $890 million ($2.24 per share). PG&E GTT has operated at a breakeven basis in 2000, while it reported a net loss from operations of $7 million ($0.02 per share) in 1999. These operations were sold on December 22, 2000.
- Also at the end of 1999, PG&E Corporation announced its plans to dispose of PG&E ES and these assets were written down to net realizable value. PG&E ES operated at a loss during 2000. However, those losses were charged against reserves established in 1999 and did not impact the current results from operations, while PG&E ES reported losses of $98 million ($0.27 per share) for 1999. Additionally, during the later half of 2000, PG&E Corporation recorded after-tax charges of $40 million ($0.11 per share) to reflect the closing of transactions to dispose of the retail energy services business and related commodity portfolio.
- PG&E ET's net income in 2000, net of restructuring charges of $13 million after-tax ($0.04 per share) related to the move of natural gas trading operations from Houston, Texas, to Bethesda, Maryland, increased $57 million compared to 1999 results due to across the board improvements in natural gas and power trading, asset management, and structured transactions. While trading in electric commodities has generally been profitable, the results of the gas trading operations have improved significantly as a result of structured transactions. Additionally, the gas trading operations benefited from the highest gas prices in a number of years. The power trading operations have been able to benefit from volatile prices throughout the United States.
- PG&E Gen and PG&E GTN earnings decreased slightly from 1999 levels, primarily attributable to a decline in operating results in the generating business and a decrease in operating income at PG&E GTN primarily as a result of settlements received in the amount of $19 million for negotiations regarding transportation contracts and other related issues, resulting in the restructuring and/or termination of these transportation contracts in 1999 with no similar transactions in 2000.

The effective tax rate for PG&E Corporation has decreased to 37.9% in 2000 compared to 95.0% in the prior year as a result of a higher effective tax rate in 1999, largely due to the disposition of PG&E GTT which resulted in a capital loss for tax purposes, which could not be fully recognized.

The decrease in performance of 1999 over 1998 results of operations is attributable to the following factors:

- PG&E Corporation had a net loss in 1999 of $73 million, or $0.20 per share. In 1998 PG&E Corporation had net income of $719 million, or $1.88 per share. The decrease was principally due to the write-down to fair value of the natural gas business in Texas and the accrual for the discontinuance of operations of the Energy Services segment. The PG&E GTT write-down was approximately $890 million after taxes or $2.42 per share and is comprised of the following pre-tax amounts: $819 million write-down of net property, plant, and equipment, $446 million write-down of goodwill, and an accrual of $10 million for selling costs. The PG&E ES discontinued operations generated a charge of $58 million after tax.
- Partially offsetting these charges were increases in Utility income of $153 million or $0.42 per share, primarily as a result of the 1999 General Rate Case.
- Also increasing income was an adjustment of a litigation reserve at GTT, associated with a court-approved settlement proposal in the amount of $35 million after tax.
- The 1998 income from continuing operation also included a loss on the sale of the Australian energy holdings of $23 million, or $0.06 per share, without a similar charge in 1999.
- In addition, PG&E Gen changed its method of accounting for major maintenance and overhauls at its generating facilities. Beginning January 1, 1999, the cost of major maintenance and overhauls, principally at the PG&E Gen business segment, has been accounted for as incurred. The change resulted in PG&E Corporation recording income of $12 million after-tax ($0.03 per share), reflecting the cumulative effect of the change in accounting principle for the year ended December 31, 1999.

PG&E Corporation has recorded income tax expense of $248 million for 1999. The effective tax rate primarily results from two factors: (1) electric industry restructuring has resulted in the reversal of temporary differences whose tax benefits were originally flowed through to customers causing an increase in income tax expense independent of pre-tax income, and (2) the disposition of PG&E GTT resulted in a capital loss for tax purposes, which could not be fully recognized.

Dividends

PG&E Corporation's historical quarterly common stock dividend was $0.30 per common share, which corresponded to an annualized dividend of $1.20 per common share.

On January 10, 2001, the Board of Directors of PG&E Corporation suspended the payment of its fourth quarter 2000 common stock dividend of $0.30 per share declared by the Board of Directors on October 18, 2000 and payable on January 15, 2001 to shareholders of record as of December 15, 2000. The California energy crisis had created a liquidity crisis for PG&E Corporation, which led to the suspension of payments of dividends to conserve cash resources. These defaulted dividends were later paid on March 2, 2001 in conjunction with the refinancing of PG&E Corporation obligations, discussed above under the Liquidity and Financial Resources section.

Additionally, the parent company refinancing agreements mentioned above prohibit dividends from being declared or paid until the term loans have been repaid. The agreement is for a term of two years with an option on behalf of PG&E Corporation to extend the term for an additional year.

On January 10. 2001, the Utility suspended the payment of its fourth quarter 2000 common stock dividend of $110 million, declared in October 2000, to PG&E Corporation and its wholly owned subsidiary PG&E Holdings, Inc. Until its financial condition is restored, the Utility is precluded from paying dividends to PG&E Corporation and PG&E Holdings, Inc.

Utility

Overall Results

The Utility's net loss allocated to common stock was $3,508 million in 2000 as compared to 1999 net income of $763 million. The decrease was primarily the result of the write-off of its remaining generation-related regulatory assets and undercollected purchased power costs, a provision for potential litigation losses, and higher income tax expense as mentioned previously.

The Utility's net income available for common stock increased to $763 million in 1999 as compared to 1998 net income of $702 million, primarily because of the impacts of the 1999 General Rate Case (GRC).

Operating Income

Operating loss for the Utility was $5,201 million in 2000 as compared to operating income of $1,993 million in 1999. This decrease in the Utility's operating income was primarily due to the write-off of its remaining generation related regulatory assets and undercollected purchased power costs. In addition, it is attributable to a provision for potential litigation losses and a lower return on its assets, due to the sale of a portion of the Utility's generating assets and the ongoing recovery of transition costs.

Operating income for the Utility was $1,993 million in 1999 as compared to $1,876 million in 1998. This increase was primarily because of the impacts of the 1999 GRC. However, the increases from the GRC were partially offset by a reduction in the Utility's authorized cost of capital and a lower return on its assets due to the sale of a significant portion of its generating assets and recovery of transition costs.

Operating Revenues

The following table shows the components of the Utility's electric revenue by customer class, natural gas revenues, and total revenues for the years ended December 31:

	2000	1999	1998
Residential	$3,351	$3,294	$3,198
Commercial	2,804	2,940	2,883
Total residential and commercial	6,155	6,234	6,081
Legislative discount	(453)	(435)	(396)
Revenues from residential and commercial	5,702	5,799	5,685
Industrial	509	864	933
Agriculture	386	392	351
Miscellaneous	257	177	222
Total electric operating revenues	$6,854	$7,232	$7,191
Total gas operating revenues	$2,783	$1,996	$1,733
Total operating revenues	$9,637	$9,228	$8,924

Utility operating revenues increased $409 million or 4.4% to $9,637 million in 2000 compared to $9,228 million in 1999. The increase in operating revenues for 2000, as compared to 1999, related primarily to higher gas prices, which are passed on to customers and collected in gas revenues, partially offset by a decrease in electric revenues. The average price of gas per thousand cubic feet was $4.92 in 2000 and $2.47 in 1999. Gas sales volumes for bundled sales and transportation decreased by 9% from 1999 sales volumes due to warmer winter weather, while gas sales volumes for transportation-only service increased by 25% due to increased demands by electric generators to meet air-conditioning loads due to warmer summer weather and new transportation contracts.

Electric sales volumes increased for all customer classes, resulting in an overall increase of 3% over 1999 sales volumes. Electric revenues from industrial and commercial customers decreased because of higher wholesale power market prices and resulting credits issued to direct access customers. These customers, principally large industrial companies, procure electricity from independent generators under long-term contracts and receive a credit on their utility bills at prevailing market prices. In accordance with CPUC regulations, the Utility provides an energy credit to those customers (known as direct access customers) who have chosen to buy their electric generation energy from an energy service provider (ESP) other than the Utility. The Utility bills direct access customers based upon fully bundled rates (generation, distribution, transmission, public purpose programs, and a competition transition charge). However, the direct access customer receives an energy credit equal to the PX price for wholesale electricity (calculated as the average market prices multiplied by customer energy usage for the period), with the customer being obligated to their ESP at their direct access contract rate. As wholesale power prices began to increase in June 2000, the level of PX credits increased correspondingly to the point where the credits exceeded the Utility's distribution and transmission charges to direct access customers. During 2000, the PX credits reduced electric revenue by $472 million, although the Utility ceased paying most of these credits in December 2000. As of March 29, 2001, the estimated total of accumulated credits for direct access customers that have not been paid by the Utility is approximately $503 million. Such amounts are reflected on the Utility's balance sheet. The actual amount that will be refunded to ESPs will be dependent upon when the rate freeze ends and whether there are any adjustments made to wholesale energy prices by FERC.

Utility operating revenues increased $304 million or 3.4% in 1999 as compared to 1998. This increase is primarily due to: (1) a $147 million increase in gas revenues from residential and commercial gas customers due to higher usage, (2) a $93 million increase in gas revenues as a result of the GRC, (3) a $43 million increase in revenues from small and medium electric customers due to increased customers, and (4) a $16 million increase in revenues from an increase in gas transportation volumes.

Operating Expenses

Utility operating expenses increased $7,603 million in 2000 compared to 1999.

The tables below summarize the changes in the Utility's operating expenses:

	For the Year ended December 31,			
(in millions)	**2000**	**1999**	**Increase (Decrease)**	**Increase (Decrease)**
Cost of electric energy, net	$ 6,741	$2,411	$4,330	179.6%
Deferred electric procurement costs	(6,465)	—	(6,465)	—
Cost of gas	1,425	738	687	93.1%
Operating and maintenance, net	2,687	2,522	165	6.5%
Depreciation, amortization, and decommissioning	3,511	1,564	1,947	124.5%
Provision for loss on generation related regulatory assets and purchased power costs	6,939	—	6,939	—
Total	$14,838	$7,235	$7,603	105.1%

	For the Year ended December 31,			
(in millions)	**1999**	**1998**	**Increase (Decrease)**	**Increase (Decrease)**
Cost of electric energy, net	$2,411	$2,321	$ 90	3.9%
Cost of gas	738	621	117	18.8%
Operating and maintenance, net	2,522	2,668	(146)	(5.5%)
Depreciation, amortization, and decommissioning	1,564	1,438	126	8.8%
Total	$7,235	$7,048	$ 187	2.7%

The overall increase in operating expenses is primarily attributable to the write-off of the Utility's transition cost regulatory assets and undercollected purchased power costs. In addition, operating expenses increased due to increases in the cost of gas during the latter half of 2000. The average price the Utility paid per thousand cubic feet of gas was $4.92 in 2000 and $2.47 in 1999.

Wholesale electric energy costs increased significantly during the latter half of 2000. The average monthly costs per kWh of purchased power during the latter half of 2000 were: June (16.33 cents), July (11.00 cents), August (18.70 cents), September (13.82 cents), October (13.62 cents), November (20.43 cents), and December (33.24 cents). The amount of purchased power costs in excess of the revenue for the generation component of frozen rates was reflected as deferred electric procurement costs prior to the year-end write-off described above. Revenues for the generation component of frozen rates were approximately 5.4 cents per kWh during 2000.

Depreciation, amortization, and decommissioning increased $1,947 million in 2000. The increase resulted primarily from an increase in recovery of transition costs resulting from higher revenues from sales to the PX of Utility-owned generation, including Diablo Canyon, and generation from QFs and other providers. As mandated by the CPUC, these revenues, in excess of the related costs, must be used to recover transition costs. See Note 2 of the Notes to the Consolidated Financial Statements.

The Utility's operating expenses increased $187 million in 1999 as compared to 1998. This increase reflected the increased cost of gas due to higher usage and the increased amortization of electric transition costs, partially offset by a decrease in operating and maintenance expense resulting from fewer owned-generation facilities in 1999 as a result of divestitures.

Dividends

Dividends paid to PG&E Corporation increased from $440 million in 1999 to $475 million in 2000, maintaining the CPUC-mandated capital structure. Dividends paid to PG&E Corporation in 1998 were $444 million.

Dividends paid to preferred shareholders remained at the same level of $25 million in 2000 and 1999. Dividends paid to preferred shareholders decreased from $29 million in 1998 to $25 million in 1999, primarily as a result of redemptions.

As previously discussed, the Utility has suspended payment of its common and preferred dividends. 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.

PG&E National Energy Group

Operating Income

Operating income at the NEG increased $1,509 million in 2000 as compared to 1999, primarily related to the charge to write PG&E GTT down to its net realizable value in 1999 with no similar charge occurring in 2000. Additionally, all business units reflected improved operating results over the prior year, despite a $22 million charge related to the relocation of the energy trading operations from Houston, Texas, to Bethesda, Maryland.

Operating income of the NEG decreased $62 million in 1999 as compared to 1998, excluding the charge to write PG&E GTT down to its net realizable value. The decline resulted from mild weather in the Northeast, lower interruptible transport revenue in the Pacific Northwest, less portfolio management activity, and trading losses in the U.S. gas portfolio. This decline was partially offset by cost containment efforts across the organization and an increase in the differential between natural gas liquids prices and the cost of natural gas.

Operating Revenues

The NEG operating revenues increased $5,003 million in 2000 compared to 1999. The NEG has focused its trading efforts on asset management and higher-margin trades, resulting in increased trading volume of electric commodities principally in the Southeast and Midwest. In addition, increases in the price of power and gas have resulted in increased revenues.

The NEG's 1999 operating revenues increased $939 million as compared to 1998, principally due to: (1) the PG&E Gen business segment receiving a full year of revenue from the New England assets acquired in September 1998, and (2) increases in trading revenues at PG&E ET reflecting the further maturation of its business. The 1999 operating revenues also reflected revenue increases at PG&E GTT resulting from an improved differential between the natural gas liquids prices and the incoming natural gas. These revenue increases were partially offset by (1) a decline in interruptible revenues in the Northwest due to the lower natural gas prices in the Southwest as compared to Canadian prices, and (2) lower transportation revenue on the Texas transmission system.

Operating Expenses

Operating expenses at the NEG increased $3,494 million in 2000 compared to the prior year. The increase results from the increased trading volumes discussed above, and increases in the cost of power and gas, partially offset by reduced depreciation and amortization expense at PG&E GTT reflective of the disposal of the PG&E GTT assets.

The NEG's operating expenses increased $2,276 million in 1999 as compared to 1998, due to the charge associated with the disposition of PG&E GTT, a full year of operating expenses associated with the generation facilities in New England, and growth of PG&E ET operations.

Dividends

The NEG currently intends to retain any future earnings to fund the development and growth of its business. Further, the NEG is precluded from paying dividends, unless it meets certain financial tests. Therefore, it is not anticipating paying any cash dividends on its common stock in the foreseeable future.

REGULATORY MATTERS

A significant portion of PG&E Corporation's operations is regulated by federal and state regulatory commissions. These commissions oversee service levels and, in certain cases, PG&E Corporation's revenues and pricing for its regulated services. Following are the percentages of 2000 revenues that fell under the jurisdiction of these various regulatory agencies:

	Utility	Consolidated
Cost of service-based	96.3%	39.2%
Market	3.7%	60.8%

The Utility is the only subsidiary with significant regulatory proceedings at this time. The Utility's significant regulatory proceedings are discussed below. Regulatory proceedings associated with electric industry restructuring are discussed above in "The California Energy Crisis." See Note 2 of the Notes to the Consolidated Financial Statements.

The Utility's General Rate Case

The CPUC authorizes an amount known as "base revenues" to be collected from ratepayers to recover the Utility's basic business and operational costs for its gas and electric distribution operations. Base revenues, which include non-fuel-related operating and maintenance costs, depreciation, taxes, and a return on invested capital, currently are authorized by the CPUC in GRC proceedings. The CPUC's final decision in the Utility's 1999 GRC application increased annual electric distribution revenues by $163 million and annual gas distribution revenues by $93 million over 1998 authorized base revenues.

In March 2000, two interveners filed applications for rehearing of the 1999 GRC decision, alleging that the CPUC committed legal errors by approving funding in certain areas that were not adequately supported by record evidence. In April 2000, the Utility filed its response to these applications for rehearing, defending the GRC decision against the allegations of error. A CPUC decision on the applications for rehearing is pending.

In the 1999 GRC decision the CPUC ordered that the Utility file a 2002 GRC. As a result of the current energy crisis, the procedural schedule has been delayed pending the CPUC's resolution of the Utility's request that it be permitted to file an alternative schedule or an alternative to the 2002 GRC. An earlier decision initially delaying the schedule affirms that rates would still become effective on January 1, 2002, although the CPUC decision may not be rendered until after that date.

Order Instituting Investigation (OII) into Holding Company Activities

On April 3, 2001, the CPUC issued an order instituting an 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 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 "ring fence" 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 (including penalties), prospective rules, or conditions, as appropriate. PG&E Corporation and the Utility believe that they have complied with applicable statutes, CPUC decisions, rules, and orders. As described above, on April 6, 2001, the Utility filed a voluntary petition for relief under Chapter 11 of the U.S. Bankruptcy Code. PG&E Corporation and the Utility believe that to the extent the CPUC seeks to investigate past conduct for compliance purposes, the investigation is automatically stayed by the bankruptcy filing. Neither the Utility nor PG&E Corporation can predict what the outcome of the investigation will be or whether the outcome will have a material adverse effect on their results of operation or financial condition.

The Utility's 2001 Attrition Rate Adjustment (ARA)

In July 2000, the Utility filed an ARA application with the CPUC to increase its 2001 electric distribution revenues by $189 million, effective January 1, 2001. The increase reflects inflation and the growth in capital investments necessary to serve customers. The Utility did not request an increase in gas distribution revenues. In December 2000, the CPUC issued an interim order finding that a decision on the application cannot be rendered by January 1, 2001, and determining that if attrition relief is eventually granted, that relief will be effective as of January 1, 2001. Hearings are scheduled to begin in June 2001, and a CPUC decision is expected by January 2002.

The Utility's Cost of Capital Proceedings

Each year, the Utility files an application with the CPUC to determine the authorized rate of return that the Utility may earn on its electric and gas distribution assets and recover from ratepayers. Since February 17, 2000, the Utility's adopted return on common equity (ROE) has been 11.22% on electric and gas distribution operations, resulting in an authorized 9.12% overall rate of return (ROR). The Utility's earlier adopted ROE was 10.6%. The adopted ROR for 2000 resulted in an increase of approximately $49 million over 1999 electric and gas distribution revenues. In May 2000, the Utility filed an application with the CPUC to establish its authorized ROR for electric and gas distribution operations for 2001. The application requests an ROE of 12.4%, and an overall ROR of 9.75%. If granted, the requested ROR would increase electric distribution revenues by approximately $72 million and gas distribution revenues by approximately $23 million. The application also requests authority to implement an Annual Cost of Capital Adjustment Mechanism for 2002 through 2006 that would replace the annual cost of capital proceedings. The proposed adjustment mechanism would modify the Utility's cost of capital based on changes in an interest rate index. The Utility also proposes to maintain its currently authorized capital structure of 46.2% long-term debt, 5.8% preferred stock, and 48% common equity. In March 2001, the CPUC issued a proposed decision recommending no change to the current 11.22% ROE for test year 2001. This authorized ROE results in a corresponding 9.12% return on rate base and no change in the Utility's electric or gas revenue requirement for 2001. A final CPUC decision is expected in the second quarter of 2001.

The Utility's FERC Transmission Rate Cases

Since April 1998, electric transmission revenues have been authorized by the FERC, including various rates to recover transmission costs from the Utility's former bundled retail transmission customers. The FERC has not yet acted upon a settlement filed by the Utility that, if approved, would allow the Utility to recover $345 million in electric transmission rates for the 14-month period of April 1, 1998 through May 31, 1999. During this period, somewhat higher rates have been collected, subject to refund. A FERC order approving this settlement is expected by the end of 2001. The Utility has accrued $24 million for potential refunds related to the period ended May 31, 1999. In April 2000, the FERC approved a settlement that permits the Utility to recover $264 million in electric transmission rates retroactively for the 10-month period from May 31, 1999 to March 31, 2000. In September 2000, the FERC approved another settlement that permits the Utility to recover $340 million annually in electric transmission rates and made this retroactive to April 1, 2000. Further, in November 2000, the FERC accepted, subject to refund, the Utility's proposal to collect $397 million annually in electric transmission rates beginning on May 6, 2001.

The Utility's Catastrophic Event Memorandum Account Proceeding

In April 2000, the CPUC approved a settlement agreement in a proceeding addressing the Catastrophic Events Memorandum Account. The settlement provided for a $59 million increase in electric distribution revenue requirement and an $11 million increase in gas distribution revenue requirement which was collected through rates during 2000. The increase compensates the Utility for costs incurred for several emergencies, including the 1991 Oakland Hills Fire and the 1998 storms.

The Utility's Electric Base Revenue Increase Proceeding

Section 368(e) of the California Public Utilities Code was adopted as part of the California electric industry restructuring legislation. It provided for an increase in the Utility's electric base revenues for 1997 and 1998, for enhancement of transmission and distribution system safety and reliability. In accordance with Section 368(e), the CPUC authorized a 1997 base revenue increase of $164 million. For 1998, the CPUC authorized an additional base revenue increase of $77 million. Section 368(e) expenditures are subject to review by the CPUC.

In July 1999, the Office of Ratepayer Advocates; a division of the CPUC, (ORA) recommended a disallowance of $88.4 million in Section 368(e) expenditures for 1997 and 1998. In August 1999, The Utility Reform Network (TURN) recommended an additional $14 million disallowance for a total recommended disallowance for 1997 and 1998 expenditures of $102.4 million. The Utility opposed the recommended disallowances and hearings were held in October 1999. It is uncertain when a proposed decision will be issued by the CPUC. Any proposed decision would be subject to comment by the parties and change by the CPUC before a final decision is issued. The Utility does not expect a material impact on its financial position or results of operations resulting from these matters.

The Utility's Performance-Based Ratemaking (PBR) Application

In June 2000, the CPUC granted the Utility's request to withdraw its PBR application filed in November 1998. The Utility had requested the withdrawal in accordance with the 1999 GRC decision issued in February 2000, which required a 2002 GRC before a PBR mechanism could be implemented. In closing the PBR proceeding, the CPUC ordered the Utility to file a new PBR application by September 2000. This application would propose financial rewards and penalties associated with utility performance in meeting prescribed standards for measures such as electric reliability and customer service.

In September 2000, the Utility filed an application with the CPUC to establish (1) performance standards and associated financial rewards and penalties for electric and gas distribution service, (2) a revenue-sharing mechanism for new categories of non-tariffed products and services (NTP&S) offered by the Utility, and (3) ratemaking for proceeds from sales or transfers of certain non-generation related land. The performance standards would cover a period of five years commencing January 1, 2001. The total maximum annual reward or penalty is $54 million per year, consisting of $52 million for electric distribution and $2 million for gas distribution. The revenue-sharing mechanism proposes to share net positive after-tax revenues from new categories of NTP&S equally between ratepayers and shareholders. Finally, the Utility requested that the CPUC establish basic rules about the allocation of gains and losses from the Utility's non-generation-related land sales. In November 2000, the CPUC suspended the proceeding until further notice.

MUNICIPALIZATION AND OTHER COMPETITION

With the uncertainties over future electric utility rates due to the California energy crisis, municipalization is under consideration by many local governments in California. Municipalization is the attempt by cities and local utility districts to take over markets from private, investor-owned utility companies. Local governments in California are increasingly looking at entering the utility business as a source of new revenue. Those that already have municipal utilities are examining expansion to provide new services or to sell existing services outside of their current boundaries. Municipalization efforts in San Francisco, Berkeley, and San Diego (among several other California cities) are being pursued by grass roots organizations and proposals to municipalize may go before voters. We cannot currently predict what the outcome will be from these actions.

As wholesale electric prices increase, alternatives to the current model become more attractive. These alternative technologies, such as distributed generation which enables siting of smaller electric generation facilities in close proximity to the electric demand, have the potential to strand Utility investment and make recovery more challenging. The CPUC has opened a rulemaking proceeding to examine various issues concerning distributed generation, including interconnection issues, who can own and operate distributed generation, environmental impacts, the role of utility distribution companies, and the rate design and cost allocation issues associated with the deployment of distributed generation facilities. This rulemaking is also intended to address other areas of potential electric competition, such as billing services. There has been little activity in this rulemaking since its issuance in 1999.

ENVIRONMENTAL MATTERS

We are subject to laws and regulations established to both maintain and improve the quality of the environment. Where our properties contain hazardous substances, these laws and regulations require us to remove those substances or remedy effects on the environment. See Note 15 of the Notes to the Consolidated Financial Statements for further discussion of environmental matters.

Utility

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. The remediation costs also reflect (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.

At December 31, 2000, the Utility expects to spend $320 million, undiscounted, for hazardous waste remediation costs at identified sites, including divested fossil-fueled power plants. 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 could spend as much as $462 million on these costs. 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.

The Utility had an environmental remediation liability of $320 million and $271 million at December 31, 2000 and 1999, respectively. The $320 million accrued at December 31, 2000 includes (1) $114 million related to the pre-closing remediation liability, associated with divested generation facilities (see further discussion in the "Generation Divestiture" section of Note 2 of the Notes to the Consolidated Financial Statements), and (2) $180 million related to remediation costs for those generation facilities that the Utility still owns, manufactured gas plant sites, and gas gathering compressor stations. Of the $320 million environmental remediation liability, the Utility has recovered $168 million through rates, and expects to recover another $87 million in future rates. The Utility is seeking recovery of the remainder of its costs from insurance carriers and from other third parties as appropriate.

In December 1999, the Utility was notified by the purchaser of its former Moss Landing power plant that it had identified a cleaning procedure used at the plant that released heated water from the intake, and that this procedure is not specified in the plant's National Pollutant Discharge Elimination System (NPDES) permit issued by the Central Coast Regional Water Quality Control Board (Central Coast Board). The purchaser notified the Central Coast Board of its findings. In March 2000, the Central Coast Board requested the Utility to provide specific information regarding the "backflush" procedure used at Moss Landing. The Utility provided the requested information to the Board in April 2000. The Utility's investigation indicated that while it owned Moss Landing, significant amounts of water were discharged from the cooling water intake. While the Utility's investigation did not clearly indicate that discharged waters had a temperature higher than ambient receiving water, the Utility believes that the temperature of the discharged water was higher than that of the ambient receiving water. In December 2000, the executive officer of the Central Coast Board made a settlement proposal to the Utility under which the Utility would pay $10 million, a portion of which would be used for environmental projects and the balance of which would constitute civil penalties. Settlement negotiations are continuing.

The Utility's Diablo Canyon employs a "once through" cooling water system which is regulated under a NPDES Permit issued by the Central Coast Board. This permit allows Diablo Canyon to discharge the cooling water at a temperature no more than 22 degrees above ambient receiving water and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, marine and wildlife habitat, shell fish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft Cease and Desist Order (CDO) alleging that, although the temperature limit has never been exceeded, the Diablo Canyon's discharge was not protective of beneficial uses. In October 2000, the Central Coast Board and the Utility reached a tentative settlement of this matter pursuant to which the Central Coast Board has agreed to find that the Utility's discharge of cooling water from the Diablo Canyon plant protects beneficial uses and that the intake technology reflects "best technology available" under Section 316(b) of the Federal Clean Water Act. As part of 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 California Superior Court.

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

PG&E National Energy Group

In October and November 1999, the U.S. Environmental Protection Agency (EPA) and several states filed suits or announced their intention to file suits against a number of coal-fired power plants in Midwestern and Eastern states. These suits relate to alleged violations of the Clean Air Act. More specifically, they allege violations of the deterioration prevention and non-attainment provisions of the Clean Air Act's new source review requirements arising out of certain physical changes that may have been made at these facilities without first obtaining the required permits. In May 2000 the NEG received a request for information seeking detailed operating and maintenance histories for the Salem Harbor and Brayton Point power plants. If EPA were to find that there were physical changes in the past that were undertaken without first receiving the required permits under the Clean Air Act, then penalties may be imposed and further emission reductions might be necessary at these plants.

In addition to the EPA, states may impose more stringent air emissions requirements. The Commonwealth of Massachusetts is considering the adoption of more stringent air emission reductions from electric generating facilities. If adopted, these requirements will impact Salem Harbor and Brayton Point. The NEG has proposed an emission reduction plan that may include modernization of the Salem Harbor power plant and use of advanced technologies for emissions removal. It is also studying various advanced technologies for emissions removal for the Brayton Point power plant.

The NEG's subsidiary, USGenNE, has proposed a number of state and regional initiatives that will require it to achieve significant reductions of emissions by 2010. The NEG expects that USGenNE will meet these requirements through a combination of installation of controls, use of emission allowances it currently owns, and purchase of additional allowances. The NEG currently estimates that USGenNE's total capital cost for complying with these requirements will be approximately $300 million.

PG&E Gen's existing power plants, including USGenNE facilities, 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 are operating pursuant to NPDES permits that have expired. For the facilities whose NPDES permits have expired, permit renewal applications are pending. It is anticipated that all three facilities will be able to continue to operate under existing terms and conditions until new permits are issued. It is estimated that USGenNE's cost to comply with the new permit conditions could be as much as $55 million through 2005. It is possible that the new permits may contain more stringent limitations than prior permits.

During September 2000, USGenNE signed a series of agreements that require, among other things, that USGenNE alter its existing waste water treatment facilities at two facilities by replacing certain unlined treatment basins, submit and implement a plan for the closure of such basins, and perform certain environmental testing at the facilities. USGenNE has incurred $4 million in 2000 and expects to complete the required steps on or before December 2001. The total expected cost of these improvements is $21 million.

Inflation

Financial statements, which are prepared in accordance with accounting principles generally accepted in the United States of America, report operating results in terms of historical costs and do not evaluate the impact of inflation. Inflation affects our construction costs, operating expenses, and interest charges. In addition, the Utility's electric revenues do not reflect the impact of inflation due to the current electric rate freeze. However, inflation at current levels is not expected to have a material adverse impact on PG&E Corporation's or the Utility's financial position or results of operations.

Quantitative and Qualitative Disclosures About Market Risk

Price Risk Management Activities

We have established a risk management policy that allows derivatives to be used for both trading and non-trading purposes (a derivative is a contract whose value is dependent on or derived from the value of some underlying asset). We use derivatives for hedging purposes primarily to offset PG&E Corporation's or the Utility's primary market risk exposures, which include commodity price risk, interest rate risk, and foreign currency risk. We also participate in markets using derivatives to gather market intelligence, create liquidity, and maintain a market presence. Such derivatives include forward contracts, futures, swaps, options, and other contracts. Net open positions often exist or are established due to PG&E Corporation's and the Utility's assessment of their responses to changing market conditions. To the extent that PG&E Corporation has an open position, it is exposed to the risk that fluctuating market prices may adversely impact its financial results.

PG&E Corporation and the Utility may only engage in the trading of derivatives in accordance with policies established by the PG&E Corporation Risk Management Committee. Trading is permitted only after the Risk Management Committee authorizes such activity subject to appropriate financial exposure limits. Under PG&E Corporation, both the NEG and the Utility have their own Risk Management Committees that address matters relating to those companies' respective businesses. These Risk Management Committees are comprised of senior officers.

Market Risk

Commodity Price Risk

Commodity price risk is the risk that changes in market prices will adversely affect earnings and cash flows. PG&E Corporation is primarily exposed to the commodity price risk associated with energy commodities such as electricity and natural gas. Therefore, PG&E Corporation's price risk management activities primarily involve buying and selling fixed-price commodity commitments into the future.

In compliance with regulatory requirements, the Utility manages price risk independently from the activities in PG&E Corporation's unregulated business. Price risk activities consist of the use of non-trading (hedging) financial instruments to reduce the impact of commodity price fluctuations for electricity and natural gas. While the use of these instruments has been authorized by the CPUC, the CPUC has yet to establish rules around how it will judge the reasonableness of these instruments. Gains and losses associated with the use of the majority of these financial instruments primarily affect regulatory accounts, depending on the business unit and the specific program involved.

In response to high wholesale electricity costs experienced during the summer of 2000, the CPUC in August 2000 eliminated the requirement to procure electricity in the spot market and authorized the Utility to enter into "bilateral agreements" with third parties. These contracts are used to purchase electricity from non-PX sources at fixed prices for terms that may extend to the end of 2005. The purpose of bilateral contracts is to lock in supply and rates on the future purchase of electricity and to reduce price volatility.

The CPUC has authorized the Utility to trade natural gas-based financial instruments to manage price and revenue risks associated with its natural gas transmission and storage assets, subject to certain conditions. Furthermore, the Utility was authorized to trade natural gas-based financial instruments to hedge the gas commodity price swings in serving core gas customers.

PG&E Corporation's business units 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. We quantify market risk 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 our positions and how likely the prices of those positions will move together. The model includes all derivatives and commodity investments in our trading portfolios and only derivative commodity investments for our non-trading portfolio (but not the related underlying hedged position). PG&E Corporation and the Utility express value-at-risk as a dollar amount of the potential loss in the fair value of our portfolios based on a 95% confidence level using a one-day liquidation period. Therefore, there is a 5% probability that the Company's portfolios will incur a loss in one day greater than its value-at-risk. The value-at-risk is aggregated for PG&E Corporation as a whole by correlating the daily returns of the portfolios for electricity and natural gas for the previous 22 trading days.

The following tables illustrate the value-at-risk for PG&E Corporation's daily commodity price risk exposure for the year ended December 31:

	2000		1999	
	Trading	Non-Trading	Trading	Non-Trading
	(Dollars in millions)			
NEG:				
Value at End of Period	$11.5	$ 8.8	$ 4.4	$ —
Average	6.8	9.5	4.3	0.6
Low	5.5	7.6	1.3	—
High	12.3	11.1	6.2	1.7
Utility:				
Value at End of Period	—	187.4	—	3.2
Average	—	24.2	—	4.0
Low	—	0.1	—	2.9
High	—	207.8	—	5.7

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.

Interest Rate Risk

PG&E Corporation and the Utility are exposed to the following types of interest rate exposure:

Floating rate exposure measures the sensitivity of corporate earnings and cash flows to changes in short-term interest rates. This exposure arises when short-term debt is rolled over at maturity, when interest rates on floating rate notes are periodically reset according to a formula or index, and when floating rate assets are financed with fixed rate liabilities. PG&E Corporation manages its exposure to short-term interest rates by using an appropriate mix of short-term debt, long-term floating rate debt, and long-term fixed rate debt.

Financing exposure measures the effect of an increase in interest rates that may occur related to any planned or expected fixed rate debt financing. This includes the exposure associated with replacing debt at maturity. PG&E Corporation will hedge financing exposure in situations where the potential impairment of earnings, cash flows, and investment returns or execution efficiency, or external factors (such as bank imposed credit agreements) necessitate hedging.

Refunding exposure measures the effect of an increase in interest rates on the ability to economically refund a callable debt instrument. Corporate bonds typically are issued with a call feature that allows the issuer to retire and replace the bonds at a lower rate if interest rates have fallen. The value of this call feature to the issuer declines with increases in interest rates. PG&E Corporation will hedge refunding exposure when it is economic to repurchase all or part of the underlying debt instrument and replace it with a debt instrument that has lower cost during its remaining life. The guideline for a refunding to be economic is that the net present value savings should exceed 5% of the par value of the debt to be refunded and the refunding efficiency should exceed 85%.

PG&E Corporation and the Utility use interest rate swaps to manage their interest rate exposure. Interest rate risk sensitivity analysis is used to measure PG&E Corporation's interest rate price risk by computing estimated changes in the fair value in the event of assumed changes in market interest rates. As of December 31, 2000, if interest rates had averaged 1% higher, it was estimated that earnings would have decreased by approximately $24 million.

Foreign Currency Risk

PG&E Corporation is exposed to the following types of foreign currency risk:

Economic exposure measures the change in value that results from changes in future operating or investing cash flows caused by the timing and level of anticipated foreign currency flows. Economic exposure includes the anticipated purchase of foreign entities, anticipated cash flows, projected revenues and expenses denominated in a foreign currency.

Transaction exposure measures changes in value of current outstanding financial obligations already incurred, but not due to be settled until some future date. This includes the agreement to purchase a foreign entity in a currency other than the U.S. dollar, an obligation to infuse equity capital into a foreign entity, foreign currency denominated debt obligations, as well as actual non-U.S. dollar cash flows such as dividends declared but not yet paid.

Translation exposure measures potential accounting derived changes in owners' equity that result from translating a foreign affiliate's financial statements from its functional currency to U.S. dollars for PG&E Corporation's consolidated financial statements.

PG&E Corporation's primary foreign currency exchange rate exposure was with the Canadian dollar. The following instruments are used to hedge foreign currency exposures: forwards, swaps, and options. Based on a sensitivity analysis at December 31, 2000, a 10% devaluation of the Canadian dollar would be immaterial to PG&E Corporation's consolidated financial statements.

New Accounting Standards

PG&E Corporation and the Utility will adopt 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," effective January 1, 2001. The Statement will require us to recognize all derivatives, as defined in the Statement, on the balance sheet at fair value. Derivatives, or any portions thereof, that are not effective hedges must be adjusted to fair value through income. If derivatives are effective hedges, depending on the nature of the hedges, changes in the fair value of derivatives either will be offset against the change in fair value of the hedged assets, liabilities, or firm commitments through earnings, or will be recognized in other comprehensive income until the hedged items are recognized in earnings. PG&E Corporation estimates that the transition adjustment to implement this new standard will be an immaterial reduction of net earnings and a negative adjustment of $377 million to other comprehensive income. The Utility estimates that the transition adjustment to implement this new standard will be an immaterial reduction of net earnings and a positive adjustment of $44 million to other comprehensive income. These adjustments will be recognized as of January 1, 2001 as a cumulative effect of a change in accounting principle. The ongoing effects will depend on the future market conditions and hedging activities at PG&E Corporation and the Utility.

PG&E Corporation and the Utility have certain derivative commodity contracts for the physical delivery of purchase quantities transacted in the normal course of business. At this time, these derivatives are exempt from the requirements of SFAS No. 133 under the normal purchases and sales exception, and thus will not be reflected on the balance sheet at fair value. The Derivative Implementation Group of the Financial Accounting Standards Board is currently evaluating the definition of normal purchases and sales. As such, certain derivative commodity contracts may no longer be exempt from the requirements of SFAS No. 133. PG&E Corporation and the Utility will evaluate the impact of the implementation guidance on a prospective basis when the final decision regarding this issue is resolved.

Legal Matters

In the normal course of business, both the Utility and PG&E Corporation are named as parties in a number of claims and lawsuits. See Note 15 of the Notes to the Consolidated Financial Statements for further discussion of significant pending legal matters.

PG&E Corporation

STATEMENTS OF CONSOLIDATED OPERATIONS

(in millions, except per share amounts)

	Year ended December 31,		
	2000	1999	1998
Operating Revenues			
Utility	$ 9,637	$ 9,228	$ 8,924
Energy commodities and services	16,595	11,592	10,653
Total operating revenues	26,232	20,820	19,577
Operating Expenses			
Cost of energy for utility	8,166	3,149	2,942
Deferred electric procurement cost	(6,465)	—	—
Cost of energy commodities and services	15,220	10,587	9,852
Operating and maintenance	3,520	3,151	3,083
Depreciation, amortization, and decommissioning	3,659	1,780	1,602
Loss on assets held for sale	—	1,275	—
Provision for loss on generation-related regulatory assets and undercollected purchased power costs	6,939	—	—
Total operating expenses	31,039	19,942	17,479
Operating Income (Loss)	(4,807)	878	2,098
Interest income	266	118	101
Interest expense	(788)	(772)	(781)
Other income (expense), net	(23)	37	(36)
Income (Loss) Before Income Taxes	(5,352)	261	1,382
Income taxes provision (benefit)	(2,028)	248	611
Income (Loss) from continuing operations	$ (3,324)	$ 13	$ 771
Discontinued operations (Note 5)			
Loss from operations of PG&E Energy Services (net of applicable income taxes of $0 million, $35 million, and $41 million, respectively)	—	(40)	(52)
Loss on disposal of PG&E Energy Services (net of applicable income taxes of $36 million, $36 million, and $0 million, respectively)	(40)	(58)	—
Net income (loss) before cumulative effect of a change in accounting principle (Note 1)	(3,364)	(85)	719
Cumulative effect of a change in an accounting principle (net of applicable income taxes of $8 million)	—	12	—
Net Income (Loss)	$ (3,364)	$ (73)	$ 719
Weighted average common shares outstanding	362	368	382
Earnings (Loss) Per Common Share, Basic and Diluted			
Income (Loss) from continuing operations	$ (9.18)	$ 0.04	$ 2.02
Discontinued operations	(0.11)	(0.27)	(0.14)
Cumulative effect of a change in an accounting principle	—	0.03	—
Net Earnings (Loss)	$ (9.29)	$ (0.20)	$ 1.88
Dividends Declared Per Common Share	$ 1.20	$ 1.20	$ 1.20

The accompanying Notes to the Consolidated Financial Statements are an integral part of this statement.

PG&E Corporation

CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

	Balance at December 31, 2000	1999
ASSETS		
Current Assets		
Cash and cash equivalents	$ 899	$ 281
Short-term investments	1,634	187
Accounts receivable		
Customers (net of allowance for doubtful accounts of $71 million and $65 million, respectively)	2,131	1,486
Energy marketing	2,211	532
Regulatory balancing accounts	222	—
Price risk management	2,039	400
Inventories	392	433
Income taxes receivable	1,241	—
Prepaid expenses and other	406	255
Total current assets	11,175	3,574
Property, Plant, and Equipment		
Utility	23,872	23,001
Non-utility		
Electric generation	2,008	1,905
Gas transmission	1,542	2,541
Construction work in progress	900	436
Other	147	184
Total property, plant, and equipment (at original cost)	28,469	28,067
Accumulated depreciation and decommissioning	(11,878)	(11,291)
Net property, plant, and equipment	16,591	16,776
Other Noncurrent Assets		
Regulatory assets	1,773	4,957
Nuclear decommissioning funds	1,328	1,264
Price risk management	2,026	329
Other	2,398	2,570
Total noncurrent assets	7,525	9,120
TOTAL ASSETS	$ 35,291	$ 29,470

PG&E Corporation

CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

	Balance at December 31, 2000	Balance at December 31, 1999
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	$ 4,530	$ 1,499
Long-term debt, classified as current	2,391	558
Current portion of rate reduction bonds	290	290
Accounts payable		
Trade creditors	3,760	708
Energy marketing	2,096	480
Regulatory balancing accounts	196	384
Other	459	559
Accrued taxes	—	211
Price risk management	1,999	323
Other	1,563	1,058
Total current liabilities	17,284	6,070
Noncurrent Liabilities		
Long-term debt	4,736	6,682
Rate reduction bonds	1,740	2,031
Deferred income taxes	1,656	3,147
Deferred tax credits	192	231
Price risk management	1,867	207
Other	3,864	3,436
Total noncurrent liabilities	14,055	15,734
Preferred Stock of Subsidiaries	480	480
Utility Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures	300	300
Common Stockholders' Equity		
Common stock, no par value, authorized 800,000,000 shares, issued 387,193,727 and 384,406,113 shares, respectively	5,971	5,906
Common stock held by subsidiary, at cost, 23,815,500 shares	(690)	(690)
Reinvested earnings (Accumulated Deficit)	(2,105)	1,674
Accumulated other comprehensive income (loss)	(4)	(4)
Total common stockholders' equity	3,172	6,886
Commitments and Contingencies (Notes 1, 2, 3, 7, 14, and 15)	—	—
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$35,291	$29,470

The accompanying Notes to the Consolidated Financial Statements are an integral part of this statement.

PG&E Corporation

STATEMENTS OF CONSOLIDATED CASH FLOWS
(in millions)

	For the year ended December 31,		
	2000	1999	1998
Cash Flows From Operating Activities			
Net income (loss)	$(3,364)	$ (73)	$ 719
Adjustments to reconcile net (loss) income to net cash provided (used) by operating activities:			
Depreciation, amortization, and decommissioning	3,659	1,780	1,602
Deferred electric procurement costs	(6,465)	—	—
Deferred income taxes and tax credits—net	(767)	(754)	(107)
Other deferred charges and noncurrent liabilities	256	102	18
Provision for loss on generation-related regulatory assets and undercollected purchased power costs	6,939	—	—
Loss on assets held for sale	—	1,275	—
Loss regulatory assets from discontinued operations	40	98	52
Cumulative effect of change in accounting principle	—	(12)	—
Net effect of changes in operating assets and liabilities:			
Short-term investments	(1,447)	(132)	1,105
Accounts receivable—trade	(2,324)	370	(342)
Inventories	41	23	(33)
Income tax receivable	(1,241)	—	—
Price risk management assets and liabilities, net	30	(28)	(16)
Accounts payable	4,568	(293)	247
Regulatory balancing accounts	(410)	305	537
Accrued taxes	(211)	108	(123)
Other working capital	324	209	199
Other—net	(404)	(823)	(470)
Net cash (used) provided by operating activities	(776)	2,155	3,388
Cash Flows From Investing Activities			
Capital expenditures	(1,758)	(1,584)	(1,619)
Acquisitions	—	—	(1,779)
Proceeds from sale of assets	415	1,014	1,106
Other—net	373	453	66
Net cash used by investing activities	(970)	(117)	(2,226)
Cash Flows From Financing Activities			
Net borrowings (repayments) under credit facilities	2,846	(145)	2,115
Long-term debt issued	1,023	—	—
Long-term debt matured, redeemed, or repurchased	(1,155)	(798)	(1,552)
Preferred stock redeemed or repurchased	—	—	(108)
Common stock issued	65	54	63
Common stock repurchased	(2)	(693)	(1,158)
Dividends paid	(436)	(465)	(470)
Other—net	23	4	(3)
Net cash provided (used) by financing activities	2,364	(2,043)	(1,113)
Net Change in Cash and Cash Equivalents	618	(5)	49
Cash and Cash Equivalents at January 1	281	286	237
Cash and Cash Equivalents at December 31	$ 899	$ 281	$ 286
Supplemental disclosures of cash flow information			
Cash paid for:			
Interest (net of amounts capitalized)	$ 719	$ 727	$ 774
Income taxes (net of refunds)	20	723	770
Supplemental disclosures of non-cash investing and financing			
Retirement of long-term debt in the sale of PG&E Gas Transmission—Texas	564	—	—

The accompanying Notes to the Consolidated Financial Statements are an integral part of this statement.

PG&E Corporation

STATEMENTS OF CONSOLIDATED COMMON STOCK EQUITY
(in millions, except share amounts)

	Common Stock	Common Stock Held by Subsidiary	Reinvested Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total Common Stock Equity	Comprehensive Income (Loss)
Balance December 31, 1997	$6,366	$ —	$ 2,543	$(12)	$ 8,897	
Net income	—	—	719	—	719	$ 719
Foreign currency translation adjustment	—	—	—	6	6	6
Comprehensive income	—	—	—	—	—	$ 725
Common stock issued (2,028,303 shares)	63	—	—	—	63	
Common stock repurchased (37,090,630 shares)	(565)	—	(593)	—	(1,158)	
Cash dividends declared on common stock	—	—	(466)	—	(466)	
Other	(2)	—	7	—	5	
Balance December 31, 1998	5,862	—	2,210	(6)	8,066	
Net loss	—	—	(73)	—	(73)	$ (73)
Foreign currency translation adjustment	—	—	—	2	2	2
Comprehensive loss	—	—	—	—		$ (71)
Common stock issued (1,879,474 shares)	54	—	—	—	54	
Common stock repurchased (23,892,425 shares)	(2)	(690)	(1)	—	(693)	
Cash dividends declared on common stock			(460)	—	(460)	
Other	(8)	—	(2)	—	(10)	
Balance December 31, 1999	5,906	(690)	1,674	(4)	6,886	
Net loss	—	—	(3,364)	—	(3,364)	$(3,364)
Common stock issued (2,847,269 shares)	65	—	—	—	65	
Common stock repurchased (59,655 shares)	(1)	—	(1)	—	(2)	
Cash dividends declared on common stock	—	—	(434)	—	(434)	
Other	1	—	20	—	21	
Balance December 31, 2000	$5,971	$(690)	$(2,105)	$ (4)	$ 3,172	

The accompanying Notes to the Consolidated Financial Statements are an integral part of this statement.

Pacific Gas and Electric Company

STATEMENTS OF CONSOLIDATED OPERATIONS
(in millions)

	Year ended December 31,		
	2000	1999	1998
Operating Revenues			
Electric	$ 6,854	$7,232	$7,191
Gas	2,783	1,996	1,733
Total operating revenues	9,637	9,228	8,924
Operating Expenses			
Cost of electric energy	6,741	2,411	2,321
Deferred electric procurement cost	(6,465)	—	—
Cost of gas	1,425	738	621
Operating and maintenance	2,687	2,522	2,668
Depreciation, amortization, and decommissioning	3,511	1,564	1,438
Provision for loss on generation-related regulatory assets and undercollected purchased power costs	6,939	—	—
Total operating expenses	14,838	7,235	7,048
Operating Income (Loss)	(5,201)	1,993	1,876
Interest income	186	45	96
Interest expense	(619)	(593)	(621)
Other income (expense), net	(3)	(9)	7
Income (Loss) Before Income Taxes	(5,637)	1,436	1,358
Income taxes provision (benefit)	(2,154)	648	629
Net Income (Loss)	(3,483)	788	729
Preferred dividend requirement	25	25	27
Income (Loss) Available for (Allocated to) Common Stock	$ (3,508)	$ 763	$ 702

The accompanying Notes to the Consolidated Financial Statements are an integral part of this statement.

Pacific Gas and Electric Company

CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

	Balance at December 31, 2000	Balance at December 31, 1999
ASSETS		
Current Assets		
Cash and cash equivalents	$ 111	$ 80
Short-term investments	1,283	21
Accounts receivable		
Customers (net of allowance for doubtful accounts of $52 million and $46 million, respectively)	1,711	1,201
Related parties	6	9
Regulatory balancing account	222	—
Inventories		
Gas stored underground and fuel oil	146	139
Materials and supplies	134	155
Income taxes receivable	1,120	—
Prepaid expenses and other	45	34
Deferred income taxes	—	119
Total current assets	4,778	1,758
Property, Plant, and Equipment		
Electric	16,335	15,762
Gas	7,537	7,239
Construction work in progress	249	214
Total property, plant, and equipment (at original cost)	24,121	23,215
Accumulated depreciation and decommissioning	(11,120)	(10,497)
Net property, plant, and equipment	13,001	12,718
Other Noncurrent Assets		
Regulatory assets	1,716	4,895
Nuclear decommissioning funds	1,328	1,264
Other	1,165	835
Total noncurrent assets	4,209	6,994
TOTAL ASSETS	$ 21,988	$ 21,470

Pacific Gas and Electric Company

CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

	Balance at December 31, 2000	Balance at December 31, 1999
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	$ 3,079	$ 449
Long-term debt, classified as current	2,374	465
Current portion of rate reduction bonds	290	290
Accounts payable		
Trade creditors	3,688	577
Related parties	138	216
Regulatory balancing accounts	196	384
Other	363	333
Accrued taxes	—	118
Deferred income taxes	172	—
Other	670	529
Total current liabilities	10,970	3,361
Noncurrent Liabilities		
Long-term debt	3,342	4,877
Rate reduction bonds	1,740	2,031
Deferred income taxes	929	2,510
Deferred tax credits	192	231
Other	2,968	2,252
Total noncurrent liabilities	9,171	11,901
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	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 321,314,760 shares	1,606	1,606
Common stock held by subsidiary, at cost, 19,481,213 shares and 7,627,765 shares, respectively	(475)	(200)
Additional paid-in capital	1,964	1,964
Reinvested earnings (Accumulated Deficit)	(1,979)	2,107
Total stockholders' equity	1,410	5,771
Commitments and Contingencies (Notes 1, 2, 7, 14, and 15)	—	—
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$21,988	$21,470

The accompanying Notes to the Consolidated Financial Statements are an integral part of this statement.

Pacific Gas and Electric Company

STATEMENTS OF CONSOLIDATED CASH FLOWS

(in millions)

	For the year ended December 31,		
	2000	1999	1998
Cash Flows From Operating Activities			
Net income (loss)	$(3,483)	$ 788	$ 729
Adjustments to reconcile net income to net cash (used) provided by operating activities:			
Depreciation, amortization, and decommissioning	3,511	1,564	1,438
Deferred electric procurement costs	(6,465)	—	—
Deferred income taxes and tax credits—net	(930)	(485)	(257)
Other deferred charges and noncurrent liabilities	480	101	31
Provision for loss on generation-related regulatory assets and undercollected purchased power costs	6,939	—	—
Net effect of changes in operating assets and liabilities:			
Short-term investments	(1,262)	(4)	1,126
Accounts receivable	(507)	187	266
Income taxes receivable	(1,120)	—	—
Accounts payable	3,063	15	203
Regulatory balancing accounts	(410)	305	537
Accrued taxes	(118)	116	(227)
Other working capital	125	(39)	(71)
Other—net	(522)	(352)	(39)
Net cash (used) provided by operating activities	(699)	2,196	3,736
Cash Flows From Investing Activities			
Capital expenditures	(1,245)	(1,181)	(1,382)
Proceeds from sale of assets	6	1,014	501
Other—net	32	234	40
Net cash used by investing activities	(1,207)	67	(841)
Cash Flows From Financing Activities			
Net borrowings (repayments) under credit facilities	2,630	(219)	668
Long-term debt issued	680	—	—
Long-term debt matured, redeemed, or repurchased	(597)	(672)	(1,413)
Preferred stock redeemed or repurchased	—	—	(108)
Common stock repurchased	(275)	(926)	(1,600)
Dividends paid	(475)	(440)	(444)
Other—net	(26)	1	(5)
Net cash provided (used) by financing activities	1,937	(2,256)	(2,902)
Net Change in Cash and Cash Equivalents	31	7	(7)
Cash and Cash Equivalents at January 1	80	73	80
Cash and Cash Equivalents at December 31	$ 111	$ 80	$ 73
Supplemental disclosures of cash flow information			
Cash paid for:			
Interest (net of amounts capitalized)	$ 587	$ 531	$ 600
Income taxes (net of refunds)	—	1,001	1,115

The accompanying Notes to the Consolidated Financial Statements are an integral part of this statement.

Pacific Gas and Electric Company

STATEMENTS OF CONSOLIDATED STOCKHOLDERS' EQUITY

(in millions, except share amounts)

	Common Stock	Additional Paid-in Capital	Common Stock Held by Subsidiary	Reinvested Earnings (Accumulated Deficit)	Accumulated Other Comprehensive (Loss)	Total Common Stock Equity	Preferred Stock Without Mandatory Redemption Provisions	Comprehensive Income (Loss)
Balance December 31, 1997	$2,018	$2,564	$ —	$ 2,671	$—	7,253	$402	
Net income	—	—	—	729	—	729	—	$ 729
Foreign currency translation adjustments	—	—	—	—	(1)	(1)	—	(1)
Comprehensive income	—	—	—	—	—	—	—	$ 728
Common stock repurchased (62,150,837 shares)	(311)	(481)	—	(808)	—	(1,600)	—	
Preferred stock redeemed (4,323,948 shares)	—	(7)	—	(3)	—	(10)	(98)	
Cash dividends declared								
Preferred stock	—	—	—	(28)	—	(28)	—	
Common stock	—	—	—	(300)	—	(300)	—	
Other	—	11	—	—	—	11	(10)	
Balance December 31, 1998	$1,707	$2,087	—	$ 2,261	(1)	$ 6,054	$294	
Net income	—	—	—	788	—	788	—	$ 788
Foreign currency translation adjustments	—	—	—	—	1	1	—	1
Comprehensive income	—	—	—	—	—	—	—	$ 789
Common stock repurchased (27,666,400 shares)	(101)	(123)	(200)	(502)	—	(926)	—	
Cash dividends declared								
Preferred stock	—	—	—	(25)	—	(25)	—	
Common stock	—	—	—	(415)	—	(415)	—	
Balance December 31, 1999	$1,606	$1,964	$(200)	$ 2,107	—	$ 5,477	$294	
Net loss	—	—	—	(3,483)	—	(3,483)	—	$(3,483)
Common stock repurchased (11,853,448 shares)	—	—	(275)	—	—	(275)	—	
Cash dividends declared								
Preferred stock	—	—	—	(25)	—	(25)	—	
Common stock	—	—	—	(578)	—	(578)	—	
Balance December 31, 2000	$1,606	$1,964	$(475)	$(1,979)	$—	$ 1,116	$294	

The accompanying Notes to the Consolidated Financial Statements are an integral part of this statement.

Note 1: General

Basis of Presentation

PG&E Corporation was incorporated in California in 1995 and became the holding company of Pacific Gas and Electric Company (the Utility) on January 1, 1997. The Utility, incorporated in California in 1905, is the predecessor of PG&E Corporation. Effective with PG&E Corporation's formation, the Utility's interests in its unregulated subsidiaries were transferred to PG&E Corporation. As discussed further in Notes 2 and 3, on April 6, 2001, the Utility filed a voluntary petition for relief under provisions of Chapter 11 of the U.S. Bankruptcy Code. Pursuant to Chapter 11 of the U.S. Bankruptcy Code, the Utility retains control of its assets and is authorized to operate its business as a debtor in possesion while being subject to the jurisdiction of the Bankruptcy Court.

This is a combined annual report of PG&E Corporation and the Utility. Therefore, the Notes to the Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation's consolidated financial statements include the accounts of PG&E Corporation, the Utility, and PG&E Corporation's wholly owned and controlled subsidiaries. The Utility's consolidated financial statements include its accounts as well as those of its wholly owned and controlled subsidiaries. All significant inter-company transactions have been eliminated from the consolidated financial statements.

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.

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).

Operations

PG&E Corporation is an energy-based holding company headquartered in San Francisco, California. PG&E Corporation's Northern and Central California energy utility subsidiary, the Utility, delivers electric service to approximately 4.6 million customers and natural gas service to approximately 3.8 million customers. PG&E Corporation's PG&E National Energy Group, Inc. (NEG) markets energy services and products throughout North America.

The NEG is an integrated energy company with a strategic focus on power generation, new power plant development, natural gas transmission, and wholesale energy marketing and trading in North America. NEG businesses include its power plant development and generation unit, PG&E Generating Company, LLC and its affiliates (collectively, PG&E Gen); its natural gas transmission unit, PG&E Gas Transmission Corporation (PG&E GT); and its wholesale energy and marketing trading unit, PG&E Energy Trading Holdings Corporation, which owns PG&E Energy Trading-Gas Corporation and PG&E Energy Trading-Power, L.P. (collectively, PG&E Energy Trading or PG&E ET). During 2000, NEG sold its energy services unit, PG&E Energy Services Corporation (PG&E ES). Also, during the fourth quarter of 2000, NEG sold its Texas natural gas and natural gas liquids business carried on through PG&E Gas Transmission, Texas Corporation and PG&E Gas Transmission Teco, Inc. and their subsidiaries (PG&E GTT).

Cash Equivalents and Short-Term Investments

Cash equivalents (stated at cost, which approximates market) include working funds and consist primarily of Eurodollar time deposits, bankers' acceptances, and commercial paper with original maturities of three months or less when purchased.

Restricted Cash

Restricted cash includes cash and cash equivalents, as defined above, which are restricted under the terms of certain agreements for payment to third parties, primarily for debt service. Restricted cash included under Cash and

Cash Equivalents in PG&E Corporation's and the Utility's Consolidated Balance Sheets as of December 31, 2000 and 1999 is as follows:

(in millions)	2000	1999
Utility	$50	$42
National Energy Group	53	81

Inventories

Inventories include materials and supplies, gas stored underground, coal, and fuel oil. Materials and supplies, coal, and gas stored underground are valued at average cost, except for the gas storage inventory of PG&E ET, which is recorded at fair value. Fuel oil is valued by the last-in first-out method.

Income Taxes

PG&E Corporation and the Utility use the liability method of accounting for income taxes. Income tax expense (benefit) includes current and deferred income taxes resulting from operations during the year. Tax credits are amortized over the life of the related property.

PG&E Corporation files a consolidated federal income tax return that includes domestic subsidiaries in which its ownership is 80% or more. The Utility and various other subsidiaries are parties to a tax-sharing arrangement with PG&E Corporation. PG&E Corporation files consolidated state income tax returns when applicable. The Utility reports taxes on a stand-alone basis.

Earnings (Loss) Per Share

Basic earnings (loss) per share is computed by dividing net income (loss) by the weighted average number of common shares outstanding during the period. Diluted earnings per share is computed by dividing net income (loss) by the weighted average number of common shares outstanding plus the assumed issuance of common shares for all potentially 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.

	Years ended December 31,		
(in millions)	2000	1999	1998
Income (loss) from continuing operations	$(3,324)	$ 13	$ 771
Discontinued operations	(40)	(98)	(52)
Net income (Loss) before cumulative effect of accounting change	(3,364)	(85)	719
Cumulative effect of accounting change	—	12	—
Net Income (Loss)	$(3,364)	$ (73)	$ 719
Earnings (Loss) per common share, Basic and Diluted:			
Weighted average common shares outstanding	362	368	382
Income (Loss) from continuing operations	$ (9.18)	$ 0.04	$ 2.02
Discontinued operations	(0.11)	(0.27)	(0.14)
Cumulative effect of accounting change	—	0.03	—
Net Income (Loss)	$ (9.29)	$(0.20)	$ 1.88

The diluted share base for 2000 excludes incremental shares of 2 million related to employee stock options. These shares are excluded due to the anti-dilutive effect as a result of the loss from continuing operations. For 1999 and 1998, the assumed conversion of stock options issued under the long-term incentive plan increased the weighted average shares outstanding for dilutive purposes to 369 million and 383 million, respectively. PG&E Corporation reflects the preferred dividends of subsidiaries as other expense for computation of both basic and diluted earnings per share.

Property, Plant, and Equipment

Plant additions and replacements are capitalized. The capitalized costs include labor, materials, construction overhead, and capitalized interest or an allowance for funds used during construction (AFUDC). AFUDC is the estimated cost of debt and equity funds used to finance regulated plant additions. Capitalized interest and AFUDC for PG&E Corporation amounted to $19 million, $18 million, and $28 million for the years ended December 31, 2000, 1999, and 1998, respectively. Capitalized interest and AFUDC for the Utility amounted to $18 million, $16 million, and $26 million for the years ended December 31, 2000, 1999, and 1998, respectively. Nuclear fuel inventories are included in property, plant, and equipment. Stored nuclear fuel inventory is stated at lower of average cost or market. Nuclear fuel in the reactor is amortized based on the amount of energy output.

The original cost of retired plant and removal costs less salvage value is charged to accumulated depreciation upon retirement of plant in service for the Utility and the NEG businesses that apply Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," as amended. For the remainder of the NEG business operations, the cost and accumulated depreciation of property, plant, and equipment retired or otherwise disposed of is removed from related accounts and included in the determination of the gain or loss on disposition.

Property, plant, and equipment are depreciated using a straight-line remaining-life method. PG&E Corporation's composite depreciation rates were 4.44%, 3.60%, and 3.89% for the years ended December 31, 2000, 1999, and 1998, respectively. The Utility's composite depreciation rates were 4.54 %, 3.41%, and 3.88% for the years ended December 31, 2000, 1999, and 1998, respectively. Estimated useful lives of property, plant, and equipment are as follows:

	Utility	Non-Utility
Electric generating facilities	20 to 50 years	20 to 50 years
Electric distribution facilities	10 to 63 years	N/A
Electric transmission	27 to 65 years	N/A
Gas distribution facilities	28 to 49 years	N/A
Gas transmission	25 to 45 years	22 to 40 years
Gas storage	25 to 48 years	N/A
Other	5 to 38 years	2 to 7 years

The useful life of the Utility's property, plant, and equipment complies with CPUC-authorized ranges.

Capitalized Software Costs

Costs incurred during the application development stage of internal use software projects are capitalized. At December 31, 2000 and 1999, capitalized software costs totaled $235 million and $216 million, net of $80 million and $59 million accumulated amortization, respectively. Such capitalized amounts are amortized in accordance with regulatory requirements ratably over the expected lives of the projects when they become operational, over periods ranging from 2 to 15 years.

Gains and Losses on Reacquired Debt

Gains and losses on reacquired debt associated with regulated operations that are subject to the provisions of SFAS No. 71 are deferred and amortized over the remaining original amortization period of the debt reacquired, consistent with ratemaking principles. Gains and losses on reacquired debt associated with unregulated operations are recognized in earnings as extraordinary gains or losses at the time such debt is reacquired.

Intangible Assets and Asset Impairment

PG&E Corporation amortizes the excess of purchase price over fair value of net assets of businesses acquired (goodwill) using the straight-line method over periods ranging from 5 to 40 years. PG&E Corporation periodically assesses goodwill and intangible assets for potential impairment.

PG&E Corporation and the Utility periodically evaluate long-lived assets, including property, plant, and equipment, goodwill, and specifically identifiable intangible assets, when events or changes in circumstances indicate that the carrying value of these assets may be impaired. The determination of whether impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets.

In addition, SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed of," requires PG&E Corporation and the Utility to write off regulatory assets when they are no longer probable of recovery. On an ongoing basis, PG&E Corporation and the Utility review their regulatory assets and liabilities for the continued applicability of SFAS No. 71 and the effect of SFAS No. 121.

Regulation and Statement of Financial Accounting Standards (SFAS) No. 71

The Utility is regulated by the CPUC, the FERC, and the Nuclear Regulatory Commission (NRC), among others. The gas transmission business in the Pacific Northwest is regulated by the FERC.

PG&E Corporation and the Utility account for the financial effects of regulation in accordance with SFAS No. 71. This statement allows for the recording of a regulatory asset or liability for costs that will be collected or refunded through the ratemaking process in the future.

Regulatory assets comprise the following:

(in millions)	Balance at December 31, 2000	1999
Rate Reduction Bonds[1]	$ 1,178	$ 727
Unamortized loss, net of gain, on reacquired debt	342	376
Regulatory assets for deferred income tax	160	705
Transition Revenue Account[1]	—	69
Transition Cost Balancing Account[1]	—	220
Diablo Canyon[1]	—	1,891
Other, net	36	907
Total Utility regulatory assets	$ 1,716	$4,895
PG&E GTN	57	62
Total PG&E Corporation regulatory assets	$ 1,773	$4,957

(1) See Note 2 of the Notes to the Consolidated Financial Statements for further discussion.

Regulatory assets are amortized over the period that the costs are reflected in regulated revenues. The Utility has amortized its eligible generation-related transition costs, including the Transition Cost Balancing Account (TCBA) and the regulatory assets related to Diablo Canyon, over the transition period in conjunction with the available competition transition charge (CTC) revenues.

During 2000, the energy crisis materially and adversely affected PG&E Corporation's and the Utility's cash flow and liquidity and created substantial uncertainty about their prospects for the future. As a result, the Utility can no longer conclude that energy costs, which have been deferred on its balance sheet in accordance with SFAS No. 71, are probable of recovery through future rates. Accordingly, the Utility wrote off the generation-related transition costs and undercollected purchased power costs at December 31, 2000 (see Note 2 of the Notes to the Consolidated Financial Statements).

In general, the Utility does not earn a return on regulatory assets where the related costs do no accrue interest. At December 31, 2000, the Utility did not earn a return on the regulatory asset related to recording deferred taxes as required by SFAS No. 109 "Accounting for Income Taxes" of $160 million. During 2000, all other assets that did not earn a return were recovered or written off as referred to above.

At December 31, 1999, the Utility did not earn a return on (1) the $410 million regulatory asset related to recording deferred taxes as required by SFAS No. 109, (2) the regulatory asset related to the Western Area Power Administration contract of $86 million, and (3) a regulatory asset related to the generation portion of certain employee benefits of $15 million.

Revenues and Regulatory Balancing Accounts

For gas utility revenues, sales balancing accounts accumulate differences between authorized and actual base revenues. Further, gas cost balancing accounts accumulate differences between the actual cost of gas and the revenues designated for recovery of such costs. The regulatory balancing accounts accumulate balances until they are refunded to or received from Utility customers through authorized rate adjustments. Utility revenues included amounts for services rendered but unbilled at the end of each year.

Revenue Recognition

Revenues derived from power generation are recognized upon output, product delivery, or satisfaction of specific targets, all as specified by contractual terms. Regulated gas transmission revenues are recorded as services are provided, based on rate schedules approved by the FERC. Substantially all of PG&E ET's operations are accounted for under a mark-to-market accounting methodology.

Staff Accounting Bulletin (SAB) No. 101, "Revenue Recognition," was issued by the Securities and Exchange Commission (SEC), on December 3, 1999. SAB No. 101, as amended, summarizes certain of the SEC staff's views in applying accounting principles generally accepted in the United States of America to revenue recognition in financial statements. PG&E Corporation's consolidated financial statements reflect the accounting principles provided in SAB No. 101.

Accounting for Price Risk Management Activities

PG&E Corporation, primarily through its subsidiaries, engages in price risk management activities for both trading and non-trading purposes. 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 the NEG's assessment of and response to changing market conditions. Non-trading activities are conducted to optimize and secure the return on risk capital deployed within the NEG's existing asset and contractual portfolio. In addition, non-trading activity exists within the Utility to hedge against price fluctuations of electricity and natural gas.

Derivative and other financial instruments associated with electricity, natural gas, natural gas liquids, and related trading activities are accounted for using the mark-to-market method of accounting. Under mark-to-market accounting, PG&E Corporation's trading contracts, including both physical contracts and financial instruments, are recorded at market value, which approximates fair value. The market prices used to value these transactions reflect management's best estimates considering various factors, including market quotes, time value, and volatility factors of the underlying commitments. The values are adjusted to reflect the potential impact of liquidating a position in an orderly manner over a reasonable period of time under present market conditions.

Changes in the market value of these contract portfolios, resulting primarily from newly originated transactions and the impact of commodity price or interest rate movements, are recognized in operating income in the period of change. Unrealized gains and losses on these contract portfolios are recorded as assets and liabilities, respectively, from price risk management.

In addition to the trading activities, as discussed previously, PG&E Corporation may engage in non-trading activities using futures, forward contracts, options, and swaps to hedge the impact of market fluctuations on energy commodity prices, interest rates, and foreign currencies when there is a high degree of correlation between price movements in the derivative and the item designated as being hedged. PG&E Corporation accounts for non-trading transactions under the deferral method. Initially, PG&E Corporation defers unrealized gains and losses on these transactions and classifies them as assets or liabilities. When the underlying item settles, PG&E Corporation recognizes the gain or loss in operating expense. In instances where the anticipated correlation of price movements does not occur, hedge accounting is terminated and future changes in the value of the derivative are recognized as gains or losses. If the hedged item is sold, the value of the associated derivative is recognized in income.

PG&E Corporation and the Utility will adopt 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" effective January 1, 2001. The Statement will require PG&E Corporation and the Utility to recognize all derivatives, as defined in the Statement, on the balance sheet at fair value. Derivatives, or any portion thereof, that are not effective hedges must be adjusted to fair value through income. If derivatives are effective hedges, depending on the nature of the hedges, changes in the fair value of derivatives either will be offset against the change in fair value of the hedged assets, liabilities, or firm commitments through earnings, or will be recognized in other comprehensive income until the hedged items are recognized in earnings. PG&E Corporation estimates that the transition adjustment to implement this new standard will be a non-material reduction of net earnings and a negative adjustment of $377 million to other comprehensive income. The Utility estimates that the transition adjustment to implement this new standard will be a non-material reduction of net earnings and a negative adjustment of $44 million to other comprehensive income. These adjustments will be recognized as of January 1, 2001 as a cumulative effect of a change in accounting principle. The ongoing effects will depend on the future market conditions and hedging activities at PG&E Corporation and the Utility.

PG&E Corporation and the Utility have certain derivative commodity contracts for the physical delivery of purchase quantities transacted in the normal course of business. At this time, these derivatives are exempt from the requirements of SFAS No. 133 under the normal purchases and sales exception, and thus will not be reflected on the balance sheet at fair value. The Derivative Implementation Group of the Financial Accounting Standards Board is currently evaluating the definition of normal purchases and sales. As such, certain derivative commodity contracts may no longer be exempt from the requirements of SFAS No. 133. PG&E Corporation and the Utility will evaluate the impact of the implementation guidance on a prospective basis when the final decision regarding this issue is resolved.

Comprehensive Income

PG&E Corporation's and the Utility's comprehensive income consists of net income and other items recorded directly to the equity accounts. The objective is to report a measure of all changes in equity of an enterprise that result from transactions and other economic events of the period other than transactions with shareholders. PG&E Corporation's and the Utility's other comprehensive income consists principally of foreign currency translation adjustments and will include changes in the market value of certain financial hedges upon the implementation of SFAS No. 133 on January 1, 2001. See Accounting for Price Risk Management Activities above for discussion of implementation of SFAS No. 133.

Cumulative Effect of Change in Accounting Method

Effective January 1, 1999, PG&E Corporation changed its method of accounting for major maintenance and overhauls of generating assets at the NEG. Beginning January 1, 1999, the cost of major maintenance and overhauls of generating assets, principally at the PG&E Gen business segment, were accounted for as incurred. Previously, the estimated cost of major maintenance and overhauls was accrued in advance in a systematic and rational manner over the period between major maintenance and overhauls. The change resulted in PG&E Corporation recording income of $12 million net of income tax ($0.03 per share) as of December 31, 1999, reflecting the cumulative effect of the change in accounting principle. The Utility has consistently accounted for major maintenance and overhauls as incurred.

Related Party Agreements

In accordance with various agreements, the Utility and other subsidiaries provide and receive various services 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 at either 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, including their share of employees, operating expenses, assets, and other cost causal methods. Additionally, the Utility purchases gas commodity and transmission services and sells reservation and other ancillary services to the 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. For the years ended December 31, 2000, 1999, and 1998, the Utility's significant related party transactions were as follows:

(in millions)	2000	1999	1998
Utility revenues from:			
Administrative services provided to PG&E Corporation	$ 12	$ 23	$17
Transportation and distribution services provided to PG&E ES	—	134	—
Gas reservation services provided to PG&E ET	12	7	1
Other	2	3	4
Utility expenses from:			
Administrative services received from PG&E Corporation	$ 83	$ 66	$58
Gas commodity and transmission services received from PG&E ET	136	30	1
Transmission services received from PG&E GT	46	47	49

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 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.

Reclassifications

Certain amounts in 1999 and 1998 financial statements have been reclassified to conform to the 2000 presentation.

Note 2: The California Energy Crisis

In 1998, California became one of the first states in the country to implement electric industry restructuring and establish a competitive market framework for electric generation. Electric industry restructuring was mandated by the California Legislature in Assembly Bill 1890 (AB 1890). The electric industry restructuring established a transition period, mandated a rate freeze, included a plan for recovery of uneconomic generation-related costs (transition costs), and encouraged the disposition of a portion of utility-owned generation facilities. The competitive market framework called for the creation of the Power Exchange (PX) and the Independent System Operator (ISO). The PX would establish market-clearing prices for electricity, and the ISO would schedule delivery of electricity for all market participants and operate certain markets for electricity. The Utility was required to purchase electricity for its customers through the PX and ISO. 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 prices for electricity sold through the PX and ISO experienced unanticipated and massive increases. The average price of electricity purchased by the Utility for the benefit of its customers was 18.2 cents per kWh for the period of June 1 through December 31, 2000, compared to 4.2 cents per kWh during the same period in 1999. The Utility was only permitted to collect approximately 5.4 cents per kWh in rates from its customers during that period. The increased cost of the purchased electricity has strained the financial resources of the Utility. Because of the rate freeze, the Utility was unable to pass on the increases in power costs to its customers through current rates. In order to finance the higher costs of energy, during the third and fourth quarter of 2000, the Utility increased its lines of credit to $1,850 million (net increase of $850 million), issued $1,240 million of debt under a 364-day facility, and issued $680 million of five-year notes.

The Utility continued to finance the higher costs of wholesale electric power while interested parties evaluated various solutions to the energy crisis. In November 2000, the Utility filed its Rate Stabilization Plan (RSP), which sought to end the rate freeze and pass along the increased wholesale electric costs to customers through increased rates. The CPUC evaluated the Utility's proposal and deferred its decision until after hearings could be held, although the CPUC did increase rates one cent per kWh for 90 days effective January 4, 2001. This increase resulted in approximately $70 million of additional revenue per month, which was not nearly enough to cover the higher wholesale costs of electricity, nor did it help with the costs already incurred.

By December 31, 2000, the Utility had borrowed more than $3.0 billion under its various credit facilities to pay its energy costs. As a result of the California energy crisis and its impact on the Utility's financial resources, PG&E Corporation's and the Utility's credit rating deteriorated to below investment grade in January 2001. This credit downgrade precluded PG&E Corporation and the Utility from access to capital markets. Commencing in January 2001, PG&E Corporation and the Utility began to default on maturing commercial paper. In addition, the Utility became unable to pay the full amount of invoices received for wholesale power purchases and made only partial payments. The Utility had no credit under which it could purchase wholesale electricity on behalf of its customers on a continuing basis and generators were only selling to the Utility under emergency actions taken by the U.S. Secretary of Energy.

In January 2001 the California Legislature and the Governor authorized the California Department of Water Resources (DWR) to purchase wholesale electric energy on behalf of the Utility's retail customers. In February 2001, the California Legislature passed California Assembly Bill 1X (AB 1X), which authorized the DWR to purchase wholesale electricity on behalf of the Utility's customers.

On March 27, 2001, the CPUC authorized an average increase in retail rates of 3.0 cents per kWh, which was in addition to the emergency 1.0 cent per kWh surcharge adopted on January 4, 2001 by the CPUC. The revenue generated by this rate increase is to be used only for electric power procurement costs that are incurred after March 27, 2001. Although the rate increase is authorized immediately, the 3.0 cent surcharge will not be collected in rates until the CPUC establishes the rate design which is not expected to be adopted until May 2001.

As more fully described below, the energy crisis has materially and adversely affected the Utility's cash flow and liquidity and has created substantial uncertainty about their prospects for the future. As a result, the Utility can no longer conclude that energy costs, which had been deferred on its balance sheet in accordance with SFAS No. 71, are probable of recovery through future rates. Accordingly, the Utility has taken a charge against earnings of $6.9 billion ($4.1 billion after tax) to write off its remaining generation-related regulatory assets and undercollected purchased power costs. This charge has resulted in an accumulated deficit at the Utility of $2.0 billion as of December 31, 2000. PG&E Corporation's accumulated deficit at December 31, 2000 is $2.1 billion. Further, the Utility does not have authority to recover any purchased power costs it incurs during 2001 in excess of revenues from retail rates. Such amounts also will be charged against earnings, as incurred, absent a regulatory or legislative solution that provides for recovery of such costs.

Under SFAS No. 71, if a rate mechanism provided by legislation or other regulatory authority is subsequently established that makes recovery from regulated rates probable as to all or a portion of the undercollection that was previously charged against earnings, a regulatory asset will be reinstated with a corresponding increase in earnings.

As discussed more fully herein, the Utility is seeking resolution on many fronts. The ongoing uncertainty and lack of successful resolution continues to have a negative impact on the Utility's ability to obtain funding and pay its debt and power procurement liabilities. As discussed further in Note 3, on April 6, 2001, the Utility sought protection from its creditors through a Chapter 11 bankruptcy filing. The filing for bankruptcy and the related uncertainty around any reorganization plan that is ultimately adopted will have a significant impact on the Utility's future liquidity and results of operations. PG&E Corporation, itself, had cash of $297 million at March 29, 2001 and believes that the funds will be adequate to maintain its operations through and beyond 2001. In addition, PG&E Corporation believes that PG&E Corporation, itself, and its other subsidiaries not subject to CPUC regulation are substantially protected from the continuing liquidity and financial difficulties of the Utility. A discussion of the events leading up to the charge, PG&E Corporation's and the Utility's mitigation efforts and the ongoing uncertainty follows.

Transition Period and Rate Freeze

California's deregulation legislation passed by the California Legislature in 1996 established a transition period, which was to begin in 1998. During this period, electric rates for all customers were frozen at 1996 levels, with rates for residential and small commercial customers being reduced in 1998 by 10% and frozen at that level. During the transition period, investor-owned utilities were given the opportunity to recover their transition costs. Transition costs were generation-related costs that proved to be uneconomic under the new industry structure.

To pay for the 10% rate reduction, the Utility refinanced $2.9 billion (the expected revenue reduction from the rate decrease) of its transition costs with the proceeds from the sale of rate reduction bonds. The bonds allow for the rate reduction by lowering the carrying cost on a portion of the transition costs and by deferring recovery of a portion of the transition costs until after the transition period. During the rate freeze, the rate reduction bond debt service did not increase the Utility customers' electric rates (See Note 9). If the transition period ends before March 31, 2002, the Utility may be obligated to return a portion of the economic benefits of the transaction to customers. The timing of any such return and the exact amount of such portion, if any, have not yet been determined.

The rate freeze was scheduled to end on the earlier of March 31, 2002 or the date the Utility has recovered all of its transition costs. The Utility believes it recovered its eligible transition costs during August 2000 or potentially earlier as a result of recording a credit to the Utility's account for tracking the recovery of transition costs in recognition of the fair market value of the Utility's hydroelectric generation facilities. On August 31, 2000, the Utility recorded a $2.1 billion credit to the Utility's account for tracking the recovery of the TCBA, which was an amount by which a negotiated $2.8 billion hydroelectric generation asset valuation exceeded the aggregate book value of such assets. At August 31, 2000, there was a balance of approximately $2.2 billion of undercollected wholesale electricity costs recorded in the regulatory balancing account called the Transition Revenue Account (TRA). If the final valuation for the hydroelectric assets is greater than $2.8 billion, as the Utility expects, the Utility will have recovered its transition costs earlier. The undercollected TRA balance as of the end of the earlier determined transition period will be less than the August 31 balance of $2.2 billion, and could be zero depending on the ultimate valuation of the hydroelectric generating facilities and when the transition period actually ends. However, the CPUC has not yet accepted the Utility's estimated market valuation of its hydroelectric assets nor has the CPUC determined that the rate freeze has ended.

Wholesale Prices of Electricity

As previously stated, beginning in June 2000, the Utility experienced unanticipated and massive increases in the wholesale costs of the electricity purchased from the PX and ISO on behalf of its retail customers. For the year ended December 31, 2000 and 1999, the average monthly prices in cents per kWh that the PX and ISO charged the Utility for electricity were as follows:

	2000	1999
January	4.38	3.15
February	3.78	2.87
March	3.24	2.87
April	3.28	2.90
May	6.08	2.82
June	16.33	2.95
July	11.00	3.85
August	18.70	4.10
September	13.82	4.09
October	13.62	6.18
November	20.43	4.46
December	33.24	3.97

It is expected that the wholesale costs will continue to be extremely high through 2001 unless significant changes occur in the wholesale electricity market. The generation-related cost component, which provides for recovery of wholesale electricity purchased by the Utility and, if available, for recovery of transition cost, was approximately 5.4 cents per kWh, during 2000.

The excess of wholesale electricity costs above the generation-related cost component available in frozen rates was deferred to the TRA. The TRA balance as of December 31, 2000, prior to being written off against earnings, was an undercollection of approximately $6.6 billion. Under current CPUC decisions, if the TRA undercollection is not recovered through frozen rates by the end of the transition period, it cannot be recovered or offset against overcollections of transition cost recovery. Once the transition period has ended and the rate freeze is over, the Utility's customers will be responsible for reasonable wholesale electricity costs. However, actual changes in customer rates will not occur until new retail rates are authorized by the CPUC or, to the extent allowed, by the bankruptcy court.

The Utility has reviewed on an ongoing basis the facts and circumstances relating to the TRA and remaining transition cost regulatory assets. Due to the lack of regulatory, legislative, or judicial relief, the Utility has determined that it can no longer conclude that its uncollected wholesale electricity costs and remaining transition costs are probable of recovery in future rates. Accordingly, the Utility wrote off, as a charge against earnings, the TRA and TCBA of approximately $6.9 billion. In addition, absent a regulatory, judicial, or legislative solution that provides for full recovery of such costs, the Utility will be unable to defer the costs of wholesale power purchases in excess of amounts recovered through rates in 2001 and such expenses are expected to reduce the Utility's future earnings accordingly.

Transition Cost Recovery

Beginning January 1, 1998, the Utility started amortizing eligible transition costs, including most generation-related regulatory assets. These transition costs were offset by or recovered through the frozen rates, market valuation of generation assets in excess of book value, net energy sales from the Utility's electric generation facilities, and the amount by which long-term contract prices to purchase electricity were lower than the PX price. Transition costs and associated recoveries are recorded in the Utility's TCBA. During the transition period, a reduced rate of return on common equity of 6.77% applies to all generation assets, including those generation assets reclassified to regulatory assets.

During the transition period, the CPUC reviews the Utility's compliance with accounting methods established in the CPUC's decisions governing transition cost recovery and the amount of transition costs requested for recovery. In January 2001, the CPUC approved all non-nuclear transition costs that were amortized from July 1, 1998, to June 30, 1999. The CPUC currently is reviewing non-nuclear transition costs amortized from July 1, 1999, to June 30, 2000.

Mitigation Efforts

The Utility is actively exploring ways to reduce its exposure to the higher wholesale electricity costs and to recover its written-off TRA and TCBA balances. As previously indicated, the Utility believes the transition period has ended and filed an application with the CPUC asking it to so rule. The Utility has also filed a lawsuit against the CPUC in Federal District Court, filed an application with the CPUC seeking approval of a five-year rate stabilization plan, filed an application with the FERC to address the current market crisis, worked with interested parties to address power market dysfunction before appropriate regulatory bodies, and hedged a portion of its open procurement position against higher purchased power costs through forward purchases. The Utility's actions and related activities are discussed below.

Application with the FERC

On October 16, 2000, the Utility joined with Southern California Edison and The Utility Reform Network (TURN), in filing a petition with the FERC requesting that the FERC (1) immediately find the California wholesale electricity market to be not workably competitive and the resulting prices to be unjust and unreasonable; (2) immediately impose a cap on the price for energy and ancillary services; and (3) institute further expedited proceedings regarding the market failure, mitigation of market power, structural solutions, and responsibility for refunds. However, the reduced price cap requested, even if approved, would still be above the approximate 5.4 cents per kWh available through frozen rates for the payment of the Utility's wholesale electricity costs.

On December 15, 2000, the FERC issued an order in response to the above filing. The remedies proposed by the FERC include, among other things: (1) eliminating the requirement that the California investor-owned utilities must sell all of their power into, and buy all of their power needs from, the PX; (2) modifying the single price auction so that bids above $150 per megawatt hour (MWh) (15 cents per kWh) cannot set the market clearing prices paid to all bidders, effective January 1, 2001 through April 30, 2001; (3) establishing an independent governing board for the ISO; and (4) establishing penalties for under-scheduling power loads. The FERC did not order any refunds based on its findings, but announced its intent to retain the discretion to order refunds for wholesale electricity costs incurred from October 2000 through December 31, 2002. In March 2001, the FERC ordered refunds of $69 million for January 2001 and indicated it would continue to review December 2000 wholesale prices. The generators have appealed the decision. Any refunds will be offset against amounts owed the generators.

Federal Lawsuit

On November 8, 2000, the Utility filed a lawsuit in federal district court in San Francisco against the CPUC. The Utility asked the court to declare that the federally-approved wholesale electricity costs the Utility has incurred to serve its customers are recoverable in retail rates both before and after the end of the transition period. The lawsuit states that the wholesale power costs the Utility has incurred are paid pursuant to filed rates, which the FERC has authorized and approved and that under the United States Constitution and numerous federal court decisions, state regulators cannot disallow such costs. The Utility's lawsuit also alleges that to the extent that the Utility is denied recovery of these mandated wholesale electricity costs by order of the CPUC, such action constitutes an unlawful taking and confiscation of the Utility's property. On January 29, 2001, the Utility's lawsuit was transferred to the federal district court in Los Angeles where Southern California Edison has its identical case pending.

Legislative Action

On February 1, 2001, the governor of California signed into law AB 1X. AB 1X extended a preliminary authority of the DWR to purchase power. Public Utilities Code Section 360.5, adopted in AB 1X, authorizes the CPUC to determine the portion of each electric utility's existing electric retail rate that represents the difference between the generation related component of the utility's retail rate in effect on January 5, 2001, and the sum of the costs of the utility's own generation, qualifying facilities (QF) contracts, existing bilateral contracts, and ancillary services (the California Procurement Adjustment or CPA). The CPA is payable to the DWR by each utility upon receipt from its retail end use customers.

The DWR has indicated that it intends to buy power only at "reasonable prices" to meet the power needs of the retail electric customer that cannot be met by the utility-owned generation or power under contract to the utilities; i.e. the utilities' net open position. As the DWR has set a yet undisclosed ceiling on what it will pay for power, the ISO has been left to pay the remainder. The ISO has purchased energy at costs above the DWR's ceiling and, in turn, is expected to bill the Utility for those costs. AB 1X does not address whether or how the Utility will be able to pay for or recover purchase power costs it has incurred because ISO purchases were not under the DWR's ceiling for "reasonable prices." PG&E Corporation and the Utility cannot predict what regulatory, legislative, or judicial actions may be taken with respect to this issue.

In response to the ISO's concern over the weakened financial condition of the Utility and its ability to pay for power purchases, on February 14, 2001, the FERC issued an order stating that the ISO could not allow the Utility to schedule power from a third party supplier, unless the Utility was creditworthy or was backed by creditworthy parties. The FERC order also stated that the ISO could continue to schedule power for the Utility as long as it comes from its own generation units and is routed over its own transmission lines. The ISO has stated that it will charge the Utility for the power it buys on an emergency basis, despite the FERC ruling. On April 6, 2001, the FERC issued a further order directing the ISO to implement its prior order which the FERC clarified applies to all third-party transactions whether scheduled or not.

Rate Stabilization Plan (RSP)

On November 22, 2000, the Utility filed an application with the CPUC seeking approval of a five-year RSP beginning on January 1, 2001. The Utility requested an initial average rate increase of 22.4%. The Utility also proposed that it receive actual costs, including a regulated return, for electricity generation provided by it with the idea that profits that would have been generated at market rates be recovered from customers later in the five-year rate stabilization period. With respect to Diablo Canyon Nuclear Power Plant (Diablo Canyon) the Utility has proposed to defer all profits (discussed below in "Diablo Canyon Benefits Sharing"), until 2003, when the allocation of revenues between ratepayers and shareholders will be readjusted. The readjustment is intended to allow, by the end of 2005, the total net revenues earned by Diablo Canyon, over the five-year plan, to be allocated equally between shareholders and ratepayers according to existing CPUC decisions.

On January 4, 2001, the CPUC issued an emergency interim decision denying the Utility's request for a rate increase. Instead, the decision permitted the Utility to establish an interim surcharge applied to electric rates on an equal-cents-per-kWh basis of 1.0 cent per kWh, subject to refund and adjustment. The surcharge was to remain in effect for 90 days from the effective date of the decision. The Utility was required to establish a balancing account to track the revenue provided by the surcharge and to apply these revenues to ongoing wholesale electricity costs. The surcharge was made permanent in the CPUC's March 27, 2001 decision, referred to below.

On January 26, 2001, an assigned CPUC commissioner's ruling was issued in the Utility's rate stabilization plan proceeding. The ruling stated that in phase one of the case, the scope of the proceeding will include (1) reviewing the independent audits of the utilities accounts to determine whether there is a financial necessity for additional relief for the utilities, (2) reviewing TURN's accounting proposal to transfer the undercollected balances in the utilities' TRAs to their respective TCBAs and reviewing the generation memorandum accounts, and (3) considering whether the rate freeze has ended only on a prospective basis.

On January 30, 2001, the independent consultants engaged by the CPUC issued their review report on the Utility's financial position as of December 31, 2000, as well as that of PG&E Corporation and the Utility's affiliates. The review found that the Utility made an accurate representation of its financial situation noting accurate representations of its borrowing capabilities, credit condition, and events of default. The review also found that the Utility accurately represented recorded entries to its TRA and TCBA. The review alleged certain deficiencies with respect to bidding strategies, cash conservation matters, and cash flow forecast assumptions. The Utility filed rebuttal testimony on February 14, 2001. Hearings to consider the issues and reports of the independent consultants began on February 20, 2001.

On March 27, 2001, the CPUC ruled on parts of the Utility's RSP and granted an increase in rates by adopting an average 3.0 cents per kWh surcharge. Although the increase is authorized immediately, the 3.0 cents per kWh surcharge will not be collected in rates until the CPUC establishes an appropriate rate design for the surcharge, which is not expected to be adopted until May 2001, at the earliest. The revenue generated by the rate increase is to be used only for electric power procurement costs that are incurred after March 27, 2001. The CPUC declared that the revenues generated by this surcharge are subject to refund (1) if not used to pay for such power purchases, (2) to the extent that generators and sellers of power make refunds for overcollections, or (3) to the extent any administrative body or court denies the refunds of overcollections in a proceeding where recovery has been hampered by a lack of cooperation from the Utility. The 3.0 cents per kWh surcharge is in addition to the emergency interim surcharge approved in January 4, 2001, which the CPUC made permanent in this decision. The CPUC also modified accounting rules in response to a proposal made by TURN as described below.

Also, on March 27, 2001, the CPUC issued a decision ordering the Utility and the other California investor-owned utilities to pay the DWR a per-kWh price equal to the applicable generation-related retail rate per kWh established for each utility as in effect on January 5, 2001, for each kWh the DWR sells to the customers of each utility. The CPUC determined that the generation-related component of retail rates should be equal to the total bundled electric rate (including the 1 cent per kWh interim surcharge adopted by the CPUC on January 5, 2001) less the following non-generation-related rates or charges: transmission, distribution, public purpose programs, nuclear decommissioning, and the fixed transition amount. The CPUC determined that the Utility's company-wide average generation-related rate component is 6.471 cents per kWh and that this is the amount that should be paid to the DWR for each kWh delivered by the DWR to the Utility's retail customers after February 1, 2001, until specific rates are calculated. The CPUC ordered the utilities to pay the DWR within 45 days after the DWR supplies power to their retail customers, subject to penalties for each day that payment is late. The amount of power supplied to retail end-use customers after March 27, 2001, for which the DWR is entitled to be paid would be based on the product of the number of kWh that the DWR provided 45 days earlier and the Utility's company-wide average generation-related rate of 6.471 cents per kWh, and the additional 3 cent per kWh surcharge described above.

The CPUC also ordered that the utilities immediately pay the sums owed to the DWR for power sold by the DWR from January 18, 2001 through January 31, 2001, under California Senate Bill 7X. Based on an estimated number of kWh sold by the DWR, the Utility paid approximately $30 million to the DWR at the rate of 5.471 cents per kWh as adopted by the CPUC.

In addition, on April 3, 2001, the CPUC adopted a method to calculate the CPA, as described in Public Utilities Code Section 360.5 (added by AB 1X effective February 1, 2001). Section 360.5 requires the CPUC to determine (1) the portion of each electric utility's electric retail rate effective on January 5, 2001, the CPA, that is equal to the difference between the generation-related component of the utility's retail rate in effect on January 5, 2001, and the sum of the costs of the utility's own generation, QFs contracts, existing bilateral contracts (i.e., entered into before February 1, 2001), and ancillary services, and (2) the amount of the CPA that is allocable to the power sold by the DWR. The CPUC decided that the CPA should be a set rate calculated by determining each utility's generation-related revenues (for the Utility the CPUC has proposed that this be equal to 6.471 cents per kWh multiplied by total kWh sales by the Utility to the Utility's retail customers), then subtracting each utility's statutorily authorized generation-related costs, and dividing the result by each utility's total kWh sales. Each utility's CPA rate will be used to determine the amount of bonds the DWR may issue.

Using the CPUC's methodology, but substituting the CPUC's cost assumptions with actual expected costs and including costs the CPUC has refused to recognize, the Utility's calculations show that the CPA for the 11-month period February through December 2001 would be negative by $2.2 billion, (i.e., there would be no CPA available to the DWR) assuming the DWR purchases 84% of the Utility's net open position. (The net open position is the amount of power that cannot be met by the utilities' own or contracted-for generation.) If AB 1X were amended to also include in the CPA all the incremental revenue from the 3 cent per kWh increase discussed above (approximately $2.3 billion for 11 months), then the amount available to the DWR for the CPA for the comparable 11-month period, assuming the Utility were allowed to recover its costs first, would be approximately $100 million. The Utility believes the method adopted by the CPUC is unlawful and inconsistent with Section 360.5 because, among other reasons, it establishes a set rate that does not reflect actual residual revenues, overstates the CPA by excluding and/or understating authorized costs, and to the extent it is dedicated to the DWR does not allow the Utility to recover its own revenue requirements and costs of service. The Utility intends to file an application for rehearing of this decision.

The CPUC noted that although the DWR has assumed responsibility to purchase some of the utilities' power requirements, it has not committed to purchase all of the utilities' net open position. To the extent the DWR does not buy enough power to cover the Utility's net open position, the ISO purchases emergency power on the high-priced spot market to meet system reliability requirements and the net open position. The ISO may attempt to charge the Utility a proportionate share of the ISO's purchases. The Utility believes that under the current circumstances and applicable tariffs it is not responsible for such ISO charges. As the DWR has not advised the CPUC of its revenue requirement for the DWR's power purchases, it is unclear how much of the 3 cent surcharge will be needed by the DWR and how much, if any, may be used by the Utility to recover its procurement costs incurred after March 27, 2001 (including any ISO charges).

Since the end of January 2001, the Utility has been paying only 15% of amounts due QFs. On March 27, 2001, the CPUC issued a decision requiring the Utility and the other California investor-owned utilities to pay QFs fully for energy deliveries made on and after the date of the decision, within 15 days of the end of the QFs' billing period. The decision permits QFs to establish a 15-day billing period as compared to the current monthly billing period. The CPUC noted that its change to the payment provision was required to maintain energy reliability in California and thus provided that failure to make a required payment would result in a fine in the amount owed to the QF. The decision also adopts a revised pricing formula relating to the California border price of gas applicable to energy payments to all QFs, including those that do not use natural gas as a fuel. Based on the Utility's preliminary review of the decision, the revised pricing formula would reduce the Utility's 2001 average QF energy and capacity payments from approximately 12.7 cents per kWh to 12.3 cents per kWh.

The CPUC also adopted TURN's proposal to transfer on a monthly basis the balance in each Utility's TRA to the Utility's TCBA. The TRA is a regulatory balancing account that is credited with total revenue collected from ratepayers through frozen rates and which tracks undercollected power purchase costs. The TCBA is a regulatory balancing account that tracks the recovery of generation-related transition costs. The accounting changes are retroactive to January 1, 1998. The Utility believes the CPUC is retroactively transforming the power purchase costs in the TRA into transition costs in the TCBA. However, the CPUC characterized the accounting changes as merely reducing the prior revenues recorded in the TCBA, thereby affecting only the amount of transition cost recovery achieved to date. The CPUC also ordered that the utilities restate and record their generation memorandum account balances to the TRA on a monthly basis before any transfer of generation revenues to the TCBA. The CPUC found that based on the accounting changes, the conditions for meeting the end of the rate freeze have not been met.

The Utility believes the adoption of TURN's proposed accounting changes results in illegal retroactive ratemaking, constitutes an unconstitutional taking of the Utility's property, and violates the federal filed rate doctrine. The Utility also believes the other CPUC decisions are similarly illegal to the extent they would compel the Utility to make payments to the DWR and QFs without providing adequate revenues for such payments. The Utility plans to challenge the decisions in appropriate legal forums.

Bilateral Contracts

Under the terms of AB 1890, the Utility was required to purchase all of its power from the PX and ISO to meet the needs of its customers. On August 3, 2000, after the California energy crisis had begun, the CPUC approved the Utility's use of bilateral contracts, subject to the CPUC approving a set of standards or criteria by which the reasonableness of such contracts would be reviewed on an after-the-fact basis. The CPUC has yet to approve such standards or criteria.

In October 2000, the Utility entered into multiple bilateral contracts with suppliers for long-term electricity deliveries. As of December 31, 2000, these contracts ranged from approximately 1,228,000 MWhs to 6,344,800 MWhs of supply annually. The contracts extended from 2001 to 2005. Each of the contracts was for delivery beginning January 1, 2001 or later. As a result of the energy crisis, certain of these contracts were terminated, subsequent to December 31, 2000.

PX Energy Credits

In accordance with CPUC regulations, the Utility provides a PX energy credit to those customers (known as direct access customers) who have chosen to buy their electric energy from an energy service provider (ESP) other than the Utility. As wholesale power prices began to increase beginning in June 2000, the level of PX credits increased correspondingly to the point where the credits exceeded the Utility's distribution and transmission charges to direct access customers. During 2000, the PX credits reduced electric revenue by $472 million, although the Utility ceased paying most of these credits in December 2000. These amounts are reflected on the accompanying consolidated balance sheet at December 31, 2000. As of March 29, 2001, the estimated total of accumulated credits for direct access customers that have not been paid by the Utility is approximately $503 million. The actual amount that will be refunded to ESPs will be dependent upon when the rate freeze ends and whether there are any adjustments made to wholesale energy prices by the FERC.

Generation Divestiture

In April 1999, the Utility sold three fossil-fueled generation plants for $801 million. At the time of sale, these three fossil-fueled plants had a combined book value of $256 million and a combined capacity of 3,065 MW.

In May 1999, the Utility sold its complex of geothermal generation facilities for $213 million. At the time of sale, these facilities had a combined book value of $244 million and a combined capacity of 1,224 MW. The Lake facility was sold at a gain of $8 million while the Sonoma facility was sold at a loss of $39 million.

The gains from the sale of the fossil-fueled generation plants and the Lake facility were used to offset other transition costs. Likewise, the loss from the sale of the Sonoma geothermal generation facilities is being recovered as a transition cost.

The Utility has retained a liability for required environmental remediation related to any pre-closing soil or groundwater contamination at the plants it has sold.

Under the California electric industry restructuring legislation, the valuation of the Utility's remaining generation assets (primarily its hydroelectric facilities) must be completed by December 31, 2001. Any excess of market value over the assets' book value would be used to offset the Utility's transition costs.

In August 2000, the Utility and a number of interested parties filed an application with the CPUC requesting that the CPUC approve a settlement agreement reached by these parties. The agreement was filed in the Utility's proceeding to determine the market value of its hydroelectric generation assets. In this settlement agreement, the Utility indicated that it would transfer its hydroelectric generation assets, at a negotiated value of $2.8 billion, to an affiliate. Due to the high wholesale prices and the corresponding increase in the value of its hydroelectric generation assets, in November 2000 as part of an application with the CPUC seeking approval of a five-year RSP, the Utility withdrew its support from the settlement agreement, eliminating it from consideration in the proceeding.

In January 2001, California Assembly Bill 6 was passed which prohibits disposal of any of the Utility's generation facilities, including the hydroelectric facilities, prior to January 1, 2006. In December 2000, the Utility submitted updated testimony in the hydroelectric valuation proceeding indicating the market value of the hydroelectric assets ranges from $3.9 billion to $4.2 billion assuming a competitive auction or other arms-length sale. At December 31, 2000, the book value of the Utility's net investment in hydroelectric generation assets was approximately $692 million.

Diablo Canyon Benefits Sharing

As required by a prior CPUC decision on June 30, 2000, the Utility filed an application with the CPUC requesting approval of its proposal for sharing with ratepayers 50% of the post-rate freeze net benefits of operating Diablo Canyon. The net benefit sharing methodology proposed in the Utility's application would be effective at the end of the current electric rate freeze for the Utility's customers and would continue for as long as the Utility owned Diablo Canyon. Under the proposal, the Utility would share the net benefits of operating Diablo Canyon based on the audited profits from operations, determined consistent with the prior CPUC decisions. If Diablo Canyon experiences losses, such losses would be deferred and netted against profits in the calculation of the net benefits in subsequent periods (or against profits in prior periods if subsequent profits are insufficient to offset such losses). Any changes to the net sharing methodology must be approved by the CPUC. The CPUC has suspended the proceedings to consider the net benefit sharing proposal. In the Utility's RSP, parties have proposed that the requirement to establish a sharing methodology be rescinded and the Diablo Canyon be placed on cost-of-service ratemaking. It is uncertain what future ratemaking will be applicable to Diablo Canyon.

Cost of Electric Energy

For the years ended December 31, 2000 and 1999, and the period March 31, 1998 (the PX establishment date) to December 31, 1998, the cost of electric energy for the Utility, reflected on the Utility's Statement of Consolidated

Operations, comprises the cost of fuel for electric generation and QF purchases, the cost of PX purchases, and ancillary services charged by the ISO, net of sales to the PX, as follows:

	Year Ended December 31,		
(in millions)	2000	1999	1998
Cost of fuel resources at market prices	$ 9,512	$3,233	$ 3,370
Proceeds from sales to the PX	(2,771)	(822)	(1,049)
Total Utility cost of electric energy	$ 6,741	$2,411	$ 2,321

Note 3: Subsequent Events

Credit Rating Downgrades

As a result of the Utility's deteriorating financial condition from the California energy crisis, the major credit agencies have downgraded the long-term and short-term credit ratings of both PG&E Corporation and the Utility. The following is a summary of current credit ratings by Standard & Poor's (S&P) and Moody's Investors Service (Moody's) as of March 29, 2001, for the Utility:

Standard & Poors	**Current Ratings**
Corporate credit rating	D/D
Commercial paper	D
Senior secured debt	CCC
Senior unsecured debt	CC
Preferred stock	D
Shelf senior secured/unsecured subordinated debt	CCC/CC
Shelf preferred stock	D
Moody's Investors Service	
Commercial paper	Not prime
Mortgage	B3
Secured pollution control bonds	B3
Issuer rating	Caa2
Senior unsecured notes	Caa2
Unsecured debentures	Caa2
Unsecured pollution control bonds	Caa2
Bank credit facility	Caa2
Preferred Stock	caa
Shelf senior secured debt	(P)B3
Shelf senior unsecured debt	(P)Caa2
Shelf preferred stock	(P)caa
Variable rate demand bonds	Speculative Grade

PG&E Corporation

On January 16 and 17, 2001, in response to the continued energy crisis, S&P and Moody's, respectively, downgraded PG&E Corporation's credit ratings to below investment grade. The downgrade, in addition to PG&E Corporation's and the Utility's non-payment of commercial paper constituted an event of default under both the $436 million and the $500 million credit facilities. In response, the banks immediately terminated their outstanding commitments under these defaulted credit facilities. Through February 28, 2001, PG&E Corporation had $501 million in outstanding commercial paper, of which $457 million came due and was not paid.

On March 2, 2001, PG&E Corporation refinanced its debt obligations with $1 billion in aggregate proceeds of two term loans under a common credit agreement with General Electric Capital Corporation and Lehman Commercial Paper, Inc. In accordance with the credit agreement, the proceeds, together with other PG&E Corporation cash, were used to pay the $501 million in outstanding commercial paper, $434 million in borrowings under PG&E Corporation's long-term revolving credit facility, and $116 million to PG&E Corporation's shareholders of record on December 15, 2000 in satisfaction of the defaulted fourth quarter 2000 common stock dividend. Further, approximately $85 million was used to pre-pay the first year's interest under the credit agreement and to pay transaction expenses associated with the debt restructuring.

The loans will mature on March 2, 2003 (which date may be extended at the option of PG&E Corporation for up to one year upon payment of a fee of up to 5% of the then outstanding indebtedness), or earlier, if a spin-off of the shares of the NEG were to occur. As required by the credit agreement, PG&E Corporation has given the lenders a security interest in the NEG. The loans prohibit PG&E Corporation from declaring dividends, making other distributions to shareholders, or incurring additional indebtedness until the loans have been repaid, although PG&E Corporation could incur unsecured indebtedness provided it meets certain requirements. The loan also prohibits NEG from making distributions to PG&E Corporation and restricts certain other intercompany transactions.

Further, as required by the credit agreement, NEG LLC has granted to affiliates of the lenders options that entitle these affiliates to purchase up to 3% of the shares of the NEG at an exercise price of $1.00 based on the following schedule:

	Percentages of Shares subject to NEG Options
Loans outstanding for:	
Less than six months	2.0%
Six to eighteen months	2.5%
Greater than eighteen months	3.0%

The option becomes exercisable on the date of full repayment or, earlier, if an initial public offering of the shares of the NEG (IPO) were to occur. The NEG has the right to call the option in cash at a purchase price equal to the fair market value of the underlying shares, which right is exercisable at any time following the repayment of the loans. If an IPO has not occurred, the holders of the option have the right to require the NEG or PG&E Corporation to repurchase the option at a purchase price equal to the fair market value of the underlying shares, which right is exercisable at any time after the earlier of full repayment of the loans or 45 days before expiration of the option. The option will expire 45 days after the maturity of the loans. PG&E Corporation will account for the options by recording the fair value of the option at issuance as a debt issuance cost to be amortized over the expected life of the loans. The options will be marked to market through an increase or decrease to current earnings.

Under the credit agreement, the NEG is permitted to make investments, incur indebtedness, sell assets, and operate its businesses pursuant to its business plan. Mandatory repayment of the loans will be required from the net after-tax proceeds received by the NEG or any subsidiary of the NEG from (1) the issuance of indebtedness, (2) the issuance or sale of any equity (except for cash proceeds from an IPO), (3) asset sales, and (4) casualty insurance, condemnation awards, or other recoveries. However, if such proceeds are retained as cash, used to pay indebtedness, or reinvested in the NEG's businesses, mandatory repayment will not be required.

Any net proceeds from an IPO must be used to reduce the outstanding balance of the loans to $500 million or less. In addition, all distributions made by the NEG to PG&E Corporation other than (1) to reimburse PG&E Corporation for corporate overhead expenses, (2) pursuant to any tax sharing arrangements which the NEG and PG&E Corporation are parties, and (3) pursuant to any note that may be payable to PG&E Corporation in connection with an IPO and similar arrangements must be used to pay the loans.

The credit agreement also prohibits PG&E Corporation from taking certain actions, including a restriction against declaring or paying any dividends for as long as the loans are outstanding. A breach of covenants, including requirements that (1) the NEG's unsecured long-term debt have a credit rating of at least BBB- by S&P or Baa3 by Moody's, (2) the ratio of fair market value of the NEG to the aggregate amount of principal then outstanding under the loans is not less than 2 to 1, and (3) PG&E Corporation maintain a cash or cash equivalent reserve of at least 15% of the total principal amount of the loans outstanding, entitles the lenders to declare the loans to be due and payable.

Utility

The Utility had been drawing on its $1 billion facility to pay maturing commercial paper. As of January 16, 2001, the Utility had drawn down $938 million under this facility. On January 16 and 17, 2001, S&P and Moody's, respectively, downgraded the Utility's credit ratings to below investment grade. This downgrade resulted in an event of default under the $850 million credit facility, while the Utility's non-payment of commercial paper exceeding $100 million constituted events of default under both the $1 billion and $850 million credit facilities.

Although they have the ability under the terms of the various agreements, no bank has called for accelerated payment of any of the Utility's outstanding debt, nor has any bank permanently waived any requirements violated which resulted in the events of default described above. Lenders have agreed to forbear from accelerating payments until April 13, 2001.

On January 10, 2001, the Board of Directors of the Utility suspended the payment of its fourth quarter 2000 common stock dividend in an aggregate amount of $110 million payable on January 15, 2001, to PG&E Corporation and PG&E Holdings, Inc., a subsidiary of the Utility. In addition, the Utility's Board of Directors decided not to declare the regular preferred stock dividends for the three-month period ending January 31, 2001, normally payable on February 15, 2001. Dividends on all Utility preferred stock are cumulative. Until cumulative dividends on preferred stock are paid, the Utility may not pay any dividends on its common stock, nor may the Utility repurchase any of its common stock.

After the downgrade, the PX notified the Utility that the ratings downgrade required the Utility to post collateral for all transactions in the PX day-ahead market. Since the Utility was unable to post such collateral, the PX suspended the Utility's trading privileges effective January 19, 2001 in the day-ahead market. The PX also sought to liquidate the Utility's block forward contracts for the purchase of power. On January 25, 2001, a California Superior Court judge granted the Utility's application for a temporary restraining order, which thereby restrained and enjoined the PX and its agents from liquidating the Utility's contracts in the block forward market, pending hearing on a preliminary injunction on February 5, 2001. Immediately before the hearing on the preliminary injunction, California Governor Gray Davis, acting under California's Emergency Services Act, commandeered the contracts for the benefit of the state. Under the Act, the state must pay the Utility the reasonable value of the contracts, although the PX may seek to recover the monies that the Utility owes to the PX from any proceeds realized from those contracts. Discussions and negotiations on this issue are currently ongoing between the state and the Utility.

As of March 29, 2001, the Utility was in default and/or had not paid the following:

Description	Amount (in millions) (unaudited)
Items not paid	
PX/ISO—real time market deliveries	$1,448
Qualifying facilities	643
Direct access credits due to energy service providers	503
Commercial paper	861
Bank loans	939*
Other	26
Total Items Not Paid	$4,420
Items coming due through April 30, 2001	
PX/ISO—real time market deliveries	$ 550
Qualifying facilities	340
Gas suppliers	470
Other	140
Total coming due	1,500
Total cash on hand at March 29, 2001	$2,600

* Loans that lenders have agreed to forbear through April 13, 2001.

Additionally, the Utility may owe the DWR for purchases that the DWR has made on behalf of the Utility's customers. As discussed further in Note 2 of the Notes to the Consolidated Financial Statements, there is a dispute over how much the Utility owes the DWR. Also, the DWR has indicated that it intends to purchase power at only "reasonable prices." The ISO has continued to purchase power at prices in excess of the DWR's as yet undisclosed ceiling and is expected to bill the Utility for the differential. The Utility does not yet know what the total expected billing is for these purchases.

As a result of (1) the failure by the state to assume the full procurement responsibility for the Utility's net open position as was provided under AB1X, (2) the negative impact of recent actions by the CPUC 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 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 uncollected purchased power costs, the Utility filed a voluntary petition for relief under provisions of Chapter 11 of the U.S. Bankruptcy Code on April 6, 2001. Pursuant to Chapter 11 of the U.S. Bankruptcy Code, 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. Subject to the approval of the bankruptcy court, the Utility's intent is to pay its ongoing costs of doing business while seeking resolution of the wholesale power crisis. It is the Utility's intention to continue to pay employees, vendors, suppliers, and other creditors to maintain essential distribution and transmission services. However, the Utility is not in a position to pay maturing or accelerated obligations, nor is the Utility in a position to pay the ISO, PX, and the QFs, the massive amounts due for the Utility's power purchases above the amount included in rates for power purchase costs. The Utility's current actions are intended to allow the Utility to continue to operate while efforts to reach a regulatory or legislative solution continue.

The Utility has also deferred quarterly interest payments on the Utility's 7.90% Deferrable Interest Subordinated Debentures, Series A, due 2025, until further notice in accordance with the indenture. The corresponding quarterly payments on the 7.90% Cumulative Quarterly Income Preferred Securities, Series A, (QUIPS) issued by PG&E Capital I, due on April 2, 2001, have been similarly deferred. Distributions can be deferred up to a period of five years per the indenture. Investors will accumulate interest on the unpaid distributions at the rate of 7.90%.

National Energy Group

In December 2000 and in January and February 2001, PG&E Corporation and the NEG undertook a corporate restructuring of the NEG, known as a "ringfencing" transaction. The ringfencing complied with credit rating agency criteria, enabling NEG, PG&E Gas Transmission, Northwest Corporation (PG&E GTN), and PG&E ET to receive or retain their own credit rating, based upon their creditworthiness. The ringfencing involved the creation of new special purpose entities (SPEs) as intermediate owners between PG&E Corporation and its non CPUC-regulated subsidiaries. These new SPEs are: PG&E National Energy Group, LLC, which owns 100% of the stock of the NEG; GTN Holdings LLC, which owns 100% of the stock of PG&E GTN; and PG&E Energy Trading Holdings LLC which owns 100% of the stock of PG&E Corporation's energy trading subsidiaries, PG&E Energy Trading—Gas Corporation, PG&E Energy Trading Holdings Corporation, and PG&E Energy Trading-Power, L.P. In addition, the NEG's organizational documents were modified to include the same structural elements as the SPEs to meet credit rating agency criteria. Ringfencing is intended to reduce the likelihood that the assets of the ringfenced entities would be substantially consolidated in a bankruptcy proceeding involving such companies' ultimate parent, and to thereby preserve the value of the "protected" entities as a whole. The SPEs require unanimous approval of their respective boards of directors, which includes an independent director, before they can (a) consolidate or merge with any entity, (b) transfer substantially all of their assets to any entity, or (c) institute or consent to bankruptcy, insolvency, or similar proceedings or actions. The SPEs may not declare or pay dividends unless the respective boards of directors has unanimously approved such action and the company meets specified financial requirements.

Note 4: Price Risk Management and Financial Instruments

Trading and Non-Trading Activities

The following table is a summary of the contract or notional amounts and maturities of commodity derivatives related to commodity price risk management as of December 31, 2000 and 1999:

Electricity, Natural Gas, and Natural Gas Liquids Contracts (billions of MMBtu equivalents[1])	Purchase (Long)	Sale (Short)	Maximum Term in Years
NEG:			
Trading Activities—December 31, 2000			
Swaps	2.04	1.95	6
Options	0.46	0.37	8
Futures	0.14	0.15	3
Forward Contracts	1.42	1.38	16
Trading Activities—December 31, 1999			
Swaps	2.38	2.33	7
Options	.94	.86	8
Futures	.19	.18	2
Forward Contracts	1.49	1.46	12
Non-Trading Activities—December 31, 2000			
Forward Contracts	1.70	0.74	22
Non-Trading Activities—December 31, 1999			
Forward Contracts	0.02	0.01	3
Utility:			
Non-Trading Activities—December 31, 2000			
Swaps	0.06	0.07	1
Forward Contracts	0.02	—	5
Non-Trading Activities—December 31, 1999			
Swaps	—	0.01	1

(1) One MMBtu is equal to one million British thermal units. Electricity contracts, measured in megawatts, were converted to MMBtu equivalents using a conversion factor of 10 MMBtus per 1 MWh. Natural gas liquids contracts were converted to MMBtu equivalents using an appropriate conversion factor for each type of natural gas liquids product.

The following table is a summary of the contract or notional amounts and maturities of PG&E Corporation's financial instruments used for non-trading activities as of December 31:

	2000		1999	
(in millions)	Notional Amount	Contract Expiration	Notional Amount	Contract Expiration
Non-Trading Activities:				
Interest Rate	$1,756	2012	$724	2003
Foreign Currency	94	2003	104	2002

Notional amounts shown represent volumes that are used to calculate amounts due under the agreements and do not necessarily represent volumes exchanged. Because the changes in market value of these derivatives used as hedges are generally offset by changes in the value of the underlying physical transactions, the amounts at risk are significantly lower than these notional amounts might suggest.

PG&E Corporation's net gain (loss) on trading contracts held during the years ended December 31, are as follows:

(in millions)	2000	1999	1998
Swaps	$ 173	$ 15	$ 69
Options	66	(41)	(49)
Futures	(106)	(36)	(63)
Forward Contracts	72	98	101
Net gain	$ 205	$ 36	$ 58

The following table discloses PG&E Corporation's estimated average fair value and ending fair value of price risk management assets and liabilities at December 31, 2000 and 1999.

	Average Fair Value		Ending Fair Value	
(in millions)	Assets	Liabilities	Assets	Liabilities
Trading Activities—December 31, 2000				
Swaps	$ 163	$ 75	$ 286	$ 121
Options	153	106	250	171
Futures	34	78	33	98
Forward Contracts	2,053	1,921	3,496	3,476
Total	$2,403	$2,180	$4,065	$3,866
Noncurrent portion			$2,026	$1,867
Current portion			$2,039	$1,999
Trading Activities—December 31, 1999				
Swaps	$ 218	$ 197	$ 50	$ 33
Options	75	87	56	41
Futures	89	119	35	58
Forward Contracts	475	356	588	398
Total	$ 857	$ 759	$ 729	$ 530
Noncurrent portion			$ 329	$ 207
Current portion			$ 400	$ 323

Credit Risk

The use of financial instruments to manage the risks associated with changes in energy commodity prices creates exposure resulting from the possibility of nonperformance by counterparties pursuant to the terms of their contractual obligations. The counterparties in PG&E Corporation's and the Utility's portfolio consist primarily of investor-owned and municipal utilities, energy trading companies, financial institutions, and oil and gas production companies. PG&E Corporation and the Utility minimize credit risk by dealing primarily with creditworthy counterparties in accordance with established credit approval practices and limits. PG&E Corporation assesses the financial strength of its counterparties at least quarterly and requires that counterparties post security in the forms 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. Neither PG&E Corporation nor the Utility has experienced material losses due to the nonperformance of counterparties in 2000. Counterparties considered to be investment grade or higher comprise 76% of the total credit exposure. At December 31, 2000, PG&E Corporation's and the Utility's gross credit risk amounted to $3.3 billion and $978 million, respectively.

Fair Value of Financial Instruments

PG&E Corporation's financial instruments consist of cash and cash equivalents, restricted cash, accounts receivable, accounts payable and certain accrued liabilities, notes payable, commercial paper, capital leases, and long-term debt.

The fair value of these financial instruments, with the exception of long-term receivables, fixed rate debt, and interest rate swaps, approximates their carrying value as of December 31, 2000 and 1999, due to their short-term nature or due to the fact that the interest rate paid on the instrument is variable.

The carrying amounts of the long-term receivables approximate fair value at December 31, 2000 and 1999, as the assumptions used to value these instruments at the acquisition date had not changed.

The fair values of long-term receivables and long-term debt were estimated using discounted cash flows analysis. based on PG&E Corporation's current incremental borrowing rate. The approximate carrying values were based on currently quoted market prices for similar types of borrowing arrangements.

The fair value of interest rate swap agreements, which are not carried on the consolidated balance sheets, is estimated by calculating the present value of the difference between the total fixed payments of the interest rate swap agreements and the total floating payments using the appropriate current market rates.

The carrying amount and fair value of PG&E Corporation's long-term receivables, long-term debt, and interest rate swaps as of December 31, 2000 and 1999, is summarized as follows:

	2000		1999	
PG&E Corporation (in millions)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term receivables	$ 611	$ 526	$ 680	$ 680
Long-term debt	9,157	9,010	9,561	9,393
Interest rate swaps	—	(73)	—	(9)

Fair value of the Utility's rate reduction bonds, and Utility obligated mandatorily redeemable preferred securities of trust holding solely Utility subordinated debentures, are all determined based on quoted market prices. Fair value of the Utility's preferred stock with mandatory provisions is based on indicative market prices. Where quoted or indicative market prices are not available, the estimated fair value is determined using other valuation techniques (for example, the present value of future cash flows). Most of the Utility's debt is determined using quoted market prices, but the fair value of a small portion of Utility debt is determined using the present value of future cash flows. See Note 3 of the Notes to the Consolidated Financial Statements for subsequent events regarding PG&E Corporation's and the Utility's credit facilities.

At December 31, 2000 and 1999, the Utility's carrying amount and ending fair value of its financial instruments was:

	2000		1999	
Utility: (in millions)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Nuclear decommissioning funds noncurrent asset (see Note 11)	$1,328	$1,328	$1,264	$1,264
Total long-term debt(1) (see Note 8)	5,716	5,320	5,342	5,217
Rate reduction bonds(2) (see Note 9)	2,030	2,044	2,321	2,265
Preferred stock with mandatory redemption provisions (see Note 7)	137	98	137	140
Utility obligated mandatorily redeemable preferred securities of trust holding solely Utility subordinated debentures (See note 7)	300	180	300	267

(1) Total long-term debt includes the current portion of long-term debt.

(2) Rate reduction bonds include the current portion of rate reduction bonds.

Note 5: Acquisitions and Disposals

On September 28, 2000, the NEG purchased for $311 million the Attala Generating Company LLC, which owns a gas-fired power plant under construction. Under the purchase agreement, the NEG prepaid the estimated remaining construction costs, which are being managed by the seller. The project, which was approximately 75% complete as of December 31, 2000, is expected to begin commercial service in July 2001. In connection with the acquisition, the NEG also assumed industrial revenue bonds in the amount of $158 million. The seller has agreed to pay off the bonds prior to December 15, 2001; accordingly, the NEG recorded a receivable equal to the amount of the outstanding bonds and accrued interest at December 31, 2000.

On January 27, 2000, PG&E Corporation signed a definitive agreement with El Paso Field Services Company (El Paso) providing for the sale to El Paso, a subsidiary of El Paso Energy Corporation, of the stock of PG&E Gas

Transmission, Texas Corporation, PG&E Gas Transmission Teco, Inc., and their subsidiaries (PG&E GTT). PG&E GTT assets consist of 8,500 miles of natural gas and natural gas liquids pipeline, nine natural gas processing plants, and natural gas storage facilities, all located in Texas. Given the terms of the sales agreement, in 1999 PG&E Corporation recognized a charge against pre-tax earnings of $1,275 million, to reflect PG&E GTT's assets at their fair value. The composition of the pre-tax charge is as follows: (1) an $819 million write-down of net property, plant, and equipment, (2) the elimination of the unamortized portion of goodwill in the amount of $446 million, and (3) an accrual of $10 million representing selling costs.

On December 22, 2000, after receipt of governmental approvals, PG&E Corporation completed the stock sale. The total consideration received was $456 million, less $150 million used to retire the PG&E GTT short-term debt, and the assumption by El Paso of PG&E GTT long-term debt having a book value of $564 million. The final sale price is subject to adjustment during a 120-day working capital true-up period. The NEG recorded a gain of approximately $20 million based on its best estimate of the final sales price.

PG&E GTT's total assets and liabilities, including the charge noted above, included in PG&E Corporation's Consolidated Balance Sheet at December 31, 1999, were as follows:

	(in millions)
Assets	
Current assets	$ 229
Noncurrent assets	988
Total assets	1,217
Liabilities	
Current liabilities	448
Noncurrent liabilities	624
Total liabilities	1,072
Net assets	$ 145

The following table reflects PG&E GTT's results of operations included in PG&E Corporation's Statement of Consolidated Operations for the years ended December 31:

(in millions)	2000	1999	1998
Revenue	$873	$ 1,753	$2,064
Operating expenses	869	3,058	2,115
Operating income (loss)	4	(1,305)	(51)
Interest expense and other, net	(36)	7	(50)
Sales price true-up	20	—	—
Income (Loss) before income taxes	(12)	(1,298)	(101)
Income tax provision (benefit)	(32)	(390)	(31)
Net income (loss)	$ 20	$ (908)	$ (70)

In December 1999, PG&E Corporation's Board of Directors approved a plan to dispose of PG&E Energy Services (PG&E ES), a wholly owned subsidiary, through a sale. The disposal has been accounted for as a discontinued operation, and PG&E Corporation's investment in PG&E ES was written down to its then estimated net realizable value. In addition, PG&E Corporation provided a reserve for anticipated losses through the anticipated date of sale. The total provision for discontinued operations was $58 million, net of income taxes of $36 million at December 31, 1999. Of this amount, $33 million (net of taxes) was allocated toward operating losses for the period leading up to the intended disposal date. In 2000, $31 million (net of taxes) of actual operating losses was charged against this reserve. During the second quarter of 2000, the NEG finalized the transactions related to the disposal of the energy commodity portion of PG&E ES for $20 million, plus net working capital of approximately $65 million, for a total of $85 million. In addition, the sale of the Value-Added Services business and various other assets was completed on July 21, 2000, for a total consideration of $18 million. For the year ended December 31, 2000, an additional estimated loss of $40 million (or $0.11 per share), net of income tax of $36 million, was recorded as actual losses in connection with the disposition exceeded that originally estimated. The principal reason for the additional loss was due to the mix of assets, and the structure and timing of the actual sales agreements, as opposed to the one reflected in the initial provision established in 1999. In addition, the worsening energy situation in California also contributed to the additional loss incurred. The PG&E ES business segment generated net losses from operations of $40 million (or $0.11 per share) for the year ended December 31, 1999.

In September 1998, PG&E Gen through its indirect subsidiary USGen New England, Inc. (USGenNE), acquired a portfolio of electric generating assets and power supply agreements from a wholly-owned subsidiary of the New England Electric System (NEES). The purchase price, including fuel and other inventories and transaction costs, was approximately $1.8 billion funded through $1.3 billion of debt and a $425 million equity contribution from PG&E Corporation. The net purchase price was allocated as follows: electric generating assets of $2.3 billion classified as property, plant, and equipment, long-term receivables of $0.8 billion, and out-of-market contractual obligations of $1.3 billion and asset contracts related to acquired power sales agreement of $45 million. The acquisition of the NEES assets was considered an asset purchase. Accordingly, the purchase has been allocated to the assets purchased and the liabilities assumed based upon an assessment of fair value at the date of acquisition. The assets acquired included hydroelectric, coal, oil, and natural gas generation facilities with a combined generating capacity of 4,000 MW. In addition, the NEG, USGenNE, assumed 23 multi-year power purchase agreements representing an additional 800 MW of production capacity. The NEG, through a wholly-owned subsidiary, entered into the agreements as part of the acquisition, which (1) provided that a wholly-owned subsidiary of NEES would make payments through January 2008 for the purchase power agreements, and (2) required that the NEG, through its wholly-owned subsidiary, provide electricity to certain NEES affiliates under contracts that expire at various times through 2008.

In July 1998, PG&E Corporation sold its Australian energy holdings for $126 million. PG&E Corporation recognized a loss of approximately $23 million related to the sale, which is included in other income (expense) on the Statement of Consolidated Operations.

Note 6: Common Stock

PG&E Corporation

PG&E Corporation has authorized 800 million shares of no-par common stock, of which 387 million and 384 million shares were issued as of December 31, 2000 and 1999, respectively.

During the years ended December 31, 2000 and 1999, PG&E Corporation repurchased $2 million and $693 million of its common stock, respectively. The 2000 repurchases were for the Dividend Reinvestment Program. The 1999 repurchases were executed through open market purchases and an accelerated share repurchase program. Under the 1999 accelerated share repurchase program agreement, PG&E Corporation repurchased in a specific transaction 16.6 million shares of its common stock at a cost of $502 million. In connection with this transaction, PG&E Corporation entered into a forward contract with an investment institution. PG&E Corporation settled the forward contract and its additional obligation of $29 million in September 1999. A wholly owned subsidiary of PG&E Corporation made this repurchase, along with subsequent stock repurchases. The stock held by the subsidiary is treated as treasury stock and reflected as stock held by subsidiary on the Consolidated Balance Sheet of PG&E Corporation.

In October 1999, the Board of Directors of PG&E Corporation authorized an additional $500 million for the purpose of repurchasing shares of PG&E Corporation's common stock. The authorization for share repurchases extends through September 30, 2001. As of December 31, 2000, a subsidiary of PG&E Corporation had repurchased 23.8 million shares at a cost of $690 million.

On January 10, 2001, the Board of Directors of PG&E Corporation suspended the payment of its fourth quarter 2000 stock dividend of $.30 per common share declared by the Board of Directors on October 18, 2000 and payable on January 15, 2001 to shareholders of record as of December 15, 2000.

On March 2, 2001, PG&E Corporation refinanced its debt obligations with the $1 billion aggregate proceeds of two term loans under a common credit agreement with General Electric Capital Corporation and Lehman Commercial Paper, Inc. (see Note 3). In accordance with the credit agreement, a part of the proceeds, together with other PG&E Corporation cash, was used to pay $116 million to PG&E Corporation shareholders of record as of December 15, 2000, in satisfaction of the defaulted fourth quarter 2000 common stock dividend. PG&E Corporation is precluded by these loan agreements from declaring further dividends or repurchasing its common stock.

Utility

PG&E Corporation and a subsidiary of the Utility hold all of the Utility's outstanding common stock. The Utility has authorized 800 million shares of $5 par value common stock of which 321 million shares were issued as of December 31, 2000 and 1999.

In April 2000, a subsidiary of the Utility repurchased from PG&E Corporation 11.9 million shares of the Utility's common stock at a cost of $275 million. In December 1999, 7.6 million shares of the Utility's common stock, with an aggregate purchase price of $200 million, was purchased by the same subsidiary of the Utility. Total shares purchased were 19.5 million with an aggregate purchase price of $475 million. These repurchases are reflected as stock held by subsidiary in the Utility's Consolidated Balance Sheet. Earlier in 1999, the Utility repurchased and cancelled 20 million shares of its common stock from PG&E Corporation for an aggregate purchase price of $726 million to maintain its authorized capital structure.

The CPUC requires the Utility to maintain its CPUC-authorized capital structure, potentially limiting the amount of dividends the Utility may pay PG&E Corporation. On January 10, 2001, the Utility suspended the payment of its fourth quarter 2000 common stock dividend of $110 million, declared in October 2000, to PG&E Corporation. The Utility has suspended payment of its common and preferred dividends. Dividends on preferred stock are cumulative. Until cumulative dividends on preferred stock are paid, the Utility may not pay any dividends on common stock.

Note 7: Preferred Stock and Utility Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures

Shareholder Rights Plan of PG&E Corporation

On December 20, 2000, the Board of Directors of PG&E Corporation declared a distribution of preferred stock purchase rights (the Rights) at a rate of one Right for each outstanding share of PG&E Corporation's common stock, no par value. The Rights apply to outstanding shares of PG&E Corporation common stock held as of the close of business on January 2, 2001, and for each share of common stock issued by PG&E Corporation thereafter and before the "distribution date", as described below. Each Right entitles the registered holder, in certain circumstances, to purchase from PG&E Corporation one one-hundredth of a share (a Unit) of PG&E Corporation's Series A Preferred Stock, par value $100 per share, at an initially fixed purchase price of $95 per Unit, subject to adjustment. Effective December 22, 2000, the PG&E Corporation Dividend Reinvestment Plan was modified to note these changes.

The Rights are not exercisable until the distribution date and will expire December 22, 2010, unless redeemed earlier by the PG&E Corporation Board of Directors. The distribution date will occur upon the earlier of (1) 10 days following a public announcement that a person or group (other than the PG&E Corporation, any of its subsidiaries, or its employee benefit plans) has acquired or obtained the right to acquire beneficial ownership of 15% or more of the then-outstanding shares of PG&E Corporation common stock and (2) 10 business days (or later, as determined by the Board of Directors) following the commencement of a tender offer or exchange offer that would result in a person or group owning 15% or more of the then-outstanding shares of PG&E Corporation common stock. After the distribution date, certain triggering events will enable the holder of each Right (other than a potential acquiror) to purchase Units of Series A Preferred Stock having twice the market value of the initially fixed exercise price, i.e., at a 50% discount. Until a Right is exercised, the holder shall have no rights as a shareholder of PG&E Corporation, including, without limitation, the right to vote or to receive dividends.

A total of 5,000,000 shares of preferred stock will be reserved for issuance upon exercise of the Rights. The Units of preferred stock that may be acquired upon exercise of the Rights will be non-redeemable and subordinate to any other shares of preferred stock that may be issued by PG&E Corporation. Each Unit of preferred stock will have a minimum preferential quarterly dividend rate of $.01 per Unit but will, in any event, be entitled to a dividend equal to the per share dividend declared on the common stock. In the event of liquidation, the holder of a Unit will receive a preferred liquidation payment.

The Rights also have certain anti-takeover effects and will cause substantial dilution to a person or group that attempts to acquire the Utility on terms not approved by PG&E Corporation's Board of Directors unless the offer is conditioned on a substantial number of Rights being acquired. The Rights should not interfere with any approved merger or other business combination, as the Board of Directors, at its option, may redeem the Rights. Thus, the Rights are intended to encourage persons who may seek to acquire control of the PG&E Corporation to initiate such an acquisition through negotiations with the PG&E Corporation Board of Directors. However, the effect of the Rights may be to discourage a third party from making a partial tender offer or otherwise attempting to obtain a substantial equity position in the equity securities of, or seeking to obtain control of the PG&E Corporation. To the extent any potential acquirors are deterred by the Rights, the Rights may have the effect of preserving incumbent management in office.

Preferred Stock of Utility

The Utility has authorized 75 million shares of $25 par value preferred stock, which may be issued as redeemable or non-redeemable preferred stock. At December 31, 2000 and 1999, the Utility had issued and outstanding 5,784,825 shares of non-redeemable preferred stock.

At December 31, 2000 and 1999, the Utility had issued and outstanding 5,973,456 shares of redeemable preferred stock. The Utility's redeemable preferred stock is subject to redemption at the Utility's option, in whole or in part, if the Utility pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. Annual dividends and redemption prices per share at December 31, 2000, range from $1.09 to $1.76 and from $25.75 to $27.25, respectively.

The Utility's redeemable preferred stock with mandatory redemption provisions consists of 3 million shares of the 6.57% series and 2.5 million shares of the 6.30% series at December 31, 2000. The 6.57% series and 6.30% series may be redeemed at the Utility's option beginning in 2002 and 2004, respectively, at par value plus accumulated and unpaid dividends through the redemption date. These series of preferred stock are subject to mandatory redemption provisions entitling them to sinking funds providing for the retirement of stock outstanding.

At December 31, 2000, the redemption requirements for the Utility's redeemable preferred stock with mandatory redemption provisions are $4 million per year beginning 2002, and $3 million per year beginning 2004 for the series 6.57% and 6.30%, respectively.

Holders of the Utility's non-redeemable preferred stock 5%, 5.5%, and 6% series have rights to annual dividends per share ranging from $1.25 to $1.50.

Due to the California energy crisis, the Utility's Board of Directors decided not to declare the regular preferred stock dividends for the three-month periods ending January 31, 2001 (normally payable on February 15, 2001) and April 30, 2001 (normally payable May 15, 2001).

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and equal preference in dividend and liquidation rights. The dividend for the three-month period ending January 31, 2001 became a dividend in arrears and, as such, will accumulate from period to period. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series. Until cumulative dividends on its preferred stock are paid, the Utility may not pay any dividends on its common stock, nor may the Utility repurchase any of its common stock. Accumulated and unpaid preferred stock dividends for the three-month period ending January 31, 2001 amounted to $6 million.

Preferred Stock of the NEG

Preferred stock of the NEG consists of $57 million of preferred stock issued by a subsidiary of PG&E Gen. The preferred stock, with $100 par value, has a stated non-cumulative quarterly dividend of $3.35 per share, and is redeemable when there is an excess of available cash. There were 549,594 shares of preferred stock outstanding at December 31, 2000 and 1999.

Utility Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures

The Utility, through its wholly owned subsidiary, PG&E Capital I (Trust), has outstanding 12 million shares of 7.9% 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 issuance of the common stock securities to purchase subordinated debentures issued by the Utility with a face value of $309 million, due 2025. These subordinated debentures are the only assets of the Trust. Proceeds from the sale of the subordinated debentures were used to redeem and repurchase higher-cost preferred stock.

The Utility's guarantee of the QUIPS, considered together with the other obligations of the Utility with respect to the QUIPS, constitutes a full and unconditional guarantee by the Utility of the Trust's contractual obligations under the QUIPS issued by the Trust. The subordinated debentures may be redeemed at the Utility's option beginning in 2000 at par value plus accrued interest through the redemption date. The proceeds of any redemption will be used by the Trust to redeem QUIPS in accordance with their terms.

Upon liquidation or dissolution of the Utility, holders of these 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 Utility's 7.90% Deferrable Interest Subordinated Debentures, Series A, due 2025, until further notice in accordance with the indenture. The corresponding quarterly payments on the 7.90% Cumulative Quarterly Income Preferred Securities, Series A, issued by PG&E Capital I due on April 2, 2001, have been similarly deferred. Distributions can be deferred up to a period of five years under the terms of the indenture. Investors will accumulate interest on the unpaid distributions at the rate of 7.90%.

Note 8: Long-Term Debt

For further information and discussion on credit ratings, downgrades, and events of default, see Note 3, Subsequent Events of the Notes to the Consolidated Financial Statements.

Long-term debt at December 31, 2000 and 1999 consisted of the following:

(in millions)	Balance at December 31, 2000	1999
Utility long-term debt		
First and refunding mortgage bonds		
Maturity — Interest rates		
2001-2003 — 6.25% to 8.75%	$ 706	$ 816
2004-2008 — 5.875% to 6.25%	600	600
2009-2021 — 6.35% to 8.08%	160	160
2022-2026 — 5.85% to 8.80%	2,004	2,004
Principal amounts outstanding	3,470	3,580
Unamortized discount net of premium	(28)	(29)
Total mortgage bonds	3,442	3,551
Senior notes, 7.375%, due 2005	680	—
Pollution control loan agreements, variable rates, due 2016-2026	1,267	1,348
Unsecured medium-term notes, 5.81% to 8.45%, due 2001-2014	305	418
Other Utility long-term debt	22	25
Total Utility long-term debt	5,716	5,342
Long-term debt, classified as current	2,374	465
Total Utility long-term debt, net of current portion	$3,342	$4,877
National Energy Group long-term debt		
First mortgage notes, 10.02% to 11.50%, due 2001-2009	$ —	$ 333
Senior notes, 7.10%, due 2005	250	248
Medium term notes		
Maturity — Interest Rates		
2001-2003 — 6.61% to 6.96%	39	70
2001-2009 — 7.35% to 9.25%	—	229
Senior debentures		
Maturity — Interest Rates		
2010 — 10.00%	159	
2025 — 7.80%	150	150
Stock margin loan, LIBOR + 0.40% due 2003	—	8
Premium on long-term debt, due 2000-2009	—	63
Amounts outstanding under credit facilities (See Note 10)	661	649
Capital lease obligations, 8.80%, due 2015	15	16
Term loans, various, 2009-2011	107	116
Mortgage loan payable, 30 day commercial paper rate plus 6.07%, due 2010	8	9
Other long-term debt	22	7
Total National Energy Group long-term debt	1,411	1,898
Current portion of long-term debt	17	93
Total National Energy Group long-term debt, net of current portion	$1,394	$1,805
Total long-term debt	$4,736	$6,682

Utility

The Utility's revolving credit agreement balance of $614 million, as of December 31, 2000, went into default subsequent to year-end and remains as such. It has been reclassified to short-term borrowings and is discussed in Note 10 of the Notes to the Consolidated Financial Statements.

For further discussion of default status, see Note 3 of the Notes to the Consolidated Financial Statements. For debt obligations, the priority and subordination is as follows: senior secured debt (first and refunding mortgage bonds), and then all other unsecured debt, including notes and bank loans.

First and Refunding Mortgage Bonds

First and refunding mortgage bonds are issued in series and bear annual interest rates ranging from 5.85% to 8.80%. All real properties and substantially all personal properties of the Utility are subject to the lien of the mortgage, and the Utility is required to make semi-annual sinking fund payments for the retirement of the bonds. Additional bonds may be issued subject to CPUC approval, up to a maximum total amount outstanding of $10 billion, assuming compliance with indenture covenants for earnings coverage and available property balances as security.

The Utility redeemed or repurchased $110 million and $281 million of the bonds in 2000 and 1999, respectively, with interest rates ranging from 6.25% to 8.80%.

Included in the total of outstanding bonds at December 31, 2000 and 1999 are $345 million of bonds held in trust for the California Pollution Control Financing Authority (CPCFA) with interest rates ranging from 5.85% to 6.625% and maturity dates ranging from 2009 to 2023. In addition to these bonds, the Utility holds long-term pollution control loan agreements with the CPCFA as described below.

Senior Notes

In November 2000, the Utility issued $680 million of five-year senior notes with an interest rate of 7.375%. The Utility used the net proceeds to repay short-term indebtedness incurred to finance scheduled payments due to the PX for August power purchases from the PX and for other general corporate purposes.

The interest rate on the senior notes is subject to adjustment until May 1, 2002. As such, in the event of a downgrade in the rating below A3 by Moody's or A- by S&P prior to May 1, 2002, the interest rate on the notes will be readjusted accordingly.

As a result of the credit rating downgrades by S&P and Moody's, as described in Note 3 of the Notes to the Consolidated Financial Statements, there will be an interest rate adjustment of 1.75% on the $680 million senior notes. The revised rate will be increased to 9.125% from 7.375% on May 1, 2001, the next interest payment date. An event of default under the senior notes occured subsequent to December 31, 2000. Under the default provisions, the trustee or holders of not less than 25% of the outstanding notes may declare the amounts outstanding due and payable by notice to the Utility. Accordingly, the amount outstanding, as of December 31, 2000, has been classified as current in the accompanying financial statements.

Pollution Control Loan Agreements

Pollution control loan agreements from the CPCFA totaled $1,267 million and $1,348 million at December 31, 2000 and 1999, respectively. Interest rates on the loans vary with average annual interest rates. For 2000 the interest rates ranged from 2.10% to 4.81%. These loans are subject to redemption by the holder under certain circumstances. These loans are secured primarily by irrevocable letters of credit (LOC), which mature in 2001 through 2003. In December 2000, two of these loans totaling $81 million, were reacquired by the Utility. On March 1, 2001, a $200 million loan was converted to a fixed interest rate of 5.35%. The Company is in default under the credit provider's reimbursement agreements due to nonpayment of $100 million of commercial paper. Due to this default, the credit providers can declare the $1,267 million of principal and interest immediately due and payable. Through March 29, 2001, no banks had accelerated the debt. Declaration of bankruptcy is also an event of default under certain of the pollution control loan agreements. Under certain of the default provisions, the trustee or holders of the pollution control bonds may declare the amount outstanding due and payable. Accordingly, amounts outstanding at December 31, 2000 under the pollution control agreements have been classified as current in the accompanying financial statements.

Medium-Term Notes

The Utility has outstanding $305 million of medium-term notes due 2001 to 2014 with interest rates ranging from 5.81% to 8.45%. An event of default under the medium-term notes occured subsequent to December 31, 2000. Under the default provisions, the trustee or holders of not less than 25% of the outstanding notes may declare amounts outstanding due and payable by notice to the Utility. Accordingly, the amount outstanding at December 31, 2000 has been classified as current in the accompanying financial statements.

National Energy Group

Long-term debt of the NEG consists of first mortgage notes and other secured and unsecured obligations.

The first mortgage notes were comprised of three series due annually through 2009, and were secured by mortgages and security interests in the natural gas transmission and natural gas processing facilities and other real and personal property of PG&E GTT. The mortgage indenture required semi-annual payments with one-half of each interest payment and one-fourth of each annual principal payment escrowed quarterly in advance. The mortgage indenture also contained covenants that restricted the ability of PG&E GTT to incur additional indebtedness and precluded cash distributions if certain cash flow coverage were not met. In January 2000, PG&E GTT obtained an amendment that provided PG&E GTT the ability to redeem in whole or in part, its mortgage notes, including the premium set forth in the mortgage note indenture, anytime after January 1, 2000. These notes were assumed by the buyer of PG&E GTT as of December 31, 2000 (see Note 5).

In May 1995, PG&E GTN issued $250 million of 10-year senior unsecured notes and $150 million of senior unsecured debentures. Other long-term debt consists of non-recourse project financing associated with unregulated PG&E Generating facilities, premiums, and other loans.

Other long-term debt consists of project financing associated with unregulated generation facilities, premiums, and other loans.

Repayment Schedule

At December 31, 2000, PG&E Corporation's combined aggregate amounts of capital spending, maturing long-term debt, and sinking fund requirements are reflected in the table below:

Expected maturity date (dollars in millions)	2001	2002	2003	2004	2005	Thereafter	Total
Utility:							
Long-term debt							
Variable rate obligations	$120	$697	$ 350	$ 40	$ 40	$ 20	$1,267
Fixed rate obligations	$274	$379	$ 354	$392	$1,012	$2,038	$4,449
Average interest rate	8.0%	7.8%	6.3%	6.4%	6.9%	7.3%	7.2%
Rate reductions bonds	$290	$290	$ 290	$290	$ 290	$ 580	$2,030
Average interest rate	6.2%	6.3%	6.4%	6.4%	6.4%	6.4%	6.4%
National Energy Group							
Long-term debt							
Variable rate obligations	$ 16	$ 94	$ 584	$ 9	$ 9	$ 80	$ 792
Fixed rate obligations	$ 1	$ 34	$ 7	$ 1	$ 251	$ 325	$ 619
Average interest rate	9.4%	6.9%	7.0%	9.4%	7.1%	8.9%	8.1%

Note 9: Rate Reduction Bonds

In December 1997, PG&E Funding LLC (SPE), a special-purpose entity wholly owned by the Utility, issued $2.9 billion of rate reduction bonds to the California Infrastructure and Economic Development Bank Special Purpose Trust PG&E-1 (Trust), a special-purpose entity. The terms of the bonds generally mirror the terms of the pass-through certificates issued by the Trust. The proceeds of the rate reduction bonds were used by the SPE to purchase from the Utility the right, known as "transition property," to be paid a specified amount from a non-bypassable tariff levied on residential and small commercial customers which was authorized by the CPUC pursuant to state legislation.

On January 4, 2001, S&P lowered the short-term credit rating of the SPE to A-3, and on January 5, 2001, Moody's lowered the short-term credit rating of the SPE to P-3. As a result, on January 8, 2001, remittances for charges paid by ratepayers for the pass-through certificates issued by the Trust were required to be made on a daily basis, as opposed to once a month, as had previously been required.

The rate reduction bonds have maturities ranging from 6 months to 7 years, and bear interest at rates ranging from 6.16% to 6.48%. The bonds are secured solely by the transition property and there is no recourse to the Utility or PG&E Corporation.

At December 31, 2000, $2,030 million of rate reduction bonds were outstanding. The combined expected principal payments on the rate reduction bonds for the years 2001 through 2005 are $290 million for each year.

While the SPE is consolidated with the Utility for purposes of these financial statements, the SPE is legally separate from the Utility. The assets of the SPE are not available to creditors of the Utility or PG&E Corporation, and the transition property is not legally an asset of the Utility or PG&E Corporation.

Note 10: Credit Facilities and Short-term Borrowings

See Note 3 for discussion of default status regarding credit facilities and short-term borrowings.

At December 31, 2000 and 1999, PG&E Corporation had borrowed $5,191 million and $2,148 million, respectively, through short-term borrowings and various credit facilities. At December 31, 2000 and 1999, $661 million and $649 million, respectively, of these borrowings were outstanding balances related to NEG credit facilities, which are classified as long-term debt because the NEG has the ability and intent to finance the amounts outstanding on a long-term basis. The weighted average interest rate on the short-term borrowings as of December 31, 2000 and 1999, was 7.4% and 5.4%, respectively.

The following table summarizes PG&E Corporation's lines of credit (see Note 8 of the Notes to the Consolidated Financial Statements) as of December 31, 2000 and 1999:

	Amount of Credit December 31, 2000		Amount of Credit December 31, 1999	
Lines of Credit (in millions)	**Revolving Credit Limits**	**Outstanding Balance**	**Revolving Credit Limits**	**Outstanding Balance**
PG&E Corporation:				
5-year Revolving Credit	$ 500	$ 185	$ 500	$ —
364-day Revolving Credit	436	—	500	—
Utility:				
5-year Revolving Credit	1,000	614	1,000	—
364-day Revolving Credit	850	—	—	—
National Energy Group:				
Revolving Credit	1,350	661	1,600	649
Total Lines of Credit	$4,136	$1,460	$3,600	$ 649
Short-Term Borrowings				
PG&E Corporation:				
Commercial Paper		746		450
Extendible Commercial Notes		—		76
Utility:				
Commercial Paper		1,225		449
Floating Rate Notes		1,240		—
National Energy Group:				
Commercial Paper		520		524
Total Commercial Paper and Short-Term Notes		$3,731		$1,499
Sub-total		$5,191		$2,148
Less: Classified as long-term debt				
NEG Revolving credit		(661)		(649)
Total Short Term Borrowings		$4,530		$1,499

PG&E Corporation

PG&E Corporation had $436 million and $500 million revolving credit facilities, which were scheduled to expire in November 2001 and August 2002, respectively. These credit facilities were used to support PG&E Corporation's commercial paper program and other liquidity requirements. As a result of the credit downgrades on January 16 and 17, 2001 (see Note 3), PG&E Corporation began to default under these credit facilities and the banks refused any additional borrowing requests and terminated their commitments under the facilities. As of December 31, 2000, $185 million had been drawn from the $500 million facility. In March 2001, PG&E Corporation secured $1 billion in aggregate proceeds from two term loans under a common credit agreement with General Electric Capital Corporation and Lehman Commercial Paper Inc. to refinance defaulted commercial paper and revolving credit agreements. In connection with PG&E Corporation's refinancing, the revolving credit facilities were cancelled. The total amount of commercial paper outstanding at December 31, 2000, backed by the two facilities, was $746 million. The total amount of commercial paper outstanding at December 31, 1999, backed by the $500 million facility was $450 million.

Utility

The Utility had a $1 billion revolving credit facility which was scheduled to expire in December 2002. In October 2000, the Utility obtained an additional $1.0 billion credit facility (which was subsequently reduced to $850 million in December 2000) which expires in December 2001. These facilities were used to support the Utility's commercial paper program and other liquidity requirements. As of December 31, 2000, $614 million had been drawn from the $1 billion facility. Due to a subsequent credit rating downgrade, the banks refused any additional borrowing requests and terminated their outstanding commitments under the Utility's two credit facilities (see Note 3). The total amount of commercial paper outstanding at December 31, 2000 backed by the two facilities was $1,225 million. The weighted average interest rate on the Utility's short-term borrowings as of December 31, 2000 and 1999 was 7.5% and 5.3%, respectively. The total amount outstanding at December 31, 1999 backed by the $1 billion facility was $449 million in commercial paper.

In addition, the Utility issued a total of $1,240 million in 364-day floating rate notes in November 2000. These notes mature on November 30, 2001, with interest payable quarterly. The nonpayment of the Utility's outstanding commercial paper is an event of default under the floating rate notes, entitling the floating rate note trustees to accelerate the repayment of these notes. (See Note 3)

National Energy Group

The NEG maintains $1,350 million in five revolving credit facilities, which support commercial paper and Eurodollar borrowing arrangements. At December 31, 2000 and 1999, the NEG had total outstanding balances related to such borrowings of $1,181 million and $1,173 million, respectively. In addition, certain letters of credit held by the NEG reduce the available outstanding facility commitments. At December 31, 2000, approximately $36 million in letters of credit were outstanding. Since the NEG has the ability and intent to refinance certain borrowings, $661 million and $649 million of such borrowings were classified as long-term debt as of December 31, 2000 and 1999, respectively (see Note 8).

Certain credit arrangements contain, among other restrictions, customary affirmative covenants, representations, and warranties and are cross-defaulted to the NEG's other obligations. The credit agreements also contain certain negative covenants including restrictions on the following: consolidations, mergers, sales of assets and investments; certain liens on the NEG's property or assets; incurrence of indebtedness; entering into agreements limiting the right of any subsidiary of the NEG to make payments to its shareholders; and certain transactions with affiliates. Certain credit agreements also require that the NEG maintain a minimum ratio of cash flow available for fixed charges and a maximum ratio of funded indebtedness to total capitalization. The NEG was in compliance with all convenants at December 31, 2000.

Note 11: Nuclear Decommissioning

Decommissioning of the Utility's nuclear power facilities is scheduled to begin for ratemaking purposes in 2015 with scheduled completion in 2034. Nuclear decommissioning means to safely remove nuclear facilities from service and reduce residual radioactivity to a level that permits termination of the Nuclear Regulatory Commission license and release of the property for unrestricted use.

The estimated total obligation for nuclear decommissioning costs, based on a 1997 site study, is $1.7 billion in 2000 dollars (or $5.1 billion in future dollars). This estimate assumes after-tax earnings on the tax-qualified and non-tax qualified decommissioning funds of 6.34% and 5.39%, respectively, as well as a future annual escalation rate of 5.5% for decommissioning costs. The decommissioning cost estimates are based on the plant location and cost characteristics for the Utility's nuclear plants. Actual decommissioning costs are expected to vary from this estimate because of changes in assumed dates of decommissioning, regulatory requirements, technology, and costs of labor, materials, and equipment. The estimated total obligation is being recognized proportionately over the license term of each facility.

For the year ended December 31, 2000, 1999, and 1998 nuclear decommissioning costs recovered in rates were $25 million, $26 million, and $33 million, respectively. The CPUC has established a Nuclear Decommissioning Cost Triennial Proceeding to review, every three years, updated decommissioning cost estimates and to establish the annual trust contribution, absent General Rate Cases.

At December 31, 2000, the total nuclear decommissioning obligation accrued was $1.3 billion and is included in the balance sheet classification of accumulated depreciation and decommissioning. Decommissioning costs recovered in rates are placed in external trust funds. These funds along with accumulated earnings will be used exclusively for decommissioning and cannot be released from the trust funds until authorized by CPUC.

The following table provides a summary of fair value, based on quoted market prices, of these nuclear decommissioning funds:

	For the year ended December 31,		
(in millions)	**Maturity Date**	**2000**	**1999**
U.S. government and agency issues	2001-2030	$ 409	$ 380
Equity securities		239	223
Municipal bonds and other	2001-2034	252	201
Gross unrealized holding gains		447	474
Gross unrealized holding losses		(19)	(14)
Fair value		$1,328	$1,264

The proceeds received from sales of securities were $1.4 billion, $1.7 billion, and $1.4 billion in 2000, 1999, and 1998, respectively. The gross realized gains on sales of securities held as available-for-sale were $74 million, $59 million, and $52 million in 2000, 1999, and 1998, respectively. The gross realized losses on sales of securities held as available-for-sale were $64 million, $60 million, and $39 million in 2000, 1999, and 1998, respectively. The cost of debt and equity securities sold is determined by specific identification.

Under the Nuclear Waste Policy Act of 1982, the U.S. Department of Energy (DOE) is responsible for the permanent storage and disposal of spent nuclear fuel. The Utility has signed a contract with the DOE to provide for the disposal of spent nuclear fuel and high-level radioactive waste from the Utility's nuclear power facilities. The DOE's current estimate for an available site to begin accepting physical possession of the spent nuclear fuel is 2010. At the projected level of operation for Diablo Canyon, the Utility's facilities are sufficient to store on-site all spent fuel produced through approximately 2006. It is likely that an interim or permanent DOE storage facility will not be available for Diablo Canyon's spent fuel by 2006. The Utility is examining options for providing additional temporary spent fuel storage at Diablo Canyon or other facilities, pending disposal or storage at a DOE facility.

Note 12: Employee Benefit Plans

Several of PG&E Corporation's subsidiaries provide noncontributory defined benefit pension plans for their employees and retirees. In addition, these subsidiaries provide contributory defined benefit medical plans for certain retired employees and their eligible dependents and noncontributory defined benefit life insurance plans for certain retired employees (referred to collectively as other benefits). For both pension and other benefit plans, the Utility's plan represents substantially all of the plan assets and the benefit obligation. Therefore, all descriptions and assumptions are based on the Utility's plan. The schedules below aggregate all of PG&E Corporation's plans.

The following schedule reconciles the plans' funded status (the difference between fair value of plan assets and the benefit obligation) to the prepaid or accrued benefit cost recorded on the consolidated balance sheet:

	Pension Benefits		Other Benefits	
(in millions)	2000	1999	2000	1999
Change in benefit obligation				
Benefit obligation at January 1	$(4,807)	$(4,977)	$ (970)	$ (949)
Service cost for benefits earned	(119)	(121)	(16)	(19)
Interest cost	(386)	(347)	(72)	(69)
Plan amendments	(347)	—	—	(4)
Actuarial gain (loss)	(33)	372	(11)	(19)
Divestiture (acquisition)	7	—	17	—
Participants paid benefits	—	—	(14)	(14)
Benefits and expenses paid	280	266	57	104
Benefit obligation at December 31	$(5,405)	$(4,807)	$(1,009)	$ (970)
Change in plan assets				
Fair value of plan assets at January 1	$ 8,153	$ 7,104	$ 1,091	$ 951
Actual return on plan assets	(66)	1,331	(33)	240
Company contributions	3	4	2	15
Plan participant contribution	—	—	14	14
Divestiture	(2)	—	—	—
Benefits and expenses paid	(280)	(286)	(62)	(103)
Fair value of plan assets at December 31	$ 7,808	$ 8,153	$ 1,012	$1,117
Funded Status				
Plan assets in excess of benefit obligation	$ 2,403	$ 3,346	$ 3	$ 121
Unrecognized prior service cost	399	93	15	17
Unrecognized net (loss) gain	(2,001)	(2,963)	(348)	(520)
Unrecognized net transition obligation	50	65	314	339
Prepaid (accrued) benefit cost	$ 851	$ 541	$ (16)	$ (43)

The Utility's share of the plan's assets in excess of the benefit obligation for pensions in 2000 and 1999 was $2,407 million and $3,344 million, respectively. The Utility's share of the prepaid (accrued) benefit cost for the pensions in 2000 and 1999 was $864 million and $556 million, respectively.

The plan assets of the Utility exceeded its share of the benefit obligation for other benefits by $3 million and $167 million in 2000 and 1999, respectively. The Utility's share of the accrued benefit liability for other benefits in 2000 and 1999 was $15 million and $22 million, respectively.

Unrecognized prior service costs and the net gains are amortized on a straight-line basis over the average remaining service period of active plan participants. The transition obligations for pension benefits and other benefits are being amortized over 17.5 years from 1987.

Net benefit income (cost) was as follows:

	Pension Benefits December 31,			Other Benefits December 31,		
(in millions)	2000	1999	1998	2000	1999	1998
Service cost for benefits earned	$(119)	$(121)	$(108)	$(17)	$(19)	$(19)
Interest cost	(386)	(347)	(333)	(72)	(69)	(64)
Expected return on assets	679	634	567	91	83	73
Amortized prior service and transition cost	(55)	(25)	(26)	(28)	(27)	(28)
Actuarial gain recognized	183	111	114	32	20	22
Settlement gain	6	—	—	18	—	—
Benefit income (cost)	$ 308	$ 252	$ 214	$ 24	$(12)	$(16)

The Utility's share of the net benefit income for pensions in 2000, 1999, and 1998 was $302 million, $253 million, and $215 million, respectively.

The Utility's share of the net benefit cost for other benefits in 2000, 1999, and 1998 was $7 million, $9 million, and $12 million, respectively.

Net benefit income (cost) is calculated using expected return on plan assets of 8.5%. The difference between actual and expected return on plan assets is included in net amortization and deferral and is considered in the determination of future net benefit income (cost). In 1999 and 1998, actual return on plan assets exceeded expected return, while actual return on plan assets was below expected in 2000.

In conformity with SFAS No. 71, regulatory adjustments have been recorded in the income statement and balance sheet of the Utility, which reflect the difference between Utility pension income determined for accounting purposes and Utility pension income determined for ratemaking, which is based on a funding approach.

The CPUC has authorized the Utility to recover the costs associated with its other benefit plans for 1993 and beyond. Recovery is based on the lesser of the annual accounting costs or the annual contributions on a tax-deductible basis to the appropriate trusts. The amount of post-employment benefit costs included in the regulatory assets as of December 31, 2000 is $34 million, and is expected to be recovered through rates.

The following actuarial assumptions were used in determining the plans' funded status and net benefit income (cost). Year-end assumptions are used to compute funded status, while prior year-end assumptions are used to compute net benefit income (cost).

	Pension Benefits December 31,			Other Benefits December 31,		
	2000	1999	1998	2000	1999	1998
Discount rate	7.5%	7.5%	7.0%	7.5%	7.5%	7.0%
Average rate of future compensation increases	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Expected long-term rate of return on plan assets	8.5%	8.5%	9.0%	8.5%	9.0%	9.0%

The assumed health care cost trend rate for 2001 is approximately 8.0%, grading down to an ultimate rate in 2005 and beyond of approximately 6.0%. The assumed health care cost trend rate can have a significant effect on the amounts reported for health care plans. A one-percentage point change would have the following effects:

(in millions)	1-Percentage Point Increase	1-Percentage Point Decrease
Effect on total service and interest cost components	$ 5	$ (4)
Effect on postretirement benefit obligation	$45	$(42)

PG&E Corporation and its subsidiaries also sponsor defined contribution pension plans. These plans are intended to qualify under Sections 401(a), 409(a), and 501(a) of the Internal Revenue Code. Employer contribution expense reflected in the accompanying PG&E Corporation Consolidated Statement of Income totaled $60 million, $53 million, and $49 million, for the years ended December 31, 2000, 1999, and 1998, respectively.

Long-Term Incentive Program

PG&E Corporation maintains a Long-Term Incentive Program (Program) that provides for grants of stock options to eligible participants with or without associated stock appreciation rights and dividend equivalents. As of December 31, 2000, 30,992,530 shares of PG&E Corporation common stock had been authorized for award under the Program, with 6,649,736 shares still available under the Program. Options granted in 2000, 1999, and 1998 had weighted average fair value at date of grant of approximately $3.26, $4.19, and $3.81 per share, respectively, using the Black-Scholes valuation method. In addition, PG&E Corporation granted stock options covering 26,852 shares on January 2, 2001 at an exercise price of $19.56, and 5,498,500 shares on January 5, 2001 at an exercise price of $12.63, the then-current market price. Significant assumptions used in the Black-Scholes valuation method for shares granted in 2000, 1999, and 1998 were: expected stock price volatility of 20.19%, 16.79%, and 17.60%, respectively; expected dividend yield of 5.18%, 3.77%, and 4.47%, respectively; risk-free interest rate of 6.10%, 4.69%, and 6.03%, respectively; and an expected 10-year life for all periods.

Outstanding stock options become exercisable on a cumulative basis at one-third each year commencing two years from the date of grant and expire ten years and one day after the date of grant. Shares outstanding at December 31, 2000 had option prices ranging from $16.75 to $34.25 and a weighted-average remaining contractual life of 9.2 years. As permitted under SFAS No. 123, "Accounting for Stock-Based Compensation," PG&E Corporation applies Accounting Principles Board Opinion No. 25 "Accounting for Stock Issued to Employees" in accounting for the Program. As the exercise prices of all stock options is equal to the respective fair market value at the date of grant, PG&E Corporation does not recognize any compensation expense related to the Program using the intrinsic value-based method. Had compensation expense been recognized using the fair value-based method under SFAS No. 123, PG&E Corporation's pro forma consolidated earnings (loss) per share would have been as follows:

	2000	1999	1998
Net earnings (loss):			
As reported	$(3,364)	$ (73)	$ 719
Pro-forma	(3,374)	(79)	717
Basic and diluted earnings (loss) per share:			
As reported	(9.29)	(0.20)	1.88
Pro-forma	(9.32)	(0.21)	1.88

The following table summarizes the Program's activity as of and for the years ended December 31:

	2000		1999		1998	
(shares in million)	**Shares**	**Weighted Average Option Price**	**Shares**	**Weighted Average Option Price**	**Shares**	**Weighted Average Option Price**
Outstanding—beginning of year	16.4	$29.42	11.1	$28.35	6.2	$26.21
Granted during year	10.2	$20.03	7.0	$30.94	6.4	$30.53
Exercised during year	(1.2)	$23.52	(0.5)	$25.86	(0.7)	$29.63
Cancellations during year	(1.1)	$26.57	(1.2)	$29.82	(0.8)	$28.16
Outstanding—end of year	24.3	$25.90	16.4	$29.43	11.1	$28.35
Exercisable—end of year	6.3	$27.73	3.0	$29.08	2.4	$29.06

The following summarizes information for options outstanding and exercisable at December 31, 2000. Of the outstanding options at December 31, 2000, 11,271,169 shares had exercise prices ranging from $16.75 to $24.38 with a weighted average remaining contractual life of 9.7 years, of which 2,143,943 shares were exercisable at a weighted average exercise price of $21.90, while 13,071,625 shares had option prices ranging from $24.50 to $34.25, with a weighted average remaining contractual life of 8.8 years, of which 4,155,548 shares were exercisable at a weighted average exercise price of $30.73.

Performance Unit Plan

PG&E Corporation grants performance units to certain officers of PG&E Corporation and its affiliates. The performance units vest one-third in each of the three years following the year of grant. Each time a cash dividend is declared on PG&E Corporation common stock, an amount equal to the cash dividend per share multiplied by the number of outstanding but unearned units held by the recipient of a performance unit will be accrued on behalf of the recipient. As soon as practicable following the end of each year, recipients will receive a cash payment of the dividends accrued for the year, modified by performance for that year as measured against the applicable performance target. The number of performance units granted and the amounts of compensation expense recognized in connection with the issuance of performance units during the years ended December 31, 2000, 1999, and 1998 was not material.

Note 13: Income Taxes

The significant components of income tax (benefit) expense for continuing operations were:

(in millions)	PG&E Corporation Year Ended December 31, 2000	1999	1998	Utility Year Ended December 31, 2000	1999	1998
Current	$(1,261)	$1,002	$718	$(1,224)	$1,133	$ 886
Deferred	(728)	(702)	(51)	(891)	(433)	(201)
Tax credits, net	(39)	(52)	(56)	(39)	(52)	(56)
Income tax (benefit) expense	$(2,028)	$ 248	$611	$(2,154)	$ 648	$ 629

In 2000, the income tax expense of PG&E Corporation was allocated to continuing operations ($2,028 million benefit) and discontinued operations ($36 million tax benefit).

The significant components of net deferred income tax liabilities were:

(in millions)	PG&E Corporation Year ended December 31, 2000	1999	Utility Year ended December 31, 2000	1999
Deferred income tax assets:				
Customer advances for construction	$ 176	$ 109	$ 176	$ 109
Unamortized investment tax credits	114	118	114	118
Provision for injuries and damages	203	185	203	185
Tax benefit of loss carryforward	70	—	100	—
Deferred contract costs	124	182	—	—
Other	322	544	233	442
Total deferred income tax assets	$1,009	$1,138	$ 826	$ 854
Deferred income tax liabilities:				
Regulatory balancing accounts	17	(47)	17	(47)
Plant in service	2,185	2,827	1,719	2,428
Income tax regulatory asset	68	297	65	287
Other	564	1,075	126	577
Total deferred income tax liabilities	2,834	4,152	1,927	3,245
Total net deferred income taxes	$1,825	$3,014	$1,101	$2,391
Classification of net deferred income taxes:				
Included in current liabilities (assets)	$ 169	$ (133)	$ 172	$ (119)
Included in noncurrent liabilities	1,656	3,147	929	2,510
Total net deferred income taxes	$1,825	$3,014	$1,101	$2,391

The differences between income taxes and amounts determined by applying the federal statutory rate to income before income tax expense for continuing operations were:

	PG&E Corporation Year ended December 31, 2000	1999	1998	Utility Year ended December 31, 2000	1999	1998
Federal statutory income tax rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) in income tax rate resulting from:						
State income tax (net of federal benefit)	4.4	10.1	3.2	4.3	6.2	6.6
Effect of regulatory treatment of depreciation differences	(2.1)	51.7	9.7	(2.0)	9.4	9.8
Tax credits—net	0.7	(19.9)	(4.0)	0.7	(3.6)	(4.1)
Effect of foreign earnings at different tax rates	0.1	(1.3)	0.6	—	—	—
Stock sale differences	(1.4)	(6.8)	—	—	—	—
Stock sale valuation allowance	1.5	30.2	—	—	—	—
Other—net	(0.3)	(4.0)	(0.3)	0.2	(1.9)	(1.0)
Effective tax rate	37.9%	95.0%	44.2%	38.2%	45.1%	46.3%

As a result of the Utility's purchased power costs which were not recovered in rates charged to the customers, PG&E Corporation and the Utility incurred a Net Operating Loss (NOL) for 2000. The NOL was carried back to prior years in accordance with federal income tax law resulting in a refund of approximately $1.2 billion. For California income tax purposes 55% of the California NOL may only be carried forward. The amount of this NOL carryforward is $1.2 billion for PG&E Corporation of which $1.7 billion is attributable to the Utility. The Company has recognized the benefits of its NOLs in the consolidated financial statements.

During 1999, PG&E Corporation generated a capital loss carryforward from the sale of stock of approximately $225 million. The capital loss carryforward expires in 2005. A valuation allowance of approximately $75 million was recorded in 1999 reflecting the estimated net realizable value of this capital loss carryforward. PG&E Corporation, based upon its forecasted net capital gains, believed that it was more likely than not that it would not be able to fully utilize the full capital loss carryforward.

Note 14: Commitments

Surety Bonds

Utility

PG&E Corporation has arranged on behalf of the Utility $456 million in surety bonds to secure future workers' compensation liabilities. Effective in March, 2001, three of the five insurers of surety bonds have cancelled their coverage. The aggregate amount of this cancellation is approximately $285 million. This cancellation relieves the insurers only for claims arising from incidents occurring after the date of cancellation. They will still be responsible indefinitely for all future claims arising from incidents occurring prior to the date of cancellation. This cancellation has not impacted the Utility's self-insurance program under California law or its ability to meet its current plan obligations.

Restructuring Trust Guarantees

Utility

A tax-exempt restructuring trust was established to oversee the development of the operating framework for the competitive generation market in California. The CPUC has authorized California utilities to guarantee bank loans of up to $85 million to be used by the trust for this purpose. Under the CPUC authorization, the Utility's remaining guarantee is for up to a maximum of $38 million of the loan. Although the remaining bank loan was repaid, the guarantee remains in place until the earlier of voluntary termination by the trust of the commitments, or the trust obtaining proceeds from permanent financing or recovery in rates, or the expiration date of bank loan commitments in December 2001.

Tolling Agreements

National Energy Group

In 2000 and 1999, the NEG, through PG&E ET, entered into tolling agreements with several counterparties giving the NEG the right to sell electricity generated by facilities owned and operated by other parties which are under construction until June 2003. Under the tolling agreements, the NEG, at its discretion, supplies the fuel to the power plants, then sells the plant's output in the competitive market. Committed payments are reduced if the plant facilities do not achieve agreed-upon levels of performance criteria. At December 31, 2000, the annual estimated committed payments under such contracts ranged from approximately $21 million to $304 million, resulting in total committed payments over the next 28 years of approximately $6.2 billion commencing at the completion of construction. Estimated amounts payable in future years are as follows:

(in millions)	
2001	$ 21
2002	98
2003	220
2004	280
2005	285
Thereafter	5,300
Total	$6,204

During 2000, the NEG paid total committed payments of approximately $12 million under tolling agreements.

Power Purchase Contracts

Utility

The Utility is required to purchase electric energy and capacity provided by independent power producers that are QFs under the Public Utilities Regulatory Policies Act of 1978 (PURPA.) The CPUC required the Utility to enter into a series of QF long-term power purchase contracts and approved the applicable terms, conditions, price options, and eligibility requirements.

Under these contracts, the Utility is required to make payments only when energy is supplied or when capacity commitments are met. Costs associated with these contracts are eligible for recovery by the Utility as transition costs through the collection of the non-bypassable CTC. The Utility's contracts with these power producers expire on various dates through 2028. Deliveries from these power producers account for approximately 23% of the Utility's 2000 electric energy requirements, and no single contract accounted for more than five percent of the Utility's energy needs.

Prior to 2000, the Utility has negotiated with several QFs for early termination of their power purchase contracts. At December 31, 2000, the total discounted future payments due under the renegotiated contracts was approximately $145 million.

Approximately half of the Utility's suppliers under long-term QF contracts have currently elected to receive PX-based prices for energy in addition to contractual capacity payments. However, pursuant to a CPUC order issued on February 22, 2001, PX-based-priced QFs reverted back to transition formula prices on January 19, 2001. Since the end of January 2001, the Utility has been partially paying amounts due QFs. On March 27, 2001, the CPUC issued a decision requiring the Utility and the other California investor-owned utilities to pay QFs fully for energy deliveries made on and after the date of the decision, within 15 days of the end of the QFs' billing period. The decision permits QFs to establish a 15-day billing period as compared to the current monthly billing period. The decision also adopts a revised pricing formula relating to the California border price of gas applicable to energy payments to all QFs, including those that do not use natural gas as a fuel. Based on the Utility's preliminary review of the decision, the revised pricing formula would reduce the Utility's 2001 average QF energy and capacity payments from approximately 12.7 cents per kWh to 12.3 cents per kWh.

The amount of energy received and the total payments made under all of these power purchase contracts were:

	Year Ended December 31,		
(in millions)	**2000**	**1999**	**1998**
Kilowatt-hours received	25,446	25,910	25,994
Energy payments	$ 1,549	$ 837	$ 943
Capacity payments	$ 519	$ 539	$ 529
Irrigation district and water agency pay	$ 56	$ 60	$ 53

National Energy Group

The NEG, through its indirect subsidiary, USGenNE, assumed rights and duties under several power purchase contracts with third-party independent power producers as part of the acquisition of the NEES assets. At December 31, 2000, these agreements provided for an aggregate of 800 MW of capacity. Under the transfer agreement, the NEG is required to pay to NEES amounts due to the third-party power producers under the power purchase contracts. The approximate dollar amounts under these agreements are as follows:

(in millions)	
2001	$ 228
2002	215
2003	217
2004	220
2005	220
Thereafter	1,585
Total	$2,685

Natural Gas Supply and Transportation Commitments

Utility

The Utility has long-term gas transportation service contracts with various Canadian and interstate pipeline companies. These agreements include provisions for payment of fixed demand charges for reserving firm capacity on the pipelines. The total demand charges that the Utility will pay each year may change due to changes in tariff rates. The total demand and volumetric transportation charges the Utility paid under these agreements were $94 million, $97 million, and $113 million in 2000, 1999, and 1998, respectively. These amounts include payments made by the Utility to PG&E GTN of $46 million, $47 million, and $49 million in 2000, 1999, and 1998, respectively, which are eliminated in the consolidated financial statements of PG&E Corporation.

The Utility's obligations related to capacity held pursuant to long-term contracts on various pipelines are as follows:

(in millions)	
2001	$100
2002	101
2003	77
2004	77
2005	68
Thereafter	29
Total	$452

As a result of regulatory changes, the Utility no longer procures gas for most of its industrial and larger commercial (non-core) customers, resulting in a decrease in the Utility's need for capacity on these pipelines. Despite these changes, the Utility continues to procure gas for substantially all of its residential and smaller commercial (core) customers and its non-core customers who choose bundled service. To the extent that the Utility's current capacity holdings exceed demand for gas transportation by its customers, the Utility will continue its efforts to broker such excess capacity.

The Utility's deteriorating credit situation has caused many of its gas suppliers to decline to sell the Utility any more gas, even under existing gas contracts, in the absence of accelerated payments. Specifically, some gas suppliers (1) have made demands that the Utility provide prepayment, cash on delivery, or other forms of payment assurance for gas supplies instead of the normal payment terms under which the Utility would pay for gas delivery, which the Utility is unable to meet given its current cash constraints, and (2) have refused to sell gas to the Utility for future periods. Failure to procure gas supplies to meet residential and smaller commercial gas (core) customer demands could result in diverting gas supplies from industrial and larger commercial gas (non-core) customers, which would only exacerbate the crisis.

The U.S. Secretary of Energy issued a temporary order on January 19, 2001 requiring the gas suppliers to continue to make deliveries to avoid a worsening natural gas shortage emergency. However, this order expired on February 7, 2000, and certain companies, representing about 10% of the Utility's natural gas suppliers, terminated deliveries after the order expired. The Utility has tried to mitigate the worsening supply situation by withdrawing more gas from storage and, when able, purchasing additional gas on the spot market. Additionally, on January 31, 2001, the CPUC authorized the Utility to pledge its gas account receivables and its gas inventories for up to 90 days (extended to 180 days in a CPUC draft decision issued on February 15, 2001) to secure gas for its core customers. At March 29, 2001, the amount of gas accounts receivable pledged was approximately $900 million. To date, approximately 30% of the Utility's suppliers of natural gas have signed security agreements with the Utility and discussions are continuing with the Utility's other suppliers. Additionally, the Utility is currently implementing a program to obtain longer term summer and winter supplies and daily spot supplies of natural gas.

National Energy Group

The NEG, through its subsidiaries PG&E Gen and PG&E ET, has entered into various gas supply and firm transportation agreements with various pipelines and transporters. Under these agreements, the NEG must make specific minimum payments each month. The approximate dollar obligations under these gas supply and transportation agreements are as follows:

(in millions)	
2001	$ 87
2002	87
2003	87
2004	85
2005	85
Thereafter	708
Total	$1,139

Acquisition of Turbine Rights

National Energy Group

On September 8, 2000, the NEG, through one of its subsidiaries, entered into operative documents with a special purpose entity (the Lessor) in order to facilitate the development, construction, financing, and leasing of several power generation projects. The Lessor has an aggregate financing commitment from debt and equity participants (the Investors) of $7.8 billion. The NEG, in its role as construction agent for the Lessor, is responsible for completing construction by the sixth anniversary of the closing date, but has limited its risk related to construction completion to less than 90% of project costs incurred to date. Upon completion of an individual project, the NEG is required to make lease payments to the Lessor in an amount sufficient to provide a return to the Investors. At the end of an individual project's operating lease term (three years from construction completion), the NEG has the option to extend the lease at fair value, purchase the project at a fixed amount (equal to the original construction cost), or act as remarketing agent for the Lessor and sell the project to an independent third party. If the NEG elects the remarketing option, the NEG may be required to make a payment to the Lessors, up to 85% of the project cost, if the proceeds from remarketing are deficient to repay the Investors. PG&E Corporation committed to fund up to $314 million of equity to support the NEG's obligation to the Lessor during the construction and post-construction periods. The NEG is attempting to replace PG&E Corporation equity support commitments with substitute commitments of the NEG.

Standard Offer Agreements

National Energy Group

USGenNE entered into three standard offer agreements with NEES' retail subsidiaries under which USGenNE will provide "standard offer" service to such subsidiaries. The standard offer agreements initially covered all of the retail customers served by NEES' distribution subsidiaries in Rhode Island, New Hampshire, and Massachusetts at the date of USGenNE's acquisition of the NEES assets. The Standard Offer Agreements continue through June 30, 2002 in New Hampshire; December 31, 2004 in Massachusetts; and December 31, 2009 in Rhode Island. The pricing per MWh is standard for all contracts and was below market prices at the date of the agreement. On January 7, 2000, USGenNE paid approximately $15 million by entering into an agreement with a third party which assumed the obligation to deliver power to NEES to serve 10% of the Massachusetts customers and 40% of the Rhode Island customers under the terms of the standard offer agreements. The payment was recorded as a deferred standard offer fee and is amortized over the remaining life of the standard offer agreements.

Operating Leases

National Energy Group

The NEG and its subsidiaries have entered into several operating lease agreements for generating facilities and office space. Lease terms vary between three and 48 years. In November 1998, a subsidiary of the NEG entered into a $479 million sale-leaseback transaction whereby the subsidiary sold and leased back a pumped storage station under an operating lease.

During 2000 and 1999, two indirect wholly owned subsidiaries of the NEG entered into two operating lease commitments relating to projects that are under construction, for which they act as the construction agent for the lessors. Upon completion of the construction projects, expected to be in 2001 and 2002, the lease terms of five years and three years, respectively, will commence. At the conclusion of each of the operating lease terms, the

NEG has the option to extend the leases at fair market value, purchase the projects, or act as remarketing agent for the lessors for sales to third parties. If the Company elects to remarket the projects, then the NEG would be obligated to the lessors for up to 85% of the project costs if the proceeds are deficient to pay the lessor's investors. PG&E Corporation has committed to fund up to $604 million in the aggregate of equity to support the NEG's obligation to the lessors during the construction and post-construction periods. The NEG is attempting to replace PG&E Corporation's equity support commitments with substitute commitments of NEG.

The approximate obligations under these operating lease agreements as of December 31, 2000 were as follows:

(in millions)	
2001	$ 97
2002	159
2003	166
2004	162
2005	88
Thereafter	965
Total	$1,637

Operating lease expense amounted to $58 million, $67 million, and $35 million in 2000, 1999, and 1998, respectively.

In addition to those obligations described above, the NEG entered into operative agreements with a special purpose entity that will own and finance construction of a facility totaling $775 million. PG&E Corporation has committed to fund up to $122 million of equity support commitments to meet the obligations to the entity. The NEG is attempting to replace the PG&E Corporation's equity support commitments with substitute commitments of NEG.

Construction

National Energy Group

An indirect wholly owned subsidiary of PG&E Gen entered into a turnkey construction contract with a third-party contractor to construct a 360-MW natural gas-fired combined-cycle power plant in Charlton, Massachusetts. The total contract value is $72 million. The contractor's responsibilities include designing and engineering the project and providing procurement and construction services, start-up, training, and performance testing. The contractor had guaranteed that substantial completion will occur on or prior to August 20, 2000. Through the date of these financial statements, substantial completion has not occurred and the contractor is paying delay damages in accordance with the terms of the turnkey construction contract. At December 31, 2000 and 1999, approximately $69 million and $54 million, respectively, had been paid to the contractor under the turnkey construction contract.

The same subsidiary also entered into a power island equipment and supply contract with Westinghouse Power Corporation (WPC) to provide the power island, the steam turbine, and the heat recovery steam generator. The total contract value is $69 million. At December 31, 2000 and 1999, approximately $67 million had been paid to WPC under the power island contract.

In another construction transaction, an indirect wholly-owned subsidiary of PG&E Gen contracted with Siemens Westinghouse Power (SWP) in 2000 to provide the combustion turbine generator, steam turbine generator and heat recovery steam generator for its 1,080-MW natural gas-fired combined cycle power plant under development in Greene County, New York. The total contract value is approximately $223 million. At December 31, 2000, approximately $69 million had been paid to SWP. Construction is expected to commence June 2001.

Long-Term Service Agreements

National Energy Group

The NEG has entered into long-term service agreements for the maintenance and repair of certain of its combustion turbine or combined-cycle generating plants under construction. These agreements, which are for periods up to 20 years, may be terminated in the event a planned construction project is cancelled. Annual amounts for long-term service agreements committed for the next five years under the current construction plan are as follows as of December 31, 2000:

(in millions)	
2001	$ 12
2002	35
2003	35
2004	34
2005	35
Thereafter	269
Total	$420

Note 15: Contingencies

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 $12 million (property damage) and $4 million (business interruption), in each case per policy period, in the event losses exceed the resources of NEIL.

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 federal legislation. 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.

Environmental Remediation

Utility

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 it 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. The remediation costs also reflect (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.

At December 31, 2000, the Utility expects to spend $320 million for hazardous waste remediation costs at identified sites, including divested fossil-fueled power plants. The cost of the hazardous substance remediation ultimately undertaken by the Utility is difficult to estimate. A change in 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 could spend as much as $462 million on these costs. 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.

The Utility had an environmental remediation liability of $320 million and $271 million at December 31, 2000 and 1999, respectively. The $320 million accrued at December 31, 2000 includes (1) $140 million related to the pre-closing remediation liability, associated with the divested generation facilities discussed further in the "Generation Divestiture" section of Note 2 of the Notes to the Consolidated Financial Statements, and (2) $180 million related to remediation costs for those generation facilities that the Utility still owns, manufactured gas plant sites, and gas gathering compressor stations. Of the $320 million environmental remediation liability, the Utility has recovered $168 million through rates, and expects to recover another $87 million in future rates. The Utility is seeking recovery of the remainder of its costs from insurance carriers and from other third parties as appropriate.

In December 1999, the Utility was notified by the purchaser of its former Moss Landing power plant that it had identified a cleaning procedure used at the plant that released heated water from the intake, and that this procedure is not specified in the plant's National Pollutant Discharge Elimination System (NPDES) permit issued by the Central Coast Regional Water Quality Control Board (Central Coast Board). The purchaser notified the Central Coast Board of its findings. In March 2000, the Central Coast Board requested the Utility to provide specific information regarding the "backflush" procedure used at Moss Landing. The Utility provided the requested information to the Board in April 2000. The Utility's investigation indicated that while it owned Moss Landing, significant amounts of water discharged from the cooling water intake. While the Utility's investigation did not clearly indicate that discharged waters had a temperature higher than ambient receiving water, the Utility believes that the temperature of the discharged water was higher than that of the ambient receiving water. In December 2000, the executive officer of the Central Coast Board made a settlement proposal to the Utility under which it would pay $10 million, a portion of which would be used for environmental projects and the balance of which would constitute civil penalties. Settlement negotiations are continuing.

The Utility's Diablo Canyon employs a "once through" cooling water system which is regulated under a NPDES Permit issued by the Central Coast Board. This permit allows Diablo Canyon to discharge the cooling water at a temperature no more than 22 degrees above ambient receiving water, and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, marine and wildlife habitat, shell fish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft Cease and Desist Order (CDO) alleging that, although the temperature limit has never been exceeded, the Diablo Canyon's discharge was not protective of beneficial uses. In October 2000, the Central Coast Board and the Utility reached a tentative settlement of this matter pursuant to which the Central Coast Board has agreed to find that the Utility's discharge of cooling water from the Diablo Canyon plant protects beneficial uses and that the intake technology reflects the "best technology available" under Section 316(b) of the Federal Clean Water Act. As part of the settlement, the Utility will take measures to preserve certain acreage north of the plant and will fund approximately $4.5 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 California's Superior Court.

PG&E Corporation believes the ultimate outcome of these matters will not have a material impact on its or the Utility's financial position or results of operations.

National Energy Group

In October and November 1999, the U.S. Environmental Protection Agency (EPA) and several states filed suits or announced their intention to file suits against a number of coal-fired power plants in Midwestern and Eastern states. These suits relate to alleged violations of the Clean Air Act. More specifically, they allege violations of the deterioration prevention and non-attainment provisions of the Clean Air Act's new source review requirements arising out of certain physical changes that may have been made at these facilities without first obtaining the required permits. In May 2000, the NEG received a request for information seeking detailed operating and maintenance histories for the Salem Harbor and Brayton Point power plants. If EPA were to find that there were physical changes in the past that were undertaken without first receiving the required permits under the Clean Air Act, then penalties may be imposed and further emission reductions might be necessary at these plants.

In addition to the EPA, states may impose more stringent air emissions requirements. The Commonwealth of Massachusetts is considering the adoption of more stringent air emission reductions from electric generating facilities. If adopted, these requirements will impact Salem Harbor and Brayton Point. The NEG has proposed an emission reduction plan that may include modernization of the Salem Harbor power plant and use of advanced technologies for emissions removal. It is also studying various advanced technologies for emissions removal for the Brayton Point power plant.

The NEG's subsidiary, USGenNE, has proposed a number of state and regional initiatives that will require it to achieve significant reductions of emissions by 2010. The NEG expects that USGenNE will meet these requirements through a combination of installation of controls, use of emission allowances it currently owns, and purchase of additional allowances. The NEG currently estimates that USGenNE's total capital cost for complying with these requirements will be approximately $270 million.

PG&E Gen's existing power plants, including USGenNE facilities, 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 are operating pursuant to NPDES permits that have expired. For the facilities whose NPDES permit have expired, permit renewal applications are pending, and it is anticipated that all three facilities will be able to continue to operate under existing terms and conditions until new permits are issued. It is estimated that USGenNE's cost to comply with the new permit conditions could be as much as $55 million through 2005. It is possible that the new permits may contain more stringent limitations than prior permits.

During September 2000, USGenNE signed a series of agreements that require, among other things, that USGenNE alter its existing waste water treatment facilities at two facilities by replacing certain unlined treatment basins, submit and implement a plan for the closure of such basins, and perform certain environmental testing at the facilities. USGenNE has incurred $4 million in 2000 and expects to complete the required steps on or before December 2001. The total expected cost of these improvements is $21 million.

Legal Matters

Utility

The Utility's Chapter 11 bankruptcy filing on April 6, 2001, discussed in Notes 2 and 3, automatically stayed the litigation described below against the Utility.

Chromium Litigation:

Several civil suits are pending against the Utility in California state 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 Hinckley, Kettleman, and Topock, California. Currently, there are claims pending on behalf of approximately 1,050 individuals. The trial of 18 test cases is currently scheduled for July 2001.

The Utility is responding to the suits and asserting affirmative defenses. The Utility will pursue appropriate legal defenses, including statute of limitations or 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. PG&E Corporation has recorded a legal 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 as of December 31, 2000, 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.

Wilson vs PG&E Corporation and Pacific Gas and Electric Company:

On February 13, 2001, two complaints were filed against PG&E Corporation and the Utility in the Superior Court of the State of California, San Francisco County: Richard D. Wilson v. Pacific Gas and Electric Company et al. (Wilson I), and Richard D. Wilson v. Pacific Gas and Electric Company, et al. (Wilson II).

In Wilson I, the plaintiff alleges that in 1998 and 1999, PG&E Corporation violated its fiduciary duties and California Business and Professions Code Section 17200 by causing the Utility to repurchase shares of Pacific Gas and Electric Company common stock from PG&E Corporation at an aggregate price of $2,326 million. The complaint alleges an unlawful business act or practice under Section 17200 because these repurchases allegedly violated PG&E Corporation's fiduciary duties, a first priority capital requirement allegedly imposed by the CPUC's decision approving the formation of a holding company, and also an implicit public trust imposed by Assembly Bill 1890, which granted authority for the issuance of rate reduction bonds. The complaint seeks to enjoin the repurchase by the Utility of any more of its common stock from PG&E Corporation or other entities or persons unless good cause is shown, and seeks restitution from PG&E Corporation of $2,326 million, with interest, on behalf of the Utility. The complaint also seeks an accounting, costs of suit, and attorney's fees.

In Wilson II, the plaintiff alleges that PG&E Corporation, the Utility, and other subsidiaries have been parties to a tax-sharing arrangement under which PG&E Corporation annually files consolidated federal and state income tax returns for, and pays, the income taxes of PG&E Corporation and participating subsidiaries. According to the plaintiff, between 1997 and 1999, PG&E Corporation collected $2,957 million from the Utility under this tax-sharing arrangement, but paid only $2,294 million (net of refunds) to all governments under the tax-sharing agreement. Plaintiff alleges that these monies were held under an express and implied trust to be used by PG&E Corporation to pay the Utility's share of income taxes under the tax-sharing arrangement. Plaintiff alleges that PG&E Corporation overcharged the Utility $663 million under the tax-sharing arrangement and has declined voluntarily to return these monies to the Utility, in violation of the alleged trust, the alleged first priority capital condition, and California Business and Professions Code Section 17200. The complaint seeks to enjoin PG&E Corporation from engaging in the activities alleged in the complaint (including the tax-sharing arrangement), and seeks restitution from PG&E Corporation of $663 million, with interest, on behalf of the Utility. The complaint also seeks an accounting, costs of suit, and attorney's fees.

PG&E Corporation's and the Utility's analysis of these complaints is at a preliminary stage, but PG&E Corporation and the Utility believe them to be without merit and intend to present a vigorous defense. PG&E Corporation and the Utility are unable to predict whether the outcome of this litigation will have a material adverse affect on their financial condition or results of operation.

National Energy Group

The NEG is involved in various litigation matters in the ordinary course of its business. Except as described below, the NEG is not currently involved in any litigation that is expected, either individually or in the aggregate, to have a material adverse effect on financial condition or results of operations.

Texas Franchise Fee Litigation Against PG&E GTT

PG&E GTT and various of its affiliates are defendants in at least two class action suits and five separate suits filed by various Texas cities. Generally, these cities allege, among other things, that (1) owners or operators of pipelines occupied city property and conducted pipeline operations without the cities' consent and without compensating the cities, and (2) the gas marketers failed to pay the cities for accessing and utilizing the pipelines located in the cities to flow gas under city streets. Plaintiffs also allege various other claims against the defendants for failure to secure the cities' consent. Damages are not quantified.

PG&E Corporation believes that the ultimate outcome of these matters will not have a material adverse impact on its financial position or its results of operations. The NEG completed the sale of PG&E GTT in December 2000.

Recorded Liability for Legal Matters:

In accordance with SFAS No. 5 "Accounting for Contingencies," PG&E Corporation makes a provision for a liability when both it is 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:

(in millions)	PG&E Corporation	Utility
Beginning balance, January 1, 2000	$106	$ 50
Provisions for liabilities	144	144
Payments	(45)	(43)
Adjustments	(20)	34
Ending balance, December 31, 2000	$185	$185

Note 16: Segment Information

PG&E Corporation has identified four 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. The Utility is one reportable operating segment and the other three are part of PG&E Corporation's NEG. These four 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.

Utility

PG&E Corporation's Northern and Central California energy utility subsidiary, Pacific Gas and Electric Company, provides natural gas and electric service to its customers.

National Energy Group

PG&E Corporation's subsidiary, the NEG, is an integrated energy company with a strategic focus on power generation, new power plant development, natural gas transmission, and wholesale energy marketing and trading in North America. The NEG businesses include its power plant development and generation unit, PG&E Generating Company, LLC and its affiliates; its natural gas transmission unit, PG&E Gas Transmission Corporation; and its wholesale energy marketing and trading unit, PG&E Energy Trading Holdings Corporation which owns PG&E Energy Trading—Power, L.P., PG&E Energy Trading-Gas Corporation, and their affiliates. During 2000, the NEG sold its energy services unit, PG&E Energy Services Corporation. Also during the fourth quarter of 2000, the NEG sold its Texas natural gas and natural gas liquids business operated through PG&E Gas Transmission, Texas Corporation and PG&E Gas Transmission Teco, Inc. and their subsidiaries.

Segment information for the years 2000, 1999, and 1998 was as follows:

		National Energy Group[4]					
			PG&E GT				
(in millions)	Utility	PG&E Gen[4]	Northwest	Texas[4]	PG&E ET	Eliminations & Other[5]	Total
2000							
Operating revenues	$ 9,623	$1,201	$ 188	$ 817	$14,414	$ (11)	$26,232
Intersegment revenues[1]	14	10	51	56	1,640	(1,771)	—
Total operating revenues	9,637	1,211	239	873	16,054	(1,782)	26,232
Depreciation, amortization and decommissioning	3,511	91	41	70	11	(65)	3,659
Interest income	186	66	1	(4)	7	10	266
Interest expense[3]	(619)	(61)	(41)	(49)	(5)	(13)	(788)
Income taxes (benefits)[2]	(2,154)	57	37	(35)	55	12	(2,028)
Income (loss) from continuing operations	(3,508)	84	58	20	27	(5)	(3,324)
Capital expenditures[6]	1,245	495	15	—	3	—	1,758
Total assets at year-end[5][6]	$21,988	$4,568	$1,204	$ —	$ 7,098	$ 433	$35,291
1999							
Operating revenues	$ 9,084	$1,116	$ 172	$1,034	$ 9,404	$ 10	$20,820
Intersegment revenues[1]	144	6	52	114	1,117	(1,433)	—
Total operating revenues	9,228	1,122	224	1,148	10,521	(1,423)	20,820
Depreciation, amortization and decommissioning	1,564	89	41	75	9	2	1,780
Interest income	45	62	—	9	4	(2)	118
Interest expense[3]	(593)	(63)	(41)	(59)	(12)	(4)	(772)
Income taxes (benefits)[2]	648	16	32	(407)	(36)	(5)	248
Income (loss) from continuing operations	763	97	68	(897)	(34)	16	13
Capital expenditures[6]	1,181	323	30	19	14	17	1,584
Total assets at year-end[5][6]	$21,470	$3,852	$1,160	$1,217	$ 1,876	$ (105)	$29,470
1998							
Operating revenues	$ 8,919	$ 645	$ 185	$1,640	$ 8,183	$ 5	$19,577
Intersegment revenues[1]	5	4	52	301	326	(688)	—
Total operating revenues	8,924	649	237	1,941	8,509	(683)	19,577
Depreciation, amortization and decommissioning	1,438	52	39	65	5	3	1,602
Interest income	96	29	1	9	6	(40)	101
Interest expense[3]	(621)	(43)	(43)	(77)	(7)	10	(781)
Income taxes (benefits)[2]	629	28	31	(47)	(17)	(13)	611
Income (loss) from continuing operations	702	106	65	(71)	(6)	(25)	771
Capital expenditures[6]	1,382	98	49	39	12	39	1,619
Total assets at year-end[5][6]	$22,950	$3,844	$1,169	$2,655	$ 2,555	$ 61	$33,234

(1) Inter-segment electric and gas revenues are recorded at market prices, which for the Utility and GTN are tariffed rates prescribed by the CPUC and the FERC, respectively.

(2) Income tax expense for the Utility is computed on a stand-alone basis. The balance of the consolidated income tax provision is allocated among the National Energy Group.

(3) Interest expense incurred by PG&E Corporation is allocated to the segments using specific identification.

(4) Income from equity-method investees for 2000, 1999, and 1998 was $65 million, $63 million, and $113 million, respectively, for PG&E Gen, and $1 million, zero, and $3 million, respectively, for PG&E GTT.

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

(6) Capital expenditures and assets of the discontinued operations of Energy Services are included in "Eliminations & Other" column. Total assets for PG&E ES at December 31, 2000, 1999, and 1998 were $1 million, $197 million, and $202 million, respectively. Capital expenditures for 2000, 1999, and 1998 were zero, $17 million, and $38 million, respectively.

QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

Quarter ended (in millions, except per share amounts)	December 31	September 30	June 30	March 31
2000				
PG&E Corporation				
Operating revenues	$ 8,082	$7,504	$5,638	$5,008
Operating income (loss)(1)(4)	(6,734)	629	622	676
Income (loss) from continuing operations	(4,096)	244	248	280
Net income (loss)(1)(4)	(4,117)	225	248	280
Earnings (loss) per common share from continuing operations, basic	(11.28)	.67	.69	.78
Earnings (loss) per common share from continuing operations, diluted	(11.28)	.67	.68	.77
Dividends declared per common share	.30	.30	.30	.30
Common stock price per share				
High	28.78	30.90	26.67	22.01
Low	18.25	22.50	20.39	18.80
Utility				
Operating revenues	$ 2,600	$2,523	$2,296	$2,218
Operating income (loss)	(6,856)	533	552	570
Net income (loss)	(4,156)	217	222	234
Income (loss) available for (allocated to) common stock	(4,163)	211	216	228
1999				
PG&E Corporation				
Operating revenues	$ 4,795	$6,217	$4,682	$5,126
Operating income (loss)(1)(2)(3)	(579)	516	480	461
Income (loss) from continuing operations	(547)	197	196	167
Net income (loss)(1)(2)(3)	(611)	185	182	171
Earnings (loss) per common share from continuing operations, basic	(1.49)	0.54	0.53	0.45
Earnings (loss) per common share from continuing operations, diluted	(1.49)	0.54	0.50	0.39
Dividends declared per common share	0.30	0.30	0.30	0.30
Common stock price per share				
High	26.69	33.25	34.00	33.69
Low	20.25	25.00	30.56	29.50
Utility				
Operating revenues	$ 2,323	$2,587	$2,233	$2,085
Operating income(3)	633	486	452	422
Net income(3)	272	185	178	153
Income available for common stock	265	179	172	147

(1) In the fourth quarter 1999, the NEG adopted a plan to dispose of the PG&E ES segment. This planned transaction has been accounted for as a discontinued operation. Results of operations of PG&E ES have been excluded from continuing operations for all periods presented. The operating loss and net loss of PG&E ES for the quarters ending March 31, June 30, and September 30, 1999, were $15 million and $8 million, $23 million and $14 million, and $20 million and $12 million, respectively. An estimated loss of $19 million ($0.05 per share), net of income taxes of $13 million, was recorded for the quarter and nine months ended September 30, 2000. Additionally, an estimated loss of $21 million ($0.06 per share), net of income taxes of $23 million, was recorded for the quarter and three-month period ended December 31, 2000.

(2) Amounts have been restated to reflect the change in accounting for major maintenance and overhauls at the NEG (see Note 1), and reclassification of PG&E ES operating results to discontinued operations (see above). The accounting change resulted in a cumulative effect being recorded as of January 1, 1999 of $12 million ($0.03 per share), net of income taxes of $8 million. Operating income previously reported for 1999 was $442 million, $454 million, and $492 million for each of the first three quarters, respectively. Net income previously reported for 1999 was $156 million ($0.42 per share), $180 million ($0.49 per share), and $183 million ($0.50 per share) for the same periods.

(3) In the fourth quarter of 1999, the Utility recorded the effects of the outcome of the GRC. This resulted in an increase of $256 million in operating income and an increase of $153 million in net income. Additionally, the NEG recorded an after-tax charge of $890 million reflecting PG&E GTT's assets at their fair market value. (See MD&A and Note 5.)

(4) In the fourth quarter of 2000, the Utility recorded a charge to earnings for the write-off of regulatory assets representing transition costs and undercollected purchased power costs. The write-off was $6.9 billion ($4.1 after-tax) and reflected the fact that based upon the current status of the California energy crisis, the Utility could no longer conclude that the regulatory assets were probable of recovery through regulated rates.

Also in the fourth quarter of 2000, the Utility recognized a $140 million ($83 million, after tax) provision for an increase in legal reserves.

INDEPENDENT AUDITORS' REPORT

To the Boards of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company

We have audited the accompanying consolidated balance sheets of PG&E Corporation and subsidiaries and Pacific Gas and Electric Company and subsidiaries as of December 31, 2000 and 1999, and the related statements of consolidated operations, cash flows and common stock equity of PG&E Corporation and the related statements of consolidated operations, cash flows and stockholders' equity of Pacific Gas and Electric Company for the years then ended. These financial statements are the responsibility of the management of PG&E Corporation and of Pacific Gas and Electric Company. Our responsibility is to express an opinion on these financial statements based on our audits. The consolidated financial statements for the year ended December 31, 1998 were audited by other auditors whose report, dated February 8, 1999, expressed an unqualified opinion on those statements.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such 2000 and 1999 financial statements present fairly, in all material respects, the financial position of PG&E Corporation and Pacific Gas and Electric Company as of December 31, 2000 and 1999, and the results of their consolidated operations and cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 of the Notes to Consolidated Financial Statements, in 1999 PG&E Corporation changed its method of accounting for major maintenance and overhauls.

The accompanying consolidated financial statements have been prepared on a going concern basis of accounting. As discussed in Notes 2 and 3 of the Notes to the Consolidated Financial Statements, Pacific Gas and Electric Company, a subsidiary of PG&E Corporation, has incurred power purchase costs substantially in excess of amounts charged to customers in rates. On April 6, 2001, Pacific Gas and Electric Company sought protection from its creditors by filing a voluntary petition under provisions of Chapter 11 of the U.S. Bankruptcy Code. These matters raise substantial doubt about Pacific Gas and Electric Company's ability to continue as a going concern. Managements' plans in regard to these matters are also described in Notes 2 and 3 of the Notes to the Consolidated Financial Statements. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

DELOITTE & TOUCHE LLP
San Francisco, California
April 6, 2001

RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

In both PG&E Corporation and Pacific Gas and Electric Company (the Utility) management is responsible for the integrity of the accompanying consolidated financial statements. These statements have been prepared in accordance with accounting principles generally accepted in the United States of America. Management considers materiality and uses its best judgment to ensure that such statements reflect fairly the financial position, results of operations, and cash flows of PG&E Corporation and the Utility.

PG&E Corporation and the Utility maintain systems of internal controls supported by formal policies and procedures which are communicated throughout PG&E Corporation and the Utility. These controls are adequate to provide reasonable assurance that assets are safeguarded from material loss or unauthorized use and that necessary records are produced for the preparation of consolidated financial statements. There are limits inherent in all systems of internal controls, based on recognition that the costs of such systems should not exceed the benefits to be derived. PG&E Corporation and the Utility believe that their systems of internal control provide this appropriate balance. PG&E Corporation management also maintains a staff of internal auditors who evaluate the adequacy of, and assess the adherence to, these controls, policies, and procedures for all of PG&E Corporation, including the Utility.

Both PG&E Corporation's and the Utility's 2000 and 1999 consolidated financial statements have been audited by Deloitte & Touche LLP, PG&E Corporation's independent auditors. The audit includes consideration of internal accounting controls and performance of tests necessary to support an opinion. The auditors' report contains an independent informed judgment as to the fairness, in all material respects, of reported results of operations and financial position.

The Audit Committee of the Board of Directors for PG&E Corporation meets regularly with management, internal auditors, and Deloitte & Touche, jointly and separately, to review internal accounting controls and auditing and financial reporting matters. The internal auditors and Deloitte & Touche LLP have free access to the Audit Committee, which consists of five outside directors. The Audit Committee has reviewed the financial data contained in this report.

PG&E Corporation and the Utility are committed to full compliance with all laws and regulations and to conducting business in accordance with high standards of ethical conduct. Management has taken the steps necessary to ensure that all employees and other agents understand and support this commitment. Guidance for corporate compliance and ethics is provided by an officers' Ethics Committee and by a Legal Compliance and Business Ethics organization. PG&E Corporation and the Utility believe that these efforts provide reasonable assurance that each of their operations is conducted in conformity with applicable laws and with their commitment to ethical conduct.

Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company[1]

David R. Andrews
Partner, McCutchen, Doyle, Brown & Enersen, LLP

Richard A. Clarke[2]
Chairman of the Board, Retired, Pacific Gas and Electric Company

Harry M. Conger[2]
Chairman of the Board and Chief Executive Officer, Emeritus, Homestake Mining Company

David A. Coulter
Vice Chairman, J.P. Morgan Chase & Co.

C. Lee Cox
Vice Chairman, Retired, AirTouch Communications, Inc. and President and Chief Executive Officer, Retired, AirTouch Cellular

William S. Davila
President Emeritus, The Vons Companies, Inc. (retail grocery)

Robert D. Glynn, Jr.
Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation and Chairman of the Board, Pacific Gas and Electric Company

David M. Lawrence, MD
Chairman and Chief Executive Officer, Kaiser Foundation Health Plan, Inc. and Kaiser Foundation Hospitals

Mary S. Metz
President, S. H. Cowell Foundation

Carl E. Reichardt
Chairman of the Board and Chief Executive Officer, Retired, Wells Fargo & Company and Wells Fargo Bank, N.A.

John C. Sawhill[3]
President and Chief Executive Officer, The Nature Conservancy (international environmental organization)

Gordon R. Smith[1]
President and Chief Executive Officer, Pacific Gas and Electric Company

Barry Lawson Williams
President, Williams Pacific Ventures, Inc. (business consulting and mediation)

(1) The composition of the Boards of Directors is the same, except that Gordon R. Smith is a director of the Pacific Gas and Electric Company Board of Directors only.

(2) Retired as a director of PG&E Corporation and Pacific Gas and Electric Company on February 21, 2001.

(3) Deceased May 18, 2000.

Permanent Committees of PG&E Corporation and Pacific Gas and Electric Company[1]

Executive Committees

Within limits, may exercise powers and perform duties of the Boards.

Robert D. Glynn, Jr., Chair
C. Lee Cox
Mary S. Metz
Carl E. Reichardt
Gordon R. Smith[1]
Barry Lawson Williams

Audit Committees

Review financial statements and internal audit and control procedures with independent public accountants.

C. Lee Cox, Chair
David R. Andrews
William S. Davila
Mary S. Metz
Barry Lawson Williams

Finance Committee

Reviews long-term financial and capital investment policies and objectives, and actions required to achieve those objectives.

Barry Lawson Williams, Chair
David R. Andrews
David A. Coulter
Carl E. Reichardt

Nominating and Compensation Committee

Recommends candidates for nomination as directors, recommends compensation and employee benefit policies and practices, and reviews planning for executive development and succession.

Carl E. Reichardt, Chair
David A. Coulter
C. Lee Cox
David M. Lawrence, MD

Public Policy Committee

Reviews public policy issues which could significantly affect customers, shareholders, employees, or the communities served, and recommends plans and programs to address such issues.

Mary S. Metz, Chair
William S. Davila
David M. Lawrence, MD

(1) The committee membership shown is effective February 21, 2001. Except for the Executive and Audit Committees, all committees listed above are committees of the PG&E Corporation Board of Directors. The Executive and Audit Committees of the PG&E Corporation and Pacific Gas and Electric Company Boards have the same members, except that Gordon R. Smith is a member of the Pacific Gas and Electric Company Executive Committee only.

Officers

PG&E Corporation

Robert D. Glynn, Jr.
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Stock Exchange Listings

PG&E Corporation's common stock is traded on the New York, Pacific, and Swiss stock exchanges. The official New York Stock Exchange symbol is "PCG" but PG&E Corporation common stock is listed in daily newspapers under "PG&E" or "PG&E Cp."(1)

Pacific Gas and Electric Company has 11 issues of preferred stock and one preferred security, all of which are listed on the American and Pacific stock exchanges.

Issue	Newspaper Symbol(1)
First Preferred, Cumulative, Par Value $25 Per Share	
Redeemable:	
7.04%	PacGE pfU
6.57%	PacGE pfY
6.30%	PacGE pfZ
5.00%	PacGE pfD
5.00% Series A	PacGE pfE
4.80%	PacGE pfG
4.50%	PacGE pfH
4.36%	PacGE pfI
Non-Redeemable:	
6.00%	PacGE pfA
5.50%	PacGE pfB
5.00%	PacGE pfC
Cumulative Quarterly Income Preferred Securities:	
7.90% Series A	PG&E Cap pfA

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PG&E Corporation
Pacific Gas and Electric Company
Annual Meetings of Shareholders

Date: May 16, 2001
Time: 3:00 p.m.

Location: Masonic Auditorium,
1111 California Street
San Francisco, California

A joint notice of the annual meetings, joint proxy statement, and proxy form are being mailed with this annual report on or about April 16, 2001, to all shareholders of record as of April 4, 2001.

10-K Report
If you would like a copy of the 2000 Form 10-K Report to the Securities and Exchange Commission, please contact the Office of the Corporate Secretary, or visit our websites, www.pgecorp.com and www.pge.com.

ATTACHMENT F

PRELIMINARY DECOMMISSIONING PLAN

TABLE OF CONTENTS

CHAPTER 1

INTRODUCTION

Prior to the end of the Diablo Canyon ISFSI life, the multi- purpose canisters (MPCs) containing spent fuel elements will be transferred from storage overpacks into transportation casks and transported offsite. Since the MPCs are designed to meet DOE guidance applicable to MPCs for storage, transport and disposal of spent fuel, the fuel assemblies will remain sealed in the MPCs such that decontamination of the MPCs is not required. Following shipment of the MPCs offsite, the Diablo Canyon ISFSI will be decommissioned by the timely identification and removal of any residual radioactive materials above the applicable NRC limits for unrestricted use; releasing the site for unrestricted use in accordance with Regulatory Guide 1.86 (Reference 1); and terminating the NRC license.

This Preliminary Decommissioning Plan has been prepared to comply with the requirements of 10 CFR 72.30 and describes the conceptual program for decontamination and decommissioning of the Diablo Canyon ISFSI, including the proposed practices and procedures for decontamination of the site and facilities, the disposal of radioactive materials, and the cost estimate associated with decommissioning. The specific methods and details of Diablo Canyon ISFSI decommissioning will be included in a formal decommissioning plan, that will be submitted for NRC review and approval prior to the commencement of decommissioning activities. Additional information regarding design features that facilitate decommissioning is provided in the Holtec references cited in Section 1.5 of the Diablo Canyon ISFSI Safety Analysis Report (SAR).

CHAPTER 2

DECOMMISSIONING OBJECTIVE, ACTIVITIES, AND TASKS

2.1 DECOMMISSIONING OBJECTIVE

The objective of decommissioning activities for the Diablo Canyon ISFSI is to remove all radioactive materials having activities above the applicable NRC release limits (currently 10 CFR Part 20, Subpart E, "Radiological Criteria for License Termination") in order that the site may be released for unrestricted use, and the NRC license terminated.

2.2 DECOMMISSIONING ACTIVITIES

Detailed information on proposed practices and procedures for decommissioning activities will be provided in a final decommissioning plan. The extent of any required decontamination efforts cannot be quantified at this time, especially in light of the Diablo Canyon Power Plant's (DCPP) "start clean/stay clean" philosophy and the efforts that will be taken throughout the life of the facility to minimize the potential for any contamination. Actual decontamination efforts and sequences of work will depend on facility operating history and whether any contamination actually exists. The descriptions presented here provide a conceptual plan for detailed engineering and planning that will occur at the end of facility operations.

The loading of spent fuel into the MPCs occurs in DCPP fuel handling building/auxiliary building, as described in Sections 4.4 and 5.1 of the Diablo Canyon ISFSI SAR. As part of each loading operation, the components that have been in contact with contaminated spent fuel pool water (i.e., the transfer cask and the top of the MPC lid) are checked for surface contamination, and are decontaminated as necessary before being transported to the cask transfer facility (CTF). Because of this requirement, it is anticipated that at the time of decommissioning, the transfer cask can be decontaminated to free release levels; if this is not the case, then it will be disposed of at an appropriate facility.

It is not anticipated that either the storage overpacks or the storage pads will have residual radioactive contamination once the MPCs are removed because: (a) the MPCs are sealed by welding that precludes leakage, (b) measures are applied when fuel is loaded into the MPCs to prevent contamination of their outer surfaces, and (c) neutron flux levels generated by the spent fuel are sufficiently low that activation of storage cask and pad materials will be insignificant, with radiation levels that support either unrestricted release of materials or release as low specific activity (LSA) material. It is anticipated that HI-STORM 100SA overpacks, which meet applicable free release criteria, may be reused at other nuclear facilities following their use at the Diablo Canyon ISFSI. The LSA material will be suitable for burial in a near-surface disposal site.

Because of the administrative controls used to check for and remove (if possible) any contamination from the HI-TRAC transfer cask prior to its leaving the fuel handling building, it is anticipated that the CTF, transporter, and fences will not be contaminated at the time of decommissioning. Therefore, they will require no decontamination or special handling and will be left in place or removed as determined by PG&E. If this is not the case, they will be decontaminated to free release levels or disposed of at an appropriate facility.

PG&E intends to submit a final decommissioning plan to the NRC at least one year prior to the final removal of MPCs from the site, and in no case later than one year prior to the expiration of the NRC operating license. The final decommissioning plan will address decontamination of the site, removal of radioactive materials, and termination of the facility-operating license, and will include a description of how the Diablo Canyon ISFSI will continue to protect the public health and the environment during decommissioning. The final decommissioning plan will be developed in accordance with the applicable NRC regulations in effect at the time of preparation of the plan. Decommissioning activities will be planned using as low as is reasonably achievable (ALARA) goals and criteria for protection of personnel from exposure to radiation and radioactive material. The final decommissioning plan will include such information as follows:

- A description of the current conditions of the ISFSI site sufficient to evaluate the acceptability of the plan.
- The choice of the alternative for decommissioning with a description of the activities involved.
- A description of controls and limits on procedures and equipment to protect occupational and public health and safety.
- A description of the planned final radiation survey.
- An updated detailed cost estimate for the chosen alternative for decommissioning; a comparison of that estimate with present funds set aside for decommissioning; and the plan for assuring the availability of adequate funds for completion of decommissioning, including means for adjusting cost estimates and associated funding levels over any storage or surveillance period.
- A description of technical specifications and quality assurance provisions in place during decommissioning.

2.3 DECOMMISSIONING TASK

Prior to the commencement of Diablo Canyon ISFSI decommissioning activities, the MPCs will be shipped offsite in licensed transportation casks. The empty overpacks will then be surveyed to determined activation and contamination levels.

Overpacks with activation and contamination levels below the applicable NRC limits for unrestricted release will be disposed of as noncontrolled material. Overpacks with contamination or activation levels above the applicable NRC limits for unrestricted release will be dismantled, with the activated or contaminated portions segregated and disposed of as low-level waste. The dismantled portions or components of overpacks that are below the applicable NRC limits for unrestricted release will be disposed of as noncontrolled material. Storage cask decontamination and decommissioning may be performed at any time following the removal of the MPC. This will allow overpack decommissioning efforts to be essentially complete by the end of MPC shipping operations. Likewise, the transfer cask will be similarly surveyed for contamination, decontaminated, or dismantled and disposed of as low-level waste after its use is no longer required.

Characterization surveys will be performed to verify that the storage pads and storage site area are free of contamination (i.e., with radiation and radioactivity levels below the applicable NRC limits for unrestricted release). In the event that the characterization surveys identify contamination levels above the applicable NRC limits for unrestricted release, the structures or components will be decontaminated using conventional decontamination techniques that minimize the volume and processing of the resulting radwaste. All low-level radioactive waste generated during decontamination efforts, and portions of any structures or components that remain contaminated, will be shipped offsite for disposal at an appropriate licensed facility.

After all the MPCs have been shipped from the Diablo Canyon ISFSI, and the overpacks and transfer cask decommissioned, a detailed radiological characterization survey will be performed of the CTF, with particular attention focused on any areas of known or historic contamination. CTF equipment or structures that may have contamination levels above applicable NRC limits for unrestricted release will be decontaminated to the extent practical using conventional methods. All radioactive material above the applicable NRC limits for unrestricted release will be removed from the site and disposed of as low-level waste.

A final radiation survey will be conducted to ensure that the ISFSI site is suitable for release in accordance with the 10 CFR 20, Subpart E criteria for decommissioning.

2.4 DECOMMISSIONING ORGANIZATION

The decommissioning organization and staff requirements will be defined in the final decommissioning plan. Trained and qualified personnel will be used to perform the technical, field, and administrative tasks required during decommissioning. To the extent practicable, the decommissioning organization will include staff from the PG&E DCPP organization to capitalize on their knowledge and familiarity with the facility. Contractors may be used to provide specialized services, or to supplement the facility staff when warranted.

CHAPTER 3

DECOMMISSIONING RECORDS

The following records will be maintained until the Diablo Canyon ISFSI is released for unrestricted use, in accordance with 10 CFR 72.30(d), and will be used to plan the actual decommissioning efforts:

- Records of spills or other unusual occurrences involving the spread of contamination in and around the facility, equipment, or site. These records will include any known information on identification of nuclides, quantities, forms, and concentrations.
- As-built drawings and modifications of structure and equipment in restricted areas.
- A document, which is updated a minimum of every 2 years, containing: (a) a list of all areas designated at any time as restricted areas as defined in 10 CFR 20.1003; and (b) a list of all areas outside of restricted areas involved in a spread of contamination as required by 10 CFR 72.30(d)(1).
- Records of decommissioning cost estimates and the funding method used.

These records will be stored at DCPP as part of the records management program, which is discussed in the ISFSI License Application, Attachment E, "Quality Assurance Program."

CHAPTER 4

DECOMMISSIONING COST ESTIMATE

Decommissioning the Diablo Canyon ISFSI will be a multiphase effort, with radioactive contamination removed upon discovery, as possible, during the operational phase. The amount of decontamination required and the extent of decommissioning efforts will be based on the usage and the history of the facility. The philosophy of operating the Diablo Canyon ISFSI is "start clean/stay clean." Thus, the intention is to maintain the facility free of radiological contamination at all times.

Nonetheless, a cost estimate for decommissioning has been performed that assumes certain areas and components will require decontamination. This cost estimate is part of the total estimate performed by TLG Services, Inc. for DCPP Units 1 and 2. This detailed estimate is contained in the PG&E March 2001 Decommissioning Funding Report to the NRC (Reference 2), as required by 10 CFR 50.75(f)(1). As shown therein, it is estimated that decommissioning the Diablo Canyon ISFSI will cost about $12.5 million when escalated to 2001 dollars - for the DECON alternative. The major cost contributors are cost of labor, radioactive waste disposal, and radiological surveys. The costs are based on several key assumptions, including regulatory requirements, estimating methodology, contingency requirements (a composite average of 26 percent was assumed), low-level radioactive waste disposal availability, high-level radioactive waste disposal options, and site restoration requirements. This ISFSI decommissioning cost estimate of $12.5 million only covers the costs for decontamination and disposal of low-level waste; it does not cover the costs for demolition and disposal of noncontaminated material, which are estimated at $6.5 million in 2001 dollars.

In developing this estimate, TLG Services had to make some assumptions regarding the spent fuel storage system and the size of the ISFSI due to PG&E having not yet selected the storage system vendor. TLG Services assumed "NUHOMS" storage casks would be used. The TLG Services' cost estimate will be updated to reflect the Holtec International HI-STORM 100 Storage system. This update will be contained in the applicable biennial PG&E Decommissioning Funding Report to the NRC; thereafter, this Preliminary Decommissioning Plan will be updated accordingly.

CHAPTER 5

DECOMMISSIONING FUNDING PLAN

PG&E has established an external sinking trust fund account for decommissioning DCPP Units 1 and 2. This account contains monies for decommissioning the Diablo Canyon ISFSI. This financial assurance mechanism is prepared in conformance with the guidance of NRC Regulatory Guide 3.66 (Reference 3) and complies with the requirements of 10 CFR 72.3(c).

The status of this account is provided in the PG&E March 2001 Decommissioning Funding Report to the NRC, as required by 10 CFR 50.75(f)(1). As shown therein, and based upon current guidelines and assumptions, PG&E is confident that this trust fund account will contain sufficient funds to accommodate the decommissioning of the Diablo Canyon ISFSI.

CHAPTER 6

DECOMMISSIONING FACITATION

The sources of contamination are the spent fuel itself and the spent fuel pool water. In conformance with 10 CFR 72.130, the spread of contamination from these sources can be controlled via various ISFSI design features and health physics measures as described herein.

The design features of the HI-STORM 100 System, plus a "start clean/stay clean" philosophy, will facilitate decommissioning the Diablo Canyon ISFSI. Radioactive materials associated with spent fuel assemblies are contained within MPCs, which have been welded before leaving the DCPP fuel handling building/auxiliary building. The MPC conforms to requirements of Section III of the ASME code and provides assurance that radioactive material will not be released from the MPC over the life of the Diablo Canyon ISFSI. Health physics measures to ensure MPC external surfaces are maintained in a clean condition are implemented during the MPC loading operations. These measures minimize contaminated fuel pool water from contacting the external surfaces of the MPC. Following fuel loading operations, a swipe survey is performed on the MPC lid and on the transfer cask. Using administrative controls, transport of the transfer cask and MPC to the CTF and storage pads is not permitted if removable contamination levels exceed defined limits. Therefore, it is expected that the transfer cask and MPCs will have minimal, if any, contamination on external surfaces. Since the MPCs are sealed to preclude release of radioactive material from inside the MPCs, minimizing contamination on the external surfaces of the MPCs transported to the ISFSI storage pads minimizes the quantity of radioactive waste and contaminated equipment.

The HI-STORM 100 System overpacks that house the MPCs are clean and have no radioactive contamination when they are fabricated. The overpacks are not used inside DCPP. Under normal conditions of MPC transfer and storage operations, the potential does not exist for contaminating the overpacks. However, the interior design of the overpacks facilitates decontamination, if necessary. The cavities of the overpacks are mostly lined with steel and coated - including the cylindrical walls, pedestal that supports the MPC, and the lid - making them relatively easy to decontaminate.

Radiation protection technicians monitor the MPC transfer operations, and perform swipe surveys of the transfer cask, MPC lid, transporter, CTF, and overpack during and following each MPC transfer operation. If the transfer cask has contamination levels on its outer surfaces above those established by administrative controls to minimize the spread of contamination, it will be decontaminated prior to movement to the CTF. These measures help to minimize the spread of any contamination to the CTF and from the CTF to the storage pads.

As shown in Section 2.4 of the HI-STORM 100 System Final Safety Analysis Report (Reference 4), the overpack materials will be only slightly activated as a result of their long-term exposure to the relatively small neutron flux emanating from the spent fuel. This will allow the slightly activated overpack materials to qualify as Class A waste in stable form in accordance with 10 CFR 61.55 (Reference 5). As such, the material would be suitable for burial in a near-surface disposal site as low specific activity (LSA) material. The results for the overpacks can be conservatively applied to the ISFSI storage pads because the overpacks shield most of the neutron flux from the spent fuel. Hence, any tasks necessary to decommission overpacks and the storage pads are expected to involve only surface decontamination, as necessary, and not removal of activation products at depths below the surface.

The design of the transfer cask also facilitates its decontamination. It has layers of gamma (lead) and neutron shield materials sandwiched between steel. The inner and outer liners both consist of coated carbon steel, which is relatively easy to decontaminate.

In order to facilitate decommissioning of the CTF, nonthreaded surfaces, where practical, are covered with a nonporous coating. This provision helps to ensure that decontamination can be performed by wiping down surfaces or stripping the coating, without the need to use more aggressive methods (e.g., abrasive blasting, scabbling) that require removal of surface concrete.

Radioactive waste generated during decontamination operations will be packaged and temporarily staged for disposal in the low level waste holding area of the CTF. It is anticipated that this low-level waste holding area will be decommissioned last, following decommissioning of the storage casks, pads, and the remainder of the CTF.

Minimal nonradioactive hazardous materials may be used or stored at the Diablo Canyon ISFSI and any that are needed to support the ISFSI operations will be identified and controlled in accordance with procedures. Strict measures will be applied to prevent any hazardous materials from contacting radioactive contamination, so that mixed hazardous and radioactive waste will not be generated at the Diablo Canyon ISFSI.

CHAPTER 7

REFERENCES

1. Regulatory Guide 1.86, Terminating of Operating License for Nuclear Reactors, USNRC, June 1974.

2. PG&E's Decommissioning Funding Reports for Diablo Canyon Power Plant Units 1 and 2 and Humboldt Bay Power Plant, Letters DCL-01-026 and HBL-01-005 to the NRC, March 30, 2001.

3. Regulatory Guide 3.66, Standard Format and Content of Financial Assurance Mechanisms Required for Decommissioning Under 10 CFR Parts 30, 40, 72 and 72, USNRC, June 1990.

4. Final Safety Analysis Report for the HI-STORM 100 System, Holtec International Report No. HI-2002444, Revision 0, July 2000.

5. 10 CFR 61.55, Waste Classification.

4.6 DECOMMISSIONING PLAN

4.6.1 PRELIMINARY DECOMMISSIONING PLAN

Prior to the end of the Diablo Canyon ISFSI life, MPCs loaded with spent fuel will be transferred from storage overpacks into transportation casks and transported offsite. Since the MPCs are designed to meet DOE guidance applicable to MPCs for storage, transport, and disposal of spent fuel, the fuel assemblies will remain sealed in the MPCs such that decontamination of the MPCs is not required. Following shipment of the MPCs offsite, the ISFSI will be decommissioned by identification and removal of any residual radioactive material, and performance of a final radiological survey. Details on decommissioning are provided in the ISFSI License Application, Attachment F, "Preliminary Decommissioning Plan." A brief summary is provided herein.

4.6.2 FEATURES THAT FACILITATE DECONTAMINATION AND DECOMMISSIONING

The design features of the Diablo Canyon ISFSI provide for inherent ease and simplicity of decommissioning the ISFSI in conformance with 10 CFR 72.130. Details on these design features and measures, that will both minimize the potential for contamination and facilitate any required decontamination efforts, are provided in the ISFSI License Application, Attachment F, "Preliminary Decommissioning Plan."

4.6.3 COST OF DECOMMISSIONING AND FUNDING METHOD

10 CFR 72.30(b) requires that the proposed decommissioning plan include a decommissioning cost estimate, a funding plan, and a method of ensuring the availability of decommissioning funds.

The philosophy of operating the Diablo Canyon ISFSI is "start clean/stay clean." Thus, the intention is to maintain the facility free of radiological contamination at all times. During the operational phase of the facility, all radioactive contamination will be removed, if possible, immediately upon its discovery.

Nonetheless, a cost estimate for decommissioning has been done that assumes certain areas and components will require decontamination. As described in the Preliminary Decommissioning Plan, this cost estimate is part of the total estimate performed by TLG Services, Inc., for the DCPP Units 1 and 2. This detailed cost estimate is contained in the PG&E Decommissioning Funding Report to the NRC (Reference 1), as required by 10 CFR 50.75(f)(1). As shown therein, it is estimated that decommissioning the Diablo Canyon ISFSI will cost about $12.5 million when escalated to 2001 dollars - for the DECON alternative. The estimate of $12.5 million only covers the costs for decontamination and disposal of low-level waste; it does not cover the costs for demolition and disposal of noncontaminated material, which are estimated at $6.5 million in 2001 dollars.

In developing this estimate, TLG Services had to make some default assumptions regarding the spent fuel storage system and the size of the ISFSI due to PG&E having not yet selected the storage system vendor. TLG Services assumed "NUHOMS" storage casks would be used. The TLG Services' cost estimate will be updated to reflect the Holtec International HI-STORM 100 System. This update will be contained in the applicable biennial PG&E Decommissioning Funding Report to the NRC; thereafter, the Preliminary Decommissioning Plan and this SAR will be updated accordingly.

PG&E has established an external sinking trust fund account for decommissioning DCPP Units 1 and 2. As discussed in the Preliminary Decommissioning Plan and the Decommissioning Funding Report to the NRC (Reference 1), this account contains designated monies for decommissioning the Diablo Canyon ISFSI.

4.6.4 LONG-TERM LAND USE AND IRREVERSIBLE COMMITMENT OF RESOURCES

Following removal of all storage casks from the ISFSI and decontamination of the storage pads and the CTF, as necessary, these structures and associated areas can be released for unrestricted use.

The security-related structures and the CTF could be dismantled and removed. The concrete storage pads and the concrete floor of the CTF could be sectioned and removed, or alternatively left in place. In either case, the storage pads and CTF areas could be covered with top soil and replanted with native vegetation; thus, returning the land to its original condition.

The long-term plan will be addressed further in the final decommissioning plan that will be submitted prior to ISFSI license termination.

4.6.5 RECORDKEEPING FOR DECOMMISSIONING

Records important to decommissioning, as required by 10 CFR 72.30(d), will be maintained until the ISFSI is released for unrestricted use. See Section 3.0 of the ISFSI License Application, Attachment F, "Preliminary Decommissioning Plan," for the type of records that will be maintained. These records will be maintained at DCPP as part of the records management system.

4.6.6 REFERENCES

1. Decommissioning Funding Reports for Diablo Canyon Power Plant Units 1 and 2 and Humboldt Bay Power Plant, PG&E Letters DCL-01-026 and HBL-01-005 to the NRC, March 30, 2001.

13 DECOMMISSIONING EVALUATION

13.1 Review Objective

The primary objective of the review is to ensure that the applicant's provisions for eventual decontamination and decommissioning of the independent spent fuel storage installation (ISFSI) or monitored retrievable storage (MRS) give reasonable assurance of adequate protection of public health and safety. The review examines the design and operational features intended to facilitate eventual decommissioning, and the proposed decommissioning plan and associated financial assurance and recordkeeping requirements.

The overview of the decommissioning evaluation process given in Figure 13.1 shows that the decommissioning evaluation draws information from the application and from the results of design criteria evaluation and the conduct of operations evaluation.

13.2 Areas of Review

The following outline shows the areas of review addressed in Section 13.4, Acceptance Criteria, and Section 13.5, Review Procedures:

Design Features
Operational Features
Decommissioning Plan

13.3 Regulatory Requirements

This section identifies and presents a high-level summary of Title 10 of the Code of Federal Regulations (CFR) Part 72 relevant to the review areas addressed by this chapter. The NRC staff reviewer should read the exact regulatory language. The decommissioning of an ISFSI or MRS at the end of its useful life must also comply with the decommissioning criteria of 10 CFR Part 20, Subpart E, "Radiological Criteria for License Termination." A matrix at the end of this section matches the regulatory requirements identified in this section to the areas of review identified in the previous section.

72.24 Contents of application: Technical information
"Each application for a license under this part ... must consist of the following:
(g) An identification and justification for the selection of those subjects that will be probable license conditions and technical specifications.
(n) A description of the quality assurance program.
(q) A description of the decommissioning plan."

72.30 Financial assurance and recordkeeping for decommissioning
(a) "Each application under this part must include a proposed decommissioning plan."
(b) "The proposed decommissioning plan must also include a decommissioning funding plan."

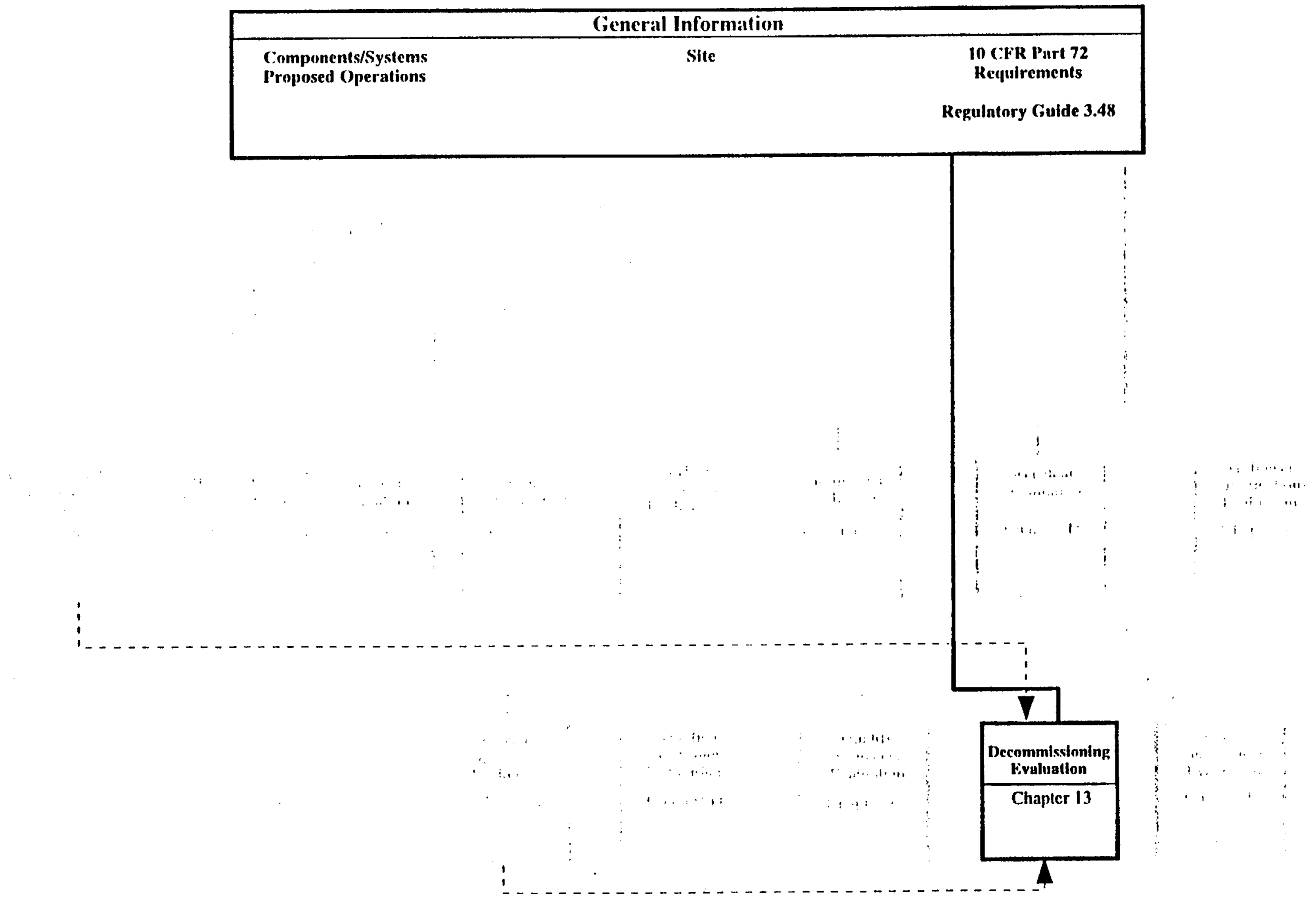

Figure 13.1 Overview of Decommissioning Evaluation

(d) "Each person licensed under this part shall keep records of information important to the decommissioning of a facility in an identified location until the site is released for unrestricted use.... Information the Commission considers important to decommissioning consists of --

(1) Records of spills or other unusual occurrences involving the spread of contamination in and around the facility, equipment, or site

(2) As-built drawings and modifications of structures and equipment in restricted areas

(3) A list contained in a single document and updated no less than every 2 years of the following:

(i) All areas designated and formerly designated as restricted areas as defined under 10 CFR 20.1003; and

(ii) All areas outside of restricted areas that require documentation under 72.30(d)(1).

(4) Records of the cost estimate performed for the decommissioning funding plan."

Subpart F - General Design Criteria

72.130. Criteria for decommissioning
"The ISFSI or MRS must be designed for decommissioning. Provisions must be made to facilitate decontamination of structures and equipment, minimize the quantity of radioactive wastes and contaminated equipment, and facilitate the removal of radioactive wastes and contaminated materials at the time the ISFSI or MRS is permanently decommissioned."

A matrix showing the primary relationship of these regulations to the specific areas of review in this chapter is given in Table 13.1. The reviewer should independently verify the relationships in this matrix to ensure that no requirements are overlooked because of unique applicant design features.

Table 13.1 Relationship of Regulations and Areas of Review

Areas of Review	10 CFR Part 72 Regulations	
	72.24	72.30
Design Features	●	●
Operational Features	●	●
Decommissioning Plan	●	●

13.4 Acceptance Criteria

The ISFSI must be decommissioned at the end of service life, and every effort must be made to terminate the license and release the ISFSI site for unrestricted use according to the requirements of 10 CFR Part 20, Subpart E, "Radiological Criteria for License Termination." The requirements related to eventual decommissioning the ISFSI or MRS applicable at the time of initial licensing are satisfied if the applicant adequately addresses the acceptance criteria for design features, operational features, and decommissioning plan.

13.4.1 Design Features

The application must identify the design features included in the design of the ISFSI or MRS that will facilitate decontamination and decommissioning. This information may be in the Safety Analysis Report (SAR) or in the decommissioning plan.

Design features include surfaces that are less susceptible to contamination (or activation) and are readily decontaminated, as well as shielding to minimize any occupational exposure associated with decontamination. Design features also include equipment to facilitate the decontamination and removal of air circulation and filtration systems, and components of waste treatment and packaging systems.

13.4.2 Operational Features

The application must identify the operational features that will facilitate eventual decontamination and decommissioning of the ISFSI or MRS. Such features include minimizing contamination buildup on components, maintaining accurate records of spills or other unusual occurrences involving the spread of contamination, and maintaining accurate as-built drawings or suitable substitutions. This information is in either the SAR or the decommissioning plan, and includes technical specifications or aspects of the proposed quality assurance (QA) program.

13.4.3 Decommissioning Plan

The application must include a proposed decommissioning plan as required by 10 CFR 72.30. The plan must describe the proposed practices and procedures for (a) the decontamination of the site and facilities, and (b) the disposal of residual radioactive materials after the stored spent fuel or high-level waste has been removed. Design features of the ISFSI or MRS that facilitate its decommissioning at the end of its useful life must be identified and discussed.

The plan should provide reasonable assurance that the proposed decontamination and decommissioning of the ISFSI or MRS will adequatly protect public health and safety and will leave the site suitable for unrestricted use. A site is considered acceptable for unrestricted use if (a) residual radioactivity has been reduced to levels that are as low as is reasonably achievable (ALARA), and (b) compliance with other radiological criteria of 10 CFR 20.1402 can be demonstrated.

The decommissioning plan submitted with the license application need not comply with the form and content requirements of Regulatory Guide 3.65, "Standard Format and Content of Decommissioning Plans for Licensees Under 10 CFR Parts 30, 40, and 70." Regulatory Guide 3.65 provides guidance on the content and format of final decommissioning plans submitted at the time of license termination.

As part of the decommissioning plan, the application must contain a funding plan, which, in turn, includes a cost estimate for the decommissioning and a financial assurance mechanism that will ensure availability of funds in the amount of the cost estimate.

Guidance on the format and content of the financial assurance mechanism and the means for cost estimating are provided in Regulatory Guide 3.66, "Standard Format and Content of Financial Assurance Mechanisms Required for Decommissioning Under 10 CFR 30, 40, 70 and 72." A legal, executed copy of the financial assurance mechanism must be provided. Acceptance criteria are provided in NUREG-1337, Rev. 1, "Standard Review Plan (SRP) for the Review of Financial Assurance Mechanisms for Decommissioning Under 10 CFR Parts 30, 40, 70, and 72."

The funding plan must be signed (i.e., certified) by an individual authorized to make financial commitments for the applicant.

13.5 Review Procedures

13.5.1 Design Features

The reviewer should first ensure that the application identifies, discusses, and justifies the design features and choices as they relate to decommissioning the ISFSI or MRS, as required by 10 CFR 72.24(g), 72.30, and 72.130.

The reviewer should determine whether the design satisfactorily facilitates decommissioning. The design can be considered to meet this requirement if (a) provisions are incorporated where feasible and economic, and (b) design choices that support decommissioning were selected over competing alternatives, or an acceptable rationale for not adopting the most favorable alternatives is provided.

In determining that the design facilitates decommissioning, the reviewer should consider the extent to which the applicant has selected design features which have characteristics favorable to decommissioning. Examples of favorable design features are:

- Selection of materials and processes to minimize waste production
- Minimize mass of shielding materials subject to activation
- Facilitate future demolition and removal by use of modular design and inclusion of lifting points (with anticipation of the size containers that may be used for transportation and permanent disposal)
- Selection of materials compatible with projected decommissioning and waste processing
- Use of minimum surface roughness finishes on structures, systems, and components (SSCs)
- Use of selected coatings to preclude penetration into porous materials of radioactive gas, condensate, or deposited aerosols (if probably present), to permit future decontamination by surface treatment
- Incorporation of features to contain leaks and spills

- Consideration of current industry technology for waste production minimization.

In performing these design reviews, the reviewer should also ensure that the design features have adequately considered health and safety, including provisions to maintain occupational and public radiation exposures ALARA during decommissioning.

13.5.2 Operational Features

The reviewer should review the SAR and decommissioning plan for operational features that facilitate eventual decommissioning and minimize the associated impacts. The reviewer should verify that the applicant has committed to a plan to keep records of spills or other unusual occurrences until the license is terminated. Records should include information on contamination that may have spread to inaccessible areas, as in the case of seepage into porous materials like concrete. Records must include any known information on identification of nuclides, quantities, forms, and concentrations. The reviewer should verify that the applicant has a plan to maintain records of as-built drawings and modifications (or suitable substitute records if drawings are not available) of structures and equipment in restricted areas.

The reviewer should consult with the reviewer for site-generated waste confinement and management (Chapter 14) to determine whether proposed operations of waste management systems have adequately addressed facilitation of decommissioning. The reviewer should consult with the radiation protection reviewer (Chapter 11) to determine whether proposed health physics surveys and recordkeeping will facilitate decommissioning.

13.5.3 Decommissioning Plan

The review has three major elements: (a) a determination of overall plan adequacy and completeness, including proposed decontamination and decommissioning activities, (b) the decommissioning cost estimate, and (c) the financial assurance mechanism.

13.5.3.1 General Provisions

In preparing for the review of the proposed decommissioning plan, the reviewer should consult the general review procedures contained in Policy and Guidance Directive FC-91-2, "Standard Review Plan: Evaluating Decommissioning Plans for Licensees Under 10 CFR Parts 30, 40, and 70." However, those review procedures apply to final plans submitted in support of license termination. The reviewer should also consult Regulatory Guide 3.65, but it also applies to plans prepared before license termination.

In determining the acceptability of the level of detail, the reviewer should consider the fact that plans submitted with license applications are prospective in nature and do not have the benefit of knowledge gained over the course of facility operation (e.g., detailed knowledge of the types, extent, and precise locations of contamination). Thus, it is not reasonable to expect plans submitted with applications to have the same level of detail as final plans, especially with respect to elements such as planned decontamination activities and the final radiation survey. As described later in this section, the consideration regarding level of detail does not apply to the decommissioning funding plan.

The reviewer should first determine that the decommissioning plan includes each of the elements required by 10 CFR 72.30. In addition to the identification and discussion of design features that facilitate decontamination and decommissioning (described in Section 13.5.1), the reviewer should ensure the plan includes a decommissioning funding plan, a cost estimate for decommissioning, and a financial assurance mechanism. The reviewer should verify that the plan is consistent with the objective of "timely removal of the facility from service and reducing residual radioactivity to a level that permits release of the property for unrestricted use and license termination."

Although the decommissioning plan specifically applies to activities licensed under Part 72, there may be interrelationships with other licensed activities, including co-located Part 50 facilities. The reviewer should evaluate any proposed provisions intended to accommodate conditions associated with the co-location of facilities. For example, the reviewer should consider a case in which a spill from reactor operations occurred underground in an area beneath a proposed ISFSI pad location and the licensee proposes to delay decommissioning this contaminated soil because of concerns with compromising ISFSI pad integrity. In this example, the reviewer should determine whether (a) such a condition was adequately addressed as part of designing the ISFSI for decommissioning, and (b) it is acceptable to include such interrelated activities as part of ISFSI decommissioning.

13.5.3.2 Cost Estimate

The cost estimate for decommissioning is expected to be a major review area that requires independent staff calculations in most cases. The reviewer should ensure that the cost estimate is based on "total project costs," including all applicable direct and indirect costs. The reviewer should ensure that the cost estimate covers the complete scope of the decommissioning plan, including:

- Planning and preparation of the facility for decommissioning
- Decontamination and dismantling of structures, systems, and components
- Packaging, transportation, and disposal of radioactive wastes
- Final radiation survey.

The reviewer should evaluate the applicant's methods and assumptions for estimating costs. The reviewer should verify that estimates are based on available technologies, practices, and disposal capacity. The reviewer should ensure that conservative adjustments have been applied to account for uncertainties in the cost estimate and that a contingency amount has also been applied.

The reviewer should consider the following items that could result in underestimating the decommissioning cost:

- Low estimates of volume of low-level waste that will probably require stabilization, containerization, transportation, and disposal

- Uncertainty in per-cubic-foot costs of disposal of low-level waste, and processing and disposal costs of pool coolant

- Need to transfer stored materials to other casks for transportation

- Low estimates of time for design and planning, obtaining regulatory approvals, and procurement of services

- Low estimate of staff and physical infrastructure costs during planning for engineering, procurement, and performance of decontamination and decommissioning operations.

The reviewer should ensure that the basis year for the dollar estimate (e.g., 1997 dollars) is identified. This year should not be for a year earlier than that in which the cost estimate is prepared. The reviewer should ensure that the plan includes provisions for updating the cost estimate, including periodic updates, as well as making changes necessitated by contamination events (e.g., spills and other accidents), new regulations, etc. The reviewer should ensure that the cost estimate does not include costs for activities not necessary to terminate the NRC license (e.g., dismantling of non-radioactive and non-contaminated structures, systems and components).

The reviewer should validate the cost estimate by performing independent calculations. The reviewer should clearly identify any methods or assumptions that differ from those in the applicant's cost estimate and discuss differences in results. The reviewer should evaluate nuclear facility cost experience available to the NRC and discuss trends that indicate how cost estimates have compared with actual costs.

13.5.3.3 Financial Assurance Mechanism

The review of the applicant's proposed financial assurance mechanism should use the specific guidance provided in NUREG/CR-1337, Rev. 1, "Standard Review Plan (SRP) for the Review of Financial Assurance Mechanisms for Decommissioning Under 10 CFR Parts 30, 40, 70, and 72." The reviewer should verify that the proposed mechanism conforms to the prescribed format and content. In reviewing the contents, the reviewer should consult with the Division of Waste Management and possibly the Office of the General Counsel for technical and legal assistance in this area.

13.6 Evaluation Findings

The reviewer should prepare evaluation findings on satisfaction of the regulatory requirements related to planning and providing for decommissioning, as identified at Section 13.3. If the documentation submitted with the application fully supports positive findings for each of the regulatory requirements, the statements of findings should be as follows (numbering is for convenience in referencing the FSRP section):

F13.1 The staff has reviewed the proposed decommissioning plan documentation submitted by the applicant for the [ISFSI/MRS] facility in accordance with the standard review plan for spent fuel dry storage facilities, and the description of the plan in the SAR. The staff has determined that the decommissioning plan submitted by the applicant sufficiently provides reasonable assurance that decommissioning issues for the [ISFSI/MRS] facility have been adequately characterized, so that the site will ultimately be available for unrestricted use for any private or public purpose. The staff, therefore, concludes that the proposed decommissioning plan complies with 10 CFR Part 72.

F13.2 The staff has reviewed the decommissioning funding plan documentation submitted by the applicant for the [ISFSI/MRS] facility in accordance with the standard review plan for spent fuel dry storage facilities. The staff has determined that the decommissioning funding plan submitted by the applicant is sufficient to provide reasonable assurance that costs related to decommissioning as characterized by the proposed decommissioning plan have been adequately estimated. The staff, therefore, concludes that the cost estimate in the decommissioning funding plan complies with 10 CFR Part 72.

F13.3 The staff has reviewed the financial assurance documentation submitted by the applicant, as part of the decommissioning funding plan for the [ISFSI/MRS] facility, in accordance with the standard review plan for spent fuel dry storage facilities. The staff has determined that the financial assurance mechanisms submitted by the applicant are sufficient to provide reasonable assurance that adequate funds will be available to decommission the facility so that the site will ultimately be available for unrestricted use for any private or public purpose. The staff, therefore, concludes that the financial assurance mechanisms in the decommissioning funding plan comply with 10 CFR Part 72.

13.7 References

NRC documents referenced are identified at Consolidated References, Section 17.