HUMBOLDT BAY ISFSI
LICENSE APPLICATION

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LICENSE APPLICATION

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LICENSE APPLICATION

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Humboldt Bay

Independent Spent Fuel Storage Installation

License Application

Pacific Gas and Electric Company
Eureka, California

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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 Humboldt Bay Power Plant (HBPP) in Eureka, California. The proposed facility is named the Humboldt Bay 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. This is provided as a separate document titled "Humboldt Bay Independent Spent Fuel Storage Installation Safety Analysis Report".
c. The Emergency Plan required by 10 CFR 72.32. This is provided as a separate document titled "Humboldt Bay Independent Spent Fuel Storage Installation Emergency Plan." (Attachment B)
d. The proposed technical specifications. These are provided as a separate document titled "Humboldt Bay Independent Spent Fuel Storage Installation Proposed Technical Specifications." (Attachment C)
e. The environmental report required by 10 CFR 72.34. This is provided in a separate document titled "Humboldt Bay Independent Spent Fuel Storage Installation Environmental Report."
f. Security information as required by 10 CFR 72, Subpart H. The physical security program for the Humboldt Bay ISFSI is being submitted under separate cover as documents titled "Humboldt Bay Independent Spent Fuel Storage Installation Physical Security Plan", "Humboldt Bay Independent Spent Fuel Storage Installation Safeguards Contingency Plan", and "Humboldt Bay Independent Spent Fuel Storage Installation Security Training" and Qualification Plan." (Reference PG&E Letter HIL-03-002, dated December 9, 2003.)
g. A training program as required by 10 CFR 72.192. This is provided as a separate document titled "Humboldt Bay Independent Spent Fuel Storage Installation Training Program." (Attachment D)

h. A description of the quality assurance program required by 10 CFR 72.24(n). This is provided as a revision to Diablo Canyon Power Plant (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 will be the owner of the Humboldt Bay Independent Spent Fuel Storage Installation.

The address for PG&E at Humboldt Bay Power Plant is:

Pacific Gas and Electric Company
Humboldt Bay Power Plant
1000 King Salmon Avenue
Eureka, CA 95503

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, 2002, PG&E Corporation had $33.7 billion in assets. PG&E Corporation generated $12.5 billion in operating revenues for 2002. As of December 31, 2002, PG&E Corporation and its subsidiaries and affiliates had approximately 22,000 employees. As of December 31, 2002, PG&E had $24.5 billion in assetsand generated $10.5 billion in operating revenues for 2002.

As of December 31, 2002, PG&E had approximately 20,400 employees and it is the sole owner and operator of HBPP.

1.4 Legal Status and Organization

PG&E is a corporation organized and exists under the laws of the State of California.I 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 2002 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 Humboldt Bay ISFSI. The total cost of building and operating the ISFSI through 2015 is estimated to be approximately $66 million. The cost assumes six storage casks are loaded to completely empty the spent fuel pool at HBPP of spent fuel and GTCC waste. Additional operating costs, beyond 2015 are estimated to be $2.7 million per year. All costs are in year 2002 dollars. The funds necessary to cover the costs of construction and operating the ISFSI will be paid from the Humboldt Decommissioning Trusts as approved by the California Public Utilities Commission.

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.

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 a settlement agreement executed with the CPUC Staff in June 2003, PG&E Corporation, PG&E and the CPUC Staff agreed to jointly support a new plan of reorganization (Settlement Plan) submitted to the Bankruptcy Court under which PG&E would be a vertically integrated utility. To become effective, among other conditions, the settlement agreement must be entered into by the CPUC by December 31, 2003. Assuming that all approvals are received in a timely fashion, PG&E anticipates exiting Chapter 11 bankruptcy in the first quarter of 2004. The funds necessary for decommissioning of the proposed ISFSI are estimated to be approximately $900,000 when escalated to 2002 dollars. The detailed cost estimate was reflected in PG&E's March 2003 Decommissioning Funding Report to the Nuclear Regulatory Commission (NRC) as required by 10 CFR 50.75 (f)(1). PG&E has established an external sinking fund account for decommissioning HBPP Unit 3, as discussed in the March 2003 Decommissioning Funding Report to the NRC. This account contains monies for decommissioning the ISFSI.

1.6 Site Location and Completion Dates

The Humboldt Bay ISFSI will be located at the HBPP within the existing owner-controlled area in Humboldt County, California.

PG&E requests that the 10 CFR Part 72 license and associated 10 CFR Part 50 license amendment be issued by the end of 2005. Assuming no delays in the review process and NRC issuance of the Humboldt Bay ISFSI license in 2005, PG&E will apply to the CPUC to use Humboldt Bay Decommissioning Trust funds for procurement and construction of the ISFSI and after CPUC approval, will proceed with ISFSI procurement and construction.

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 Humboldt Bay ISFSI are contained in Chapter 9 of the Humboldt Bay ISFSI Safety Analysis Report (SAR). 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 existing HBPP organization can accommodate the ISFSI storage-related responsibilities without the need for obtaining additional personnel. Qualified contractor personnel may be used for cask handling and 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 Humboldt Bay ISFSI will use sealed multi-purpose canisters (MPCs) placed inside Holtec HI-STAR HB storage overpacks to store spent fuel and other approved contents from the HBPP Unit 3. The spent fuel assemblies that meet the Humboldt Bay ISFSI Technical Specifications and Humboldt Bay ISFSI SAR Chapter 10 requirements will be placed into the MPCs under water in the HBPP Unit 3 spent fuel pool. The loaded MPCs and associated HI-STAR HB 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, the cavity backfilled with helium, and the vent and drain ports in the lid welded closed. The HI-STAR HB cask will then be transported to the ISFSI storage vault. At the ISFSI storage vault, the HI-STAR HB will be placed in the vault where it will remain until it is taken off-site by the Department of Energy. The HI-STAR HB storage overpack and vault are totally passive systems with sufficient cooling to maintain safe fuel cladding temperatures. The HI-STAR HB storage cask provides shielding, and no radioactive materials are anticipated to be released under any operating conditions.

The Humboldt Bay ISFSI is designed to store the spent fuel resulting from the operation of the HBPP Unit 3. The total spent fuel storage design capacity of the facility is 400 spent fuel assemblies or up to five casks including a sixth cask for storage of greater than Class C waste.

The SAR filed with this application describes the design criteria for the dry cask storage system, transporter, storage vault, and all related matters pertaining to operation of the ISFSI. The Holtec International HI-STAR 100 System Final Safety Analysis Report Revision 1 contains detailed descriptions of the dry cask storage system and how it meets the prescribed criteria. This documentation has been previously filed with the NRC and is specifically relied upon in this application, as referenced herein. The NRC has previously issued Certificate of Compliance 72-1008 for the HI-STAR 100 system. The combination of the Humboldt Bay ISFSI SAR and the Holtec reports listed in the Humboldt Bay SAR Section 1.5 provide all the information required by 10 CFR 72.

The Humboldt Bay 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 SARs 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 Humboldt Bay ISFSI complies with all the applicable 10 CFR 72 general design criteria. The specific conformance of the Humboldt Bay 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 4.2-11.

5.0 Operating Procedures-Administrative and Management Controls

The Humboldt Bay ISFSI will be operated under the same management organization responsible for operation of the HBPP Unit 3. This organization is described in Chapter 9 of the Humboldt Bay ISFSI SAR.

Procedures for operation of the Humboldt Bay ISFSI will be developed by PG&E and incorporated into existing HBPP station procedures. Operation of the Humboldt Bay ISFSI will consist of loading spent fuel and associated nonfuel hardware fuel into MPCs and HI-STAR HB casks, sealing the MPCs, transporting the HI-STAR HB and MPC to the ISFSI storage vault, and placing the loaded HI-STAR HB cask into the ISFSI storage vault.

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 Humboldt Bay 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, as revised to be applicable to the Humboldt Bay ISFSI. 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 Humboldt Bay ISFSI SAR, and in Attachment E, personnel working at the Humboldt Bay ISFSI will receive training to provide and maintain a well-qualified work force for safe operation of the ISFSI.

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 Humboldt Bay ISFSI SAR. This system will meet the requirements of 10 CFR 72.72.

9.0 Physical Protection

The physical security program for the Humboldt Bay ISFSI is provided in the Humboldt Bay ISFSI 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. These documents are being submitted under separate cover. (Reference PG&E Letter HIL-03-002 dated December 9, 2003.)

10.0 Decommissioning Plan

The dry cask storage system design concept used at the Humboldt Bay ISFSI features inherent ease and simplicity for decommissioning. At the end of its service lifetime, decommissioning of the Humboldt Bay ISFSI will be accomplished by removing the HI-STAR HBs containing the spent fuel from the storage vault 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.

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

A preliminary decommissioning plan is provided in Attachment F.

11.0 Emergency Plan

The Humboldt Bay ISFSI 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 Humboldt Bay ISFSI. The Humboldt Bay ISFSI Emergency Plan has been developed to reflect the actions to be taken during postulated events described in Chapter 8 of the SAR.

The Humboldt Bay ISFSI Emergency Plan is included as Attachment B.

12.0 Environmental Report

The environmental impacts of all aspects of the Humboldt Bay 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.

HUMBOLDT BAY ISFSI
LICENSE APPLICATION

ATTACHMENT A

PG&E YEAR IN REVIEW & FINANCIAL STATISTICAL REPORT

PG&E Corporation 2002 Annual Report

Corporate Overview

PG&E Corporation is a national energy company with approximately $12 billion in revenues in 2002, and approximately $34 billion in assets at the end of 2002. It is the parent company of Pacific Gas and Electric Company (the Utility), one of the largest combination natural gas and electric utilities in the United States, serving Northern and Central California. PG&E Corporation is also the parent company of PG&E National Energy Group, Inc. (PG&E NEG), an integrated energy company with operations that include power generation, wholesale energy marketing and trading, risk management, and natural gas transmission in North America.

Financial Highlights
PG&E Corporation

(unaudited, dollars in millions, except per share amounts)	2002	2001
Operating Revenues	$ 12,495	$ 12,210
Net Income (Loss)		
Net income from operations [1]	$ 864	$ 1,099
Headroom [2]	1,051	
Items impacting comparability [3]	(2,789)	
Reported net income (loss)	$ (874)	$ 1,099
Income (Loss) Per Common Share, fully diluted		
Net income from operations [1]	$ 2.33	$ 3.02
Headroom [2]	2.83	
Items impacting comparability [3]	(7.52)	
Reported net income (loss) per common share	$ (2.36)	$ 3.02
Dividends Per Common Share	$ –	$ –
Total Assets	$ 33,696	$ 35,963
Number of common shareholders at December 31	117,816	125,739
Number of common shares outstanding at December 31	405,486,015 [4]	387,898,848 [4]

[1] Net income from operations does not meet the guidelines of accounting principles generally accepted in the United States of America. It excludes items impacting comparability and should not be considered an alternative to net income.

[2] Headroom reflects the current recovery in the Utility's existing electric rates of prior uncollected costs previously written-off in accordance with accounting principles generally accepted in the United States of America.

[3] Items impacting comparability for the year ended December 31, 2002 include PG&E NEG impairments and write-offs of merchant assets, long-term turbine prepayments and related capitalized development and construction costs of $1.6 billion ($4.21 per share) related to the planned sale, transfer or abandonment of these assets; an impairment charge of $767 million ($2.07 per share) related to the planned sale of USGen New England and Energy Trading Canada which are assets held for sale and classified as discontinued operations; net charges of $156 million ($0.42 per share) for hedge contracts, primarily interest rate swaps, at PG&E NEG that were terminated by counterparties as a result of defaults in the terms of various financing arrangements; the net effect of incremental interest costs of $351 million ($0.95 per share) from the increased amount and cost of debt resulting from the Utility's Chapter 11 filing; the write-off of $68 million ($0.18 per share) of previously capitalized debt costs and discounts associated with PG&E Corporation's prepayment of its Tranche A loan and changes in the terms of its Tranche B loan in conjunction with its loan waiver extension; the net cumulative effect of a changes in accounting principle and mark-to-market methodology of $55 million ($0.14 per share); restructuring costs at PG&E NEG of $27 million ($0.07 per share), generally consisting of external legal consulting and financial advisory fees, severance costs and lease cancellation costs; increased costs of $132 million ($0.36 per share) related to the Utility's Chapter 11 filing and generally consisting of external legal consulting and financial advisory fees; and net tax charges of $66 million ($0.18 per share) primarily related to a valuation allowance against state deferred tax assets of PG&E NEG that are not probable of future realization. Partially offsetting these charges was the Utility's net reversal of wholesale energy charges of $352 million ($0.95 per share); and the third quarter change in the mark-to-market value of PG&E NEG warrants of $42 million ($0.11 per share) outstanding under PG&E Corporation's loans.

Items impacting comparability in 2001 include the collection of previously written-off transition costs of $458 million ($1.26 per share) and the cumulative effect of a change in accounting principle of $9 million ($0.02 per share) partially offset by a loss of $66 million ($0.18 per share) on a involuntary terminations of gas transportation hedges resulting from the Utility's bankruptcy; incremental interest costs of $262 million ($0.72 per share) from the increased amount and cost of debt resulting from the California energy crisis and the Utility's bankruptcy; increased costs of $78 million ($0.21 per share) related to the Utility's bankruptcy and generally consisting of external legal consulting and financial advisory fees; the net prior year impacts associated with current year decisions issued by the California Public Utilities Commission on rehearings of the Utility's 1999 General Rate Case of $26 million ($0.07 per share); and the loss on termination of certain contracts with Enron Corp. of $35 million ($0.10 per share) attributed to its bankruptcy filing.

(4) 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.

SELECTED FINANCIAL DATA

(in millions, except per share amounts)	2002	2001	2000	1999	1998
PG&E Corporation [1]					
For the Year					
Operating revenues	$ 12,495	$ 12,210	$ 12,568	$ 10,956	$ 11,532
Operating income (loss)	1,132	2,591	(4,929)	829	2,097
Income (Loss) from continuing operations	(57)	983	(3,423)	(49)	762
Earnings (Loss) per common share from continuing operations, basic	(0.15)	2.71	(9.45)	(0.13)	1.99
Earnings (Loss) per common share from continuing operations, diluted	(0.15)	2.70	(9.45)	(0.13)	1.99
Dividends declared per common share	–	–	1.20	1.20	1.20
At Year-End					
Book value per common share	$ 9.47	$ 11.91	$ 8.76	$ 19.13	$ 21.08
Common stock price per share	13.90	19.24	20.00	20.50	31.50
Total assets	33,696	35,963	36,152	29,588	33,234
Long-term debt (excluding current portion)	4,345	7,222	5,475	6,785	7,422
PG&E NEG debt in default	4,230	–	–	–	–
Rate reduction bonds (excluding current portion)	1,160	1,450	1,740	2,031	2,321
Financial debt subject to compromise	5,605	5,651	–	–	–
Redeemable preferred stock and securities of subsidiaries (excluding current portion)	335	635	635	635	635
Pacific Gas And Electric Company [1]					
For the Year					
Operating revenues	$ 10,514	$ 10,462	$ 9,637	$ 9,228	$ 8,924
Operating income (loss)	3,913	2,478	(5,201)	1,993	1,876
Income (Loss) available for (allocated to) common stock	1,794	990	(3,508)	763	702
At Year-End					
Total assets	$ 24,551	$ 25,269	$ 21,988	$ 21,470	$ 22,950
Long-term debt (excluding current portion)	2,739	3,019	3,342	4,877	5,444
Rate reduction bonds (excluding current portion)	1,160	1,450	1,740	2,031	2,321
Financial debt subject to compromise	5,605	5,651	–	–	–
Redeemable preferred stock and securities (excluding current portion)	286	586	586	586	586

[1] See Management's Discussion and Analysis of Financial Condition and Results of Operations and Notes to the Consolidated Financial Statements for discussion of matters relating to certain data.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

PG&E Corporation is an energy-based holding company headquartered in San Francisco, California that conducts its business through two principal subsidiaries: Pacific Gas and Electric Company (the Utility), an operating public utility engaged primarily in the business of providing electricity, natural gas distribution, and transmission services throughout most of Northern and Central California, and PG&E National Energy Group, Inc. (PG&E NEG), a company engaged in power generation, wholesale energy marketing and trading, risk management, and natural gas transmission.

The Utility filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code (Bankruptcy Code) in the Bankruptcy Court for the Northern District of California (Bankruptcy Court) on April 6, 2001. Pursuant to Chapter 11, the Utility retains control of its assets and is authorized to operate its business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court. The factors causing the Utility to take this action are discussed in this Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) and in Note 2 of the Notes to the Consolidated Financial Statements.

PG&E NEG and its subsidiaries are principally located in the United States and Canada and include:

- PG&E Generating Company, LLC and its subsidiaries (collectively, PG&E Gen LLC);
- PG&E Energy Trading Holdings Corporation and its subsidiaries (collectively, PG&E Energy Trading or PG&E ET);
- PG&E Gas Transmission Corporation and its subsidiaries (collectively, PG&E GTC), which includes PG&E Gas Transmission, Northwest Corporation and its subsidiaries, including North Baja Pipeline, LLC (NBP) (collectively, PG&E GTN).

PG&E NEG also has other less significant subsidiaries.

PG&E National Energy Group, LLC owns 100 percent of the stock of PG&E NEG, GTN Holdings, LLC owns 100 percent of the stock of PG&E GTN, and PG&E Energy Trading Holdings, LLC owns 100 percent of the stock of PG&E ET. The organizational documents of PG&E NEG and these limited liability companies require unanimous approval of their respective boards of directors, including at least one independent director, before they can:

- Consolidate or merge with any entity;
- Transfer substantially all of their assets to any entity; or
- Institute or consent to bankruptcy, insolvency or similar proceedings or actions.

The limited liability companies may not declare or pay dividends unless the respective boards of directors have unanimously approved such action, and the company meets specified financial requirements.

As a result of the sustained downturn in the power industry, PG&E NEG and its affiliates have experienced a financial downturn, which caused the major credit rating agencies to downgrade PG&E NEG's and its affiliates' credit ratings to below investment grade. PG&E NEG is currently in default under various recourse debt agreements and guaranteed equity commitments totaling approximately $2.9 billion. In addition, other PG&E NEG subsidiaries are in default under various debt agreements totaling approximately $2.5 billion, but this debt is non-recourse to PG&E NEG. PG&E NEG and these subsidiaries continue to negotiate with their lenders regarding a restructuring of this indebtedness and these commitments. The factors affecting PG&E NEG's business causing these defaults and the principal actions being taken by PG&E NEG are discussed later in this

MD&A and in Note 3 of the Notes to the Consolidated Financial Statements.

During the fourth quarter of 2002, PG&E NEG and certain subsidiaries have agreed to sell or have sold certain assets, have abandoned other assets, and have significantly reduced energy trading operations. As a result of these actions, PG&E NEG has incurred pre-tax charges to earnings of approximately $3.9 billion in 2002. PG&E NEG and its subsidiaries are continuing their efforts to abandon, sell, or transfer additional assets in an ongoing effort to raise cash and reduce debt, whether through negotiation with lenders or otherwise. As a result, PG&E NEG expects to incur additional substantial charges to earnings in 2003 as it restructures its operations. In addition, if a restructuring agreement is not reached and the lenders exercise their default remedies, or if the financial commitments are not restructured, PG&E NEG and certain of its subsidiaries may be compelled to seek protection under or be forced into a proceeding under the Bankruptcy Code. Management does not expect that the liquidity constraints of PG&E NEG and its subsidiaries will affect the financial condition of PG&E Corporation or the Utility.

PG&E Corporation has identified three reportable operating segments:

- Utility;
- Integrated Energy and Marketing, or the Generation Business; and
- Interstate Pipeline Operations, or the Pipeline Business.

These segments were determined based on similarities in the following characteristics:

- Economic;
- Products and services;
- Types of customers;
- Methods of distribution;
- Regulatory environment; and
- How information is reported to and used by PG&E Corporation's chief operating decision makers.

These three reportable operating segments provide different products and services and are subject to different forms of regulation or jurisdictions. Financial information about each reportable operating segment is provided in this MD&A and in Note 17 of the Notes to the Consolidated Financial Statements.

This discussion and analysis explains the general financial condition and the results of operations of PG&E Corporation and its subsidiaries including:

- Factors that affect each business;
- A comparison of revenues and expenses and why they changed between years;
- Where earnings came from;
- How all of this affects overall financial condition;
- What expenditures for capital projects were for 2000 through 2002, and are expected to be through 2004; and
- The expected sources of cash for future capital expenditures.

This is a combined annual report of PG&E Corporation and the Utility and includes separate Consolidated Financial Statements for each of these two entities. The Consolidated Financial Statements of PG&E Corporation reflect the accounts of PG&E Corporation, the Utility, PG&E NEG, and other 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 combined MD&A should be read in conjunction with the Consolidated Financial Statements.

Forward-looking statements and risk factors

This combined annual report, including the Letter to Shareholders and this MD&A, contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements are based on current expectations and on 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," "could," "should," "would," "may," 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 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 from historical results, include:

Recovery of Under-collected Power Procurement and Transition Costs Previously Written Off. The extent to which the Utility is able to recover its under-collected power procurement and transition costs previously written off depends on many factors, including:

- What costs the California Public Utilities Commission (CPUC) determines are eligible for recovery as transition costs;
- When the Utility's rate freeze ended, as determined by the CPUC;
- Sales volatility and the level of direct access customers (i.e., those customers who choose an alternative energy provider);
- Changes in the California Department of Water Resources' (DWR), revenue requirements required to be remitted to the DWR from existing retail rates;
- Changes in the Utility's authorized revenue requirements;
- Future regulatory or judicial decisions that determine whether the Utility is allowed under state law to recover under-collected power procurement and transition costs from its customers after the end of the rate freeze; and
- The outcome of the Utility's claims against the CPUC Commissioners for recovery of under-collected power procurement and transition costs based on the federal filed rate doctrine.

Refundability of Amounts Previously Collected. Whether the Utility is required to refund to ratepayers amounts previously collected depends on many factors including:

- Whether the CPUC determines that certain transition or procurement costs recovered in revenues collected by the Utility were not eligible transition costs or otherwise reduces the amount of revenues authorized to recover such transition or procurement costs;
- Whether the CPUC ultimately determines that certain past power procurement costs incurred by the Utility were not reasonably incurred and should be disallowed; and
- The purposes for which the CPUC ultimately determines that surcharges approved by the CPUC in January, March, and May 2001 may be used.

Outcome of the Utility's Bankruptcy Case. The pace and outcome of the Utility's bankruptcy case will be affected by:

- Whether the Bankruptcy Court confirms the Utility's proposed plan of reorganization (Utility's Plan), the alternative plan sponsored by the CPUC and the Official Committee of Unsecured Creditors (the CPUC/OCC Plan), or some other plan of reorganization;
- Whether regulatory and governmental approvals required to implement a confirmed plan are obtained and the timing of such approvals;
- Whether there are any delays in implementation of a plan due to litigation related to regulatory, governmental, or Bankruptcy Court orders; and
- Future equity or debt market conditions, future interest rates, future credit ratings,

and other factors that may affect the ability to implement either plan or affect the amount and value of the securities proposed to be issued under either plan.

Operating Environment. The amount of operating income and cash flows the Utility may record may be influenced by the following:

- Future regulatory actions regarding the Utility's procurement of power for its retail customers;
- The terms and conditions of the Utility's long-term generation procurement plan as approved by the CPUC;
- The ability of the Utility to timely recover in full its costs including its procurement costs;
- Future sales levels, which can be affected by general economic and financial market conditions, changes in interest rates, weather, conservation efforts, outages, and the level of direct access customers;
- The demand for and pricing of natural gas transportation and storage services, which may be affected by weather, overall gas fired generation, and price spreads between various natural gas delivery points;
- Changes in the Utility's authorized revenue requirements; and
- Acts of terrorism, storms, earthquakes, accidents, mechanical breakdowns, or other events or perils that result in power outages or damages to the Utility's assets or operations, to the extent not covered by insurance.

Legislative and Regulatory Environment. PG&E Corporation's and the Utility's business may be impacted:

- By legislative or regulatory changes affecting the electric and natural gas industries in the United States; and
- By heightened regulatory and enforcement agency focus on the merchant energy business including investigations into "wash" or "round-trip" trading, specific trading strategies and other industry issues, with the potential for changes in industry regulations and in the treatment of PG&E NEG by state and federal agencies.

Regulatory Proceedings and Investigations. PG&E Corporation's and the Utility's business may be affected by:

- The outcome of the Utility's various regulatory proceedings pending at the CPUC and at the Federal Energy Regulatory Commission (FERC); and
- The outcome of the CPUC's pending investigation into whether the California investor-owned utilities (IOUs), have complied with past CPUC decisions, rules or orders authorizing their holding company formations and/or governing affiliate transactions, as well as applicable statutes.

Pending Legal Proceedings. PG&E Corporation's and the Utility's future results of operation and financial conditions may be affected by the outcomes of:

- The lawsuits filed by the California Attorney General and the City and County of San Francisco against PG&E Corporation alleging unfair or fraudulent business acts or practices based on alleged violations of conditions established in the CPUC's holding company decisions;
- The outcome of the California Attorney General's petition requesting revocation of PG&E Corporation's exemption from the Public Utility Holding Company Act of 1935; and
- Other pending litigation.

Competition. PG&E Corporation's and the Utility's future results of operations and financial condition may be affected by:

- The threat of municipalization which may result in stranded Utility investment, loss of customer growth, and additional barriers to cost recovery;

- Changes in the level of direct access customer cost responsibility and other surcharges related to direct access, and competition from other service providers to the extent restrictions on direct access are removed;
- The development of alternative energy technologies;
- The ability to compete for gas transmission services into Southern California and with alternative storage providers throughout California; and
- The growth of distributed generation or self-generation.

Environmental and Nuclear Matters. PG&E Corporation's and the Utility's future results of operations and financial condition may be affected by:

- The effect of compliance with existing and future environmental laws, regulations, and policies, the cost of which could be significant;
- Whether the Utility is able to fully recover in rates the costs of complying with existing and future environmental laws, regulations, and policies, the cost of which could be significant; and
- Whether the Utility incurs costs in connection with its nuclear facilities that exceed the Utility's insurance coverage and other amounts set aside for decommissioning and other potential liabilities.

Accounting and Risk Management. PG&E Corporation's and the Utility's future results of operations and financial condition may be affected by:

- The effect of new accounting pronouncements;
- Changes in critical accounting estimates;
- Volatility in income resulting from mark-to-market accounting and changes in mark-to-market methodologies;
- The extent to which the assumptions underlying critical accounting estimates, mark-to-market accounting, and risk management programs are not realized; and
- The volatility of commodity fuel and electricity prices, and the effectiveness of risk management policies and procedures designed to address volatility.

Efforts to Restructure PG&E NEG's Indebtedness. Whether PG&E NEG and certain of its subsidiaries seek protection under or are forced into a proceeding under the Bankruptcy Code will be affected by:

- The outcome of PG&E NEG's negotiations with lenders under various credit facilities, as well as with representatives of the holders of PG&E NEG's Senior Notes, to restructure PG&E NEG's and its subsidiaries' indebtedness and commitments;
- The terms and conditions of any sale, transfer, or abandonment of certain of PG&E NEG's merchant assets, including its New England generating assets, that PG&E NEG may enter into; and
- The terms and conditions under which certain generating projects will be transferred to the project lenders as required by recent restructuring agreements.

PG&E NEG Operational Risks. PG&E Corporation's future results of operation and financial condition will be affected by:

- The extent to which PG&E NEG incurs further charges to earnings as a result of the abandonment, sale or transfer of assets, or termination of contractual commitments, whether such transactions occur in connection with restructuring of PG&E NEG's indebtedness or otherwise;

- Any potential charges to income that would result from the reduction and potential discontinuance of PG&E NEG's energy trading and marketing operations, including tolling transactions;
- Any potential charges to income that would result from the discontinuance or transfer of any of PG&E NEG's merchant generation assets;
- The inability of PG&E NEG, its merchant asset and other subsidiaries, including US Gen New England, Inc., to maintain sufficient liquidity necessary to meet their commodity and other obligations.
- The extent to which PG&E NEG's current construction of generation, pipeline, and storage facilities are completed and the pace and cost of that completion, including the extent to which commercial operations of these construction projects are delayed or prevented because of financial or liquidity constraints, changes in the national energy markets and by the extent and timing of generating, pipeline, and storage capacity expansion and retirements by others; or by various development and construction risks such as PG&E NEG's failure to obtain necessary permits or equipment, the failure of third-party contractors to perform their contractual obligations, or the failure of necessary equipment to perform as anticipated and the potential loss of permits or other rights in connection with PG&E NEG's decision to delay or defer construction;
- The impact of layoffs and loss of personnel at PG&E NEG; and
- Future sales levels which can be affected by economic conditions, weather, conservation efforts, outages, and other factors.

Current Conditions in the Energy Markets and the Economy. PG&E Corporation's future results of operations and financial condition will be affected by changes in the energy markets, changes in the general economy, wars, embargoes, financial markets, interest rates, other industry participant failures, the markets' perception of energy merchants and other factors.

Actions of PG&E NEG Counterparties. PG&E Corporation's future results of operations and financial condition may be affected by:

- The extent to which counterparties demand additional collateral in connection with PG&E ET's trading and nontrading activities and the ability of PG&E NEG and its subsidiaries to meet the liquidity calls that may be made; and
- The extent to which counterparties seek to terminate tolling agreements and the amount of any termination damages they may seek to recover from PG&E NEG as guarantor.

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

This MD&A should be read in conjunction with the Consolidated Financial Statements and Notes to the Consolidated Financial Statements included herein.

Market Conditions and Business Environment

During 2002, adverse changes in the electric power and gas utility industry and energy markets affected PG&E Corporation, the Utility, and PG&E NEG's business including:

- Contractions and instability of wholesale electricity and energy commodity markets;
- Significant decline in generation margins (spark spreads) caused by excess supply and reduced demand in most regions of the United States;
- Loss of confidence in energy companies due to increased scrutiny by regulators, elected officials, and investors as a result of a string of financial reporting scandals;

- Heightened scrutiny by credit rating agencies prompted by these market changes and scandals which resulted in lower credit ratings for many market participants; and
- Resulting significant financial distress and liquidity problems among market participants leading to numerous financial restructurings and less market participation.

LIQUIDITY AND FINANCIAL RESOURCES

Utility

In 1998, the State of California implemented electric industry restructuring and established a framework allowing generators and other electricity providers to charge market-based prices for electricity sold on the wholesale market. The implementing legislation also established a retail electricity rate freeze and a plan for recovery of generation-related costs that were expected to be uneconomic under the new market framework. State regulatory action further strongly encouraged the Utility to sell a majority of its fossil fuel-fired generation facilities and made it economically unattractive to retain its remaining generation facilities. The resulting sales of generation facilities in turn made the Utility more dependent on the newly deregulated wholesale electricity market. Beginning in June 2000, wholesale prices for electricity began to increase. Prices moderated somewhat in the fall before increasing to unprecedented levels in November 2000 and later months. Since the Utility's retail rates were frozen, it financed the higher costs of wholesale electricity by issuing debt and drawing on its credit facilities. The Utility's inability to recover its electric procurement costs from customers ultimately resulted in billions of dollars in defaulted debt and unpaid bills and caused the Utility to file a voluntary petition for relief under the Bankruptcy Code in the Bankruptcy Court on April 6, 2001.

While in bankruptcy, the Utility is not allowed to pay liabilities incurred before it filed for bankruptcy without permission from the Bankruptcy Court. Additionally,

- While in bankruptcy, the Utility does not have access to external funding from capital markets;
- The Utility is in default under its credit facilities, commercial paper, floating rate notes, senior notes, pollution control loan agreements, and medium-term notes, as a result of its failure to pay certain of its obligations. However, the event of default under each security has been stayed in accordance with the bankruptcy proceedings; and
- The Utility has been making capital investments (investments in property, plant, and equipment) out of its cash on hand under the supervision of the Bankruptcy Court. The Utility anticipates that it will be able to continue making such necessary capital investments in the future, subject to Bankruptcy Court approval.

As a result of the California energy crisis and the Utility's bankruptcy filing, a number of qualifying facilities (QFs) requested the Bankruptcy Court to either terminate their contracts to sell electricity to the Utility, or have the contracts suspended for the summer of 2001 so the QFs could sell electricity at market-based rates. Since July 2001, the Utility has entered into 264 five-year agreements with QFs (authorized by the Bankruptcy Court) to assume their power purchase agreements. See Note 16 of the Notes to the Consolidated Financial Statements for a discussion of the QF power purchase agreements.

In March 2002, the Bankruptcy Court authorized the Utility to pay certain pre- and post-petition interest on certain claims prior to emerging from bankruptcy. The Bankruptcy Court also authorized the Utility to make certain principal payments on pre-petition secured debt that has matured. See the Cash Flows section of this MD&A for a discussion of the Utility's interest and principal payments made during 2002.

Since filing for bankruptcy, the Utility has been accruing interest on its pre-petition liabilities at the required rates included in the Utility's proposed plan of reorganization. As a result, the payment of such interest did not have a material adverse impact on its financial condition or results of operations.

The Utility will continue to accrue interest on its pre-petition liabilities at the required rates in 2003. However, due to the uncertainty of the ultimate outcome of the bankruptcy proceedings, the Utility is not able to estimate the amount of interest that will be paid in 2003.

The Utility and PG&E Corporation have jointly filed a proposed plan of reorganization (Plan) that, if approved, would enable the Utility to emerge from bankruptcy. The Utility Plan, and an alternative plan proposed by the CPUC and the OCC are currently moving through the Chapter 11 process. In November 2002, the Bankruptcy Court began the confirmation trial to determine which plan, if any, the Bankruptcy Court will confirm. The Bankruptcy Court has scheduled hearing dates through the end of March 2003. PG&E Corporation and the Utility are not able to predict the ultimate outcome of the Utility's bankruptcy proceedings, including which plan, if any, the Bankruptcy Court may confirm.

Both the Plan and the alternative plan propose issuing new debt as part of the reorganization. PG&E Corporation and the Utility have incurred, and will continue to incur throughout the reorganization process, legal, accounting, trustee, and other fees associated with the debt issuance. In addition, PG&E Corporation and the Utility have incurred and will continue to incur consulting fees for assistance with the implementation of either plan. The majority of the debt issuance fees and consulting expenses incurred thus far have been expensed and are included in Reorganization Professional Fees and Expenses in the Consolidated Statements of Operations, though a small amount has been capitalized. The Utility will continue to expense costs associated with the reorganization process that do not specifically relate to certain services associated with issuing new debt.

On January 1, 2003, the IOUs, including the Utility, resumed procuring electricity to meet their customers' net open position under California Senate Bill (SB) 1976. For discussion of the requirements contained in SB 1976, see "Regulatory Matters" section of the MD&A and Note 2 of the Notes to the Consolidated Financial Statements.

See Note 2 of the Notes to the Consolidated Financial Statements for further discussion of the California energy crisis, the Utility's voluntary petition for relief under the Bankruptcy Code, and the status of the Chapter 11 confirmation hearings.

PG&E NEG

PG&E NEG has been significantly impacted by adverse changes in the energy markets in 2002. New generation came online while the demand for power was dropping. This oversupply and reduced demand resulted in low spark spreads (the net of power prices less fuel costs) and depressed operating margins. These changes in the power industry have had a significant negative impact on the financial results and liquidity of PG&E NEG. Before July 31, 2002, most of the various debt instruments of PG&E NEG and its affiliates carried investment grade credit ratings assigned by Standard & Poor's Ratings Group (S&P) and Moody's Investors Service (Moody's). Since July 31, 2002, these credit rating agencies have downgraded all of PG&E NEG's debt facilities to below investment grade.

PG&E NEG is currently in default under various recourse debt agreements and guaranteed equity commitments totaling approximately $2.9 billion. In addition, other PG&E NEG subsidiaries are in default under various debt agreements totaling approximately $2.5 billion, but this debt is non-recourse to PG&E NEG. On November 14, 2002, PG&E NEG defaulted on the repayment of its $431 million 364-day tranche of its corporate revolving credit facility (Corporate Revolver). This resulted in a default under the two-year tranche of the Corporate Revolver, which had an outstanding balance of $273 million at December 31, 2002, the majority of which supports outstanding letters of credit. The default under the Corporate Revolver also constitutes a cross-default under PG&E NEG's (amounts outstanding at December 31, 2002): (1) Senior Notes ($1 billion), (2) guarantee of its turbine revolving credit facility (Turbine Revolver) ($205 million), and (3) equity commitment guarantees for GenHoldings I, LLC's (Gen Holdings) credit facility ($355 million), La Paloma credit facility ($375 million) and Lake Road credit facility ($230 million). In addition, on November 15, 2002, PG&E NEG failed to pay a $52 million interest payment due under the Senior Notes. PG&E NEG does not currently have sufficient cash to meet its financial obligations and has ceased making payments on its debt and equity commitments.

PG&E NEG and its subsidiaries are restructuring their operations to increase cash, reduce financial obligations, dispose of merchant plant facilities, and decrease energy trading operations. PG&E NEG's objective is to limit its asset trading and risk management activities to only what is necessary for energy management services to facilitate the transition of PG&E NEG's merchant generation facilities through their sale, transfer or abandonment. PG&E NEG will then further reduce and transition to only retain limited capabilities to ensure fuel procurement and power logistics for PG&E NEG's retained independent power plant operations. These restructuring activities have caused material charges to earnings in 2002, and are anticipated to cause substantial additional charges to earnings in 2003.

PG&E NEG, its subsidiaries and their lenders are engaged in discussions regarding restructuring of these commitments. If a restructuring agreement is not reached and the lenders exercise their default remedies, or if the financial commitments are not restructured, PG&E NEG and certain of its subsidiaries may be compelled to seek protection under or be forced involuntarily into proceedings under the Bankruptcy Code.

PG&E Corporation is participating with PG&E NEG, its subsidiaries and their lenders in negotiations to restructure PG&E NEG's and its subsidiaries' commitments. However, under the terms of its credit agreement, PG&E Corporation is limited as to the amount and conditions under which it can provide cash to PG&E NEG. In particular, the Credit Agreement limits PG&E Corporation's ability to make investments in PG&E NEG and its subsidiaries from existing cash to 75 percent of the net cash tax savings (less certain costs and expenses) actually received by PG&E Corporation as a result of certain sales and debt restructuring transactions of PG&E NEG and its subsidiaries. See further details in "PG&E Corporation-Debt Financing" below.

If the negotiations with PG&E NEG's lenders prove unsuccessful and if lenders exercise their default remedies and PG&E NEG is forced to seek protection under or is forced into a proceeding under the Bankruptcy Code, management does not expect the liquidity constraints at PG&E NEG and its subsidiaries will affect the financial condition of PG&E Corporation or the Utility.

Asset transfers, sales and abandonments, liquidity issues, and restructuring activities have resulted in substantial charges to earnings in 2002. In addition, PG&E NEG and its subsidiaries expect to incur additional substantial charges to earnings in 2003 primarily related to:

- The reduction in energy trading activities;
- The possible settlement of tolling arrangements, see discussion of tolling agreements in this MD&A under Commitments and Capital Expenditures–Tolling Agreements;
- Charges related to the adoption of Statement of Financial Accounting Standards (SFAS) No. 143, "Accounting for Asset Retirement Obligations" (see discussion in this MD&A under Accounting Pronouncements issued but not yet adopted);
- A possible settlement under the Attala tolling agreement and related lease (see discussion below in Impairments, Write-offs, and Other Charges);
- Potential conversion of existing debt and equity funding commitments to new discounted obligations, including potential write-offs of deferred financing costs; and
- Further restructuring costs.

Impairments, Write-offs, and Other Charges

The following table outlines the pre-tax charges for impairments, write-offs, and other charges that PG&E NEG and its subsidiaries recorded:

(in millions)	Fourth Quarter 2002	Year Ended December 31, 2002
Impairment of GenHoldings projects	$1,147	$1,147
Impairment of Lake Road and La Paloma projects	452	452
Impairment of Mantua Creek project	279	279
Impairment of Turbines & Other Related Equipment costs	30	276
Termination of Interest Rate Swaps on Lake Road, La Paloma, and GenHoldings projects	189	189
Impairment of Dispersed Generation	88	118
Impairment of Goodwill	–	95
Impairment of Project Development Costs	57	76
Impairment of Southaven Loan	74	74
Impairment of Prepaid Rents related to the Attala lease	43	43
Impairment of Kentucky Hydro project	18	18
Total Pre-tax Impairments, Write-offs, and Other Charges	$2,377	$2,767
Discontinued Operations – Pre-tax Loss on disposal of USGen New England, Inc.	1,123	1,123
Pre-tax loss on disposal of ET Canada	25	25
Total Pre-tax Charges	$3,525	$3,915

Impairment of GenHoldings I LLC Projects: GenHoldings, a subsidiary of PG&E NEG, is obligated under its credit facility to make equity contributions to fund construction of the Athens, Covert and Harquahala generating projects. This credit facility is secured by these projects in addition to the Millennium generating facility. GenHoldings defaulted under its credit agreement in October 2002 by failing to make equity contributions to fund construction draws for the Athens, Covert and Harquahala generating projects. Although PG&E NEG has guaranteed GenHoldings' obligation to make equity contributions of up to $355 million, PG&E NEG notified the GenHoldings' lenders that it would not make further equity contributions on behalf of GenHoldings. In November and December 2002, the lenders executed waivers and amendments to the credit agreement under which they agreed to continue to waive until March 31, 2003, the default caused by GenHoldings' failure to make equity contributions. In addition, certain of these lenders have agreed to increase their loan commitments to an amount sufficient to provide: (1) the funds necessary to complete construction of the Athens, Covert and Harquahala facilities; and (2) additional working capital facilities to enable each project, including Millennium, to timely pay for its fuel requirements and to provide its own collateral to support natural gas pipeline capacity reservations and independent transmission operator requirements. The November and December increased loan commitments rank equally with each other but are senior to amounts loaned through and including the October credit extension.

In consideration of the lenders' forbearance and additional funding, PG&E NEG and GenHoldings have agreed to cooperate with any reasonable proposal by the lenders regarding disposition of the equity in or assets of any or all of the GenHoldings subsidiaries holding the Athens, Covert, Harquahala, and Millennium projects in connection with the restructuring of PG&E NEG's and its subsidiaries' financial commitments to such lenders. The amended credit agreement provides that an event of default will occur if the Athens, Covert, Harquahala, and Millennium projects are not transferred to the lenders or their designees on or before March 31, 2003. Such a default would trigger lender remedies, including the right to foreclose on the projects. Under the waiver, PG&E NEG has re-affirmed its guarantee of GenHoldings' obligation to make equity contributions of approximately $355 million to these projects. Neither PG&E NEG nor GenHoldings currently expects to have sufficient funds to make this payment. The requirement to pay $355 million remains an obligation of PG&E

NEG that would survive the transfer of the projects.

In accordance with the provisions of SFAS No. 144 "Accounting For the Impairment or Disposal of Long-Lived Assets," the long-lived assets of GenHoldings at December 31, 2002 were tested for impairment. As a result of the test, the assets were determined to be impaired and were written-down to fair value. Based on the current estimated fair value of these assets, GenHoldings recorded a pre-tax loss from impairment of $1.147 billion in the fourth quarter of 2002.

Impairment of Lake Road and La Paloma Projects: On November 14, 2002, PG&E NEG defaulted under its equity commitment guarantees for the Lake Road and the La Paloma credit facilities. As of December 4, 2002, PG&E NEG and certain of its subsidiaries entered into agreements with respect to each of the Lake Road and La Paloma generating projects providing for (1) funding of construction costs required to complete the La Paloma facility; and (2) additional working capital facilities to enable each subsidiary to timely pay for its fuel requirements and to provide its own collateral to support natural gas pipeline capacity reservations and independent transmission system operator requirements, as well as for general working capital purposes. Lenders extending new credit under these agreements have received liens on the projects that are senior to the existing lenders' liens. These agreements provide, among other things, that the failure to transfer right, title and interest in, to and under the Lake Road and La Paloma projects to the respective lenders by June 9, 2003, will constitute a default under the agreements. The failure to transfer the facilities would entitle the lenders to accelerate the new indebtedness and exercise other remedies.

The Lake Road and La Paloma projects have been financed entirely with debt. PG&E NEG has guaranteed the repayment of a portion of the project subsidiary debt of approximately $230 million for Lake Road and $375 million for La Paloma, which amounts represent the subsidiaries' equity contribution in the projects. The lenders have demanded the immediate payment of these equity contributions. Neither the PG&E NEG subsidiaries nor PG&E NEG have sufficient funds to make these payments. The requirement to make the payments will remain an obligation of PG&E NEG that would survive the transfer of the projects.

In accordance with the provisions of SFAS No. 144, the long-lived assets of the Lake Road and La Paloma project subsidiaries at December 31, 2002, were tested for impairment. As a result of the test, these assets were determined to be impaired and were written down to fair value. Based on the current estimated fair value of these assets, the Lake Road and La Paloma project subsidiaries recorded a pre-tax loss from impairment of approximately $186 million and $266 million, respectively, in the fourth quarter of 2002.

Impairment of Mantua Creek Project: The Mantua Creek project is a nominal 897 megawatt (MW) combined cycle merchant power plant located in the Township of West Deptford, New Jersey. Construction began in October 2001 and the project was 24 percent complete as of October 31, 2002. Due to liquidity concerns, PG&E NEG could no longer provide equity contributions to the project and efforts to sell the project were unsuccessful. Beginning in the fourth quarter of 2002, contracts with vendors were suspended or terminated to eliminate an increase in project costs. In December 2002, the project provided notices of termination to the Pennsylvania, New Jersey, Maryland Independent System Operator (PJM), and other significant counterparties. With all significant contracts terminated, PG&E NEG's subsidiary will abandon this project in early 2003. PG&E NEG's subsidiary has written off the capitalized development and construction costs of $257 million at December 31, 2002. In addition, PG&E NEG has recorded an accrual of $22 million for charges and associated termination costs at December 31, 2002.

Impairment of Turbines and Other Related Equipment: To support PG&E NEG's electric generating development program, PG&E NEG subsidiaries had contractual commitments and options to purchase a significant number of combustion turbines and related equipment. PG&E NEG subsidiaries' commitment to purchase combustion turbines and related equipment exceeded the new planned development activities discussed herein. In the second quarter of 2002, these PG&E NEG subsidiaries recognized a pre-tax charge of $246 million. The charge consisted of the impairment of the previously capitalized costs associated with prior payments made under the terms of the turbine and equipment contracts in the amount of $188 million and an accrual of $58 million for future termination payments required under the turbine and related equipment contracts. In addition, at that time, the PG&E NEG subsidiaries retained capitalized prepayment costs associated with three development projects that were to be further developed or sold. In the fourth quarter of 2002, these PG&E NEG subsidiaries incurred an additional pre-tax charge of $30 million for the write-off of prior turbine prepayments associated with the impairment of the remaining development projects as discussed below.

In November 2002, subsidiaries of PG&E NEG reached agreement with General Electric Company (GEC) to terminate its master turbine purchase agreement and with General Electric International, Inc. (GEII) to terminate its master long-term service agreement. GEC and GEII have agreed to reduce the termination fees from approximately $34 million to approximately $22 million and to defer payment of the reduced fees to December 31, 2004. The costs to terminate this contract were accrued for in the second quarter of 2002 as discussed above.

Also in November 2002, Mitsubishi Power Systems, Inc. (MPS) notified PG&E NEG's subsidiary that it was terminating the turbine purchase agreement for failure to pay past due amounts and failure to collateralize PG&E NEG's guarantee. While PG&E NEG's subsidiary has disputed that such amounts were due before January and July 2003 and has asserted that a breach under PG&E NEG's guarantee did not give rise to a breach of the turbine purchase agreement, neither PG&E NEG nor its subsidiary intends to contest the termination. The costs to terminate this contract were accrued for in the second quarter of 2002, as discussed above. On January 31, 2003, a termination payment of $4.5 million was made with the remaining amount of $9.5 million expected to be paid in July 2003.

Termination of Interest Rate Swaps on Lake Road, La Paloma and GenHoldings Projects: As a result of the Lake Road and La Paloma project subsidiaries' failure to make required equity payments under interest rate hedge contracts entered into by them, the counterparties to such interest rate hedge contracts have terminated the contracts. Settlement amounts due from the Lake Road and La Paloma project subsidiaries in connection with such terminated contracts are, in the aggregate, $61 million and $78 million, respectively. Further, as a result of GenHoldings' failure to make required payments under interest rate hedge contracts entered into by GenHoldings, the counterparties to such interest rate hedge contracts terminated the contracts during December 2002. Settlement amounts due by GenHoldings in connection with such terminated contracts are, in the aggregate, approximately $50 million. The Lake Road and La Paloma project subsidiaries and GenHoldings incurred a pre-tax charge to earnings in the fourth quarter of 2002 for these amounts totaling $189 million.

Impairment of Dispersed Generation: PG&E NEG is seeking a buyer for PG&E Dispersed Generation, LLC, Plains End, LLC, Dispersed Properties, LLC and 100 percent of the capital stock of Ramco Inc, (collectively, referred to as Dispersed Gen Companies or Dispersed Generation). In accordance with the provisions of SFAS No. 144, the long-lived assets of the Dispersed Gen Companies were tested for impairment. As a result of the test, these assets were determined to be impaired and were written down to fair value. Based on the current estimated fair value (based on the estimated proceeds) of a sale, Dispersed Generation recorded a pre-tax loss from impairment of $88 million in the fourth quarter of 2002. This is in addition to a pre-tax loss from impairment of $30 million that was recorded in the third quarter of 2002, which related to certain equipment (turbines, generators, transformers, etc.) that was purchased and/or refurbished and held for future expansion at current Dispersed Generation facilities.

Impairment of Goodwill: SFAS No. 142 "Goodwill and Other Intangible Assets," requires that goodwill be reviewed at least annually for impairment. Due to significant adverse changes within the national energy markets, PG&E NEG and its subsidiaries elected to test its goodwill for possible impairment in the third quarter of 2002. Based upon the results of the fair value test, PG&E NEG and it subsidiaries recognized a goodwill impairment loss of $95 million in the third quarter of 2002. The fair value of the segment was estimated using the discounted cash flows method. At December 31, 2002, there was no goodwill remaining at PG&E NEG and its subsidiaries.

Impairment of Development Costs: In the second quarter of 2002, PG&E NEG project subsidiaries recognized an impairment loss related to the capitalized costs associated with certain development projects. These PG&E NEG subsidiaries analyzed the potential future cash flow from those projects that it no longer anticipated developing and recognized an impairment of the asset value it was carrying for those projects. The aggregate pre-tax impairment charge recorded by these PG&E NEG subsidiaries for its development assets (excluding associated equipment) was $19 million recorded in the second quarter of 2002. At that time, these PG&E NEG subsidiaries continued to develop or planned to sell three additional projects. These subsidiaries have ceased developing these projects and sought to sell the development assets. To date, these subsidiaries have been unsuccessful in selling these projects and have tested the capitalized costs associated with the projects for impairment at December 31, 2002. Based upon the results of these tests, an additional aggregate pre-tax impairment charge of approximately $57 million was recorded by these subsidiaries for their development assets (excluding associated equipment costs as discussed above) in the fourth quarter of 2002. While these subsidiaries have impaired all of their development projects, they have not abandoned the permits or rights to these projects. It is anticipated that these permits and rights will be abandoned for all development projects in 2003.

Impairment of Southaven Power LLC Loan Receivable: PG&E ET signed a tolling agreement with Southaven Power LLC (Southaven) dated June 1, 2000, pursuant to which PG&E ET was required to provide credit support that meets certain requirements set forth in the agreement. PG&E ET satisfied this obligation by providing an investment-grade guarantee from PG&E NEG. The original maximum amount of the guarantee was $250 million. However, this amount was reduced by approximately $74 million, the amount of a subordinated loan that PG&E ET made to Southaven on August 31, 2002.

Southaven has advised PG&E ET that it believes an event of default under the tolling agreement has taken place with respect to the obligation for a guarantee because PG&E NEG is no longer investment-grade as defined in the agreement and because PG&E ET has failed to provide, within 30 days from the downgrade, substitute credit support that meets the requirements of the agreement. Under the tolling agreement, Southaven has the right to terminate the agreement and seek a termination payment. In addition, PG&E ET has provided Southaven with a notice of default with respect to Southaven's performance under the tolling agreement. If this default is not cured, PG&E ET has the right to terminate the agreement and seek recovery of a termination payment. On February 4, 2003, PG&E ET provided a notice of termination. Southaven has objected to the notice and has filed suit in connection with this matter. PG&E ET has recorded an impairment of the loan receivable due to the uncertainty associated with the recoverability of the loan, which was subordinate to the senior debt of the project and reliant upon operations of the plant under the terms of the tolling agreement.

Impairment of Prepaid Rents on Attala Lease: On May 7, 2002, Attala Generating Company LLC (Attala Generating), an indirect wholly owned subsidiary of PG&E NEG, completed a $340 million sale and leaseback transaction whereby it sold and leased back its approximately 526 MW generation facility located in Mississippi to a third-party special purpose entity.

PG&E NEG has provided a $300 million guarantee to support the payment obligations of another indirect wholly owned subsidiary, Attala Energy Company LLC (Attala Energy) under a tolling agreement entered into with Attala Generating. The payments under the 25-year term tolling agreement provide Attala Generating, as lessee, with sufficient cash flows during the term of the tolling agreement to pay rent under a 37-year lease and certain other operating costs. Due to current energy market conditions, Attala Energy is unable to make the payments under the tolling agreement and failed to make the required payment due on November 22, 2002, to Attala Generating. Failure to cure this payment default constituted an event of default under the tolling agreement as of November 27, 2002. Further, PG&E NEG's failure to pay maturing principal under its Corporate Revolver on November 14, 2002, became an event of default under the tolling agreement upon Attala Energy's failure to replace the PG&E NEG guarantee by December 16, 2002. On December 31, 2002, the tolling agreement terminated following notice of termination given by Attala Generating. The parties are currently determining the termination payment, if any, that Attala Energy would owe Attala Generating. Despite the termination of the tolling agreements, Attala Energy remains obligated to provide an acceptable guarantee or collateral to secure its obligations under the tolling agreement, including the payment of any termination payment that may be determined to be due.

No default has occurred under the related lease and Attala Generating timely made the $22.2 million lease payment due on January 2, 2003. However, the lease provides that failure to replace the tolling agreement with a satisfactory replacement tolling agreement within 180 days after the first default under the tolling agreement, which occurred on November 27, 2002, will constitute an event of default under the lease. After the termination payment has been determined in accordance with the tolling agreement and if Attala Energy or PG&E NEG both fail, or have failed, to provide security as required by the tolling agreement, the time period would not extend beyond the 60th day after such failure to provide security. Upon the occurrence of an event of default under the lease, the lessor would be entitled to exercise various remedies, including termination of the lease and foreclosure of the assets securing the lease. At December 31, 2002, Attala Generating wrote-off prepaid rental payments of $43 million due to the uncertainty of future cash flows associated with the lease.

Impairment of Kentucky Hydro Project: The Kentucky Hydro Generating Project consists of two run-of-river hydroelectric power plants located in Kentucky on the Ohio River. The project negotiated a turnkey, fixed price contract with VA Tech MCE Corporation (VA Tech) and issued a limited notice to proceed in August 2001. Beginning in the fourth quarter of 2002, all work on the project was suspended except for minimal expenditures to maintain the FERC licenses. The termination cost due to VA Tech of approximately $14 million was fully paid. VA Tech terminated the contract effective December 6, 2002. As part of the settlement of PG&E NEG subsidiary's partnership arrangement, this subsidiary assigned its partnership interest to the original developer, W.V. Hydro, on February 7, 2003. PG&E NEG has written-off the capitalized development and construction costs and provided for all termination costs by recording a pre-tax charge of $18 million at December 31, 2002.

Asset Held For Sale – U.S. Gen New England: Consistent with its previously announced strategy to dispose of certain merchant assets, in December 2002, the Board of Directors of PG&E Corporation approved management's plan for the proposed sale of USGen New England Inc. (USGenNE). Under the provisions of SFAS No. 144, the equity of USGenNE has been accounted for as an asset held for sale at December 31, 2002. This requires that the assets be recorded at the lower of fair or book value. Based on the current estimated fair value (based on the estimated proceeds) of a sale of USGenNE, a pre-tax loss of $1.1 billion, with no tax benefits associated with the loss, was recorded in the fourth quarter of 2002. It is anticipated that the sale of the USGenNE assets will occur during 2003. This loss on sale, as well as the operating results from USGenNE, have been reported as discontinued operations in the financial statements of PG&E NEG and subsidiaries at December 31, 2002.

Assets Held for Sale – ET Canada: In December 2002, the proposed sale of PG&E Energy Trading, Canada Corporation (ET Canada) to Seminole Gas Company Limited was approved. Based upon the sales price, PG&E Energy Trading Holdings Corporation, the direct owner of the shares of ET Canada, recorded a $25 million pre-tax loss, with no tax benefits associated with the loss, on the disposition of ET Canada. The transaction is anticipated to close by the end of February or early March 2003. In accordance with the provisions of SFAS No. 144, the equity of ET Canada has been classified as assets held for sale and will be reflected as discontinued operations in the financial statements of PG&E NEG and subsidiaries as of December 31, 2002.

COMMITMENTS AND CAPITAL EXPENDITURES

The following table provides information about PG&E Corporation, the Utility and PG&E NEG's contractual obligations and commitments at December 31, 2002.

(Dollars in millions)	2003	2004	2005	2006	2007	Thereafter
Utility:						
Power purchase agreements	$1,984	$1,701	$1,544	$1,446	$1,377	$8,492
Natural gas supply and transportation	595	138	83	26	10	–
Nuclear fuel	59	50	12	13	14	65
Other Commitments	60	45	39	24	11	11
Long-term debt:						
Liabilities not subject to compromise:						
Fixed rate principal obligations	281	310	290	–	–	2,139
Average interest rate	6.25%	6.25%	5.88%	–	–	7.25%
Liabilities subject to compromise:						
Fixed rate principal obligations	173	54	696	1	1	261
Average interest rate	7.40%	7.51%	9.56%	9.45%	9.45%	5.95%
7.90 Percent Deferrable Interest Subordinated Debentures	–	–	–	–	–	300
Variable rate principal obligations	349	265	–	–	–	–
Rate reduction bonds	290	290	290	290	290	–
Average interest rate	6.36%	6.42%	6.42%	6.44%	6.48%	–
PG&E NEG:						
Fuel supply and natural gas transportation agreements	105	91	91	88	75	380
Power purchase agreement	217	220	220	220	225	1,140
Operating leases	70	79	79	81	84	807
Long-Term Service Agreements	41	7	7	7	7	36
Payment in lieu of taxes	28	21	14	16	17	97
Construction commitments	237	–	–	–	–	–
Tolling agreements	62	62	62	62	62	482
Long-term debt:						
Fixed rate obligations	6	–	250	–	–	250
Variable rate obligations	86	3	60	52	4	11
Average interest rate	6.41%	6.57%	6.92%	7.33%	7.31%	7.10%
PG&E Corporation:						
Long-term debt:						
Fixed rate obligations (9.50% Convertible Subordinated Notes)	–	–	–	–	–	280
Average interest rate	–	–	–	–	–	9.50%
Variable rate [1]	–	–	–	842	–	–

[1] $720 million outstanding at December 31, 2002, with 4 percent interest compounded yields value of $842 million at maturity.

Utility

The Utility's contractual commitments include natural gas supply and transportation agreements, purchase power agreements (including agreements with QFs, irrigation districts and water agencies, bilateral power purchase contracts, and renewable energy contracts), nuclear fuel agreements, operating leases and other commitments.

The Utility's commitments under financing arrangements include obligations to repay first and refunding mortgage bonds, senior notes, medium-term notes, pollution control loan agreements, Deferrable Interest Subordinated Dedentures, lines of credit, letters of credit, floating rate notes, and commercial paper.

PG&E Funding LLC, a wholly owned subsidiary of the Utility is also obligated to make scheduled principal payments on its rate reduction bonds.

For further detailed discussion of the Utility's contractual commitments and obligations, see Notes 4, 5, and 16 of the Notes to the Consolidated Financial Statements.

PG&E NEG

PG&E NEG subsidiaries have the following contractual commitments:

Fuel Supply and Transportation Agreements – PG&E NEG, through its various subsidiaries, has entered into gas supply and firm transportation agreements with a number of pipelines and fuel transportation services. Under these agreements, PG&E NEG's subsidiaries must make specified minimum payments each month.

Power Purchase Agreements – USGenNE assumed rights and duties under several power purchase contracts with third party independent power producers as part of the acquisition of the New England Electric System assets. As of December 31, 2002, these agreements provided for an aggregate of approximately 800 MW of capacity. USGenNE is required to pay New England Power Company amounts due to third-party producers under the power purchase contracts.

Operating Leases – Various subsidiaries of PG&E NEG entered into several operating lease agreements for generating facilities and office space. Lease terms vary between 3 and 48 years.

In November 1998, USGenNE entered into a $479 million sale-leaseback transaction whereby the subsidiary sold and leased back a pumped storage station under an operating lease.

On May 7, 2002, Attala Generating completed a $340 million sale and leaseback transaction whereby it sold and leased back its facility to a third party special purpose entity. The related lease is being accounted for as an operating lease. See discussion above for further information relating to the Attala lease agreement.

Operating lease expense amounted to $78 million, $54 million, and $70 million in 2002, 2001, and 2000, respectively.

Long-Term Service Agreements – Various subsidiaries of PG&E NEG have entered into long-term service agreements for the maintenance and repair of certain combustion turbine or combined-cycle generating plants. These agreements are for periods up to 18 years.

Payments in Lieu of Property Taxes – Various subsidiaries of PG&E NEG have entered into certain agreements with local governments that provide for payments in lieu of property taxes for some of its generating facilities.

Construction Commitments – Various subsidiaries of PG&E NEG currently have four projects (Athens, Covert, La Paloma, and Harquahala) under construction. PG&E NEG's construction commitments are generally related to the major construction agreements including the construction and other related contracts. Certain construction contracts also contain commitments to purchase turbines and related equipment.

Tolling Agreements – PG&E ET entered into tolling agreements with several counterparties allowing PG&E NEG the right to sell electricity generated by facilities owned and operated by other parties. Under the tolling agreements, PG&E 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. See Tolling Agreements below for additional information relating to these agreements.

Guarantees

PG&E NEG's and its subsidiaries' guarantees fall into four broad categories:

- Equity commitments;
- PG&E ET's energy trading and non-trading activities related to PG&E NEG's merchant energy portfolio excluding tolling agreements;
- Tolling agreements; and
- Other guarantees.

Equity Commitments: Refer to discussion above on impairments under "Market Conditions and Business Environment."

Activities Related to Merchant Portfolio Operations: PG&E NEG and certain subsidiaries have provided guarantees to approximately 232 counterparties in support of PG&E ET's energy trading and non-trading activities related to PG&E NEG's merchant energy portfolio in the face amount of $2.7 billion. Typically, the overall exposure under these guarantees is only a fraction of the face value of these guarantees, since not all counterparty credit limits are fully used at any time. As of January 31, 2003, PG&E NEG and its subsidiaries' aggregate exposure under these guarantees was approximately $82.8 million. The amount of such exposure varies daily depending on changes in market prices and net changes in position. In light of the downgrades, some counterparties have sought and others may seek replacement security to collateralize the exposure guaranteed by PG&E NEG and its subsidiaries.

PG&E GTN and PG&E ET have terminated the arrangements pursuant to which PG&E GTN provided guarantees on behalf of PG&E ET such that PG&E GTN will provide no new guarantees on behalf of PG&E ET.

At January 31, 2003, PG&E ET's estimated exposure not covered by a guarantee (excluding exposure under tolling agreements) was approximately $90 million.

To date, PG&E ET has met those replacement security requirements properly demanded by counterparties and has not defaulted under any of its master trading agreements although one counterparty has alleged a default. No demands have been made upon the guarantors of PG&E ET's obligations under these trading agreements. In the past, PG&E ET has been able to negotiate acceptable arrangements and reduce its overall exposure to counterparties when PG&E ET or its counterparties have faced similar situations. There can be no assurance that PG&E ET can continue to negotiate acceptable arrangements in the current circumstances. PG&E NEG cannot quantify with any certainty the actual future calls on PG&E ET's liquidity. PG&E NEG's and its subsidiaries' ability to meet these calls on their liquidity will vary with market price volatility, uncertainty with respect to PG&E NEG's financial condition and the degree of liquidity in the energy markets. The actual calls for collateral will depend largely upon the ability to enter into forbearance agreements, and pre- and early-pay arrangements with counterparties, the continued performance of PG&E NEG companies under the underlying agreements, whether counterparties have the right to demand such collateral, the execution of master netting agreements and offsetting transactions, changes in the amount of exposure, and other commercial considerations.

Tolling Agreements: PG&E ET has entered into tolling agreements with several counterparties under which it, at its discretion, supplies the fuel to the power plants and then sells the plant's output in the competitive market. Payments to the counterparties are reduced if the plants do not achieve agreed-upon levels of performance. The face amount of PG&E NEG's and its subsidiaries' guarantees relating to PG&E

ET's tolling agreements is approximately $600 million. The tolling agreements currently in place are with: (1) Liberty Electric Power, L.P. (Liberty) guaranteed primarily by PG&E NEG and secondarily by PG&E GTN for an aggregate amount of up to $150 million; (2) DTE-Georgetown, LLC (DTE) guaranteed by PG&E GTN for up to $24 million; (3) Calpine Energy Services, L.P. (Calpine) for which no guarantee is in place; (4) Southaven guaranteed by PG&E NEG for up to $175 million; and (5) Caledonia Generating, LLC (Caledonia) guaranteed by PG&E NEG for up to $250 million.

Liberty – Liberty has provided notice to PG&E ET that the ratings downgrade of PG&E NEG constituted a material adverse change under the tolling agreement requiring PG&E ET to replace the guarantee and post security in the amount of $150 million. PG&E ET has not posted such security. Liberty has the right to terminate the agreement and seek recovery of a termination payment. Under the terms of the guarantees to Liberty for the aggregate $150 million, Liberty must first proceed against PG&E NEG's guarantee, and can demand payment under PG&E GTN's guarantee only if (1) PG&E NEG is in bankruptcy or (2) Liberty has made a payment demand on PG&E NEG which remains unpaid five business days after the payment demand is made. In addition, PG&E ET has provided notices to Liberty of several breaches of the tolling agreement by Liberty and has advised Liberty that, unless cured, these breaches would constitute a default under the agreement. If these defaults remain uncured, PG&E ET has the right to terminate the agreement and seek recovery of a termination payment.

DTE – By letter dated October 14, 2002, DTE provided notice to PG&E ET that the downgrade of PG&E GTN constituted a material adverse change under the tolling agreement between PG&E ET and DTE and that PG&E ET was required to post replacement security within ten days. By letter dated October 23, 2002, PG&E ET advised DTE that because there had not been a material adverse change with respect to PG&E GTN within the meaning of the tolling agreement, PG&E ET was not required to post replacement security. If PG&E ET was required to post replacement security and it failed to do so, DTE would have the right to terminate the tolling agreement and seek recovery of a termination payment.

Calpine – The tolling agreement states that on or before October 15, 2002, Calpine was to have issued a full notice to proceed under its construction contract to its engineering, procurement and construction contractor for the Otay Mesa facility. On October 16, 2002, PG&E ET asked Calpine to confirm that it had issued this full notice to proceed and Calpine was not able to do so to the satisfaction of PG&E ET. Consequently, PG&E ET advised Calpine by letter dated October 30, 2002, that it was terminating the tolling agreement effective November 29, 2002. Calpine has indicated that this termination was improper and constituted a default under the agreement, but has not taken any further action.

Caledonia and Southaven New Tolling Agreements – PG&E ET signed a tolling agreement with Caledonia dated as of September 20, 2000, pursuant to which PG&E ET is to provide credit support as defined in the tolling agreement. PG&E ET satisfied this obligation by providing a guarantee from PG&E NEG that was investment-grade as defined in the agreement. The amount of the guarantee now does not exceed $250 million. By letter dated August 31, 2002, Caledonia advised PG&E ET that it believed an event of default under the tolling agreement had taken place with respect to this obligation as PG&E NEG was no longer investment-grade as defined in the tolling agreement and because PG&E ET had failed to provide, within thirty days from the downgrade substitute credit support that met the requirements of the tolling agreement. Caledonia has the right to terminate the agreement and seek a termination payment. In addition, PG&E ET has provided Caledonia with a notice of default respecting Caledonia's performance under the tolling agreement concerning the inability of the facility to inject its output into the local grid. Caledonia has not cured this default and on February 4, 2003, PG&E ET provided a notice of termination.

PG&E ET signed a tolling agreement with Southaven dated as of June 1, 2000, under which PG&E ET is required to provide credit support as defined in the agreement. PG&E ET satisfied this obligation by providing an investment-grade guarantee from PG&E NEG as defined in the tolling agreement. The amount of the guarantee is approximately $175 million. By letter dated August 31, 2002, Southaven advised PG&E ET that it believed an event of default under the tolling agreement had taken place as PG&E NEG was no longer investment-grade as defined in the tolling agreement and because PG&E ET had failed to provide, within thirty days from the downgrade, substitute credit support that met the requirement of the tolling agreement. Southaven has the right to terminate the agreement and seek a termination payment. In addition, PG&E ET has provided Southaven with a notice of default respecting Southaven's performance under the tolling agreement concerning the inability of the facility to inject its output into the local grid. Southaven has not cured this default and on February 4, 2003, PG&E ET provided a notice of termination.

On February 7, 2003, Southaven filed emergency petitions to compel arbitration or alternatively, a temporary restraining order and preliminary injunction with the Circuit Court for Montgomery County, Maryland. The Court has denied the relief requested and has set the matter for hearing on February 27, 2003.

PG&E ET is not able to predict whether the counterparties will seek to terminate the agreements or whether the Court will grant the requested relief. Accordingly, it is not able to predict whether or the extent to which these proceedings will have a material adverse effect on PG&E NEG's financial condition or results of operation.

Under each tolling agreement determination of the termination payment is based on a formula that takes into account a number of factors including market conditions such as the price of power and the price of fuel. In the event of a dispute over the amount of any termination payment that the parties are unable to resolve by negotiation, the tolling agreement provides for mandatory arbitration. The dispute resolution process could take as long as six months to more than a year to complete. To the extent that PG&E ET did not pay these damages, the counterparties could seek payment under the guarantees for an aggregate amount not to exceed $600 million. PG&E NEG is unable to predict whether counterparties will seek to terminate their tolling agreements. PG&E NEG does not currently expect to be able to pay any termination payments that may become due.

Other Guarantees

PG&E NEG has provided guarantees related to other obligations by PG&E NEG companies to counterparties for goods or services. PG&E NEG does not believe that it has significant exposure under these guarantees. The most significant of these guarantees relate to performance under certain construction and equipment procurement contracts. In the event PG&E NEG is unable to provide any additional or replacement security which may be required as a result of rating downgrades, the counterparty providing the goods or services could suspend performance or terminate the underlying agreement and seek recovery of damages. These guarantees represent guarantees of subsidiary obligations for transactions entered into in the ordinary course of business. Some of the guarantees relate to the construction or development of PG&E NEG's power plants and pipelines. These guarantees are described below.

PG&E NEG has issued guarantees for the performance of the contractors building the Harquahala and Covert power projects for up to $555 million. Any exposure under the guarantees for construction completion is mitigated by guarantees in favor of PG&E NEG from the constructor and equipment vendors related to performance, schedule, and cost. The constructor and various equipment vendors are performing under their underlying contracts.

PG&E NEG has issued $100 million of guarantees to the constructor of the Harquahala and Covert projects to cover certain separate cost-sharing arrangements. Failure to perform under those separate cost-sharing arrangements or the related guarantees would not have an impact on the constructor's obligations to complete the Harquahala and Covert projects pursuant to the construction contracts. However, in the event that the construction contractor incurs certain un-reimbursed project costs or cost overruns, the contractor could assert a claim against PG&E NEG's subsidiary or PG&E NEG under its guarantees. PG&E NEG believes that no claim can be validly asserted by the construction contractor as of the date hereof.

PG&E NEG has provided a $300 million guarantee to support a tolling agreement that a wholly owned subsidiary, Attala Energy, has entered into with Attala Generating. See discussion above under "Impairment of Prepaid Rents on Attala Lease," for additional discussion of this guarantee.

In addition to those discussed above, PG&E NEG has guarantees for commitments undertaken by PG&E NEG or subsidiaries in the ordinary course of business for services such as facility and equipment leases, ash disposal rights, and surety bonds.

Credit Facility Summary:

PG&E NEG has the following credit facilities outstanding at January 31, 2003:

(in millions)	Total Bank Commitment	Balance
PG&E NEG Inc. – Tranche A (2 year facility) [a]	$264	$264
PG&E NEG Inc. – Tranche B (364 day facility) [a]	431	431
PG&E ETH and Subsidiaries – Facility One	35	34
PG&E ETH and Subsidiaries – Facility Two	19	19
PG&E Generating LLC	7	7
USGen New England	100	88
PG&E GTC and Subsidiaries	125	53
Total	$981	$896

[a] PG&E NEG is currently in default on both its Tranche A and Tranche B credit facility.

PG&E CORPORATION

Due to the Utility's deteriorating liquidity and financial condition during the California energy crisis in 2000, PG&E Corporation refinanced its debt obligations through a credit agreement (Original Credit Agreement) with General Electric Capital Corporation (GECC) and Lehman Commercial Paper Inc. (LCPI) in 2001. The proceeds of this refinancing were used to pay commercial paper, borrowings under PG&E Corporation's long-term revolving credit facility, and a fourth quarter 2000 dividend to shareholders. During 2002, PG&E Corporation negotiated new terms to amend the Original Credit Agreement. In August 2002, PG&E Corporation made a voluntary prepayment of principal and interest totaling $607 million to the GECC portion of the debt.

On October 18, 2002, PG&E Corporation entered into a Second Amended Credit Agreement (Credit Agreement) with the remaining lenders for a total amount of $720 million. Of the total amount secured under the Credit Agreement, $420 million covered amounts retained under the prior credit agreement and $300 million represented new loans (New Loans and collectively referred to as the Loans). These New Loans were released from a separate escrow account to PG&E Corporation on January 17, 2003, concurrent with a funding fee payment of $9 million.

All obligations of PG&E Corporation under the Credit Agreement are secured by a perfected first-priority security interest in the outstanding common stock of the Utility and all proceeds thereof. With respect to 35 percent of such common stock pledged for the benefit of the lenders, the lenders have customary rights of a secured creditor, provided that certain regulatory approvals may be required in connection with any foreclosure on such stock. With respect to the remaining 65 percent, such common stock has been pledged for the benefit of the lenders, but the lenders have no ability to control such common stock under any circumstances and do not have any of the typical rights and remedies of a secured creditor. However, the lenders do have the right to receive any cash proceeds received upon a disposition of such common stock.

All obligations of PG&E Corporation under the Credit Agreement continue to be secured by a perfected first priority security interest in 100 percent of the equity interests in PG&E NEG LLC and 100 percent of the common stock of PG&E NEG and all proceeds thereof.

The Credit Agreement limits the ability of PG&E Corporation and some of its subsidiaries to grant liens, consolidate, merge, purchase or sell assets, declare or pay dividends, incur indebtedness, or make advances, loans, and investments. In addition, PG&E Corporation may not use the proceeds of the New Loans to make investments in PG&E NEG LLC or PG&E NEG, or any of their subsidiaries or, in the Utility, except as specifically permitted by the terms of the loans or as required by applicable law or the conditions adopted by the CPUC with respect to holding companies. However, the Credit Agreement generally permits:

- PG&E NEG LLC, PG&E NEG, and their respective subsidiaries to enter into sales and other dispositions of assets in the ordinary course of business and in certain qualified transactions;
- PG&E Corporation to use existing cash to make investments in PG&E NEG (limited to 75 percent of the net cash tax savings actually received by PG&E Corporation from certain PG&E NEG transactions after October 1, 2002) in connection with certain sales and debt restructuring transactions of PG&E NEG and its subsidiaries;
- PG&E Corporation to make investments funded from existing cash, and to pay obligations of PG&E NEG and its subsidiaries (including, without limitation, any obligations for which PG&E Corporation becomes a surety or a guarantor) up to a cumulative amount not to exceed $15 million;
- PG&E NEG LLC, PG&E NEG, or their respective subsidiaries to grant liens or incur debt;
- PG&E Corporation and the Utility to consummate the transactions contemplated in the Utility's Plan; and
- PG&E Corporation to spin off 100 percent of the equity interests in PG&E NEG LLC and 100 percent of the common stock of PG&E NEG, and all proceeds thereof, with the consent of lenders holding more than 50.1 percent of the aggregate outstanding principal amount of the Loans.

The Credit Agreement provides for stated events of default and events requiring mandatory prepayment of the Loans. See Note 4 of the Notes to the Consolidated Financial Statements for further discussion of the Credit Agreement.

In connection with the Utility's proposed plan of reorganization, PG&E Corporation intends to negotiate with the lenders to obtain their consent to the issuance of up to $700 million of PG&E Corporation equity and the contribution of some of the proceeds of issuance to the capital of the Utility.

In connection with the Credit Agreement, PG&E Corporation also has issued to the lenders additional warrants to purchase 2,669,390 shares of common stock of PG&E Corporation, with an exercise price of $0.01 per share. PG&E Corporation has agreed to provide, following consummation of a plan of reorganization of the Utility, registration rights in connection with the shares issuable upon exercise of these warrants.

The net proceeds of the Loans will be used to fund corporate working capital and for general corporate purposes.

PG&E Corporation's Convertible Subordinated Notes (Notes) in the aggregate principal amount of $280 million were issued on June 25, 2002.

The Notes, maturing on June 30, 2010, have an interest rate of 9.50 percent, and provide the holder of the Notes with a one-time right to require PG&E Corporation to repurchase the Notes on June 30, 2007, at a purchase price equal to the principal amount plus accrued and unpaid interest (including any liquidated damages and pass-through dividends).

CASH FLOWS

Utility

The following section discusses the Utility's significant cash flows from operating, investing, and financing activities for the years ended December 31, 2002, 2001, and 2000.

Operating Activities

Results from the Utility's consolidated cash flows from operating activities for the years ended 2002, 2001, and 2000 are as follows:

(in millions)	Year Ended December 31,		
	2002	2001	2000
Net income (loss)	$1,819	$1,015	$(3,483)
Depreciation, amortization, and decommissioning included in net income	1,193	896	3,511
Reversal of ISO accrual included in net income	(970)	–	–
Increase in accounts payable	198	1,312	3,063
Payments authorized by the Bankruptcy Court on amounts classified as liabilities subject to compromise	(1,442)	(16)	–
(Increase) Decrease in income taxes receivable	(50)	1,120	(1,120)
Other operating activity adjustments	386	438	(1,416)
Net cash provided by operating activities	$1,134	$4,765	$555

Operating activities provided net cash of $1.1 billion in 2002 and $4.8 billion in 2001. The decrease during the period is primarily due to the following factors:

- The Utility filed for bankruptcy in April 2001, which automatically stayed all payments on liabilities incurred prior to the bankruptcy. Subsequent to the bankruptcy, the Utility resumed paying its ongoing expenses in the ordinary course of business. As a result, the growth in accounts payable is $1.1 billion lower in 2002 compared to 2001;
- The Utility received a $1.1 billion income tax refund in 2001; no comparable refund was received in 2002;
- In 2002, approximately $901 million in principal owed to QFs prior to the bankruptcy was repaid by the Utility under Bankruptcy Court approved agreements. Among other things, the agreements provided for repayments of amounts owed to QFs prior to the bankruptcy either in full or in 6 to 12 monthly installments; and

- In 2002, the Bankruptcy Court issued an order authorizing the Utility to pay pre- and post-petition interest to:
  1. Holders of certain undisputed claims, including commercial paper, senior notes, floating rate notes, medium-term notes, Deferrable Interest Subordinated Debentures (QUIDS), prior bond claims, revolving line of credit claims, and secured debt claims;
  2. Trade creditors, including QFs; and
  3. Certain other general unsecured creditors.

The Utility paid approximately $1 billion in pre- and post-petition interest related to these claims during 2002. The interest payments included accrued interest on financial debt previously classified as liabilities subject to compromise totaling $433 million.

Operating activities provided net cash of $4.8 billion in 2001 and $0.6 billion in 2000. The increase in 2001 was primarily due to an increase in net income and the receipt of a $1.1 billion income tax refund in 2001. Of the $4.5 billion increase in net income, $2.6 billion was attributable to a decrease in depreciation, a non-cash expense. See the Results of Operations section of this MD&A for a discussion of the Utility's net income.

Investing Activities

Results from the Utility's consolidated cash flows from investing activities for the years ended 2002, 2001, and 2000 are as follows:

(in millions)	Year Ended December 31, 2002	2001	2000
Capital expenditures	$(1,546)	$(1,343)	$(1,245)
Other investing activities	37	5	38
Net cash used by investing activities	$(1,509)	$(1,338)	$(1,207)

Cash used by investing activities in 2002, 2001, and 2000, was primarily for capital expenditures related to improvements to the Utility's electricity and natural gas transmission and distribution systems.

While the Utility is in bankruptcy, capital expenditures are being funded with cash provided by operating activities.

Financing Activities

Results from the Utility's consolidated cash flows from financing activities for the years ended 2002, 2001, and 2000 are as follows:

(in millions)	Year Ended December 31, 2002	2001	2000
Net (repayments) borrowings under credit facilities and short-term borrowings	$ –	$ (28)	$2,630
Net, long-term debt issued, matured, redeemed, or repurchased	(333)	(111)	373
Rate reduction bonds matured	(290)	(290)	(290)
Common stock repurchased	–	–	(275)
Dividends paid	–	–	(475)
Other financing activities	–	(1)	(26)
Net cash provided (used) by financing activities	$(623)	$(430)	$1,937

Except as contemplated in the Utility's proposed plan of reorganization discussed in Note 2 of the Notes to the Consolidated Financial Statements, the Utility has no plans to seek external financing as a source of funding. Additionally, the Utility is not allowed to pay dividends on its preferred or common stock while in bankruptcy without Bankruptcy Court approval. As discussed in Note 9 and 10 of the Notes to the Consolidated Financial Statements, the Utility did not declare or pay common and preferred stock dividends in 2001 or 2002. Preferred stock dividends have a cumulative feature in which preferred stock dividends must be brought current before any dividends can be distributed to common stockholders. Further, the preferred stocks have a mandatory sinking fund feature in which funds are set-aside for the future periodic retirement of outstanding preferred stock. Until cumulative dividend payments on the Utility's preferred stock and mandatory sinking fund payments are made, the Utility may not pay dividends on its common stock. See Note 10 of the Notes to the Consolidated Financial Statements for a discussion of the Utility's preferred stock.

2002

Financing activities used $623 million of net cash in 2002 primarily reflecting the repayments of long-term debt and rate reduction bonds. Pursuant to Bankruptcy Court approval, the Utility repaid $333 million in principal on its mortgage bonds that matured in March 2002. PG&E Funding LLC, a wholly owned subsidiary of the Utility, also repaid $290 million in principal on its rate reduction bonds during 2002. PG&E Funding LLC and the rate reduction bonds are not included in the Utility's bankruptcy.

2001

Financing activities used $430 million of net cash in 2001 primarily for repayments of long-term debt and rate reduction bonds. The repayment of long-term debt included payments on:

(in millions)	
Medium-term notes	$ 18
Mortgage bonds	93
Net repayment of long-term debt	$111

The payments on the medium-term notes and the mortgage bonds were made before the Utility's April 2001 bankruptcy filing.

PG&E Funding LLC repaid $290 million in principal on its rate reduction bonds during 2001. As previously mentioned, the rate reduction bonds are not included in the Utility's bankruptcy.

2000

Financing activities provided $1.9 billion of net cash in 2000 primarily due to borrowings under credit facilities and short-term borrowings, partially offset by (1) principal payments on long-term debt and rate reduction bonds, (2) common stock repurchases, and (3) dividend payments. Net borrowings under credit facilities and short-term borrowings included the following:

(in millions)	
Credit facility draws	$ 614
Commercial paper issuance	776
364-day floating rate notes issuance	1,240
Net borrowings under credit facilities and short-term borrowings	$2,630

The Utility issued, repaid, redeemed, or repurchased long-term debt as follows:

(in millions)	
Issuance of:	
Senior notes	$680
Maturity of:	
Mortgage bonds	(110)
Various medium-term notes	(113)
Other long-term debt	(3)
Repurchase of:	
Various pollution control loan agreements	(81)
Net issuance, repayment, redemption, and repurchase of long-term debt	$373

PG&E Funding LLC repaid $290 million in principal on its rate reduction bonds during 2000.

As previously mentioned, the rate reduction bonds are not included in the Utility's bankruptcy.

In April 2000, a subsidiary of the Utility repurchased 11.9 million shares of the Utility's common stock from PG&E Corporation at a cost of $275 million. The repurchase was made so that the Utility could maintain its CPUC-authorized capital structure, which is the level of common and preferred equity the Utility may maintain in relation to debt.

PG&E NEG

The cash from operations for the years 2002, 2001, and 2000 will not be indicative of the future cash flow from operations due to the changes in the operations of PG&E NEG (discussed above).

To the extent that the commitments of PG&E NEG and its subsidiaries can be restructured, future cash from operations will be principally generated by the PG&E NEG pipeline business as well as dividends from PG&E NEG's independent power producer generation project companies which are accounted for under the equity method of accounting. If the commitments are not restructured, PG&E NEG and its subsidiaries will not generate sufficient funds to meet its outstanding cash requirements and may file or be forced into bankruptcy.

In addition to the impacts of PG&E NEG's downgrades, PG&E NEG's and its subsidiaries' ability to service these obligations is impacted by constraints on the ability to move cash from one subsidiary to another or to PG&E NEG itself. PG&E NEG's subsidiaries must now independently determine, in light of each company's financial situation, whether any proposed dividend, distribution or intercompany loan is permitted and is in such subsidiary's interest. Therefore, Consolidated Statements of Cash Flow and Consolidated Balance Sheets quantifying PG&E NEG's cash and cash equivalents do not reflect the cash actually available to PG&E NEG or any particular subsidiary to meet its obligations.

At January 31, 2003, PG&E NEG and its subsidiaries had the following unrestricted cash and short-term investment balances (not including in-transit items):

(in millions)	
PG&E NEG	$126
PG&E ET and Subsidiaries	98
PG&E Gen and Subsidiaries	97
PG&E GTN and Subsidiaries	17
Other	60
Consolidated PG&E NEG	$398

Operating Activities

Results from PG&E NEG's consolidated cash flows from operating activities for the years ended 2002, 2001, and 2000 are as follows on a summarized basis:

(in millions)	2002	2001	2000
Net income (loss)	$(3,423)	$171	$152
Adjustments to reconcile net income to net cash (used) provided by operating activities before price risk management assets and liabilities	3,539	(38)	119
Subtotal	116	133	271
Price risk management assets and liabilities, net	99	130	(21)
Net effect of changes in operating assets and liabilities:			
Restricted cash	(62)	(62)	3
Net, accounts receivable, accounts payable and accrued liabilities	100	42	65
Inventories, prepaids, deposits and other	(471)	143	(154)
Net cash provided (used) by operating activities	$ (218)	$386	$164

During 2002, PG&E NEG used net cash from operating activities of $218 million. Net cash from operating activities before changes in operating assets and liabilities and price risk management assets and liabilities was $116 million in 2002, created principally from results of operations offset by the timing of deferred tax benefits and lower distributions from unconsolidated affiliates. Change in price risk management assets and liabilities increased cash flow by $99 million due to realization of cash from price risk management activities. The change in inventories, prepaid expenses, deposits, and other liabilities decreased cash flow by $471 million primarily due to increased credit collateral deposit requirements in PG&E NEG's trading operations. Adding to these cash outflows were $62 million of increased in restricted cash requirements.

During 2001, PG&E NEG generated net cash from operating activities of $386 million. Net cash from operating activities before changes in operating assets and liabilities and price risk management assets and liabilities was $133 million in 2001, created principally from results of operations offset by the timing of deferred tax benefits and lower distributions from unconsolidated affiliates. Change in price risk management assets and liabilities increased cash flow by $130 million due to realization of cash from price risk management activities. PG&E NEG's net cash inflow related to the change in accounts receivable, accounts payable, and accrued liabilities from operations assets and liabilities was $42 million. The change in inventories, prepaid expenses, deposits, and other liabilities increased cash flow by $143 million primarily due to repayments of margin deposits in PG&E NEG's trading operations. Offsetting these cash inflows were $62 million of increased restricted cash requirements in several of PG&E NEG's projects in construction.

During 2000, PG&E NEG generated net cash from operating activities of $164 million. Net cash from operating activities before changes in operating assets and liabilities and price risk management assets and liabilities was $271 million in 2000, created principally from the timing of deferred tax benefits and higher distributions from unconsolidated affiliates.

Change in price risk management assets and liabilities decreased cash flow by $21 million. PG&E NEG's net cash inflow related to the change in accounts receivables, accounts payable, and accrued liabilities increased cash flow by $65 million. The change in inventories, prepaid expenses, deposits, and other liabilities decreased cash flow by $154 million principally due to increased margin deposits in PG&E NEG's trading operations.

Investing Activities

The cash outflows from investing activities for the years 2002, 2001, and 2000 will not be indicative of the future cash outflow from investing activities due to the changes in the operations of PG&E NEG (discussed above). Depending on the results of the restructuring negotiations discussed above, it is anticipated that future cash outflows from investing operations will be principally generated by our pipeline business principally related to maintenance capital expenditures.

Results from PG&E NEG's consolidated cash flows from investing activities for the years ended 2002, 2001, and 2000 are as follows:

(in millions)	2002	2001	2000
Capital expenditures	$(1,485)	$(1,426)	$(900)
Acquisition of generating assets	–	(107)	(311)
Proceeds from sale of assets (equity investments)	46	–	442
Proceeds from sale leaseback	340	–	–
Long-term prepayment on turbines	(15)	(89)	(132)
Investment in Southaven project	(74)	–	–
Repayment of note receivable from PG&E Corporation	75	–	–
Long-term receivable	136	81	75
Other, net	(63)	7	(38)
Net cash used in investing activities	$(1,040)	$(1,534)	$(864)

Total capital expenditures detailed by business segment and expenditure amount associated with construction work in progress for the year ended 2002, 2001, and 2000 are as follows:

(in millions)	2002	2001	2000
Capital expenditure by business segment:			
Integrated energy and marketing activities	$1,294	$1,324	$885
Interstate pipeline operations	191	102	15
Total capital expenditures	$1,485	$1,426	$900
Expenditure associated with construction work in progress	$1,353	$1,318	$722

During 2002, PG&E NEG used net cash of $1,040 million in investing activities compared to $1,534 million for the same period in 2001, or a decrease of $494 million. The decrease in cash used in investing activities from period to period was primarily due to proceeds from the Attala Generating sale leaseback transaction providing $340 million, proceeds of $46 million from the partial sale of PG&E NEG's interest in Hermiston and the repayment of a $75 million loan from PG&E Corporation to PG&E GTN. Offsetting these proceeds were capital expenditures of $1,485 million in 2002 versus $1,426 million in 2001. These capital expenditures were used primarily for construction work in progress and were financed by non-recourse debt. Due to PG&E NEG's default on making equity commitments, these construction projects will potentially be transferred to lenders in 2003. Advanced development and turbine prepayments were $144 million less in 2002 versus 2001 due to the reductions and cancellations of new construction efforts. All remaining development assets and related turbine and other equipments contracts will be abandoned and terminated during 2003. As a result of investment downgrades, PG&E ET replaced a $74 million letter of credit issued to Southaven with cash pursuant to a subordinated loan agreement. No such activity occurred in 2001.

Included in investing activities for 2002 and 2001 are cash flows of $136 million and $81 million respectively related to the long-term receivable from New England Power Company (NEPC) associated with the assumption of power purchase agreements. These cash flows offset cash payments made to NEPC which are reflected in operating activities. PG&E NEG intends to sell USGenNE in 2003.

During 2001, PG&E NEG used net cash of $1.5 billion for investing activities, which were primarily attributable to capital expenditures associated with generating projects in construction, its purchase of the Mountain View wind project, and prepayments on turbines and related equipment.

During 2000, PG&E NEG used net cash of $864 million for investing activities. The primary cash outflows from investing activities were for capital expenditures associated with generating projects in construction, the acquisition of Attala, and prepayments on the turbines and related equipment. These outflows were partially offset by the receipt of $442 million in proceeds from sales of assets and equity investments. Included in investing activities is a cash flow of $75 million related to the long-term receivable from NEPC associated with the assumption of power purchase agreements. These cash flows offset cash payments made to NEPC which are reflected in operating activities.

Financing Activities

Results from PG&E NEG's consolidated cash flows from financing activities for the years ended December 31, 2002, 2001, and 2000 are as follows:

(in millions)	2002	2001	2000
Net borrowings (repayments) under credit facilities	$ –	$ (189)	$ (5)
Repayment of obligations due related parties and affiliates	(100)	–	–
Advances from PG&E Corporation	–	–	79
Long-term debt issued	1,506	1,114	711
Long-term debt matured, redeemed, or repurchased	(403)	(757)	(85)
Notes issuance, net of discount and issuance costs	–	987	–
Deferred financing costs	(41)	(39)	–
Capital contributions	–	–	608
Distributions	–	–	(106)
Net cash provided by financing activities	$ 962	$1,116	$1,202

During 2002, PG&E NEG provided net cash flows from financing activities of $962 million.

PG&E NEG's cash inflows from financing activities were primarily attributable to increases in long-term debt issued relating to the continuing completion of PG&E NEG's construction facilities and borrowings under construction financing.

During 2001, net cash provided by financing activities was $1.1 billion, principally from the net proceeds related to the issuance of the Senior Unsecured Notes due 2011.

During 2000, net cash provided by financing activities was $1.2 billion. Net cash provided by financing activities resulted primarily from non-recourse project debt of $711 million, and capital contributions by PG&E Corporation of $608 million, partially offset by distributions to PG&E Corporation of $106 million.

PG&E Corporation

The following section discusses PG&E Corporation's significant cash flows from operating, investing, and financing activities for the years ended December 31, 2002, 2001, and 2000.

Operating Activities

Results from PG&E Corporation's consolidated cash flows from operating activities for the years ended December 31, 2002, 2001, and 2000 are as follows:

(in millions)	Year Ended December 31,		
	2002	2001	2000
Net income (loss)	$ (874)	$1,099	$(3,364)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	1,309	1,002	3,595
Net effect of changes in operating assets and liabilities:			
Restricted cash	(513)	(66)	(6)
Accounts receivable	51	1,000	(1,941)
Accounts payable	377	1,213	4,200
Payments authorized by the Bankruptcy Court on amounts classified as liabilities subject to compromise	(1,442)	(16)	-
Assets and liabilities of operations held for sale	34	(117)	64
Other, net	1,592	1,166	(1,793)
Net cash provided by operating activities	$ 534	$5,281	$ 755

Net cash provided by operating activities was $534 million in 2002, $5,281 million in 2001, and $755 million in 2000.

The decrease during 2002 was primarily due to the following factors:

- The continued operation of the Utility as a debtor-in-possession under the Bankruptcy Code and the prior year impact of an income tax refund.
- Increased working capital requirements of PG&E NEG, primarily due to increased credit collateral deposit requirements in PG&E NEG's trading operations.

The increase during 2001 was primarily due to the Utility's pre-petition obligations being stayed under the Bankruptcy Code, and deliveries on previously held trading positions at PG&E NEG.

Investing Activities

Results from PG&E Corporation's consolidated cash flows from investing activities for the year ended 2002, 2001, and 2000 are as follows:

(in millions)	Year Ended December 31,		
	2002	2001	2000
Capital expenditures	$(3,032)	$(2,773)	$(2,334)
Other, net	482	(103)	656
Net cash used by investing activities	$(2,550)	$(2,876)	$(1,678)

Net cash used in investing activities in 2002, 2001, and 2000 was primarily for capital expenditures at the Utility and construction and development projects at PG&E NEG.

The decrease in cash used in investing activities in 2002, compared to 2001, was primarily due to the proceeds received by PG&E NEG from Attala Generating.

Financing Activities

Results from PG&E Corporation's consolidated cash flows from financing activities for the year ended 2002, 2001, and 2000 are as follows:

(in millions)	Year Ended December 31, 2002	2001	2000
Net borrowings (repayments) under credit facilities	$ –	$(1,148)	$ 2,846
Long-term debt issued	2,414	3,008	1,659
Long-term debt matured, redeemed, or repurchased	(1,644)	(868)	(1,155)
Dividends paid	–	(109)	(436)
Other, net	(214)	(316)	86
Net cash provided by financing activities	$ 556	$ 567	$ 3,000

Net cash generated through financing activities in 2002, 2001, and 2000 was principally achieved through long-term debt issuances and increased borrowings under new and existing credit facilities. The decrease in net cash provided by financing activities in 2002, compared to 2001, of $11 million, was a result of the Utility's repayment of long-term debt, partly offset by PG&E NEG's increased borrowings under new and existing credit facilities.

During 2002, PG&E Corporation negotiated new terms to amend the Original Credit Agreement, reducing the principal balance from $1 billion to $720 million which included $300 million in new long-term debt.

RESULTS OF OPERATIONS

In this section, PG&E Corporation discusses earnings and the factors affecting them for each operating segment. The table below details certain items from the accompanying Consolidated Statements of Operations by operating segment for the years ended December 31, 2002, 2001, and 2000.

		PG&E National Energy Group					
(in millions)	**Utility**	**Total PG&E NEG**	**Integrated Energy & Marketing Activities**	**Interstate Pipeline Operations**	**PG&E NEG Eliminations**	**PG&E Corporation, Eliminations and Other [1]**	**Total**
2002							
Operating revenues [2]	$10,514	$ 2,075	$ 1,855	$ 253	$(33)	$ (94)	$12,495
Operating expenses	6,601	4,812	4,653	109	50	(50)	11,363
Operating income (loss)	$ 3,913	$(2,737)	$(2,798)	$ 144	$(83)	$ (44)	1,132
Interest income							132
Interest expense							(1,454)
Other income (expense), net							90
Loss before income taxes							(100)
Income benefit							(43)
Loss from continuing operations							(57)
Net loss							$ (874)
2001 [3]							
Operating revenues [2]	$10,462	$ 1,920	$ 1,680	$ 246	$ (6)	$(172)	$12,210
Operating expenses	7,984	1,787	1,679	109	(1)	(152)	9,619
Operating income (loss)	$ 2,478	$ 133	$ 1	$ 137	$ (5)	$ (20)	2,591
Interest income							167
Interest expense							(1,209)
Other income (expense), net							(31)
Income before income taxes							1,518
Income taxes							535
Income from continuing operations							983
Net income							$ 1,099
2000 [3]							
Operating revenues [2]	$ 9,637	$ 3,127	$ 2,009	$1,112	$ 6	$(196)	$12,568
Operating expenses	14,838	2,858	1,937	906	15	(199)	17,497
Operating income (loss)	$(5,201)	$ 269	$ 72	$ 206	$ (9)	$ 3	(4,929)
Interest income							214
Interest expense							(788)
Other income (expense), net							(23)
Loss before income taxes							(5,526)
Income benefit							(2,103)
Loss from continuing operations							(3,423)
Net loss							$(3,364)

[1] PG&E Corporation eliminates all inter-segment transactions in consolidation.

[2] Operating revenues and expenses reflect the adoption during 2002 of a new accounting policy implementing a change from gross to net method of reporting revenues and expenses on trading activities. Prior year amounts for trading activities have been reclassified to conform with the new net presentation.

[3] Prior periods amounts have been restated to reflect the reclassification of USGenNE, Mountain View, and ET Canada operating results to discontinued operations.

PG&E Corporation – Consolidated

Overall Results

PG&E Corporation's net loss for the year ended December 31, 2002, was $874 million, compared to net income of $1,099 million for the same period in 2001, and a net loss of $3,364 million for the same period in 2000.

The significant changes in pre-tax income for both years ended December 31, 2002 and 2001, when compared to prior year are summarized in the table below:

(in millions)	2002	2001
PG&E Corporation		
Interest expense	(163)	(87)
Other income	79	(1)
Utility		
Electric revenues	852	472
Natural gas revenues	(800)	353
Cost of electricity	1,292	3,967
Deferred electric procurement costs	–	(6,465)
Cost of natural gas	878	(407)
Operating and maintenance	(432)	302
Depreciation amortization and decommissioning	(297)	2,615
Provision for loss on generation-related regulatory assets and under-collected power costs	–	6,939
Reorganization fees and expenses	(58)	(97)
Interest and other income	(49)	(431)
Interest expense	(582)	(2,750)
PG&E NEG		
Revenues	155	(1,207)
Cost of revenues	(197)	1,217
Impairments, write-offs, and other charges	(2,767)	–
Operating expenses	(61)	(146)
Cumulative effect of change in accounting principle	(70)	9
Discontinued operations	(1,244)	48

PG&E Corporation's results of operations continue to be impacted by the California energy crisis, the Utility's bankruptcy filing, and the current liquidity and financial downturn at PG&E NEG. The overall results of the Utility and PG&E NEG are discussed separately below. Please see the Liquidity and Financial Resources section above, and Notes 2 and 3 of the Notes to the Consolidated Financial Statements for more information.

The changes in performance for the years ended December 31, 2002 and 2001, are attributable to the following factors:

PG&E Corporation

Interest Expense

In the third quarter, PG&E Corporation wrote off unamortized loan fees and discounts of $83 million relating to the prepayments of a portion of outstanding debt and $70 million relating to ratings waiver extensions. In addition, PG&E Corporation wrote off $38 million of unamortized loan discounts representing the value of unvested PG&E NEG options associated with the note prepayment.

Other Income

The third quarter change in the market value of vested PG&E NEG warrants previously issued in connection with the PG&E Corporation March 1, 2001, Credit Agreement totaled $71 million.

Dividends

No dividends were declared in 2002 or 2001 in accordance with the Credit Agreement, which prohibits PG&E Corporation from declaring or paying dividends until the term loans have been repaid.

In March 2001, PG&E Corporation paid $109 million of defaulted fourth quarter 2000 dividends in conjunction with the refinancing of PG&E Corporation obligations.

Utility

Electric Revenues

The following table shows a breakdown of the Utility's electric revenue by customer class:

(in millions)	Year ended December 31,		
	2002	2001	2000
Residential	$ 3,646	$ 3,396	$ 3,062
Commercial	4,588	4,105	3,110
Industrial	1,449	1,554	1,053
Agricultural	520	525	420
Total	10,203	9,580	7,645
Direct access credits	$ (285)	$ (461)	$(1,055)
DWR pass-through revenue	(2,056)	(2,173)	–
Miscellaneous	316	380	264
Total electric operating revenues	$ 8,178	$ 7,326	$ 6,854

Electric revenues in 2002 increased $852 million, or 11.6 percent, from 2001. This increase in electric revenues was primarily due to three factors:

- The amount of CPUC-authorized surcharges increased $751 million in 2002 from 2001. This increase reflects the collection of a $0.035 per kilowatt-hour (kWh) surcharge, effective June 2001, for all of 2002, as compared to the collection of this surcharge for only seven months during the twelve-month period ended December 31, 2001.
- Direct access credits in 2002 decreased $176 million from 2001. In accordance with CPUC regulations, the Utility provides an energy credit to direct access customers (those who buy their electricity from another energy service provider, or ESP). The Utility bills direct access customers based on fully bundled rates, which includes generation, distribution, transmission, and other components. However, each direct access customer receives an energy credit equal to the procurement component of the fully bundled rates, which includes (1) the Utility's estimated procurement and generation cost, and (2) the Utility's

generation component of the frozen rate for electricity provided by the DWR.

The decrease in direct access credits was due to a decrease in the average direct access credit per kWh offset by an increase in the total electricity provided to direct access customers by ESPs. The average direct access credit per kWh was higher in 2001 because in the beginning of 2001 the Utility used the California Power Exchange (PX) price for wholesale electricity to calculate direct access credits. Subsequent to the closure of the PX in January 2001, direct access credits have been calculated based on the procurement component of the fully bundled rate, which has been significantly lower than the PX price. The average direct access credit decreased from $0.116 per kWh in 2001 to $0.038 per kWh in 2002. In 2002, ESPs supplied approximately 7,433 gigawatt-hours (GWh) of electricity to direct access customers, compared to 3,982 GWh in 2001.

- Revenue passed through to the DWR decreased by $117 million in 2002. The Utility passes revenue through to the DWR for electricity procured by the DWR to cover the Utility's net open position (the amount of electricity needed by retail electric customers that cannot be met by utility-owned generation or electricity under contract to the Utility). Since January 2001, the DWR has been responsible for procuring electricity required to cover the Utility's net open position. Revenues collected on behalf of the DWR and the related costs are not included in the Utility's Consolidated Statement of Operations because the Utility acts only as the DWR's billing and collection agent.

  The decrease in DWR pass-through revenues in 2002 was primarily due to a decrease in the Utility's net open position, which was created by (1) an increase in electricity supplied by ESPs to direct access customers, and (2) an increase in the amount of electricity the Utility was able to purchase from QFs due to renegotiated payment terms through the Utility's bankruptcy proceeding. The decrease in the Utility's net open position in 2002 was partially offset by the accrual of an additional $369 million in pass-through revenues in 2002 due to changes proposed by the DWR to the methodology used to calculate DWR remittances (see Note 2 of the Notes to the Consolidated Financial Statements).

Electric revenues in 2001 increased $472 million, or 6.9 percent, from 2000 mainly due to the CPUC-authorized surcharges implemented in January and June 2001 and a decrease in direct access credits. The decrease in direct access credits was due to a decrease in total electricity provided to direct access customers by direct access ESPs. In 2001, energy service providers supplied approximately 3,982 GWh of electricity to direct access customers, compared to 9,662 GWh in 2000.

The increase in electric revenues in 2001 was offset by revenues of $2,173 million passed through to the DWR in 2001, with no such amount in 2000.

Cost of Electricity

The following table shows a breakdown of the Utility's cost of electricity:

(in millions)	Year ended December 31,		
	2002	2001	2000
Cost of purchased power	$ 1,980	$ 3,224	$ 6,642
Fuel used in own generation	97	102	99
Other adjustments to cost of electricity	(595)	(552)	-
Total cost of electricity	$ 1,482	$ 2,774	$ 6,741
Average cost of purchased power per kWh	$ 0.081	$ 0.143	$ 0.152
Total purchased power (GWh)	24,552	22,592	43,762

The cost of electricity in 2002 decreased $1,292 million, or 46.6 percent, from 2001. The decrease was attributable to the following factors:

- A decrease in the average cost of purchased power. The more favorable price reflected the significantly lower prices for electricity subsequent to the stabilization of the energy market in the second half of 2001. In addition, the average cost of electricity decreased because the Utility purchased more electricity from QFs, other generators, and irrigation districts, which provided electricity at a lower cost than the electricity the Utility purchased on the market in the beginning of 2001. In 2002, the DWR purchased all of the electricity needed to meet the Utility's net open position, whereas in 2001 the Utility purchased the electricity itself through the PX market through the first half of January. As previously discussed, the Utility serves as a collection agent for the DWR and therefore does not reflect the DWR's cost of electricity in its Consolidated Statement of Operations; and
- A net $595 million reduction to the cost of electricity recorded in March 2002 as a result of FERC and CPUC decisions, which allowed the Utility to reverse previously accrued California Independent System Operator (ISO) charges and to true-up the amount of previously accrued pass-through revenues payable to the DWR (see Note 2 of the Notes to the Consolidated Financial Statements).

Offsetting the above impacts were amounts recorded during 2001 that reduced purchased power costs by $552 million for the market value of terminated bilateral contracts with no similar amounts in 2002.

The cost of electricity in 2001 decreased $3,967 million, or 58.8 percent, from 2000. This decrease was primarily due to the following two factors:

- After the first half of January 2001, the Utility no longer purchased electricity through the PX market. Instead, the DWR purchased electricity on behalf of the Utility's customers to cover the Utility's net open position; and
- A statewide energy conservation campaign led the Utility's customers to use approximately 3 percent less energy than in 2000.

In 2000, the Utility deferred $6.5 billion in under-collected electric procurement costs. At the end of 2000, the Utility could no longer conclude that its under-collected electric procurement costs and generation-related regulatory assets were probable of recovery and therefore charged $6.9 billion to expense for these costs. There were no similar events in 2001.

Natural Gas Revenues

Natural gas revenues are made up of bundled gas revenues and transportation only revenues.

The following table shows a breakdown of the Utility's natural gas revenue:

(in millions)	Year ended December 31,		
	2002	2001	2000
Bundled gas revenues	$1,882	$3,107	$2,229
Transportation service only revenue	316	375	338
Other	138	(346)	216
Total Natural Gas Revenues	$2,336	$3,136	$2,783

In 2002, natural gas revenues decreased $800 million, or 25.5 percent, from 2001 primarily as a result of a lower average cost of natural gas, which was passed along to customers through lower rates. The average bundled price of natural gas sold during 2002 was $6.72 per thousand cubic feet (Mcf) as compared to $10.55 per Mcf in 2001.

The decrease in transportation service only revenue resulted primarily from a decrease in demand for gas transportation services by gas-fired electric generators in California.

Increases in other gas revenues were mainly due to a decrease in the deferral of natural gas revenue in 2002, which was attributed to the abnormally high price for natural gas in the beginning of 2001. The Utility tracks natural gas revenues and costs in natural gas balancing accounts. Over-collections and under-collections are deferred until they are refunded to or received from the Utility's customers through rate adjustments.

In 2001, natural gas revenues increased $353 million, or 12.7 percent, due to a higher average cost of natural gas, which was passed on to customers through higher rates. The average bundled price of natural gas sold during 2001 was $10.55 per Mcf, compared to $8.40 per Mcf in 2000. The increase was offset by an approximate 4 percent decrease in usage in 2001 primarily as a result of conservation efforts.

The increase in transportation service only revenue was primarily due to an increase in demand for gas transportation services by gas-fired electric generators in California.

Decreases in other gas revenues were mainly due to an increase in the deferral of natural gas revenue in 2001, which was attributed to the abnormally high price for natural gas in 2001. As previously discussed, over-collections are deferred in natural gas balancing accounts until they are refunded to customers through rate adjustments.

Cost of Natural Gas

The following table shows a breakdown of the Utility's cost of natural gas:

(in millions)	Year ended December 31,		
	2002	2001	2000
Cost of natural gas purchased	$853	$1,593	$1,331
Cost of gas transportation	101	239	94
Total cost of natural gas	$954	$1,832	$1,425

In 2002, the Utility's cost of natural gas decreased $878 million, or 47.9 percent, from 2001 primarily due to a decrease in the average market price of natural gas purchased from $6.77 per Mcf in 2001 to $3.38 per Mcf in 2002.

Additionally, the Utility's cost to transport gas to its service area decreased significantly in 2002 due to $111 million in costs recognized in 2001 related to the involuntary termination of gas transportation hedges caused by a decline in the Utility's credit rating. There were no similar events in 2002.

In 2001, the Utility's cost of natural gas increased $407 million, or 28.6 percent, primarily due to an increase in the average cost of natural gas from $5.07 per Mcf in 2000 to $6.77 per Mcf in 2001. Furthermore, as mentioned above, in 2001 the Utility's cost to transport gas to its service area increased significantly due to $111 million in costs related to the involuntary termination of gas transportation hedges.

Other Operating Expenses

Operating and Maintenance

In 2002, the Utility's operating and maintenance expenses increased $432 million, or 18.1 percent, from 2001. This increase is mainly due to the following factors:

- Increases in employee benefit plan-related expenses primarily due to unfavorable returns on plan investments and lower interest rates, which caused a decrease in discount rates on the Utility's present-valued benefit obligations;
- Increases in environmental liability estimates;
- Increases in customer accounts and service expenses related to the Utility's new customer billing system;
- The amortization of previously deferred electric transmission related costs, which are now being collected in rates; and
- The deferral of over-collected electric revenue associated with the rate reduction

bonds. Prior to 2000, these revenues were used to finance the rate reduction implemented in 1998.

In 2001, the Utility's operating and maintenance expenses decreased $302 million, or 11.2 percent, primarily due to a reserve for chromium litigation of $140 million recorded in 2000, and lower regulatory and generation-related costs.

Depreciation, Amortization, and Decommissioning

Depreciation, amortization, and decommissioning expenses increased $297 million, or 33.1 percent, in 2002. This increase was due mainly to amortization of the rate reduction bond regulatory asset, which began in January 2002, and totaled $290 million through December 31, 2002. The rate reduction bond regulatory asset is discussed further in the "Regulatory Matters" section of this MD&A.

Depreciation, amortization, and decommissioning expenses decreased $2,615 million, or 74.5 percent, in 2001 due to accelerated depreciation of generation-related assets in 2000. Less depreciation was recorded in 2001 as the majority of the generation-related assets had been fully depreciated after the acceleration.

Interest Income

In accordance with the American Institute of Certified Public Accountants' Statement of Position (SOP) 90-7, the Utility reports reorganization interest income separately on the Consolidated Statements of Operations. Such income primarily includes interest earned on cash accumulated during the proceedings. Interest income decreased $49 million, or 39.8 percent, in 2002. The decrease in interest income in 2002 was due in most part to lower average interest rates on the Utility's short-term investments.

In 2001, the Utility's interest income decreased $63 million, or 33.9 percent, compared to 2000 due primarily to the write-off of generation-related regulatory balancing account interest. The decrease was offset by increases in interest on short-term investments and balancing accounts.

Interest Expense

In 2002, the Utility's interest expense increased $14 million, or 1.4 percent, from 2001 due to the Utility's bankruptcy proceeding, which has resulted in higher negotiated interest rates and an increased level of unpaid debts accruing interest. See the discussion of interest rates in Note 2 of the Notes to the Consolidated Financial Statements.

In 2001, the Utility's interest expense increased $355 million, or 57.3 percent, compared to 2000 due to increased debt levels and higher interest rates as a result of the Utility's credit rating downgrade and subsequent bankruptcy.

Reorganization Fees and Expenses

In accordance with SOP 90-7, the Utility reports reorganization fees and expenses separately on the Consolidated Statements of Operations. Such costs primarily include professional fees for services in connection with Chapter 11 proceedings and totaled $155 million in 2002 and $97 million in 2001.

PG&E NEG

Overall Results

The year ended 2002 included an expected loss on the disposal of USGenNE of $1.1 billion and on ET Canada of $25 million. Additionally, the earnings from operations of USGenNE, ET Canada, and Mountain View were reclassified to discontinued operations. USGenNE, ET Canada, and Mountain View Power Partners, LLC and Mountain View Power Partners II, LLC (collectively referred to as Mountain View) were determined to be Assets Held for Sale per SFAS No. 144. As such, their operating results were reclassified to discontinued operations and an evaluation of the value on an asset-by-asset basis conducted. PG&E NEG determined that USGenNE's and ET Canada's book values exceeded their anticipated selling prices and as such recorded losses on disposal. Earnings from operations included in discontinued operations were $11 million or a decrease of $96 million principally due to USGenNE's unfavorable operating results and market conditions in New England.

The year ended 2002 included a net loss for the cumulative effect of a change in accounting principle of $61 million. The cumulative effect was based on PG&E NEG's adoption as of April 1, 2002, of interpretations issued by the Derivatives Implementation Group (DIG), DIG C15 and DIG C16, reflecting the mark-to-market value of certain contracts that had previously been accounted for under the accrual basis as normal purchases and sales.

PG&E NEG's income from continuing operations (after-tax) was a loss of $2.2 billion in 2002 or a decrease of $2.3 billion from the prior year. The decline in pre-tax operating income was mainly due to one-time impairments, write-offs and other charges previously discussed and taken during 2002 of $2.8 billion.

PG&E NEG's net income (after discontinued operations and cumulative effect of a change in accounting principle) was $171 million for the year ended 2001, an increase of $19 million from the year ended 2000.

The year ended 2001 included earnings from discontinued operations related to USGenNE, Mountain View, and ET Canada of $107 million, or an increase of $8 million from 2000. In addition, the year ended 2000 included a loss from discontinued operations of $40 million related to losses on the disposal of PG&E Energy Services Corporation.

The year ended 2001 included a net gain for the cumulative effect of a change in accounting principle of $9 million. The cumulative effect was based on an interpretation issued by the DIG C11 that clarified how certain commodity contracts should be treated. In applying this new DIG guidance, PG&E NEG determined that one of its derivative contracts no longer qualified for normal purchases and sales treatment and must be marked-to-market through earnings.

PG&E NEG's income from continuing operations (after-tax) was $55 million in 2001 or a decrease of $38 million from the prior year. The decline in pre-tax operating income of $97 million in 2001 was primarily due to the sale of Pacific Gas Transmission Teco, Inc., and subsidiaries (collectively referred to as PG&E GTT) in December 2000 which provided operating income of $77 million in 2000, and a charge in the fourth quarter of 2000 of $60 million related to the termination of certain contracts resulting from the Enron bankruptcy (principally related to PG&E NEG's energy trading business). These declines were partially offset by the sale of a development project in the third quarter of 2001, which provided operating income of $23 million, and general improvement in operating margins in the Integrated Energy and Marketing Activities (Energy) segment. Net interest expense was $33 million lower in 2001 as compared to the prior year, principally due to increased capitalization of interest for projects under construction.

Operating Revenues

PG&E NEG's operating revenues were $2.1 billion for the year ended 2002, an increase of $155 million from the year ended 2001. These revenue increases occurred primarily in PG&E NEG's Energy segment principally due to new generation plants coming on line within the wholesale energy business. The principal drivers in the increase in PG&E NEG's Interstate Pipeline Operation (Pipeline) segment's operating revenues, which increased $7 million, were due to the North Baja pipeline commencing operations and PG&E GTN contract termination settlements. These operating revenue increases in the Pipeline segment were slightly offset by weak pricing fundamentals on gas transportation to the California and Pacific Northwest gas markets compared to the same period last year.

PG&E NEG's operating revenues were $1.9 billion in 2001, a decrease of $1.2 billion or 39 percent from 2000. This decline in operating revenues occurred within both PG&E NEG's Energy and Pipeline segments. The decline in PG&E NEG's Energy segment of $329 million is mainly due to lower trade volumes and lower realized prices in the third and fourth quarter of 2001. These declines generally were due to higher commodity prices in the wake of the California energy crisis in the second half of 2000 and the decline in economic activity in the U.S. in the second half of 2001. The decline in PG&E NEG's Pipeline segment of $866 million is primarily due to the sale of PG&E GTT in December 2000.

Operating Expenses

PG&E NEG's operating expenses were $4.8 billion for the year ended 2002, an increase of $3 billion from the same period in the prior year. These increases occurred primarily in PG&E NEG's Energy segment, principally due to impairments, write-offs, and other charges previously discussed of $2.8 billion. The cost of commodity sales and fuel increased $197 million in line with the increases in operating revenues, compressed spark spreads, and new generation plants coming on line within the wholesale energy business. Operations, maintenance and management costs increased $33 million in 2002 as compared to the same period last year primarily due to new plants coming on line. In addition, depreciation and amortization costs increased $15 million in the period also mainly due to new plants coming on line. Administrative and general costs increased in 2002 as compared to the same period last year due to charges associated with PG&E NEG's cost reduction and restructuring programs. These increases were slightly offset on a year-to-date basis by lower costs in the first half of 2002 associated with lower employee related expense.

PG&E NEG's operating expenses were $1.8 billion in 2001, a decrease of $1.1 billion from 2000. This decline in operating expenses occurred within both PG&E NEG's Energy and Pipeline segments. The decline in PG&E NEG's Energy segment of $258 million is mainly due to lower trade volumes and lower realized prices achieved primarily in the third and fourth quarters of 2001. These declines generally were due to higher commodity prices in the wake of the California energy crisis in the second half of 2000, and the decline in economic activity in the U.S. in the second half of 2001. The decline in PG&E NEG's Pipeline segment of $792 million is primarily due to the sale of PG&E GTT in December 2000.

INFLATION

PG&E Corporation and the Utility prepare financial statements in accordance with accounting principles generally accepted in the United States of America. This means PG&E Corporation and the Utility report operating results in terms of historical costs and do not evaluate the impact of inflation.

Inflation affects 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, PG&E Corporation and the Utility do not expect current inflation levels to have a material adverse impact on PG&E Corporation's or the Utility's financial position or results of operations.

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.

Utility

The Utility is the only subsidiary with significant regulatory proceedings or issues at this time. These are discussed below. Regulatory proceedings associated with electric industry restructuring are further discussed in Note 2 of the Notes to the Consolidated Financial Statements.

DWR Revenue Requirement and Servicing Order

In January 2001, the DWR began purchasing electricity on behalf of the Utility's customers in accordance with a new state law, Assembly Bill (AB) 1X, that authorized the DWR to purchase electricity for California utility customers to the extent that it could not be supplied or purchased by the utilities (the amount of electricity needed to meet customers' demand that cannot be provided by the IOUs, either through their own generation or by suppliers under contracts with the IOUs, is referred to as the net open position). The DWR initially purchased electricity on the spot market until it was able to enter into long-term contracts for the supply of electricity. Under AB 1X, the DWR was prohibited from entering into new agreements to purchase electricity to meet the net open position of the California IOUs after December 31, 2002.

The DWR pays for its costs of purchasing electricity from a revenue requirement charged to Utility ratepayers (power charge) and proceeds of the DWR's $11.3 billion bond financing completed in November 2002 (see "DWR Bond Charge" below).

In February 2002, the CPUC approved a decision that set the statewide DWR revenue requirement for 2001 and 2002. In March 2002, the CPUC reallocated the amounts contained in the February 2002 decision among the customers of the three California IOUs. The March 2002 decision allocated $4.4 billion of a total statewide power charge revenue requirement of approximately $9.0 billion to the Utility's customers. Of the $4.4 billion allocated to the customers of the Utility, approximately $1.8 billion related to 2002 power charges and approximately $2.6 billion related to 2001 power charges.

In May 2002, the CPUC approved a servicing order between the Utility and the DWR, which sets forth the terms and conditions under which the Utility provides the transmission and distribution of the DWR-purchased electricity; addresses billing, collection and related services on behalf of the DWR; and addresses the DWR's compensation to the Utility for providing these services. In October 2002, the DWR filed a proposed amendment to the CPUC's May 2002 servicing order. The DWR's proposed amendment changes the calculation that determines the amount of revenues that the Utility must pass-through to the DWR. This proposed amendment would also be used to true-up previous amounts passed through to the DWR as well as future payments. Under its statutory authority, the DWR may request the CPUC to order the utilities to implement such amendments, and the CPUC has approved such amendments in the past without significant change. In December 2002, the CPUC approved an operating order requiring the Utility to perform the operational, dispatch, and administrative functions for the DWR's allocated contracts beginning on January 1, 2003. (See "CPUC Operating Order" below.) The operating order, which applies prospectively, includes the DWR's proposed method of calculating the amount of revenues that the Utility must pass-through to the DWR. As a result, as of December 31, 2002, the Utility has accrued an additional $369 million (pre-tax) liability for pass-through revenues for electricity provided by the DWR to the Utility's customers in 2002 and 2001. A separate proceeding will consider a revision or true-up for the revenue requirements remitted to the DWR for 2002 and 2001 costs, once final 2002 cost data is available. This true-up proceeding is scheduled for April 2003.

In December 2002, the CPUC issued a decision allocating approximately $2 billion of the DWR's 2003 power charge-related revenue requirement to the Utility's customers. This revenue requirement includes the costs associated with the DWR contracts allocated to the Utility's customers by the CPUC in September 2002. The DWR plans to submit a revised 2003 power charge-related revenue requirement to the CPUC in late March 2003.

Before the DWR's 2003 statewide revenue requirement filing with the CPUC in August 2002, the Utility filed comments with the DWR alleging that major portions of the DWR's revenue requirements were not "just and reasonable" as required by AB 1X and that the DWR was not complying with the procedural requirements of AB 1X in making its determination. On August 26, 2002, the Utility filed with the DWR a motion for reconsideration of the DWR's determination that its revenue requirements were "just and reasonable." The DWR denied the Utility's motion on October 8, 2002. On October 17, 2002, the Utility filed a lawsuit in a

California court asking the court to find that the DWR's revenue requirements had not been demonstrated to be "just and reasonable" and lawful, and that the DWR had violated the procedural requirements of AB 1X in making its determination. In part, the Utility based its allegations on the State of California's petition pending before the FERC seeking to set aside many of the DWR contracts on the basis that they are not "just and reasonable." The Utility asked that the court order the DWR's revenue requirement determination be withdrawn as invalid, and that the DWR be precluded from imposing its revenue requirements on the Utility and its customers until it has complied with the law. No schedule has yet been set for consideration of the lawsuit.

Until the CPUC modifies the curent frozen rate structure, changes to the DWR's 2003 revenue requirement may affect the Utility's future earnings. Because the Utility acts as a collection agent for the DWR, amounts collected on behalf of the DWR (related to its revenue requirement) are excluded from the Utility's revenues.

DWR Bond Charge

On October 24, 2002, the CPUC issued a decision that, in part, imposes bond charges to recover the DWR's bond costs from most bundled customers starting November 15, 2002, although the decision found that the Utility would not need to increase customer's overall rates to incorporate the bond charge. The DWR bond charge also will be imposed on all direct access customers, as described below.

On December 30, 2002, the CPUC revised the 2003 bond charge to $0.005 per kWh, effective January 6, 2003. The Utility expects to accrue bond-related charges of approximately $336 million during the 12 months ending November 14, 2003.

Until the CPUC implements bottoms-up billing (billing for specific rate components) for the Utility, any bond charges will reduce the amount of revenue available to recover previously written-off under-collected purchased power costs and transition costs.

Senate Bill 1976

Under AB 1X, the DWR is prohibited from entering into new agreements to purchase electricity to meet the net open position of the California IOUs after December 31, 2002. In September 2002, the Governor signed California SB 1976 into law. SB 1976 required that each California IOU submit, within 60 days after the CPUC allocated existing DWR contracts for electricity procurement to the customers of each California IOU, an electricity procurement plan to meet the residual net open position associated with that utility's customer demand. SB 1976 requires that each procurement plan include one or more of the following features:

- A competitive procurement process under a format authorized by the CPUC, with the costs of procurement obtained in compliance with the authorized bidding format being recoverable in rates;
- A clear, achievable, and quantifiable incentive mechanism that establishes benchmarks for procurement and authorizes the IOUs to procure electricity from the market subject to comparison with the CPUC-authorized benchmarks; or
- Upfront and achievable standards and criteria to determine the acceptability and eligibility for rate recovery of a proposed transaction and an expedited CPUC pre-approval process for proposed bilateral contracts to ensure compliance with the individual utility's procurement plan.

SB 1976 provides that the CPUC may not approve the procurement plan if it finds the plan contains features or mechanisms, which would impair restoration of the IOU's creditworthiness or would lead to a deterioration of the IOU's creditworthiness. SB 1976 also indicates that procurement activities in compliance with an approved procurement plan will not be subject to after-the-fact reasonableness review. The CPUC is permitted to establish a regulatory process to verify and ensure that each contract was administered in accordance with its terms and that contract disputes are resolved reasonably.

A central feature of the SB 1976 regulatory framework is its direction to the CPUC to create new electric procurement balancing accounts to track and allow recovery of the differences between recorded revenues and costs incurred under an approved procurement plan. The CPUC must review the revenues and costs associated with the IOU's electric procurement plan at least semi-annually and adjust rates or order refunds, as appropriate, to properly amortize the balancing accounts. Until January 1, 2006, the CPUC must establish the schedule for amortizing the over-collections or under-collections in the electric procurement balancing accounts so that the aggregate over-collections or under-collections reflected in the accounts do not exceed 5 percent of the IOU's actual recorded generation revenues for the prior calendar year, excluding revenues collected on behalf of the DWR. Mandatory semi-annual review and adjustment of the balancing accounts will continue until January 1, 2006, after which time the CPUC is required to conduct electric procurement balancing account reviews and adjust retail ratemaking amortization schedules for the balancing accounts as the CPUC deems appropriate and in a manner consistent with the requirements of SB 1976 for timely recovery of electric procurement costs.

On January 1, 2003, the California IOUs resumed the function of procuring electricity to meet that portion of their customers' needs that is not covered by the combination of the allocation of electricity from existing DWR contracts and the IOU's own electric resources and contracts.

Allocation of DWR Electricity to Customers of the IOUs

Consistent with applicable law and CPUC orders, since 2001, the Utility and the other California IOUs have acted as the billing and collection agents for the DWR's sales of its electricity to retail customers. In September 2002, the CPUC issued a decision to allocate the electricity provided under existing DWR contracts to the customers of the IOUs. This decision required the Utility, along with the other IOUs, to begin performing all the day-to-day scheduling, dispatch, and administrative functions associated with the DWR contracts allocated to the IOUs' portfolios on January 1, 2003. The DWR retains legal and financial responsibility for these contracts.

Under AB 1X, the CPUC has no review authority over the reasonableness of procurement costs in the DWR's contracts, although the Utility's administration of DWR contracts allocated to its customers and its dispatch of the electricity associated with those contracts may be subject to reasonableness reviews. Under a December 2002 interim opinion, the CPUC established a maximum annual procurement disallowance equal to twice the Utility's annual administrative costs of managing procurement activities, including the administration and dispatch of electricity associated with DWR allocated contracts. The Utility anticipates that its annual administrative cost of managing procurement activities in 2003 will be approximately $18 million.

The DWR has stated publicly that it intends to transfer full legal title of, and responsibility for, the DWR electricity contracts to the IOUs as soon as possible. However, SB 1976 does not contemplate a transfer of title of the DWR contracts to the IOUs. In addition, the operating order issued by the CPUC in December 2002 implementing the Utility's operational and scheduling responsibility with respect to the DWR allocated contracts specifies that the DWR will retain legal and financial responsibility for the contracts and that the December 2002 order does not result in an assignment of the DWR allocated contracts to the Utility. However, there can be no assurance that either the State of California or the CPUC will not provide the DWR with authority to affect such a transfer of legal title in the future. The Utility has informed the CPUC, the DWR, and the State of California that the Utility would vigorously oppose any attempt to transfer the DWR allocated contracts to the Utility without its consent.

CPUC Operating Order

In December 2002, the CPUC adopted an operating order requiring the Utility to perform the operational, dispatch, and administrative functions for the DWR's allocated contracts beginning on January 1, 2003. (Similar operating orders were also adopted for the other two California IOUs.) The operating order sets forth the terms and conditions under which the Utility will administer the DWR allocated contracts and requires the Utility to dispatch all of the generating assets within its portfolio on a least-cost basis for the benefit of the Utility's customers. The order specifies that the DWR will retain legal and financial responsibility for the DWR allocated contracts and that the order does not result in an assignment of the allocated DWR contracts to the Utility.

Operating Agreement

The CPUC had previously ordered the IOUs to work with the DWR to submit to the CPUC proposed operating agreements governing the DWR allocated contracts. When the operating orders were issued, the DWR and the IOUs had not yet finalized their separate operating agreements. In its decision issuing the operating orders, the CPUC noted that if the IOUs and the DWR eventually reach mutual agreement, the CPUC would consider modifying its decision on an expedited basis to terminate the operating orders and approve the operating agreements, assuming that the operating agreements adopted a framework that was substantially similar to the one imposed by the operating orders.

On December 20, 2002, the Utility and the DWR executed an operating agreement following several months of negotiation. The agreement provides that it will not become effective unless approved by the CPUC. The Utility has submitted the agreement to the CPUC for approval and has requested that the CPUC terminate the operating order and approve the operating agreement.

Although the operating order and the operating agreement have fundamentally the same objectives, the operating agreement, among other things:

- Provides an adequate contractual basis for establishing a limited agency relationship between the Utility and the DWR;
- Limits the Utility's contractual liability to the DWR and other parties to $5 million per year plus 10 percent of damages in excess of $5 million with a limit of $50 million over the term of the agreement; and
- Clarifies that the DWR does not intend to, nor is it the DWR's responsibility to, review the Utility's least-cost dispatch performance, other than to verify compliance with the supplier contracts.

On December 30, 2002, the Utility filed an application for rehearing of the operating order decision with the CPUC. On January 1, 2003, after having reserved all rights associated with challenges to the operating order, the Utility commenced providing contract administration, scheduling and dispatch services to the DWR under the CPUC's operating order.

Approval of Procurement Plan

In October 2002, the CPUC issued a decision ordering the Utility to resume full procurement on January 1, 2003. In December 2002, the CPUC issued an interim opinion adopting the revised electricity procurement plan for 2003 that the Utility submitted in 2002 and authorized the Utility to enter into contracts designed to hedge its residual net open position for the first quarter of 2004. The CPUC found that the maximum annual procurement disallowance exposure that each IOU should face for all of its procurement activities should be limited to twice the IOU's annual administrative costs of managing procurement activities, including its administration and dispatch of electricity associated with DWR contracts allocated to its customers. The Utility anticipates that its annual administrative costs of managing procurement activities in 2003 will be approximately $18 million. While the Utility's procurement plan covered procurement activities only for the 2003 calendar year, the CPUC authorized the IOUs to extend their planning into the first quarter of 2004.

Effective January 1, 2003, the Utility established the Energy Resource Recovery Account (ERRA) to record and recover electricity costs, excluding the DWR's electricity contract costs, associated with the Utility's authorized procurement plan. Electricity costs recorded in the ERRA include, but are not limited to, fuel costs for retained generation, QF contracts, inter-utility contracts, ISO charges, irrigation district contracts, other power purchase agreements, bilateral contracts, forward hedges, pre-payments, collateral requirements associated with procurement (including disposition of surplus electricity), and ancillary services. The Utility offsets these costs by reliability-must-run revenues, the Utility's allocation of surplus sales revenues and the ERRA revenue requirement. The CPUC has approved, on a preliminary basis, a starting ERRA revenue requirement of $2.0 billion for the Utility.

The CPUC has authorized the Utility to file an application to change retail electricity rates at any time that its forecasts indicate it will face an under-collection of electricity procurement costs in excess of 5 percent of its prior year's generation and procurement revenues, excluding amounts collected for the DWR. The Utility currently estimates that its 5 percent threshold amount will be approximately $224 million.

In February 2003, the Utility filed its 2003 ERRA forecast application requesting that the CPUC reset the Utility's 2003 ERRA revenue requirement to $1.4 billion and that the ERRA trigger threshold of $224 million be adopted. The CPUC will examine the Utility's forecast of costs for 2003 and will finalize the Utility's starting ERRA revenue requirement and ERRA trigger threshold when it reviews the Utility's ERRA application.

The Utility intends to submit its long-term procurement plan, covering the next 20 years by April 1, 2003, and the CPUC has stated that it plans to issue a final decision on the Utility's long-term procurement plan in November 2003.

In April 2001, the California Public Utilities Code was amended to require that the CPUC ensure that errors in estimates of demand elasticity or sales by the Utility do not result in material over- or under-collections of costs by the Utility. The Utility intends to address implementation of this new law in connection with pending proceedings at the CPUC relating to recovery of components of its costs of service.

2001 Annual Transition Cost Proceeding: Review of Reasonableness of Electricity Procurement

On January 11, 2002, as directed by the CPUC, the Utility filed a report with the CPUC detailing the reasonableness of the Utility's electric procurement and generation scheduling and dispatch activities for the period July 1, 2000, through June 30, 2001. In this proceeding, the CPUC will review the reasonableness of the Utility's procurement of wholesale electricity from the PX and ISO during the height of the 2000 - 2001 California energy crisis. With the exception of a limited right to purchase electricity from third parties beginning in August 2000, all of the Utility's wholesale electric purchases during this period were required to be made exclusively from or through the PX and ISO markets pursuant to FERC-approved tariffs. Prior CPUC decisions have determined that such purchases should be deemed reasonable. In addition, the Utility's complaint against the CPUC Commissioners asserts that the costs of such purchases are recoverable in the Utility's retail rates without further review by the CPUC under the federal filed rate doctrine. However, a CPUC administrative law judge is asserting jurisdiction to review the reasonableness of the Utility's wholesale electric purchases from the PX and ISO in the proceeding. A report from the CPUC's Office of Ratepayer Advocates (ORA) regarding the Utility's procurement activities for the covered period is due April 28, 2003. It is possible this review could result in disallowance of certain costs associated with the Utility's purchases from the PX and ISO during the 2000 - 2001 period.

Retained Generation Revenue Requirement

The CPUC has approved a 2002 revenue requirement of $3 billion for recovery of costs of generation the Utility retains, including electric purchase expenses, depreciation, operating expenses, taxes, and return on investment, based on the net regulatory value as of December 31, 2000.

The CPUC has allowed the Utility to recover reasonable costs incurred in 2002 for its own electric generation, subject to reasonableness review in the Utility's 2003 General Rate Case (GRC) proceeding. The decision does not change retail electric rates and the Utility does not expect it to have an impact on the Utility's results of operations. Instead, the decision defers consideration of future rate changes until the CPUC addresses the status of the retail rate freeze. The CPUC also deferred addressing recovery of the Utility's past unrecovered generation-related costs.

The CPUC is considering the Utility's 2003 retained generation revenue requirement as part of the Utility's 2003 GRC proceeding. The Utility's 2003 GRC application requested an increase in non-fuel generation revenue requirements of $149 million over the amount authorized for 2002. This requested revenue requirement increases the Utility's estimated fuel and procurement costs recorded in the ERRA (see "Approval of Procurement Plan" above), and the DWR's power charges.

Divestiture of Retained Generation Facilities

The California Legislature passed AB 6X in January 2001 prohibiting utilities from divesting their remaining power plants before January 1, 2006. The Utility believes this law does not supersede or repeal existing provisions of AB 1890, California's 1996 electric industry restructuring legislation, requiring the CPUC to establish a market value for the Utility's remaining generating assets by the end of 2001, based on appraisal, sale or other divestiture. The Utility has filed comments on this matter with the CPUC. However, the CPUC has not yet issued a decision.

On January 2, 2002, the CPUC issued a decision finding that AB 6X had materially affected the implementation of AB 1890. The CPUC scheduled further proceedings to address the impact of AB 6X on the AB 1890 rate freeze for the Utility and to determine the extent and disposition of the Utility's remaining unrecovered transition costs. In its November 2002 decision regarding surcharge revenues (see "One-Cent, Three-Cent, and Half-Cent Surcharge Revenues" below), the CPUC reiterated that it had yet to decide when the rate freeze ended and the disposition of any under-collected costs remaining at the end of the rate freeze.

On January 17, 2002, the Utility filed an administrative claim with the State of California Victim Compensation and Government Claims Board, or Claims Board, alleging that AB 6X violates the Utility's statutory rights under AB 1890. The Utility's claim seeks compensation for the denial of its right to at least a $4.1 billion market value of its retained generating facilities. On March 7, 2002, the Claims Board formally denied the Utility's claim. Having exhausted remedies before the Claims Board, on September 6, 2002, the Utility filed a complaint against the State of California for breach of contract in the California Superior Court. On January 9, 2003, the Superior Court granted the State's request to dismiss the Utility's complaint, finding that AB 1890 did not constitute a contract. The Utility has 60 days to file an appeal and intends to do so.

Direct Access Suspension and Cost Responsibility Surcharge

Until September 2001, California utility customers could choose to buy their electricity from the Utility (bundled customers) or from an alternative power supplier through "direct access" service. Direct access customers receive distribution and transmission service from the Utility, but purchase electricity (generation) from their alternative provider. In September 2001, the CPUC, pursuant to AB 1X, suspended the right of retail end-use customers to choose direct access service, thereby preventing additional customers from entering into contracts to purchase electricity from alternative providers. Customers that entered into direct access contracts on or before September 20, 2001, were permitted to remain on direct access.

In November 2002, the CPUC issued a decision assessing an exit fee, or non-bypassable charge, on direct access customers to avoid a shift of costs from direct access customers to bundled service customers.

The decision establishes the Cost Responsibility Surcharge (CRS) and imposes a cap of $0.027 per kWh. The CPUC required the utilities to implement this surcharge on January 1, 2003. The CPUC has indicated that it will establish an expedited review schedule to determine whether the cap should be adjusted. The CPUC also has indicated that it will reach a decision on whether this cap should be adjusted, and whether trigger mechanisms for adjusting the cap should be established, by July 1, 2003. The Utility implemented the $0.027 per kWh CRS on January 1, 2003. (See "Direct Access Credits" below.)

Funds remitted under the CRS will be applied first to the DWR, then to the Utility's ongoing procurement and generation costs. Direct access customers who have returned to bundled service will be responsible for their share of the unrecovered costs resulting from the CRS. To the extent the cap results in an under-collection of DWR charges, the shortfall would have to be remitted to the DWR from bundled customers' funds. On an interim basis while the CPUC examines a long-term plan for financing the CRS, interest on under-collections will be assessed at the interest rate paid by the DWR on bonds issued to finance electricity purchases.

The Utility does not expect that the CPUC's implementation of this decision or the level of the CRS cap will have a material adverse effect on its results of operations or financial condition.

Direct Access Credits

When the direct access credit was established, direct access customers paid the full bundled rate less a credit based on the Schedule PX price. Under this methodology, when the Schedule PX price exceeded the bundled rates, the direct access customer received a bill credit. As a result, during the energy crisis, direct access customers did not contribute to the Utility's transition cost recovery nor did they pay for transmission and distribution services. Under the interim direct access credit methodology in place since the PX ceased operations in January 2001, the Utility has calculated the Schedule PX price using an estimate of its cost of service for its retained generation and the Utility's generation component of the frozen rate for energy provided by the DWR. Beginning January 1, 2003, the Utility reduced this direct access credit by the additional direct access exit fee of up to the $0.027 per kWh CRS cap.

Additionally, direct access customers paid the one-cent surcharge in 2001 and 2002, but were exempt from the three-cent surcharge and half-cent surcharge. In May 2001, the Utility also requested authorization to charge direct access customers for the three-cent surcharge. One party filed a protest indicating that direct access customers should not pay the three-cent surcharge, nor the one-cent surcharge beginning June 1, 2001. The one-cent surcharge generates approximately $80 million in revenues per year from direct access customers. The CPUC has not yet ruled on this issue. It is unclear how or whether direct access customers would be reimbursed if the CPUC rules that direct access customers should not have paid this charge. In November 2002, the CPUC determined that direct access customers should pay a portion of DWR's costs beginning in 2003 to keep bundled customers indifferent as to the level of direct access. As a result, on January 1, 2003, direct access customers began paying a $0.027 per kWh surcharge, and they no longer pay the $0.01 per kWh surcharge.

On May 31, 2002, the Utility filed its proposal for calculating the post-PX direct access credit that would continue allowing direct access customers to receive a credit for generation-related costs avoided as a result of their self-procurement. Specifically, the Utility proposed that the credit be based on avoided procurement costs. The Utility also proposed to move to bottoms-up billing (billing for specific rate components rather than a frozen rate) for direct access customers as quickly as possible. Under bottoms-up billing, direct access customers' rates would be calculated based on the services they actually take from the Utility, such as transmission and distribution, the fixed transition amount related to the rate reduction bond repayment (if applicable), and any non-bypassable charges that the CPUC approves including nuclear decommissioning and public purpose programs, as well as the direct access Customer Responsibility Surcharge described above. Consequently, direct access customers would pay at least the same non-procurement charges that are applicable to bundled customers.

The Utility proposed to adjust the direct access credit retroactively to December 28, 2000, using the Dow Jones Index after January 18, 2001, and to limit the amount of the credit to the price cap established by the FERC.

One-Cent, Three-Cent, and Half-Cent Surcharge Revenues

In the first quarter of 2001, the CPUC authorized the Utility to begin collecting energy purchase surcharge revenues totaling $0.04 per kWh (composed of a $0.01 per kWh surcharge revenue approved in January and a $0.03 per kWh surcharge revenue approved in March). The CPUC ordered the Utility to apply these new rates only to "ongoing procurement costs" and "future power purchases."

Although the CPUC authorized the $0.03 per kWh surcharge in March 2001, the Utility did not begin collecting the revenues until June 2001. As a result, in May 2001, the CPUC authorized the Utility to collect an additional $0.005 per kWh surcharge revenue for 12 months to make up for the time lag in collection of the $0.03 per kWh surcharge revenues. Although the collection of this "half-cent surcharge" was originally scheduled to end on May 31, 2002, the CPUC issued a resolution ordering the Utility to continue collecting the half-cent surcharge until further consideration by the CPUC. The Utility had recorded a regulatory liability for these $0.01 per kWh and $0.03 per kWh surcharge revenues when such surcharges exceeded ongoing procurement costs and a regulatory liability for the $0.005 per kWh surcharge revenues billed subsequent to May 31, 2002. These regulatory liabilities totaled $222 million as of September 30, 2002, and $65 million as of December 31, 2001.

In November 2002, the CPUC approved a decision modifying the restrictions on the use of revenues generated by the surcharges to permit the revenues to be used for the purpose of securing or restoring the Utility's reasonable financial health, as determined by the CPUC. The CPUC will determine in other proceedings how the surcharge revenues can be used, whether there is any cost or other basis to support specific surcharge levels, and whether the resulting rates are just and reasonable. After the CPUC determines when the AB 1890 rate freeze ended, the CPUC will determine the extent and disposition of the Utility's under-collected costs, if any, remaining at the end of the rate freeze. If the CPUC determines that the Utility recovered revenues in excess of its transition costs or in excess of other permitted uses, the CPUC may require the Utility to refund such excess revenues.

In a case currently pending before it relating to the CPUC's settlement with Southern California Edison (SCE), another California IOU, the Supreme Court of California is considering whether the CPUC has the authority to enter into a settlement which allows SCE to recover under-collected procurement and transition costs in light of the provisions of AB 1890. The Utility cannot predict the outcome of this case or whether the CPUC or others would attempt to apply any ruling to the Utility. If the Utility is ordered to refund material amounts to ratepayers, the Utility's financial condition and results of operations would be materially adversely affected.

In December 2002, the CPUC issued a decision authorizing the Utility to stop tracking amounts related to the $0.01 per kWh and $0.03 per kWh surcharge revenues as a separate regulatory liability and instead record them as a reduction of under-collected purchased power costs and transition costs. As a result, in January 2003, the Utility filed a letter with the CPUC requesting to withdraw its regulatory liability account used to track $0.01 per kWh and $0.03 per kWh surcharge revenues in excess of ongoing procurement costs.

Based on this December 2002 CPUC decision and an agreement between the CPUC and SCE, in which SCE was allowed to use its half-cent surcharge to offset its DWR revenue requirement, the Utility reversed its $222 million of regulatory liabilities related to the $0.01 per kWh and $0.03 per kWh surcharge revenues and the $0.005 per kWh surcharge revenues during the fourth quarter of 2002. (Of this amount, $157 million was originally recorded as a regulatory liability during 2002; as such, the reversal of this amount has no impact on current year earnings).

1999 GRC

Through a GRC proceeding, 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.

The 1999 GRC decision ordered an audit to assess the contribution of the Utility's 1999 electric and gas distribution capital additions to system reliability, capacity, and adequacy of service. The audit began in February 2002 and a final report was issued on November 8, 2002. The final report concludes, "in general the [Utility's] 1999 overall capital expenditure program appears quite acceptable." The final report offers recommendations to improve the Utility's distribution capital investment process, but recommends no adjustments to the Utility's distribution rate base.

In October 2001, the CPUC reopened the record in the 1999 GRC to review the Utility's actual 1998 capital spending on electric distribution compared with the forecast used to determine 1999 rates. This would result in an adjustment of the adopted 1998 capital spending forecast level to conform to the 1998 recorded level. The Utility does not expect a material impact on its financial position or results of operations from the remaining proceedings.

On December 1, 2002, the CPUC issued a decision further modifying the 1999 GRC decision that prospectively adopted a $10.6 million downward annual adjustment to supervision costs in customer records and collection expenses. There was no material impact on the Utility's financial position or results of operations.

2003 GRC

In the 2003 GRC, the CPUC will determine the amount of authorized base revenues the Utility can collect from ratepayers to recover its basic business and operational costs for gas and electric distribution operations for 2003 through 2005. On November 8, 2002, the Utility requested a $447 million increase in its electric distribution revenue requirements and a $105 million increase in its gas distribution revenue requirements, over the current authorized amounts. The Utility also will seek an attrition rate adjustment (ARA) increase for 2004 and 2005. The ARA mechanism is designed to avoid a reduction in earnings in years between GRCs to reflect increases in rate base and expenses.

The electric distribution revenue requirement increase would not increase overall bundled electric rates over their current authorized levels. However, the gas bill for a typical residential customer would rise by approximately 2.6 percent or $0.99 per month.

Additionally, as directed by the CPUC in the Utility's 2002 retained generation proceeding (see "Retained Generation Revenue Requirement" above), the Utility submitted testimony supporting the costs of operating the Utility's generation facilities and fuel and purchased power costs. The Utility requested an increase of approximately $61 million over the interim 2002 retained generation revenue requirement authorized by the CPUC. On October 25, 2002, the CPUC issued a decision ordering the Utility to resume the procurement function on January 1, 2003. That decision also directed the Utility to amend its GRC application to remove certain generation-related fuel and purchased power costs from its GRC and instead to include them in another CPUC proceeding. In its GRC, the Utility forecasts a decrease in these costs in 2003. This decrease offsets the forecast increase in costs to operate the Utility's generation facilities. Removing the fuel and purchase power from the generation-related revenue requirement set forth in the GRC would result in an increase in the forecast generation-related revenue requirement of approximately $80 million to $90 million.

On December 17, 2002, the CPUC granted the Utility's request that the revenue requirement established in the 2003 GRC be effective January 1, 2003, even though the CPUC will not issue a final decision on the 2003 GRC until sometime after that date.

The Utility cannot predict what amount of revenue requirements, if any, the CPUC will authorize for the 2003 through 2005 period. The CPUC Commissioner assigned to the 2003 GRC has adopted a schedule for this proceeding that includes a target date for a final decision of February 5, 2004.

2002 ARA Request

In April 2002, the CPUC conditionally authorized a request by the Utility for interim attrition relief and made any attrition relief ultimately granted effective as of April 22, 2002. In June 2002, the Utility filed its 2002 ARA application, requesting a $76.7 million increase to its annual electric distribution revenue requirement, and a $19.5 million increase to its annual gas distribution revenue requirement. In December 2002, a proposed decision was issued that would deny this request. The Utility filed comments in late December 2002 arguing that the proposed decision was based on a fundamental misunderstanding of the facts. In February 2003, an alternate proposed decision was issued that would grant a $63.5 million increase to the Utility's annual electric distribution revenue requirement, and a $10.3 million increase to the Utility's annual gas distribution revenue requirement. A final decision is expected to be issued in the first quarter of 2003.

In the 2003 GRC, the CPUC asked parties to comment on the Utility's need for a 2002 ARA proceeding. The Utility informed the CPUC in November 2001 that the Utility would need a 2002 ARA to recover escalating electric and gas distribution service costs.

Cost of Capital Proceedings

Each year, the Utility files an application with the CPUC to determine the authorized rate of return the Utility may earn on its electric and gas distribution assets.

On November 7, 2002, the CPUC issued a final decision in the Utility's 2003 Cost of Capital proceeding that retained the Utility's return on common equity (ROE) at the current authorized level of 11.22 percent. This final decision also increased the Utility's authorized cost of debt to 7.57 percent from 7.26 percent, and held in place the current authorized capital structure of 48 percent common equity, 46.2 percent long-term debt, and 5.8 percent equity. The final decision also holds open the case to address the impact on the Utility's ROE, costs of debt and preferred stock, and ratemaking capital structure of the implementation and financing of a bankruptcy plan of reorganization. The Utility is required to file an advice letter within 30 days of completing any such financing to request authority to true up its test year 2003 ratemaking capital structure, long-term debt and preferred stock cost, risks, and ROE. The Utility does not expect a material impact on the Utility's financial position or results of operations from the remaining proceedings.

FERC Prospective Price Mitigation Relief

In response to the unprecedented increase in wholesale electricity prices during 2000 and 2001, the FERC issued a series of orders in the spring and summer of 2001 and July 2002 aimed at mitigating future extreme wholesale energy prices. These orders established a cap on bids for real-time electricity and ancillary services of $250 per megawatt-hour (MWh) and established various automatic mitigation procedures. Recently, the FERC proposed to adopt a safety net bid cap as part of the mitigation plan for wholesale energy markets and has requested comments on the appropriate value for such a bid cap.

Also, in June and July 2001, the FERC's chief administrative law judge conducted settlement negotiations among power sellers, the State of California, and the California IOUs in an attempt to resolve disputes regarding past electric sales. Various parties, including the Utility and the State of California, are seeking up to $8.9 billion in refunds for electricity overcharges on behalf of buyers. The negotiations did not result in a settlement, but the judge recommended that the FERC conduct further hearings to determine possible refunds and what the power sellers and buyers are each owed. On December 12, 2002, a FERC administrative law judge issued an initial decision finding that power companies overcharged the utilities, the State of California and other buyers from October 2, 2000 to June 2001 by $1.8 billion, but that California buyers still owe the power companies $3 billion, leaving $1.2 billion in unpaid bills. The time period reviewed in the FERC hearings excludes the claims for refunds for overcharges that occurred before October 2, 2000, and after June 2001 when the DWR entered into contracts to buy electricity. Additional hearings are scheduled to conclude in February 2003.

The Utility has recorded $1.8 billion of generator claims made in its bankruptcy case as Liabilities Subject to Compromise. If the FERC administrative law judge's initial recommendation is upheld by the FERC, these claims would be reduced to approximately $1 billion based on the re-calculation of market prices according to the refund methodology recommended in the initial decision. After the FERC considers any additional evidence that may be presented, if the FERC determines that time periods before October 2, 2000, should be considered, or that additional market transactions or a different refund methodology are appropriate, such decisions could materially increase or decrease the amount of generator claims for which the Utility is determined to be liable. The Utility cannot predict the ultimate amount of generator claims for which it could be liable. The Utility also sold generation into the ISO and PX markets in the relevant time period. The amount of generator claims for which the Utility is determined to be liable would be net of any amounts owed to the Utility for such sales. The Utility cannot predict when the FERC will issue a decision, nor can it predict whether a refund will be ordered or the amount the Utility might receive.

FERC Transmission Rate Cases

Electric transmission revenues and both wholesale and retail transmission rates are regulated by the FERC. On January 29, 2003, the FERC approved a settlement that allows the Utility to recover in electric transmission rates $292 million on an annual basis from March 31, 1998, until October 29, 1998, and $316 million on an annual basis from October 30, 1998, until May 30, 1999. During that period, somewhat higher rates were collected, subject to refund. As a result of this settlement, the Utility will refund $30 million it had accrued for potential refunds related to the 14-month period ended May 30, 1999. The transmission rates charged to electric retail and new wholesale transmission customers are adjusted for other transmission revenue credits related to ISO congestion management charges and other transmission-related services billed by the ISO and remitted to the Utility as a transmission owner.

The Utility currently has other transmission rate cases pending with the FERC including:

- An application that would allow the Utility to recover $545 million in electric retail transmission rates annually. Filed on January 13, 2003, the 44 percent increase over the revenue requirement currently in effect is mainly attributable to significant capital additions made to the Utility's transmission system to accommodate load growth, to maintain the infrastructure, and to ensure safe and reliable service. In addition, the request includes a 15-year useful life for transmission plant coming into service in 2003 and a return on equity of 13.5 percent. The January 13 filing date will allow proposed rates to go into effect, subject to refund, no later than August 13, 2003; and

- A proposal for the FERC to increase the Utility's electricity and transmission-related rates charged to the WAPA. The majority of the requested increase is related to passing through market electricity prices billed to the Utility by the ISO and others for services, which apply to WAPA under a pre-existing contract between the Utility and WAPA. The FERC denied this request, as well as a request for a rehearing. The Utility has appealed the denial of its request for a rehearing to the U.S. Court of Appeals for the D.C. Circuit. Pending a decision from the Court, until December 31, 2004, the date the WAPA contract expires, the Utility will continue to calculate WAPA's rates on a yearly basis using the formula specified in WAPA's contract. Any revenue shortfall or benefit resulting from this contract is included in rates through the end of the contract period as a purchased power cost. The Utility cannot estimate the difference between its cost to meet its obligations to WAPA and revenues it receives from WAPA because both the purchase price and the amount of energy that WAPA will need from the Utility through the end of the contract are uncertain.

Scheduling Coordinator Costs

The Utility serves as the scheduling coordinator to schedule transmission with the ISO for the Utility's existing wholesale transmission customers. The ISO bills the Utility for providing certain services associated with these contracts. These ISO charges are referred to as the "scheduling coordinator (SC) costs." These costs historically have been tracked in the transmission revenue balancing account (TRBA) in order to recover these costs from retail and new wholesale transmission customers (TO Tariff customers).

On August 5, 2002, the FERC ruled that the Utility should refund to TO Tariff customers the scheduling coordinator costs that the Utility collected from them. In November 2002, the FERC denied the Utility's request for rehearing. On December 9, 2002, the Utility appealed the FERC's decision in the U.S. Court of Appeals for the D.C. Circuit. In the absence of an order from the FERC granting recovery of these costs in the TRBA, the Utility has made accounting entries to reflect the SC costs as accounts receivable under the Scheduling Coordinator Services (SCS) Tariff described below.

In January 2000, the FERC accepted a filing by the Utility to establish the SCS Tariff. The SCS Tariff was filed to serve as an alternative mechanism for recovery of the SC costs from existing wholesale customers if the Utility was ultimately unable to recover these costs in the TRBA. The FERC also conditionally granted the Utility's request that the SCS Tariff be effective retroactive to March 31, 1998. However, the FERC suspended the procedural schedule until the final decision was issued regarding the inclusion of SC costs in the TRBA. In September 2002, the Utility filed a notice with the FERC indicating its intent to request that the FERC resume the SCS Tariff proceeding if the request for rehearing of the FERC's August 5 order was not granted. For the period beginning April 1998 through December 31, 2002, the Utility transferred $107 million of scheduling coordinator costs from the TRBA to accounts receivable net of a $66 million reserve for potential uncollectible costs. The Utility also has disputed approximately $27 million of these costs as incorrectly billed by the ISO. Any refunds that ultimately may be made by the ISO would offset the accounts receivable and corresponding reserve.

The Utility does not expect the outcome of this proceeding to have a material adverse effect on its results of operations or financial condition.

Gas Accord II

In 1998, the Utility implemented a ratemaking pact called the Gas Accord, separating its gas transportation and storage services from its distribution services, and changing the terms of service and rate structure for gas transportation. The Gas Accord allows residential and small commercial customers (core customers) to purchase gas from competing suppliers, establishes an incentive mechanism whereby the Utility recovers its core procurement costs, and establishes gas transportation rates through 2002 and gas storage rates through March 2003. Under the Gas Accord, the Utility is at-risk for recovery of its gas transportation and storage costs and does not have regulatory balancing account protection for over- or under-collections of revenues. Under the Gas Accord, the Utility sells a portion of the transportation and storage capacity at competitive market-based rates. Revenues are sensitive to changes in the weather, natural gas fired generation and price spreads between two delivery or pricing points.

On October 9, 2001, the Utility asked the CPUC to extend the terms and conditions of the existing Gas Accord for two years and to maintain current gas transportation and storage rates during the extension.

In August 2002, the CPUC approved a settlement agreement among the Utility and other parties that provided for a one-year extension of its existing gas transportation and storage rates. The settlement also provided for a one-year extension of terms and conditions of service, including the Core Procurement Incentive Mechanism (for further discussion see "Utility Natural Gas Commodity Price Risk"), as well as rules governing contract extensions and an open season for new contracts. The Gas Accord II settlement left open to subsequent litigation the issues raised in the application in so far as they relate to the second year of the two-year application.

In October 2002, the assigned CPUC administrative law judge issued a ruling that granted, in part, the Utility's motion to postpone the procedural schedule for litigation of the unresolved issues. In January 2003, the Utility filed an amended application proposing to permanently retain the Gas Accord market structure, and requested a $55 million increase in the Utility's gas transmission rates for 2004 and storage rates for the period from April 1, 2004, to March 31, 2005. This request represents a 12.9 percent increase in the Utility's revenue requirement and a 13.4 percent return on equity.

The existing gas transportation and storage rates will continue until the CPUC approves such changes. The Gas Accord II proposal includes rates set based on a demand or throughput forecast basis. In addition it proposes that, at the beginning of the adopted Gas Accord II agreement period, a contract extension and an open season be held for any uncontracted capacity rights. The Utility may experience a material reduction in operating revenues (1) if the Utility were unable to renew or replace existing transportation contracts at the beginning or throughout the Gas Accord II period, (2) the Utility were to renew or replace those contracts on less favorable terms than adopted by the CPUC, or (3) overall demand for transportation and storage services were less than adopted by the CPUC in setting rates. In any of these cases, the Utility's financial condition and results of operations could be adversely affected.

The Utility cannot predict what the outcome of this litigation will be, or whether the outcome will have a material adverse effect on its results of operations or financial condition.

El Paso Capacity Decision

In May 2002, the FERC directed El Paso Natural Gas Company (El Paso) to change the way it allocates space on its pipeline. The order required shippers east of California with capacity rights on El Paso's pipeline to convert their capacity rights from unlimited "full requirement" to a limited contract demand amount of firm capacity. These shippers had to decide by July 31, 2002, how much El Paso capacity they would need in demand contracts and how much capacity they would give up.

In July 2002, the CPUC required California IOUs to sign up for El Paso pipeline capacity given up by the shippers and not subscribed to by replacement shippers serving California. The CPUC pre-approved such costs as just and reasonable. The decision stated that this requirement would spread El Paso reservation charges over as many ratepayers as possible to minimize the impact on any particular utility's customers.

The decision also addressed current capacity issues. It ordered the utilities to retain their current capacity levels on any interstate pipeline and to sell any excess capacity to a third party under short-term capacity release arrangements. To the extent the utilities comply with the decision, they will be able to fully recover their costs associated with existing capacity contracts.

In Phase II of this proceeding, the CPUC is addressing other issues that relate to these proposed rules, including (1) cost allocation of the El Paso capacity among the Utility's customers, (2) short-term capacity releases, and (3) details about the guaranteed rate recovery of the utilities' costs for subscription to interstate pipeline capacity. Phase II hearings are scheduled for the end of April 2003.

Since the July CPUC decision, the Utility has signed contracts for capacity on El Paso totaling approximately $50.8 million beginning November 2002 through December 2007, assuming no contracts set to expire before the end of 2007 are extended. The Utility has filed with the CPUC to recover both prepayments made to El Paso and ongoing capacity costs on the El Paso and the Transwestern Pipeline Company (Transwestern) pipelines. Under a previous CPUC decision, the Utility could not recover any costs paid to Transwestern for gas pipeline capacity through 1997. The Gas Accord (see "Gas Accord II" above) provided for partial recovery of Transwestern costs during the period 1998 through 2002. However, because of the El Paso decision, the Utility may be authorized to recover its future gas pipeline capacity purchases, which could result in additional revenues to recover costs of approximately $82 million over the remaining contract period that ends in March 2007.

On December 19, 2002, the CPUC issued a resolution that would delay the Utility's recovery of some of these costs. The resolution grants the Utility's request to recover in rates El Paso capacity costs and prepayments made to El Paso, subject to reallocation between customers in Phase II of the proceeding. However, the resolution also ordered the Utility to continue to treat Transwestern capacity costs as it had prior to the July 2002 CPUC decision. Recovery of Transwestern costs not currently authorized is being addressed in Phase II of the proceeding. The Utility does not expect the outcome of this matter to have a material adverse impact on its financial position or results of operations.

Rate Reduction Bonds

California's electric industry restructuring law (AB 1890) required that retail electric rates for residential and small commercial customers be reduced by 10 percent and frozen at that level until the earlier of March 31, 2002, or when the Utility fully recovered certain costs associated with the transition to a deregulated energy market.

To pay for the 10 percent rate reduction, the legislation authorized the issuance of rate reduction bonds to be repaid by residential and small commercial customers through the collection of a separate non-bypassable charge called the Fixed Transition Amount (FTA). The Utility sold its rights to collect FTA charges to its subsidiary PG&E Funding LLC for $2.9 billion in cash. To fund the purchase, PG&E Funding LLC issued $2.9 billion of rate reduction bonds (see discussion of "Rate Reduction Bonds" in Note 5 of the Notes to the Consolidated Financial Statements). The bonds allow for the rate reduction by lowering the carrying cost on a portion of the Utility's transition costs and by spreading recovery of that reduction over the life of the bonds.

Because of the 10 percent rate reduction, the amount of revenue the Utility had available in its frozen rates to recover its transition costs was reduced. Before the first quarter of 2002, to the extent that transition costs were not recovered because of the 10 percent rate reduction, the Utility deferred these transition costs through the rate reduction bond regulatory asset (RRBRA). The RRBRA will be recovered through future FTA charges.

In the first quarter of 2002, the Utility stopped deferring transition costs into the RRBRA and began amortizing the balance of the RRBRA concurrent with the amortization of the rate reduction bonds debt. The Utility recorded amortization expense of $290 million for the 12 months ended December 31, 2002. The Utility recorded deferred transition costs of $458 million for the 12 months ended December 31, 2001. The balance of the RRBRA was $1,346 million at December 31, 2002, and $1,636 million at December 31, 2001.

The proceeds of the rate reduction bonds included amounts sufficient to pay income taxes that would be levied on future FTA revenues. The Utility benefited from the receipt of this cash up front as it reduced the overall level of financing the Utility was required to maintain. Before the first quarter of 2002, the financing cost benefit was credited to ratepayers through a reduction in the amount of transition costs that were deferred into the RRBRA. When the Utility stopped deferring transition costs into the RRBRA, the Utility began crediting this benefit to a regulatory balancing account. The balance credited to residential and small commercial customers through this account was $102 million at December 31, 2002 and $17 million at December 31, 2001.

Annual Earnings Assessment Proceeding for Energy Efficiency Program Activities

The Utility administers general and low-income energy efficiency programs, and has been authorized to earn incentives based on a portion of the net present value of the savings achieved by the programs, incentives based on accomplishing certain tasks, and incentives based on expenditures. Each year the Utility files an earnings claim in the Annual Earnings Assessment Proceeding (AEAP), a forum for stakeholders to comment on, and for the CPUC to verify, the Utility's claim. On March 21, 2002, the CPUC eliminated the opportunity for shareholder incentives in connection with the California utilities' 2002 energy efficiency programs. This decision does not preclude the opportunity to recover shareholder incentives in connection with previous years' energy efficiency programs.

In May 2002, 2001, and 2000, the Utility filed its annual applications claiming incentives of approximately $106 million. The CPUC has delayed action on these proceedings and the Utility has not included any earnings associated with incentives in the Utility's Consolidated Statements of Operations.

On March 13, 2002, an administrative law judge for the CPUC requested comments on whether incentives adopted for pre-1998 energy efficiency programs should be reduced or eliminated for claims in future years. Out of the total $106 million in shareholder incentives claimed by the Utility for its 2002, 2001, and 2000 AEAP filings, $74 million is related to pre-1998 energy efficiency programs. The CPUC has not yet ruled on the comments.

The Utility cannot predict the outcome of these proceedings, or whether the outcome will have a material adverse effect on its results of operations or financial condition.

Baseline Allowance Increase

In April 2002, the CPUC required the Utility to increase baseline allowances for certain residential customers by May 1, 2002. An increase to a customer's baseline allotment increases the amount of their monthly usage that is covered under the lowest possible rate and is exempt from surcharges. The CPUC deferred consideration of corresponding rate changes until a later phase of the proceeding and ordered the utilities to track the under-collections associated with their respective baseline quantity changes in an interest-bearing balancing account. The Utility estimates the annual revenue shortfall to be approximately $96 million for electric and $6 million for gas. The Utility is charging the electric-related shortfall against earnings because it cannot predict the outcome of the second phase of the proceeding, nor can it conclude that recovery of the electric-related balancing account is probable. The total electric revenue shortfall for the period May through December 2002 was $69.8 million.

Issues that may be resolved during the second phase of the proceeding in early 2003 include items that could involve additional revenues at risk such as demographic revisions to baseline allowances, special allowances, and changes to baseline territories or seasons. The Utility estimated additional annual revenue shortfalls from this second phase, if adopted, of $79.6 million for electric service and $11 million for gas service, plus $11.6 million in administration costs spread out over three to five years. Included in this amount is an estimated $18 million annual shortfall resulting from a settlement allowing common-area electric accounts to switch from residential to commercial rates. The settlement, approved by the CPUC on January 16, 2003, is designed to allow common-area accounts to avoid disproportionately high rate increases caused by the five-tiered residential electric surcharges adopted in June 2001. The new five-tiered residential rate structure resulting from the $0.03 per kWh average surcharge assesses surcharges for usage above 130 percent of a customer's baseline allowance. Because most of the usage of large common area accounts falls within the highest rate tiers, these accounts pay disproportionately high bills as a result of this rate design. By contrast, the Utility's surcharges for commercial customers do not vary based on usage levels. As with the baseline quantity changes from the first phase, the CPUC deferred common area cost allocation and rate design issues to the second phase.

The Utility cannot predict what the outcome of the second phase of the proceeding will be, nor can it conclude that recovery of the electric baseline related balancing account is probable. Any electric revenue shortfalls will continue to be charged to earnings and will reduce revenue available to recover previously written-off under-collected purchased power costs and transition costs.

Nuclear Decommissioning Cost Triennial Proceeding Application

In March 2002, the Utility filed an application to increase the Utility's nuclear decommissioning revenue requirements for the years 2003 through 2005. The Utility seeks to recover $24 million in revenue requirements relating to the Diablo Canyon Nuclear Decommissioning Trusts and $17.5 million in revenue requirements relating to the Humboldt Bay Power Plant Decommissioning Trusts. The Utility also anticipates recovering $7.3 million in CPUC-jurisdictional revenue requirements for Humboldt Bay Unit 3 SAFSTOR (a mode of decommissioning) operating and maintenance costs, and escalation associated with that amount in 2004 and 2005. The Utility proposes continuing to collect the revenue requirement through a charge in electric rates, and to record the revenue requirement and the associated revenues in a balancing account. Until post-rate freeze ratemaking is implemented, the increase in revenue requirements would reduce the amount of revenues available to offset electric generation costs.

The ORA filed testimony with the CPUC that included lower estimates on contingencies, escalation rates and the cost of disposal of low-level radioactive wastes, and a higher estimate for returns on investments in the Decommissioning Trusts. If ORA's estimates were adopted, the Utility would not need to make any new contributions to the Decommissioning Trusts for the years 2003 through 2005, since the current amounts in the Decommissioning Trusts would be adequate to pay for expected decommissioning activities. The CPUC held hearings in September 2002 and is expected to reach a final decision during April 2003.

ADDITIONAL SECURITY MEASURES

Since the September 11, 2001, terrorist attacks, PG&E Corporation and the Utility have been working to assess the need for physical security upgrades at critical facilities. Various federal regulatory agencies have issued orders requiring additional safeguards, including a May 2002 Nuclear Regulatory Commission, or NRC, order. The NRC order required decommissioned nuclear facilities, such as the Utility's Humboldt Bay Power Plant, to implement interim security compensatory measures. Facilities affected by PG&E Corporation's and the Utility's assessments include generation facilities, transmission substations, and gas transmission facilities. The security upgrades will require additional capital investment and an increased level of operating costs. However, neither PG&E Corporation nor the Utility believes these costs will have a material impact on their consolidated financial position or results of operations.

RISK MANAGEMENT ACTIVITIES

PG&E Corporation and the Utility are exposed to various risks associated with their operations, the marketplace, contractual obligations, financing arrangements and other aspects of their business. PG&E Corporation and the Utility actively manage these risks through risk management programs. These programs are designed to support business objectives, minimize costs, discourage unauthorized risk, and reduce the volatility of earnings and manage cash flows. At PG&E Corporation and the Utility, risk management activities often include the use of energy and financial derivative instruments and other instruments and agreements.

These derivatives include forward contracts, futures, swaps, options, and other contracts.

- A forward contract is a commitment to purchase or sell a fixed amount of a commodity at a specified future date at a specified price;
- A futures contract is a standardized commitment, traded on an organized exchange, to purchase or sell a fixed amount of a commodity at a specified future date at a specified price;
- A swap contract is an agreement between two counterparties to exchange cash flows in the future based on changes in the underlying commodity or index; and
- An option contract provides the right, but not the obligation, to buy or sell the underlying asset at a predetermined price in the future.

PG&E Corporation uses derivatives for both non-trading and trading (i.e., speculative) purposes. The Utility uses derivatives for non-trading purposes only.

PG&E Corporation and the Utility may use energy and financial derivatives and other instruments and agreements to mitigate the risks associated with an asset (e.g., the natural position embedded in asset ownership and regulatory arrangements), liability, committed transaction, or probable forecasted transaction. Additionally, PG&E Corporation may engage in trading activities for purposes of generating profit, gathering market intelligence, creating liquidity, and maintaining a market presence. These instruments are used in accordance with approved risk management policies adopted by a senior officer-level risk oversight committee. Derivative activity is permitted only after the risk oversight committee approves appropriate risk limits for such activity. The organizational unit proposing the activity must successfully demonstrate that there is a business need for such activity and that the market risks will be adequately measured, monitored, and controlled.

The activities affecting the estimated fair value of trading activities and the non-trading activities balance, included in net price risk management assets and liabilities, are presented below.

(in millions)	Year Ended December 31, 2002	2001
Fair values of trading contracts at beginning of period	$ 58	$ 199
Net (gain) loss on contracts settled during the period	(121)	(296)
Fair value of new contracts when entered into	2	–
Changes in fair values attributable to changes in valuation techniques and assumptions	(12)	–
Other changes in fair values	51	155
Fair values of trading contracts outstanding at end of period	(22)	58
Fair value of non-trading contracts at the end of the period	(270)	63
Net Price Risk Management Assets (Liabilities) at end of period	(292)	121
Amounts reclassified as net price risk management assets (liabilities) held for sale	(377)	55
Net price risk management assets (liabilities) reported on the Consolidated Balance Sheets	$ 85	$ 66

The changes in fair values attributable to changes in valuation and assumptions, as reported in the table above, are composed of a $14 million loss related to PG&E NEG's implementation of a new methodology for estimating forward prices in illiquid periods, for which price information is not readily available, and a $2 million gain related to changes in assumptions used to value transportation contracts. This change in forward prices is described more fully in Note 1 of the Notes to the Consolidated Financial Statements.

PG&E Corporation estimates the gross mark-to-market value of its non-trading and trading contracts at December 31, 2002, using the midpoint of quoted bid and ask prices, where available.

When market data is not available, PG&E Corporation uses its forward price curve methodology described in Note 1 of the Notes to the Consolidated Financial Statements.

The gross mark-to-market valuation is then adjusted for the time value of money, creditworthiness of contractual counterparties, market liquidity in future periods, and other adjustments necessary to determine fair value. Most of PG&E Corporation's risk management models are reviewed by or purchased from third-party experts in specific derivative applications.

The following table shows the fair value of PG&E Corporation's trading contracts grouped by maturity at December 31, 2002.

(in millions)	Fair Value of Trading Contracts [1]				
	Maturity Less than One Year	Maturity One-Three Years	Maturity Four-Five Years	Maturity in Excess of Five Years	Total Fair Value
Source of Prices Used in Estimating Fair Value					
Actively quoted markets [2]	$ 6	$ 10	$ –	$ –	$ 16
Provided by other external sources	(26)	7	(13)	(3)	(35)
Based on models and other valuation methods [3]	(23)	(30)	(15)	65	(3)
Total Mark-to-Market	$ (43)	$ (13)	$ (28)	$ 62	$ (22)

(1) Excludes all non-trading contracts, including non-trading contracts that receive mark-to-market accounting treatment.
(2) Actively quoted markets are exchanged traded quotes.
(3) In many cases, these prices are an input into option models that calculate a gross mark-to-market value from which fair value is derived.

The amounts disclosed above are not indicative of likely future cash flows. The future value of trading contracts may be impacted by changes in underlying valuations, new transactions, market liquidity, and PG&E Corporation's risk management portfolio needs and strategies.

Market Risk

Market risk is the risk that changes in market conditions will adversely affect earnings or cash flow.

PG&E Corporation categorizes market risks as price risk, interest rate risk, foreign currency risk, and credit risk. These market risks may impact PG&E Corporation's and its subsidiaries' assets and trading portfolios. Immediately below is an overview of PG&E Corporation's market risks, followed by detailed descriptions of the market risks and explanations as to how each of these risks are managed.

- Price risk results from the Utility's or PG&E NEG's exposure to the impacts of market fluctuations in price and transportation costs of commodities such as electricity, natural gas, other fuels, and other energy-related products;
- Interest rate risk primarily results from exposure to the volatility of interest rates as a result of financing or refinancing through the issuance of variable-rate and fixed-rate debt;
- Foreign currency risk results from exposure to volatilities in currency rates; and
- Credit risk results from exposure to counterparties who may fail to perform under their contractual obligations.

Price Risk

Price risk is the risk that changes in primarily commodity market prices will adversely affect earnings and cash flows. Below are descriptions of the Utility's and PG&E NEG's specific price risks.

Also described below is the value-at-risk methodology, which is PG&E Corporation's and the Utility's method for assessing the prospective risk that exists within a portfolio for price risk.

Utility Electric Commodity Price Risk

Purchased Power

In compliance with regulatory requirements, the Utility manages commodity price risk independently from the activities in PG&E Corporation's unregulated businesses. The Utility also reports its commodity price risk separately for its electric and natural gas businesses.

Since January 2001, the DWR has been responsible for procuring electricity required to cover the Utility's net open position. The Utility bills its customers for these DWR electricity purchases and remits amounts collected to the DWR based on their CPUC approved revenue requirement. To the extent that the Utility's electricity rates remain frozen, and the CPUC increases the portion of the DWR's revenue requirement allocated to the Utility's customers to cover adverse market price changes or other factors, the Utility has commodity price risk. The Utility is exposed to price risk to the extent that the cost of new electricity purchases increases, or the revenue from new wholesale sales decreases.

The DWR's authority to enter into new electricity purchase contracts expired January 1, 2003. SB 1976 and CPUC orders required the California IOUs, including the Utility, to resume responsibility for procuring the electricity to meet the residual net open position by January 1, 2003.

On December 19, 2002, the CPUC issued an interim opinion granting the Utility authority to enter into contracts designed to hedge the residual net open position through the first quarter of 2004. The CPUC's interim opinion also established a maximum annual procurement disallowance equal to twice the Utility's annual administrative costs of managing procurement activities, including the administration and dispatch of electricity associated with DWR allocated contracts. However, the Utility can provide no assurance that the CPUC will not increase or eliminate this maximum annual procurement disallowance in the future. Such a change would increase the Utility's exposure to electric commodity price risk.

The residual net open position is expected to increase over time due to periodic expirations of existing and DWR allocated procurement contracts. The Utility can provide no assurance that electricity will continue to be available for purchase in quantities sufficient to satisfy the residual net open position as these or other events occur. Even if the Utility were able to purchase electricity in quantities sufficient to satisfy the residual net open position, it would be exposed to wholesale electricity commodity price fluctuations and uncertain commercial terms.

Conversely, the amount of energy provided by the DWR contracts will likely result in significant excess electricity during various periods, which the Utility will be required to attempt to sell on the open market.

Nuclear Fuel

The Utility has purchase agreements for nuclear fuel components and services for use in operating the Diablo Canyon generating facility. The Utility relies on large, well-established international producers for its long-term agreements in order to diversify its commitments and ensure security of supply. Pricing terms are also diversified, ranging from fixed prices to base prices that are adjusted using published information. In January 2002, the U.S. International Trade Commission imposed tariffs of up to 50 percent on imports from certain countries providing nuclear fuel. If these tariffs remain in place, the Utility's nuclear fuel costs may rise because there are a limited number of suppliers in the world for such fuel. The Utility's ratemaking for retained generation is cost-of-service-based; however, to the extent that the Utility's electricity rates remain frozen, changes in the cost of nuclear fuel would impact the amount of revenues the Utility has available to recover its previously written-off under-collected purchased electric generation costs. For this reason, the Utility is exposed to price risk to the extent that the cost of nuclear fuel increases.

Utility Natural Gas Commodity Price Risk

Through 2003, the Core Procurement Incentive Mechanism (CPIM) determines how much of the cost of procuring natural gas for its customers may be included in the Utility's natural gas procurement rates. Under the CPIM, the Utility's procurement costs are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas prices at the points where the Utility typically purchases natural gas. If costs fall within a range, or tolerance band currently 99 percent to 102 percent, around the benchmark, they are considered reasonable and may be fully recovered in customer rates. Ratepayers and shareholders share equally the costs and savings outside the tolerance band.

In addition, the Utility has contracts for transportation capacity on various natural gas pipelines. A recent CPUC decision found that the Utility's acquisition of additional interstate transportation capacity was reasonable and that all interstate transportation capacity already held by the Utility was also reasonable. A future decision will allocate the cost of the transportation capacity between customer groups and will also determine the date on which all transportation capacity costs held by the Utility prior to July 2002 will be recoverable.

Under the Gas Accord, shareholders are at risk for any revenues from the sale of capacity on the Utility's gas transmissions and storage facilities. Under the Gas Accord, the Utility sells a portion of the pipeline and storage capacity at competitive market-based rates. Revenues are generally lower when throughput volumes are lower than expected and when the price spreads between two delivery points narrow. In August 2002, the CPUC approved a settlement agreement between the Utility and other parties that provided for a one-year extension of the Utility's existing gas transmission and storage rates and terms and conditions of service through the end of 2003. (The Gas Accord was originally scheduled to expire on December 31, 2002.) For further discussion, see "Gas Accord II" in the "Regulatory Matters" section of the MD&A.

PG&E NEG Price Risk

PG&E NEG is exposed to price risk from its portfolio of proprietary trading contracts and its portfolio of electric generation assets and supply contracts that serve wholesale and industrial customers, and various merchant plants currently in development and construction.

As described above, PG&E NEG is in the process of reducing and unwinding its trading positions. Additionally, asset hedge positions associated with the merchant plants will either remain with the assets or be terminated. PG&E NEG has significantly reduced their energy trading operations in an ongoing effort to raise cash and reduce debt. PG&E NEG's objective is to limit its asset trading and risk management activities to only what is necessary for energy management services to facilitate the transition of PG&E NEG's merchant generation facilities through their sale, transfer, or abandonment process. PG&E NEG will then further reduce and transition to only retain limited capabilities to ensure fuel procurement and power logistics for PG&E NEG's retained independent power plant operations.

Value-at-Risk

PG&E Corporation and the Utility measure price risk exposure using value-at-risk and other methodologies that simulate future price movements in the energy markets to estimate the probability of future potential losses. Price risk is quantified using what is referred to as the variance-covariance technique of measuring value-at-risk, which provides a consistent measure of risk across diverse energy markets and products. This methodology requires the selection of a number of important assumptions including a confidence level for losses, price volatility, market liquidity, and a specified holding period. This technique uses historical price movements data and specific, defined mathematical parameters to estimate the characteristics of and the relationships between components of assets and liabilities held for price risk management activities. PG&E Corporation therefore uses the historical data for calculating the expected price volatility of its portfolio's contractual positions to project the likelihood that the prices of those positions will move together.

The value-at-risk model includes all of PG&E Corporation's and the Utility's commodity derivatives and other financial instruments over the entire length of the terms of the transactions in the trading and non-trading portfolios. PG&E Corporation's and the Utility's value-at-risk calculation is a dollar amount reflecting the maximum potential one-day loss in the fair value of their portfolios due to adverse market movements over a defined time horizon within a specified confidence level. This calculation is based on a 95 percent confidence level, which means that there is a 5 percent probability that PG&E Corporation's portfolios will incur a loss in value in one day at least as large as the reported value-at-risk. For example, if the value-at-risk is calculated at $5 million, there is a 95 percent probability that if prices moved against current positions, the reduction in the value of the portfolio resulting from such one-day price movements would not exceed $5 million. There would also be a 5 percent probability that a one-day price movement would be greater than $5 million.

The following table illustrates the potential one-day unfavorable impact for price risk as measured by the value-at-risk model, based on a one-day holding period. A two-year comparison of daily value-at-risk is included in order to provide context around the one-day amounts. The high and low valuations represent the highest and lowest of the values during 2002.

The average valuation represents the average of the values during 2002.

(in millions)	December 31, 2002	December 31, 2001	Year Ended December 31, 2002 Average	High	Low
Utility					
Non-trading activities [1]	$ 4.0	$ 3.6	$ 2.1	$ 5.8	$ 0.3
PG&E NEG					
Trading activities	8.2	5.8	5.2	9.7	2.1
Non-trading activities:					
Non-trading contracts that receive mark-to-market accounting treatment [2]	2.7	–	2.9	3.9	2.1
Non-trading contracts accounted for as hedges [3]	9.4	10.3	12.5	18.6	9.4

(1) Includes the Utility's gas portfolio only, as this represents the Utility's only commodity price risk through year end 2002.

(2) Includes derivative power and fuels contracts that do not qualify under the SFAS No. 133 normal purchases and normal sales exception and do not qualify to be accounted for as cash flow hedges.

(3) Includes only the risk related to the derivative instruments that serve as hedges and does not include the related underlying hedged item. Any gain or loss on these derivative commodity instruments would be substantially offset by a corresponding gain or loss on the hedged commodity positions, which are not included.

Value-at-risk has several limitations as a measure of portfolio risk, including, but not limited to, underestimation of the risk of a portfolio with significant options exposure, inadequate indication of the exposure of a portfolio to extreme price movements, and the inability to address the risk resulting from intra-day trading activities. Value-at-risk also does not reflect the significant regulatory and legislative risks currently facing the Utility or the risks relating to the Utility's bankruptcy proceedings.

PG&E NEG's value-at-risk levels have increased at December 31, 2002, as compared to levels at December 31, 2001, due to strong prices and increased market volatility across all commodities in 2002. It is expected that PG&E NEG's value-at-risk levels will eventually peak and start to decrease because, as previously discussed, PG&E NEG is in the process of reducing and unwinding its trading positions. Additionally, asset hedge positions associated with the merchant plants will either remain with the assets or be terminated. See the discussion above in the MD&A's "Liquidity and Financial Resources – PG&E NEG" section for further information regarding PG&E NEG's current financial situation.

Interest Rate Risk

Interest rate risk is the risk that changes in interest rates could adversely affect earnings or cash flows. Specific interest rate risks for PG&E Corporation and the Utility include the risk of increasing interest rates on working capital facilities, variable rate tax-exempt pollution control bonds, and other variable rate debt.

PG&E Corporation may use the following interest rate instruments to manage its interest rate exposure: interest rate swaps, interest rate caps, floors, or collars, swaptions, or interest rate forward and futures contracts. Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At December 31, 2002, if interest rates changed by 1 percent for all variable rate debt at PG&E Corporation and the Utility, the change would affect net income by approximately $35 million for PG&E Corporation and $33 million for the Utility, based on variable rate debt and hedging derivatives and other interest rate-sensitive instruments outstanding.

The table included above in this MD&A's Commitments and Capital Expenditures section provides the maturity of the carrying amounts and the related weighted average interest rates on PG&E Corporation's interest bearing securities, by expected maturity dates.

Foreign Currency Risk

Foreign currency risk is the risk of changes in value of pending financial obligations in foreign currencies in relation to the U.S. dollar.

PG&E Corporation and the Utility are exposed to such risk associated with foreign currency exchange variations related to Canadian-denominated purchase and swap agreements. PG&E Corporation is also exposed to foreign currency risk resulting from the need to translate Canadian-denominated financial statements of an affiliate into U.S. dollars in the PG&E Corporation Consolidated Financial Statements. PG&E Corporation and the Utility use forwards, swaps, and options to hedge foreign currency exposure.

For the Utility, changes in gas purchase costs due to fluctuations in the value of the Canadian dollar would be passed through to customers in rates, as long as the overall costs of purchasing gas are within a 99 percent to 102 percent tolerance band of the benchmark price under the CPIM mechanism, as discussed above. The Utility's customers and shareholders would share in the costs or savings outside of the tolerance band equally.

PG&E Corporation and the Utility use sensitivity analysis to measure their exchange rate exposure to the Canadian dollar. Based on a sensitivity analysis at December 31, 2002, a 10 percent devaluation of the Canadian dollar would be immaterial to PG&E Corporation's and the Utility's Consolidated Financial Statements.

Credit Risk

Credit risk is the risk of loss that PG&E Corporation and the Utility would incur if counterparties failed to perform their contractual obligations (these obligations are reflected as Accounts Receivable – Customers, net; notes receivable included in Other Noncurrent Assets – Other; Price Risk Management (PRM) assets; and Assets held for sale on the balance sheet). PG&E Corporation and the Utility conduct business primarily with customers or vendors, referred to as counterparties, in the energy industry. These counterparties include other investor-owned utilities, municipal utilities, energy trading companies, financial institutions, and oil and gas production companies located in the United States and Canada. This concentration of counterparties may impact PG&E Corporation's and the Utility's overall exposure to credit risk because their counterparties may be similarly affected by economic or regulatory changes or other changes in conditions.

PG&E Corporation and the Utility manage their credit risk in accordance with their respective Risk Management Policies. The policies establish processes for assigning credit limits to counterparties before entering into agreements with significant exposure to PG&E Corporation and the Utility. These processes include an evaluation of a potential counterparty's financial condition, net worth, credit rating, and other credit criteria as deemed appropriate, and are performed at least annually.

Credit exposure is calculated daily, and in the event that exposure exceeds the established limits, PG&E Corporation and the Utility take immediate action to reduce the exposure, or obtain additional collateral, or both. Further, PG&E Corporation and the Utility rely heavily on master agreements that require the counterparty to post security, referred to as credit collateral, in the form of cash, letters of credit, corporate guarantees of acceptable credit quality, or eligible securities if current net receivables and replacement cost exposure exceed contractually specified limits.

PG&E Corporation and the Utility calculate gross credit exposure for each counterparty as the current mark-to-market value of the contract (that is, the amount that would be lost if the counterparty defaulted today) plus or minus any outstanding net receivables or payables, prior to the application of the counterparty's credit collateral.

In 2002, PG&E Corporation's and the Utility's credit risk increased due in part to downgrades of some counterparties credit ratings to levels below investment grade. The downgrades increase PG&E Corporation's or the Utility's credit risk because any collateral provided by these counterparties in the form of corporate guarantees or eligible securities may be of lesser or no value. Therefore, in the event these counterparties failed to perform under their contracts, PG&E Corporation and the Utility may face a greater potential maximum loss. In contrast, PG&E Corporation and the Utility do not face any additional risk if counterparties' credit collateral is in the form of cash or letters of credit, as this collateral is not affected by a credit rating downgrade.

For the year ended December 31, 2002, PG&E Corporation and the Utility have recognized no losses due to the contract defaults or bankruptcies of counterparties. However, in 2001, PG&E Corporation terminated its contracts with a bankrupt company, which resulted in a pre-tax charge to earnings of $60 million related to trading and non-trading activities, after application of collateral held and accounts payable.

At December 31, 2002, and at December 31, 2001, PG&E Corporation had no single counterparty that represented greater than 10 percent of PG&E Corporation's net credit exposure. At December 31, 2002, the Utility had one investment grade counterparty that represented 21 percent of the Utility's net credit exposure, and one below investment grade counterparty that represented 11 percent of the Utility's net credit exposure. At December 31, 2001, the Utility had no single counterparty that represented greater than 10 percent of the Utility's net credit exposure.

The schedule below summarizes PG&E Corporation's and the Utility's credit risk exposure to counterparties that are in a net asset position, with the exception of exchange-traded futures (the exchange provides for contract settlement on a daily basis), as well as PG&E Corporation's and the Utility's credit risk exposure to counterparties with a greater than 10 percent net credit exposure, at December 31, 2002, and December 31, 2001:

(in millions)	Gross Credit Exposure Before Credit Collateral[1]	Credit Collateral[2]	Net Credit Exposure[2]	Number of Counterparties >10%	Net Exposure of Counterparties >10%
At December 31, 2002					
PG&E Corporation	$ 1,165	$ 195	$ 970	–	$ –
Utility [3]	288	113	175	2	55
At December 31, 2001					
PG&E Corporation	$ 1,203	$ 207	$ 996	–	$ –
Utility [3]	271	127	144	–	–

(1) Gross credit exposure equals mark-to-market value (adjusted for applicable credit valuation adjustments), notes receivable, and net (payables) receivables where netting is allowed. Gross and net credit exposure amounts reported above do not include adjustments for time value, liquidity, or model.

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

(3) The Utility's gross credit exposure includes wholesale activity only. Retail activity and payables incurred prior to the Utility's bankruptcy filing are not included. Retail activity at the Utility consists of the accounts receivable from the sale of gas and electricity to millions of residential and small commercial customers.

At December 31, 2002, approximately $205 million, or 21 percent of PG&E Corporation's net credit exposure was to entities that had credit ratings below investment grade. At December 31, 2002, approximately $64 million, or 37 percent of the Utility's net credit exposure was to entities that had credit ratings below investment grade. At December 31, 2001, approximately $244 million, or 25 percent of PG&E Corporation's net credit exposure was to entities that had credit ratings below investment grade. At December 31, 2001, approximately $32 million, or 22 percent of the Utility's net credit exposure was to entities that had credit ratings below investment grade. Investment grade is determined using publicly available information, i.e., rated at least Baa3 by Moody's and BBB- by S&P. If the counterparty provides a guarantee by a higher rated entity (e.g., its parent), the credit rating determination is based on the rating of its guarantor.

At December 31, 2002, approximately $65 million, or 7 percent of PG&E Corporation's net credit exposure was with counterparties at PG&E NEG that are not rated. At December 31, 2001, none of PG&E Corporation's net credit exposure was with counterparties at PG&E NEG that were not rated. Most counterparties with no credit rating are governmental authorities which are not rated, but which PG&E Corporation has assessed as equivalent to investment grade. Other counterparties with no credit rating are subject to an internal assessment of their credit quality and a credit rating designation.

PG&E Corporation has regional concentrations of credit exposure to counterparties that conduct business primarily in the western United States and also to counterparties that conduct business primarily throughout North America. The Utility has a regional concentration of credit risk associated with its receivables from residential and small commercial customers in northern California. However, the risk of material loss due to nonperformance from these customers is not considered likely. Reserves for uncollectible accounts receivable are provided for the potential loss from nonpayment by these customers based on historical experience. The Utility has a net regional concentration of credit exposure totaling $175 million to counterparties that conduct business primarily throughout North America.

CRITICAL ACCOUNTING POLICIES

The preparation of Consolidated Financial Statements in accordance with accounting principles generally accepted in the United States involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Certain of these estimates and assumptions are considered to be Critical Accounting Policies, due to their complexity, subjectivity, and uncertainty, along with their relevance to the financial performance of PG&E Corporation. Actual results may differ substantially from these estimates. These policies and their key characteristics are outlined below.

In 2001, PG&E Corporation and the Utility adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Hedging Activities" (collectively, SFAS No. 133), which required all derivative instruments to be recognized in the financial statements at their fair value. Prior to its rescission, PG&E Corporation accounted for its energy trading activities in accordance with Emerging Issues Task Force (EITF) No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities", and SFAS No. 133, which require certain energy trading contracts to be accounted for at fair values using mark-to-market accounting. See discussion of Rescission of EITF 98-10 below.

Effective for the third quarter ended September 30, 2002, PG&E Corporation adopted the net method of recognizing realized gains and losses on energy trading contracts. Under the net method, revenues and expenses are netted and trading gains (or losses) are reflected in revenues on the income statement, as opposed to reporting revenues and expenses under the previously used gross method.

PG&E Corporation and the Utility have derivative commodity contracts for the physical delivery of purchase and sale quantities such as natural gas and power transacted in the normal course of business. These derivatives are exempt from the requirements of SFAS No. 133 under the normal purchases and sales exception, and are not reflected on the balance sheet at fair value. See further discussion in Notes 1 and 11 of the Notes to the Consolidated Financial Statements.

PG&E Corporation and the Utility apply SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," to their regulated operations. Under SFAS No. 71, regulatory assets represent capitalized costs that would otherwise be charged to expense. These costs are later recovered through regulated rates. Regulatory liabilities are rate actions of a regulator that will later be credited to customers through the rate making process. Regulatory assets and liabilities are recorded when it is probable that these items will be recovered or reflected in future rates. If it is determined that these items are no longer probable of recovery under SFAS No. 71, then they will be written-off at that time. At December 31, 2002, PG&E Corporation reported regulatory assets of $2.2 billion, including current regulatory balancing accounts receivable and regulatory liabilities of $1.8 billion, including current regulatory balancing accounts payable. See Note 1 of the Notes to the Consolidated Financial Statements.

The Utility records revenues as electricity and natural gas are delivered. A portion of the revenue recognized has not yet been billed. Unbilled revenues are determined by factoring the actual load (energy) delivered with recent historical usage and rate patterns.

Due to the Utility's filing for bankruptcy in 2001, the financial statements for both PG&E Corporation and the Utility are prepared in accordance with SOP 90-7, which is used by reorganizing entities operating under the Bankruptcy Code. Under SOP 90-7, certain claims against the Utility prior to its bankruptcy filing are recorded as Liabilities Subject to Compromise. The Utility reported a total of $9.4 billion of Liabilities Subject to Compromise at December 31, 2002. While the Utility operates under the protection of the Bankruptcy Court, the realization of assets and the liquidation of liabilities is subject to uncertainty, as additional claims to Liabilities Subject to Compromise can change due to such actions as the resolution of disputed claims or certain Bankruptcy Court actions. See Note 2 of the Notes to the Consolidated Financial Statements.

The Utility records an environmental remediation liability when site assessments indicate that remediation is probable and the cost can be reasonably estimated. This liability is based on site investigations, remediation, operations, maintenance, monitoring, and closure. This liability is reviewed on a quarterly basis, and is recorded at the lower range of estimated costs, unless there is a better estimate available. At December 31, 2002, the Utility's undiscounted environmental remediation liability was $331 million. The Utility's future cost could increase to as much as $444 million if (1) the other potentially responsible parties are not financially able to contribute to these costs, (2) the extent of contamination or necessary remediation is greater than anticipated, or (3) the Utility is found to be responsible for clean-up costs at additional sites.

The process of estimating remediation liabilities is difficult and changes in the estimate could occur given the uncertainty concerning the Utility's ultimate liability, the complexity of environmental laws and regulations, the selection of compliance alternatives, and the financial ability of other responsible parties. PG&E NEG estimates that it may be required to spend up to approximately $608 million before insurance proceeds for environmental compliance at certain of its operating facilities. To date, PG&E NEG has spent approximately $13 million on environmental compliance. See Note 16 of the Notes to the Consolidated Financial Statements.

Since the CPUC authorized the collection of incremental surcharge revenues in January and March 2001, the Utility has used generation-related revenues in excess of generation-related costs to recover approximately $1.9 billion (after-tax) in previously written-off under collected purchased power and generation-related charges. For the 12 months ended December 31, 2002, total surcharge revenues recognized were $1.8 billion (after-tax). For the 12 months ended December 31, 2001, total surcharge revenues recognized were $1.3 billion (after-tax). The Utility has not provided reserves for potential refunds of these surcharges as it believes that recent regulatory orders and actions provide evidence that it is not probable that a refund will be ordered. However, it is possible that subsequent decisions by the CPUC may affect the amount and timing of these surcharge revenues recovered by the Utility and that subsequent CPUC decisions may order the Utility to refund all or a portion of the surcharge revenues collected. See Note 2 of the Notes to the Consolidated Financial Statements and risk factors discussed in the Overview section of this MD&A for further discussion. See Note 1 of the Notes to the Consolidated Financial Statements for further discussion of accounting policies and new accounting developments.

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

Consolidation of Variable Interest Entities – In January 2003 the Financial Accounting Standards Board (FASB) issued Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46), which expands upon existing accounting guidance addressing when a company should include in its financial statements the assets, liabilities, and activities of another entity. FIN 46 notes that many of what are now referred to as "variable interest entities" have commonly been referred to as special-purpose entities or off-balance sheet structures. However, the Interpretation's guidance is to be applied to not only these entities but to all entities found within a company. FIN 46 provides some general guidance as to the definition of a variable interest entity. PG&E Corporation is currently evaluating all entities to determine if they meet the FIN 46 criteria as variable interest entities.

Until the issuance of FIN 46, one company generally included another entity in its Consolidated Financial Statements only if it controlled the entity through voting interests. FIN 46 changes that by requiring a variable interest entity to be consolidated by a company if that company is subject to a majority of the risk of loss from the variable interest entity's activities or entitled to receive a majority of the entity's residual returns, or both. A company that consolidates a variable interest entity is now referred to as the "primary beneficiary" of that entity.

FIN 46 requires disclosure of variable interest entities that the company is not required to consolidate but in which it has a significant variable interest.

The consolidation requirements of FIN 46 apply immediately to variable interest entities created after January 31, 2003. The consolidation requirements apply to variable interest entities created before January 31, 2003, in the first fiscal year or interim period beginning after June 15, 2003, so these requirements would be applicable to PG&E Corporation in the third quarter 2003.

Certain new and expanded disclosure requirements apply to all financial statements issued after January 31, 2003, regardless of when the variable interest entity was established. These disclosures are required if there is an assessment that it is reasonably possible that an enterprise will consolidate or disclose information about a variable interest entity when FIN 46 becomes effective. PG&E Corporation is currently evaluating the impacts of FIN 46's initial recognition, measurement, and disclosure provisions on its Consolidated Financial Statements.

Guarantor's Accounting and Disclosure Requirements for Guarantees – In November 2002, the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). FIN 45 expands on the accounting guidance of SFAS No. 5, "Accounting for Contingencies," SFAS No. 57, "Related Party Disclosures," and SFAS No. 107, "Disclosures about Fair Value of Financial Instruments." FIN 45 also incorporates, without change, the provisions of FASB Interpretation No. 34, "Disclosures of Indirect Guarantees of the Indebtedness of Others," which it supersedes.

FIN 45 elaborates on the existing disclosure requirements for most guarantees. It clarifies that a guarantor's required disclosures include the nature of the guarantee, the maximum potential undiscounted payments that could be required, the current carrying amount of the liability, if any, for the guarantor's obligations (including the liability recognized under SFAS No. 5), and the nature of any recourse provisions or available collateral that would enable the guarantor to recover amounts paid under the guarantee.

FIN 45 also clarifies that at the time a company issues a guarantee, it must recognize an initial liability for the fair value of the obligation it assumes under that guarantee, including its ongoing obligation to stand ready to perform over the term of the guarantee in the event that specified triggering events or conditions occur. This information must also be disclosed in interim and annual financial statements.

FIN 45 does not prescribe a specific account for the guarantor's offsetting entry when it recognizes the liability at the inception of the guarantee, noting that the offsetting entry would depend on the circumstances in which the guarantee was issued. There also is no prescribed approach included for subsequently measuring the guarantor's recognized liability over the term of the related guarantee. It is noted that the liability would typically be reduced by a credit to earnings as the guarantor is released from risk under the guarantee.

The initial recognition and initial measurement provisions apply on a prospective basis to guarantees issued or modified after December 31, 2002. PG&E Corporation is currently evaluating the impact of FIN 45's initial recognition and measurement provisions on its Consolidated Financial Statements. The disclosure requirements for FIN 45 are effective for financial statements of interim or annual periods ending after December 15, 2002, and have been incorporated into PG&E Corporation's December 31, 2002, disclosures of guarantees.

Rescission of EITF 98-10 – In October 2002, the Emerging Issues Task Force rescinded EITF 98-10. Energy trading contracts that are derivatives in accordance with SFAS No. 133 will continue to be accounted for at fair value under SFAS No. 133. Contracts that were previously marked to market as trading activities under EITF 98-10 that do not meet the definition of a derivative will be recorded at cost, with a one-time adjustment to be recorded as a cumulative effect of a change in accounting principle as of January 1, 2003. For PG&E Corporation, the majority of trading contracts are derivative instruments as defined in SFAS No. 133. The rescission of EITF 98-10 has no effect on the accounting for derivative instruments used for non-trading purposes, which continue to be accounted for in accordance with SFAS No. 133.

The reporting requirements associated with the rescission of EITF 98-10 are to be applied prospectively for all EITF 98-10 energy trading contracts entered into after October 25, 2002. For all EITF 98-10 energy trading contracts in existence at or prior to October 25, 2002, the estimated impact of the first quarter 2003 cumulative effect of a change in accounting principle is a loss of $5 million, net of taxes at December 31, 2002.

Accounting for Costs Associated with Exit or Disposal Activities – In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities," which addresses accounting for restructuring and similar costs. SFAS No. 146 supersedes previous accounting guidance, principally EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity" (EITF 94-3). PG&E Corporation will adopt the provisions of SFAS No. 146 for restructuring activities initiated after December 31, 2002. SFAS No. 146 requires that the liability for costs associated with an exit or disposal activity be recognized when the liability is incurred. Under EITF 94-3, a liability for an exit cost was recognized at the date of the company's commitment to an exit plan if certain other criteria were met. SFAS No. 146 also establishes that the liability initially should be measured and recorded at fair value. Accordingly, the prospective implementation of SFAS No. 146 may affect the timing of recognizing future restructuring costs as well as the amounts recognized.

Accounting for Asset Retirement Obligations – In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." PG&E Corporation and the Utility will adopt this Statement effective January 1, 2003. SFAS No. 143 provides accounting requirements for costs associated with legal obligations to retire tangible, long-lived assets. Under the Statement, the asset retirement obligation is recorded at fair value in the period in which it is incurred by increasing the carrying amount of the related long-lived asset. In each subsequent period, the liability is accreted to its present value and the capitalized cost is depreciated over the useful life of the related asset. Upon adoption, the cumulative effect of applying this Statement will be recognized as a change in accounting principle in the Consolidated Statements of Operations. However, rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with this statement and costs recovered through the ratemaking process. Regulatory assets and liabilities may be recorded when it is probable that the asset retirement costs will be recovered through the ratemaking process.

PG&E Corporation estimates the impact of adopting SFAS No. 143 effective January 1, 2003 will be as follows:

- The Utility will adjust its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. The Utility will also recognize asset retirement obligations associated with the decommissioning of other fossil generation assets.

  At December 31, 2002, the total nuclear decommissioning obligation accrued was $1.3 billion and is included in accumulated depreciation and decommissioning on the Consolidated Balance Sheets (see Note 13, "Nuclear Decommissioning"). The Utility had accrued, at December 31, 2002, $52 million to decommission certain fossil generation assets based on its estimate of the decommissioning obligation under the accounting principles in effect at that time. These decommissioning obligations are also included in accumulated depreciation and decommissioning on the Consolidated Balance Sheets.

  The Utility estimates it will recognize an adjustment to its recorded nuclear and fossil facility decommissioning obligations in the range of an increase of $222 million to a decrease of $192 million for asset retirement obligations in existence as of January 1, 2003. The estimated cumulative effect of a change in accounting principle from unrecognized accretion expense and adjustments to depreciation and decommissioning expense accrued to date will range from a loss of $19 million to a gain of $17 million (pre-tax).

- PG&E NEG estimates that it will recognize a liability in the range of $11 million to $21 million for asset retirement obligations on January 1, 2003. The cumulative effect of a change in accounting principle from unrecognized accretion and depreciation expense is estimated to be a loss in the range of $4 million to $6 million (pre-tax).

PENSION AND OTHER POST-RETIREMENT PLANS

PG&E Corporation and its subsidiaries provide qualified and non-qualified non-contributory defined benefit pension plans for their employees, retirees, and non-employee directors. PG&E Corporation and its subsidiaries also 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). Amounts that PG&E Corporation and the Utility recognize as obligations to provide pension benefits under SFAS No. 87, "Employers' Accounting for Pensions," and other benefits under SFAS No. 106. "Employers Accounting for Postretirement Benefits other than Pensions" are based on certain actuarial assumptions. Actuarial assumptions used in determining pension obligations include the discount rate, the average rate of future compensation increases, and the expected return on plan assets. Actuarial assumptions used in determining other benefit obligations include the discount rate, the average rate of future compensation increases, the expected return on plan assets, and the assumed health care cost trend rate. While PG&E Corporation and the Utility believe the assumptions used are appropriate, significant differences in actual experience, plan changes, or significant changes in assumptions may materially affect the recorded pension and other benefit obligations and future plan expenses.

Pension and other benefit funds are held in external trust funds. Trust assets, including accumulated earnings, must be used exclusively for pension and other benefit payments. Consistent with the trusts' investment policies, assets are invested in U.S. equities, non-U.S.

equities, and fixed income securities. Investment securities are exposed to various risks, such as interest rate, credit, and overall market volatility risks. As a result of these risks, it is reasonably possible that the market values of investment securities could increase or decrease in the near term. Increases or decreases in market values could materially affect the current value of the trusts and, as a result, the future level of pension and other benefit expense.

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit trusts, resulting in a weighted average rate of return on plan assets. Fixed income returns were based on historic returns for the broad U.S. bond market. Equity returns were determined by applying a market risk premium of 3.5 percent to the U.S. bond market return. For the Utility Retirement Plan, the assumed return of 8.1 percent compares to a ten-year actual return of 8.4 percent.

The rate used to discount pension and other post-retirement benefit plan liabilities was based on a yield curve developed from the Moody's AA Corporate Bond Index at December 31, 2002. This yield curve has discount rates that vary based on the maturity of the obligations. The estimated future cash flows for the pension and other post retirement obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate. The resulting rate was validated by comparison to the yield of a high-quality, non-callable corporate bond portfolio with cash flows corresponding to expected future benefit payments. For the Utility Retirement Plan, a 25 basis point decrease in the discount rate would increase the accumulated benefit obligation by approximately $240 million.

TAXATION MATTERS

The Internal Revenue Service (IRS) has completed its audit of PG&E Corporation's 1997 and 1998 consolidated U.S. federal income tax returns and has assessed additional federal income taxes of $70 million (including interest). PG&E Corporation has filed protests contesting certain adjustments made by the IRS in that audit and currently is discussing these adjustments with the IRS' Appeals Office. The IRS also is auditing PG&E Corporation's 1999 and 2000 consolidated U.S. federal income tax returns, but has not issued its final report. However, the IRS has proposed adjustments totaling $77 million (including interest). The resolution of these matters with the IRS is not expected to have a material adverse effect on PG&E Corporation's earnings. All of PG&E Corporation's federal income tax returns prior to 1997 have been closed. In addition, California and certain other state tax authorities currently are auditing various state tax returns. The results of these audits are not expected to have a material adverse effect on PG&E Corporation's earnings. In the third quarter of 2002, PG&E Corporation re-evaluated its position with respect to the expected realization of certain synthetic fuel tax credits, and as a result, recorded additional tax benefits totaling $43 million.

Deferred tax assets with respect to impairments and write-offs at PG&E NEG were recorded in 2002. Due to uncertainty in realizing state tax benefits associated with these deferred tax assets, valuation allowances were established.

A valuation allowance of $97 million associated with state tax benefits was recorded in continuing operations. In addition, a valuation allowance of $87 million associated with state tax benefits was recorded in discontinued operations.

ENVIRONMENTAL AND LEGAL MATTERS

PG&E Corporation and the Utility are subject to laws and regulations established both to maintain and to improve the quality of the environment. Where PG&E Corporation's and the Utility's properties contain hazardous substance, these laws and regulations require PG&E Corporation and the Utility to remove those substances or to remedy effects on the environment. Also, in the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits. See Note 16 of the Notes to the Consolidated Financial Statements for further discussion of environmental matters and significant pending legal matters.

PG&E Corporation
CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per share amounts)	Year ended December 31,		
	2002	2001	2000
Operating Revenues			
Utility	$10,514	$10,462	$ 9,637
Energy commodities and services	1,981	1,748	2,931
Total operating revenues	12,495	12,210	12,568
Operating Expenses			
Cost of electricity and natural gas for utility	2,436	4,606	8,166
Deferred electric procurement cost	–	–	(6,465)
Cost of energy commodities and services	1,323	1,047	1,990
Depreciation, amortization, and decommissioning	1,309	1,002	3,595
Operating and maintenance	3,373	2,867	3,272
Impairments, write-offs, and other charges	2,767	–	–
Provision for loss on generation-related regulatory assets and under-collected purchased power costs	–	–	6,939
Reorganization professional fees and expenses	155	97	–
Total operating expenses	11,363	9,619	17,497
Operating Income (Loss)	1,132	2,591	(4,929)
Reorganization interest income	71	91	–
Interest income	61	76	214
Interest expense	(1,454)	(1,209)	(788)
Other income (expense), net	90	(31)	(23)
Income (Loss) Before Income Taxes	(100)	1,518	(5,526)
Income tax provision (benefit)	(43)	535	(2,103)
Income (Loss) from Continuing Operations	(57)	983	(3,423)
Discontinued Operations			
Earnings from operations of USGenNE, Mountain View, and ET Canada (net of income taxes of $3 million in 2002, $73 million in 2001, and $75 million in 2000)	11	107	99
Loss on disposal of USGenNE and ET Canada (net of income taxes of $381 million)	(767)	–	–
Loss on disposal of PG&E Energy Services (net of income taxes of $36 million)	–	–	(40)
Net Income (Loss) Before Cumulative Effect of Changes in Accounting Principles	(813)	1,090	(3,364)
Cumulative effect of changes in accounting principles (net of income taxes of $42 million in 2002 and $6 million in 2001)	(61)	9	–
Net Income (Loss)	$ (874)	$ 1,099	$ (3,364)
Weighted Average Common Shares Outstanding, Basic	371	363	362
Earnings (Loss) Per Common Share, from Continuing Operations, Basic	$ (0.15)	$ 2.71	$ (9.45)
Net Earnings (Loss) Per Common Share, Basic	$ (2.36)	$ 3.03	$ (9.29)
Earnings (Loss) Per Common Share, from Continuing Operations, Diluted	$ (0.15)	$ 2.70	$ (9.45)
Net Earnings (Loss) Per Common Share, Diluted	$ (2.36)	$ 3.02	$ (9.29)
Dividends Declared Per Common Share	$ –	$ –	$ 1.20

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED BALANCE SHEETS

(in millions)	Balance at December 31, 2002	2001
ASSETS		
Current Assets		
Cash and cash equivalents	$ 3,895	$ 5,355
Restricted cash	708	195
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $113 million and $89 million, respectively)	2,747	2,750
Regulatory balancing accounts	98	75
Price risk management	498	240
Inventories	347	383
Assets held for sale	707	744
Prepaid expenses and other	480	135
Total current assets	9,480	9,877
Property, Plant and Equipment		
Utility	27,045	25,963
Non-utility:		
Electric generation	636	961
Gas transmission	1,761	1,514
Construction work in progress	1,560	2,383
Other	177	195
Total property, plant and equipment	31,179	31,016
Accumulated depreciation and decommissioning	(14,251)	(13,615)
Net property, plant and equipment	16,928	17,401
Other Noncurrent Assets		
Regulatory assets	2,053	2,319
Nuclear decommissioning funds	1,335	1,337
Price risk management	398	363
Deferred income taxes	657	–
Assets held for sale	916	2,254
Other	1,929	2,412
Total other noncurrent assets	7,288	8,685
TOTAL ASSETS	$ 33,696	$ 35,963

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)	Balance at December 31, 2002	2001
LIABILITIES AND STOCKHOLDERS' EQUITY		
Liabilities Not Subject to Compromise		
Current Liabilities		
Short-term borrowings	$ –	$ 330
Debt in default	4,230	–
Long-term debt, classified as current	298	381
Current portion of rate reduction bonds	290	290
Accounts payable:		
Trade creditors	1,273	1,020
Regulatory balancing accounts	360	360
Other	660	530
Interest payable	139	26
Income taxes payable	129	610
Price risk management	506	152
Liabilities of operations held for sale	699	570
Other	685	696
Total current liabilities	9,269	4,965
Noncurrent Liabilities		
Long-term debt	4,345	7,222
Rate reduction bonds	1,160	1,450
Deferred income taxes	1,439	1,479
Deferred tax credits	144	153
Price risk management	305	385
Liabilities of operations held for sale	793	1,002
Other	2,963	2,999
Total noncurrent liabilities	11,149	14,690
Liabilities Subject to Compromise		
Financing debt	5,605	5,651
Trade creditors	3,580	5,555
Total liabilities subject to compromise	9,185	11,206
Commitments and Contingencies (Notes 1, 2, 3 and 16)	–	–
Preferred Stock of Subsidiaries	480	480
Utility Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures	–	300
Common Stockholders' Equity		
Common stock, no par value, authorized 800,000,000 shares, issued 405,486,015 and 387,898,848 shares, respectively	6,274	5,986
Common stock held by subsidiary, at cost, 23,815,500 shares	(690)	(690)
Accumulated deficit	(1,878)	(1,004)
Accumulated other comprehensive income (loss)	(93)	30
Total common stockholders' equity	3,613	4,322
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$33,696	$35,963

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	Year Ended December 31,		
	2002	2001	2000
Cash Flows from Operating Activities			
Net loss (income)	$ (874)	$ 1,099	$(3,364)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	1,309	1,002	3,595
Deferred electric procurement costs		–	(6,465)
Reversal of ISO accrual	(970)	–	–
Deferred income taxes and tax credits, net	(521)	(535)	(819)
Price risk management assets and liabilities, net	(142)	164	33
Other deferred charges and noncurrent liabilities	263	(744)	256
Provision for loss on generation-related regulatory assets and under-collected purchased power costs	–	–	6,939
Loss on impairment or disposal of assets	2,767	–	–
Loss from discontinued operations	1,148	–	40
Cumulative effect of change in accounting principle	61	(9)	–
Net effect of changes in operating assets and liabilities:			
Restricted cash	(513)	(66)	(6)
Accounts receivable	51	1,000	(1,941)
Inventories	36	(75)	68
Accounts payable	377	1,213	4,200
Accrued taxes	(481)	1,851	(1,452)
Regulatory balancing accounts, net	(23)	311	(410)
Payments authorized by the Bankruptcy Court on amounts classified as liabilities subject to compromises (Note 2)	(1,442)	(16)	–
Assets and liabilities of operations held for sale, net	34	(117)	64
Other working capital	(330)	(399)	331
Other, net	(216)	602	(314)
Net cash provided by operating activities	534	5,281	755
Cash Flows from Investing Activities			
Capital expenditures	(3,032)	(2,773)	(2,334)
Net proceeds from sales of businesses	–	–	415
Other, net	482	(103)	241
Net cash used by investing activities	(2,550)	(2,876)	(1,678)
Cash Flows from Financing Activities			
Net borrowings (repayments) under credit facilities	–	(1,148)	2,846
Long-term debt issued	2,414	3,008	1,659
Long-term debt matured, redeemed, or repurchased	(1,644)	(868)	(1,155)
Rate reduction bonds matured	(290)	(290)	–
Common stock issued	217	15	65
Common stock repurchased	–	(1)	(2)
Dividends paid	–	(109)	(436)
Other, net	(141)	(40)	23
Net cash provided by financing activities	556	567	3,000
Net change in cash and cash equivalents	(1,460)	2,972	2,077
Cash and cash equivalents at January 1	5,355	2,383	306
Cash and cash equivalents at December 31	$ 3,895	$ 5,355	$ 2,383
Supplemental disclosures of cash flow information			
Cash paid for:			
Interest (net of amounts capitalized)	$ 1,414	$ 579	$ 748
Income taxes paid (refunded), net	971	(692)	20
Supplemental disclosures of noncash investing and financing activities			
Retirement of long-term debt on the sale of PG&E Gas Transmission, Texas	–	–	564
Transfer of liabilities and other payables subject to compromise from operating assets and liabilities	419	11,400	–

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

(in millions, except share amounts)	Common Stock	Common Stock Held by Subsidiary	Reinvested Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholders' Equity	Comprehensive Income (Loss)
Balance at 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 at December 31, 2000	5,971	(690)	(2,105)	(4)	3,172	
Net income	–	–	1,099	–	1,099	$ 1,099
Cumulative effect of adoption of SFAS No. 133 and interpretations	–	–	–	(243)	(243)	(243)
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133	–	–	–	237	237	237
Net reclassification to earnings	–	–	–	42	42	42
Foreign currency translation adjustment	–	–	–	(1)	(1)	(1)
Other	–	–	–	(1)	(1)	(1)
Comprehensive income						$ 1,133
Common stock issued (739,158 shares)	16	–	–	–	16	
Common stock repurchased (34,037 shares)	(1)	–	–	–	(1)	
Other	–	–	2	–	2	
Balance at December 31, 2001	5,986	(690)	(1,004)	30	4,322	
Net loss	–	–	(874)	–	(874)	$ (874)
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133	–	–	–	(139)	(139)	(139)
Net reclassification to earnings	–	–	–	13	13	13
Foreign currency translation adjustment	–	–	–	2	2	2
Other	–	–	–	1	1	1
Comprehensive income						$ (997)
Common stock issued (17,582,636 shares)	217	–	–	–	217	
Other	71	–	–	–	71	
Balance at December 31, 2002	$6,274	$(690)	$(1,878)	$ (93)	$ 3,613	

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company, a Debtor-in-Possession
CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions)	Year Ended December 31, 2002	2001	2000
Operating Revenues			
Electric	$ 8,178	$ 7,326	$ 6,854
Natural gas	2,336	3,136	2,783
Total operating revenues	10,514	10,462	9,637
Operating Expenses			
Cost of electricity	1,482	2,774	6,741
Deferred electric procurement cost	–	–	(6,465)
Cost of natural gas	954	1,832	1,425
Operating and maintenance	2,817	2,385	2,687
Depreciation, amortization, and decommissioning	1,193	896	3,511
Provision for loss on generation-related regulatory assets and under-collected purchased power costs	–	–	6,939
Reorganization professional fees and expenses	155	97	–
Total operating expenses	6,601	7,984	14,838
Operating Income (Loss)	3,913	2,478	(5,201)
Reorganization interest income	71	91	–
Interest income	3	32	186
Interest expense (non-contractual interest of $149 million for 2002 and $164 million for 2001)	(988)	(974)	(619)
Other income (expense), net	(2)	(16)	(3)
Income (Loss) Before Income Taxes	2,997	1,611	(5,637)
Income tax provision (benefit)	1,178	596	(2,154)
Net Income (Loss)	1,819	1,015	(3,483)
Preferred dividend requirement	25	25	25
Income (Loss) Available for (Allocated to) Common Stock	$ 1,794	$ 990	$(3,508)

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company, a Debtor-in-Possession
CONSOLIDATED BALANCE SHEETS

(in millions)	Balance at December 31, 2002	2001
ASSETS		
Current Assets		
Cash and cash equivalents	$ 3,343	$ 4,341
Restricted cash	150	53
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $59 million and $48 million, respectively)	1,900	2,063
Related parties	17	18
Regulatory balancing accounts	98	75
Inventories:		
Gas stored underground and fuel oil	154	218
Materials and supplies	121	119
Income taxes receivable	50	–
Prepaid expenses	110	80
Deferred income taxes	5	–
Total current assets	5,948	6,967
Property, Plant and Equipment		
Electric	18,922	18,153
Gas	8,123	7,810
Construction work in progress	427	323
Total property, plant and equipment (at original cost)	27,472	26,286
Accumulated depreciation and decommissioning	(13,515)	(12,929)
Net property, plant and equipment	13,957	13,357
Other Noncurrent Assets		
Regulatory assets	2,011	2,283
Nuclear decommissioning funds	1,335	1,337
Other	1,300	1,325
Total other noncurrent assets	4,646	4,945
TOTAL ASSETS	$ 24,551	$ 25,269

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company, a Debtor-in-Possession
CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)	Balance at December 31, 2002	2001
LIABILITIES AND STOCKHOLDERS' EQUITY		
Liabilities Not Subject to Compromise		
Current Liabilities		
Long-term debt, classified as current	$ 281	$ 333
Current portion of rate reduction bonds	290	290
Accounts payable:		
Trade creditors	380	333
Related parties	130	86
Regulatory balancing accounts	360	360
Other	374	289
Interest payable	126	26
Income taxes payable	-	295
Deferred income taxes	-	65
Other	625	599
Total current liabilities	2,566	2,676
Noncurrent Liabilities		
Long-term debt	2,739	3,019
Rate reduction bonds	1,160	1,450
Regulatory liabilities	1,461	1,485
Deferred income taxes	1,485	1,028
Deferred tax credits	144	153
Other	1,274	1,239
Total noncurrent liabilities	8,263	8,374
Liabilities Subject to Compromise		
Financing debt	5,605	5,651
Trade creditors	3,786	5,733
Total liabilities subject to compromise	9,391	11,384
Commitments and Contingencies (Notes 1, 2, and 16)	-	-
Preferred Stock With Mandatory Redemption Provisions		
6.30% and 6.57%, outstanding 5,500,000 shares, due 2002-2009	137	137
Company Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures		
7.90%, 12,000,000 shares, due 2025	-	300
Stockholders' Equity		
Preferred stock without mandatory redemption provisions		
Nonredeemable, 5% to 6%, outstanding 5,784,825 shares	145	145
Redeemable, 4.36% to 7.04%, outstanding 5,973,456 shares	149	149
Common stock, $5 par value, authorized 800,000,000 shares, issued 321,314,760 shares	1,606	1,606
Common stock held by subsidiary, at cost, 19,481,213 shares	(475)	(475)
Additional paid-in capital	1,964	1,964
Reinvested earnings (accumulated deficit)	805	(989)
Accumulated other comprehensive income (loss)	-	(2)
Total stockholders' equity	4,194	2,398
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$24,551	$25,269

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company, a Debtor-in-Possession
CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	Year Ended December 31,		
	2002	**2001**	**2000**
Cash Flows from Operating Activities			
Net income (loss)	$ 1,819	$ 1,015	$(3,483)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Deferred electric procurement costs	-	-	(6,465)
Depreciation, amortization, and decommissioning	1,193	896	3,511
Deferred income taxes and tax credits, net	378	(306)	(930)
Other deferred charges and noncurrent liabilities	102	(954)	480
Reversal of ISO accrual (Note 2)	(970)	-	-
Provision for loss on generation-related regulatory assets and under-collected purchased power costs	-	-	6,939
Net effect of changes in operating assets and liabilities:			
Restricted cash	(97)	(3)	(8)
Accounts receivable	212	105	(507)
Income tax receivable	(50)	1,120	(1,120)
Inventories	62	(57)	14
Accounts payable	198	1,312	3,063
Income taxes payable	(295)	295	(118)
Regulatory balancing accounts, net	(23)	311	(410)
Payments authorized by the Bankruptcy Court on amounts classified as liabilities subject to compromise (Note 2)	(1,442)	(16)	-
Other working capital	11	711	111
Other, net	36	336	(522)
Net cash provided by operating activities	1,134	4,765	555
Cash Flows from Investing Activities			
Capital expenditures	(1,546)	(1,343)	(1,245)
Proceeds from sale of assets	11	-	6
Other, net	26	5	32
Net cash used by investing activities	(1,509)	(1,338)	(1,207)
Cash Flows from Financing Activities			
Net (repayments) borrowings under credit facilities and short-term borrowings	-	(28)	2,630
Long-term debt issued	-	-	680
Long-term debt matured, redeemed, or repurchased	(333)	(111)	(307)
Rate reduction bonds matured	(290)	(290)	(290)
Common stock repurchased	-	-	(275)
Dividends paid	-	-	(475)
Other, net	-	(1)	(26)
Net cash provided (used) by financing activities	(623)	(430)	1,937
Net change in cash and cash equivalents	(998)	2,997	1,285
Cash and cash equivalents at January 1	4,341	1,344	59
Cash and cash equivalents at December 31	$ 3,343	$ 4,341	$ 1,344
Supplemental disclosures of cash flow information			
Cash received for:			
Reorganization interest income	$ 75	$ 87	$ -
Cash paid for:			
Interest (net of amounts capitalized)	1,105	361	587
Income taxes (net of refunds)	1,186	(556)	-
Reorganization professional fees and expenses	99	19	-
Supplemental disclosures of noncash investing and financing activities			
Transfer of liabilities and other payables subject to compromise from operating assets and liabilities, net	419	11,400	-

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company, a Debtor-in-Possession
CONSOLIDATED STATEMENTS OF 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 Income (Loss)	Total Common Stockholders' Equity	Preferred Stock Without Mandatory Redemption Provisions	Comprehensive Income (Loss)
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	
Net Income	–	–	–	1,015	–	1,015	–	$ 1,015
Cumulative effect of adoption of SFAS No. 133	–	–	–	–	90	90	–	90
Mark-to-market adjustments for hedging	–	–	–	–	(5)	(5)	–	(5)
Net reclassification to earnings	–	–	–	–	(85)	(85)	–	(85)
Foreign currency translation adjustments	–	–	–	–	(2)	(2)	–	(2)
Comprehensive income								$ 1,013
Preferred stock dividend requirement	–	–	–	(25)	–	(25)	–	
Balance December 31, 2001	1,606	1,964	(475)	(989)	(2)	2,104	294	
Net Income	–	–	–	1,819	–	1,819	–	$ 1,819
Foreign currency translation adjustments	–	–	–	–	2	2	–	2
Comprehensive income								$ 1,821
Preferred stock dividend	–	–	–	(25)	–	(25)		
Balance December 31, 2002	$1,606	$1,964	$(475)	$ 805	$ –	$ 3,900	$294	

See accompanying Notes to the Consolidated Financial Statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1: GENERAL

Organization and Basis of Presentation

PG&E Corporation, incorporated in California in 1995, is an energy-based holding company headquartered in San Francisco, California. PG&E Corporation conducts its business through various subsidiaries, principally Pacific Gas and Electric Company (the Utility), an operating regulated electric and natural gas distribution and transmission utility company, and PG&E National Energy Group, Inc. (PG&E NEG), a power generation, wholesale energy marketing and trading, risk management, and natural gas transmission company.

The Consolidated Financial Statements of PG&E Corporation and of the Utility have been prepared on a going concern basis, which contemplates continuity of operations, realization of assets and repayment of liabilities in the ordinary course of business. However, as a result of the bankruptcy of the Utility and current liquidity concerns at PG&E NEG and its subsidiaries, as further discussed below, such realization of assets and liquidation of liabilities are subject to uncertainty.

Consolidation Policy

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 (GAAP) 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. As these estimates involve judgments on a wide range of factors, including future economic conditions, that are difficult to predict, actual results could differ significantly 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).

Nature of Operations

The Utility, incorporated in California in 1905, provides electric service to approximately 4.8 million customers and natural gas service to approximately 4.0 million customers in Northern and Central California. Effective January 1, 1997, PG&E Corporation became the holding company of the Utility and its subsidiaries. The Utility is the predecessor of PG&E Corporation.

PG&E NEG, incorporated on December 18, 1998, as a wholly owned subsidiary of PG&E Corporation (shortly thereafter, PG&E Corporation contributed various subsidiaries to PG&E NEG). The main subsidiaries of PG&E NEG include the following:

- PG&E Generating Company, LLC and its subsidiaries (collectively, PG&E Gen LLC);
- PG&E Energy Trading Holdings Corporation and its subsidiaries (collectively, PG&E Energy Trading or PG&E ET);
- PG&E Gas Transmission Corporation and its subsidiaries (collectively, PG&E GTC), which includes PG&E Gas Transmission, Northwest Corporation and its subsidiaries, including North Baja Pipeline, LLC (NBP) (collectively, PG&E GTN).

PG&E NEG also has other less significant subsidiaries.

PG&E National Energy Group, LLC owns 100 percent of the stock of PG&E NEG, GTN Holdings LLC owns 100 percent of the stock of PG&E GTN, and PG&E Energy Trading Holdings LLC owns 100 percent of the stock of PG&E ET. The organizational documents of PG&E NEG and these limited liability companies require unanimous approval of their respective boards of directors, including at least one independent director, before they can:

- Consolidate or merge with any entity;
- Transfer substantially all of their assets to any entity; or
- Institute or consent to bankruptcy, insolvency or similar proceedings or actions.

The limited liability companies may not declare or pay dividends unless the respective boards of directors have unanimously approved such action, and the company meets specified financial requirements.

Bankruptcy of the Utility

As discussed further in Note 2, on April 6, 2001, the Utility filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code (Bankruptcy Code) in the United States Bankruptcy Court for the Northern District of California (Bankruptcy Court). Under Chapter 11, the Utility continues to control its assets and is allowed to operate its business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court.

Due to the Utility's Chapter 11 filing, the financial statements for both PG&E Corporation and the Utility are prepared in accordance with the American Institute of Certified Public Accountants' Statement of Position (SOP) 90-7, which is applied by reorganizing entities operating under the bankruptcy code. Under SOP 90-7, certain liabilities of the Utility existing prior to its bankruptcy filing are classified as Liabilities Subject to Compromise. Additionally, professional fees and expenses directly related to the Chapter 11 proceeding and interest income on funds accumulated during the bankruptcy are reported separately as reorganization items. Finally, the extent to which the Utility's reported interest expense differs from its stated contractual interest is disclosed on the Consolidated Statements of Operations.

PG&E NEG

The Consolidated Financial Statements have been prepared on a going concern basis, which contemplates continuity of operations, realization of assets and repayment of liabilities in the ordinary course of business. However, as a result of current liquidity concerns at PG&E NEG and its subsidiaries and restructuring discussions with their lenders, such realization of assets and liquidation of liabilities are subject to uncertainty.

As a result of the sustained downturn in the power industry, PG&E NEG and its affiliates have experienced a financial downturn which caused the major credit rating agencies to downgrade PG&E NEG's and its affiliates' credit ratings to below investment-grade. PG&E NEG is currently in default under various recourse debt agreements and guaranteed equity commitments totaling approximately $2.9 billion. In addition, other PG&E NEG subsidiaries are in default under various debt agreements totaling $2.5 billion, but this debt is non-recourse to PG&E NEG. PG&E NEG, its subsidiaries and their lenders are engaged in discussions to restructure PG&E NEG's and its subsidiaries debt obligations and other commitments. PG&E NEG and certain subsidiaries have significantly reduced their energy trading operations. These asset transfers, sales, and abandonments have caused substantial charges to earnings in 2002 of approximately $3.9 billion. PG&E NEG and its subsidiaries are continuing these efforts to abandon, sell or transfer additional assets in an ongoing effort to raise cash, reduce debt, whether through negotiation with lenders or otherwise. As a result, PG&E expects to incur additional substantial charges in 2003 as it restructures operations. If a restructuring agreement is not reached and the lenders exercise their default remedies or if the financial obligations and commitments are not restructured, PG&E NEG and certain of its subsidiaries may be compelled to seek protection under or be forced involuntarily into proceedings under the Bankruptcy Code.

Earnings (Loss) Per Share

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

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

(in millions, except per share amounts)	Year ended December 31,		
	2002	2001	2000
Income (loss) from continuing operations	$ (57)	$ 983	$ (3,423)
Discontinued operations	(756)	107	59
Net income (loss) before cumulative effect of accounting change	(813)	1,090	(3,364)
Cumulative effect of accounting change	(61)	9	-
Net Income (loss)	$ (874)	$1,099	$ (3,364)
Weighted average common shares outstanding, basic	371	363	362
Add: Employee Stock Options and PG&E Corporation shares held by grantor trusts	-	1	-
Shares outstanding for diluted calculations	371	364	362
Earnings (Loss) Per Common Share, Basic			
Income (loss) from continuing operations	$(0.15)	$ 2.71	$ (9.45)
Discontinued operations	(2.04)	0.29	0.16
Cumulative effect of change in accounting principle	(0.17)	0.02	-
Rounding	-	0.01	-
Net earnings (loss)	$(2.36)	$ 3.03	$ (9.29)

(in millions, except per share amounts)	Year ended December 31,		
	2002	2001	2000
Earnings (Loss) Per Common Share, Diluted			
Income (loss) from continuing operations	$(0.15)	$ 2.70	$ (9.45)
Discontinued operations	(2.04)	0.29	0.16
Cumulative effect of change in accounting principle	(0.17)	0.02	-
Rounding	-	0.01	-
Net earnings (loss)	$(2.36)	$ 3.02	$ (9.29)

The diluted earnings per share for the year ended December 31, 2002, excludes approximately two million incremental shares related to employee stock options and shares held by grantor trusts, two million incremental shares related to warrants, and ten million incremental shares related to the 9.5 percent Convertible Subordinated Notes and includes associated interest expense of $8 million (net of income tax of $5 million) due to the antidilutive effect upon loss from continuing operations. In addition, the diluted share base for the year ended December 31, 2000, excludes two million incremental shares related to employee stock options and shares held by grantor trusts to secure deferred compensation obligations due to the antidilutive effect upon loss from continuing operations.

PG&E Corporation reflects the preferred dividends of subsidiaries as other expense which is used to calculate both basic and diluted earnings per share.

Summary of Significant Accounting Policies

Adoption of New Accounting Policies

Consolidation of Variable Interest Entities – In January 2003 the Financial Accounting Standards Board (FASB) issued Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46), which expands upon existing accounting guidance addressing when a company should include in its financial statements the assets, liabilities, and activities of another entity. FIN 46 notes that many of what are now referred to as "variable interest entities" have commonly been referred to as special-purpose entities or off-balance sheet structures. However, the Interpretation's guidance is to be applied to not only these entities but to all entities found within a company. FIN 46 provides some general guidance as to the definition of a variable interest entity. PG&E Corporation is currently evaluating all entities to determine if they meet the FIN 46 criteria as variable interest entities.

Until the issuance of FIN 46, one company generally included another entity in its Consolidated Financial Statements only if it controlled the entity through voting interests. FIN 46 changes that by requiring a variable interest entity to be consolidated by a company if that company is subject to a majority of the risk of loss from the variable interest entity's activities or entitled to receive a majority of the entity's residual returns, or both. A company that consolidates a variable interest entity is now referred to as the "primary beneficiary" of that entity.

FIN 46 requires disclosure of variable interest entities that the company is not required to consolidate but in which it has a significant variable interest.

The consolidation requirements of FIN 46 apply immediately to variable interest entities created after January 31, 2003. The consolidation requirements apply to variable interest entities created before January 31, 2003, in the first fiscal year or interim period beginning after June 15, 2003, so these requirements would be applicable to PG&E Corporation in the third quarter 2003. Certain new and expanded disclosure requirements apply to all financial statements issued after January 31, 2003, regardless of when the variable interest entity was established. These disclosures are required if there is an assessment that it is reasonably possible that an enterprise will consolidate or disclose information about a variable interest entity when FIN 46 becomes effective. PG&E Corporation is currently evaluating the impacts of FIN 46's initial recognition, measurement, and disclosure provisions on its Consolidated Financial Statements.

Guarantor's Accounting and Disclosure Requirements for Guarantees – In November 2002, the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). FIN 45 expands on the accounting guidance of Statement of Financial Accounting Standards (SFAS) No. 5, "Accounting for Contingencies," SFAS No. 57, "Related Party Disclosures," and SFAS No. 107, "Disclosures about Fair Value of Financial Instruments." FIN 45 also incorporates, without change, the provisions of FASB Interpretation No. 34, "Disclosures of Indirect Guarantees of the Indebtedness of Others," which it supersedes.

FIN 45 elaborates on the existing disclosure requirements for most guarantees. It clarifies that a guarantor's required disclosures include the nature of the guarantee, the maximum potential undiscounted payments that could be required, the current carrying amount of the liability, if any, for the guarantor's obligations (including the liability recognized under SFAS No. 5), and the nature of any recourse provisions or available collateral that would enable the guarantor to recover amounts paid under the guarantee.

FIN 45 also clarifies that at the time a company issues a guarantee, it must recognize an initial liability for the fair value of the obligation it assumes under that guarantee, including its ongoing obligation to stand ready to perform over the term of the guarantee in the event that specified triggering events or conditions occur.

This information must also be disclosed in interim and annual financial statements.

FIN 45 does not prescribe a specific account for the guarantor's offsetting entry when it recognizes the liability at the inception of the guarantee, noting that the offsetting entry would depend on the circumstances in which the guarantee was issued. There also is no prescribed approach included for subsequently measuring the guarantor's recognized liability over the term of the related guarantee. It is noted that the liability would typically be reduced by a credit to earnings as the guarantor is released from risk under the guarantee.

The initial recognition and initial measurement provisions apply on a prospective basis to guarantees issued or modified after December 31, 2002. PG&E Corporation is currently evaluating the impact of FIN 45's initial recognition and measurement provisions on its Consolidated Financial Statements. The disclosure requirements for FIN 45 are effective for financial statements of interim or annual periods ending after December 15, 2002, and have been incorporated into PG&E Corporation's December 31, 2002, disclosures of guarantees in these footnotes.

Accounting for Stock-Based Compensation – Transition and Disclosures – On December 31, 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosures, an Amendment of FASB Statement No. 123." This Statement provides alternative methods of transition for companies who voluntarily change to the fair value-based method of accounting for stock-based employee compensation in accordance to SFAS No. 123, "Accounting for Stock-Based Compensation." SFAS No. 148 does not permit the use of the original SFAS No. 123 prospective method of transition for changes to the fair value based method made in fiscal years beginning after December 15, 2003. The Statement also requires prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based compensation and the effect of the method used on reported results. This Statement is effective upon its issuance.

PG&E Corporation continues to account for stock-based compensation using the intrinsic value method in accordance with the provisions of Accounting Principles Board Opinion (APB) No. 25, "Accounting for Stock Issued to Employees," elected under SFAS No. 123, as amended. As a result, the adoption of this Statement did not have any impact on the Consolidated Financial Statements of PG&E Corporation or the Utility.

Please refer to the Stock-Based Compensation section of this Note 1 for additional information.

Change from Gross to Net Method of Reporting Revenues and Expenses on Trading Activities – Effective for the quarter ended September 30, 2002, PG&E Corporation changed its method of reporting gains and losses associated with energy trading contracts from the gross method of presentation to the net method. PG&E Corporation believes that the net method provides a more accurate and consistent presentation of energy trading activities on the financial statements. Amounts to be presented under the net method include all gross margin elements related to energy trading activities, including both unrealized and realized trades and both physical and financial trades.

Before implementation of the net method, PG&E Corporation already had reported unrealized gains and losses on trading activities on a net basis in operating revenues. However, PG&E Corporation had reported realized gains and losses on a gross basis in operating income, as both operating revenues and costs of commodity sales and fuel. PG&E Corporation is now reporting all gains and losses from trading activities, including amounts that are realized, on a net basis as operating revenues. This will provide greater consistency in reporting the results of all energy trading activities. All prior year financial statements have been reclassified to conform to the net method.

Implementation of the net method has no net effect on gross margin, operating income, or net income. Accordingly, PG&E Corporation continues to report realized income from non-trading activities on a gross basis in operating revenues and operating expenses. The schedule below summarizes the amounts impacted by the change in methodology on PG&E Corporation's Consolidated Statements of Operations for the years ended December 31, 2001 and 2000.

(in millions)	Prior Method of Presentation (Gross Method)		As Presented (Net Method)	
	2001	2000	2001	2000
Energy commodities and services[1]	$11,647	$15,809	$1,841	$3,062
Cost of energy commodities and services[2]	11,026	14,933	1,220	2,186
Net subtotal	$ 621	$ 876	$ 621	$ 876

[1] These amounts, as presented in the net method, differ from the financial statements due to the exclusion of equity earnings in affiliates, and eliminations and other, which amounted to net charges of $93 million and $131 million at December 31, 2001, and 2000, respectively.

[2] These amounts, as presented in the net method, differ from the financial statements due to the exclusion of eliminations and other, which amounted to net charges of $172 million and $196 million at December 31, 2001, and 2000, respectively.

Rescission of EITF 98 - 10 – In October 2002, the Emerging Issues Task Force (EITF) rescinded EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." Energy trading contracts that are derivatives in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities" (collectively, SFAS No. 133), will continue to be accounted for at fair value under SFAS No. 133. Contracts that were previously marked to market as trading activities under EITF 98-10 that do not meet the definition of a derivative will be recorded at cost, with a one-time adjustment to be recorded as a cumulative effect of a change in accounting principle as of January 1, 2003. For PG&E Corporation, the majority of trading contracts are derivative instruments as defined in SFAS No. 133. The rescission of EITF 98-10 has no effect on the accounting for derivative instruments used for non-trading purposes, which continue to be accounted for in accordance with SFAS No. 133.

The reporting requirements associated with the rescission of EITF 98-10 are to be applied prospectively for all EITF 98-10 energy trading contracts entered into after October 25, 2002. For all EITF 98-10 energy trading contracts in existence at or prior to October 25, 2002, the estimated impact of the first quarter 2003 cumulative effect of a change in accounting principle is a loss of $5 million, net of taxes at December 31, 2002.

Change in Estimate Due to Changes in Certain Fair Value Assumptions – PG&E Corporation estimates the gross mark-to-market value of its trading contracts and certain non-trading contracts using forward curves. The forward curves used to calculate mark-to-market value have liquid periods (includes continuous maturities starting from the month for which broker quotes are available on a daily basis) and illiquid periods (includes those maturities for which broker quotes are not readily available). When market data is not available, PG&E Corporation historically has utilized alternative pricing methodologies, including third-party pricing curves, the extrapolation of forward pricing curves using historically reported data, and interpolation between existing data points. The gross mark-to-market valuation is then adjusted for time value of money, creditworthiness of contractual counterparties, market liquidity in future periods, and other adjustments necessary to determine fair value. For trading activities, these models are used to estimate the fair value of long-term transactions including certain tolling agreements. For non-trading activities, these models are used to estimate the fair value of certain derivative contracts accounted for as cash flow hedges or at fair value through earnings under SFAS No. 133.

Beginning in the third quarter of 2002, PG&E Corporation implemented a new model for projecting forward power and gas prices during illiquid periods. This new process primarily impacts the estimation of power prices. The model estimates forward power prices in illiquid periods using the mid-point of the marginal cost curve (the lowest variable cost of generation available in a particular region) and the forecast curve (the price at which a generation unit will recover its capital costs and a return on investment). Assumptions about cost recovery are combined with assumptions about volatility and correlation in an option model to project forward power prices. Interpolation methods continue to be used for intermediate periods when broker quotes are intermittent. In addition to implementing the new process for projecting forward power prices in illiquid periods, PG&E Corporation also enhanced its models to better incorporate certain physical characteristics of its power plants, and to account for uncertainties surrounding projected forward prices, volumetric assumptions, and modeling complexity. PG&E Corporation also refined its process for estimating the bid-ask spread in illiquid periods for purposes of liquidity adjustments.

All of these changes in fair values are being accounted for on a prospective basis as a change in accounting estimate. The change in fair values had a pre-tax income effect of a $14 million loss from trading activities and a pre-tax gain of $25 million from non-trading activities. These income effects, totaling a pre-tax gain of $11 million for both trading and non-trading activities, were recognized in the quarter ended September 30, 2002.

Accounting for Gains and Losses on Debt Extinguishment and Certain Lease Modifications – On July 1, 2002, PG&E Corporation adopted SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections." This Statement eliminates the current requirement that gains and losses on debt extinguishment be classified as extraordinary items. Instead, such gains and losses will generally be classified as interest expense. During 2002, PG&E Corporation recorded $115 million of debt extinguishment losses as a charge to interest expense relating to note prepayments and ratings waiver extensions.

In addition, SFAS No. 145 eliminates an inconsistency in lease accounting by requiring that modifications of capital leases that result in reclassification as operating leases be accounted for consistently with sale-leaseback accounting rules. This provision did not have any impact on the Consolidated Financial Statements of PG&E Corporation or the Utility at the date of adoption.

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

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

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

The cumulative effect of the change in accounting principle for DIG C15 and C16 was a net charge of $61 million, after-tax, and included the recognition of the fair market value of the five contracts impacted by DIG C15 and C16 and the impairment charge for the equity method investment. The Utility was not impacted by these accounting changes.

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

Accounting for the Impairment or Disposal of Long-Lived Assets – On January 1, 2002, PG&E Corporation adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS No. 144 supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of," but retains its fundamental provision for recognizing and measuring impairment of long-lived assets to be held and used. This Statement requires that all long-lived assets to be disposed of by sale be carried at the lower of carrying amount or fair value less cost to sell, and that depreciation cease to be recorded on such assets. SFAS No. 144 standardizes the accounting and presentation requirements for all long-lived assets to be disposed of by sale, and supersedes previous guidance for discontinued operations of business segments. The initial adoption of this Statement at January 1, 2002, did not have any impact on the Consolidated Financial Statements of PG&E NEG. During 2002, PG&E NEG recorded certain impairment charges in accordance with SFAS No. 144 (see Note 6, "Discontinued Operations" and Note 7, "Impairments, Write-offs, and Other Charges").

Accounting for Goodwill and Other Intangible Assets – On January 1, 2002, PG&E Corporation adopted SFAS No. 142, "Goodwill and Other Intangible Assets." This Statement eliminates the amortization of goodwill and requires that goodwill be reviewed at least annually for impairment. Upon implementation of this Statement, the transition impairment test for goodwill was performed as of January 1, 2002, and no impairment loss was recorded. Goodwill amortization expense was $5 million in 2001 and 2000. During 2002, PG&E NEG recorded a charge for impairment of goodwill in accordance with SFAS No. 142 (see Note 7, Impairment, Write-offs, and Other Charges). The Utility had no goodwill on its balance sheet at December 31, 2002, or December 31, 2001.

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

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

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

(in millions)	Balance at December 31,			
	2002		2001	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
PG&E NEG:				
Service agreements	$ 33	$ 7	$ 33	$ 6
Power sale agreements	14	9	25	8
Other agreements	12	6	17	5
Utility:				
Hydro licenses and other agreements	67	16	66	14
PG&E Corporation Consolidated	$126	$38	$141	$33

PG&E NEG's amortization expense on intangible assets was $7 million in 2002, $3 million in 2001, and $4 million in 2000. The Utility's amortization expense of intangible assets was $3 million in 2002, $2 million in 2001, and $2 million in 2000.

The following schedule shows the estimated amortization expenses for intangible assets for full years 2003 through 2007.

(in millions)	2003	2004	2005	2006	2007
PG&E NEG	$4	$3	$3	$3	$3
Utility	$3	$3	$3	$3	$3

Accounting for Asset Retirement Obligations – In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." PG&E Corporation and the Utility will adopt this Statement effective January 1, 2003. SFAS No. 143 provides accounting requirements for costs associated with legal obligations to retire tangible, long-lived assets. Under the Statement, the asset retirement obligation is recorded at fair value in the period in which it is incurred by increasing the carrying amount of the related long-lived asset. In each subsequent period, the liability is accreted to its present value and the capitalized cost is depreciated over the useful life of the related asset. Upon adoption, the cumulative effect of applying this Statement will be recognized as a change in accounting principle in the Consolidated Statements of Operations. However, rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with this statement and costs recovered through the ratemaking process. Regulatory assets and liabilities may be recorded when it is probable that the asset retirement costs will be recovered through the ratemaking process.

PG&E Corporation estimates the impact of adopting SFAS No. 143 effective January 1, 2003, will be as follows:

- The Utility will adjust its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. The Utility will also recognize asset retirement obligations associated with the decommissioning of other fossil generation assets.

  At December 31, 2002, the total nuclear decommissioning obligation accrued was $1.3 billion and is included in accumulated depreciation and decommissioning on the Consolidated Balance Sheets (see Note 13, "Nuclear Decommissioning"). The Utility has accrued, at December 31, 2002, $52 million to decommission certain fossil generation assets based on its estimate of the decommissioning obligation under the accounting principles in effect at that time. These decommissioning obligations are also included in accumulated depreciation and decommissioning on the Consolidated Balance Sheets.

  The Utility estimates it will recognize an adjustment to its recorded nuclear and fossil facility decommissioning obligations in the range of an increase of $222 million to a decrease of $192 million for asset retirement obligations in existence as of January 1, 2003. The estimated cumulative effect of a change in accounting principle from unrecognized accretion expense and adjustments to depreciation and decommissioning expense accrued to date will range from a loss of $19 million to a gain of $17 million (pre-tax).

- PG&E NEG estimates that it will recognize a liability in the range of $11 million to $21 million for asset retirement obligations on January 1, 2003. The cumulative effect of a change in accounting principle from unrecognized accretion and depreciation expense is estimated to be a loss in the range of $4 million to $6 million (pre-tax). The impact to PG&E NEG of implementing SFAS No. 143 by its unconsolidated affiliates is expected to be immaterial.

Cash and Cash Equivalents

Invested cash and other investments with original maturities of three months or less are considered cash equivalents. Cash equivalents are stated at cost, which approximates fair value. PG&E Corporation's and the Utility's cash equivalents are held in a variety of funds that mainly invest in:

- Certificates of deposit and time deposits;
- Bankers' acceptances and other short-term securities issued by banks;
- Asset-backed securities;
- Repurchase agreements;
- High-grade commercial paper; and
- Discounted notes issued or guaranteed by the United States government or its agencies.

In general, the securities are purchased on the date of issue and held in the accounts until maturity. Substantially all of PG&E Corporation's and the Utility's cash equivalents on hand at December 31, 2002, have matured and have been reinvested.

At December 31, 2002, two funds held balances greater than 10 percent of PG&E Corporation's and the Utility's cash and cash equivalents balance. They were the Citifunds Institutional Liquid Reserves Fund and the Fiduciary Trust Company International.

Restricted Cash

Restricted cash includes cash and cash equivalents, as defined above, which are (1) restricted under the terms of certain agreements for payment to third parties, and (2) held in escrow as collateral required by the California Independent System Operator (ISO) and other counterparties.

Inventories

Inventories include materials and supplies, gas stored underground, coal, and fuel oil. Materials, supplies, and gas stored underground are valued at average cost. Coal and fuel oil are valued using the last-in first-out method. PG&E ET's natural gas inventory is valued at cost as discussed in Note 1, Recission of EITF 98-10.

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. Investment tax credits are amortized over the life of the related property. Other tax credits, primarily synthetic fuel tax credits, are recognized in income as earned.

PG&E Corporation files a consolidated U.S. (federal) income tax return that includes domestic subsidiaries in which its ownership is 80 percent or more. In addition, PG&E Corporation files combined state income tax returns where applicable. PG&E Corporation and the Utility are parties to a tax-sharing arrangement under which the Utility determines its income tax provision (benefit) on a stand-alone basis.

PG&E NEG is included in the consolidated tax return of PG&E Corporation. Certain creditors of PG&E NEG have asserted that past payments from tax benefits gave rise to an implied tax sharing agreement between PG&E Corporation and PG&E NEG. PG&E Corporation disputes this assertion.

Property, Plant and Equipment

Property, Plant and Equipment are reported at its original cost, unless impaired under the provisions of SAFS No. 144. Original costs include:

- Labor and 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 that is allowed to be recorded as part of the costs of construction projects. AFUDC is recoverable from customers through rates once the property is placed in service.

Capitalized Interest and AFUDC

(in millions)	Year ended December 31,		
	2002	2001	2000
PG&E Corporation	$42	$22	$19
Utility	27	18	18

PG&E Corporation and the Utility periodically evaluate long-lived assets, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of these assets may be impaired.

PG&E Corporation charged the original cost of retired plant and removal costs less salvage value to accumulated depreciation upon retirement of plant in service for the Utility and for PG&E NEG's lines of business that apply SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," as amended. For the remainder of PG&E NEG business operations, the cost and accumulated depreciation of property, plant and equipment retired or otherwise disposed of from related accounts are included in the amounts in the determination of the gain or loss on disposition.

Depreciation

Property, plant and equipment are depreciated on a straight-line basis over estimated useful lives, less any residual or salvage value.

Composite depreciation rates	Year ended December 31,		
	2002	2001	2000
PG&E Corporation	3.36%	3.07%	4.49%
Utility	3.42%	3.63%	4.54%

Estimated useful lives	Utility	PG&E NEG
Electric generating facilities	15 to 50 years	20 to 50 years
Electric distribution facilities	16 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	15 to 40 years
Gas storage	25 to 48 years	N/A
Other	5 to 40 years	2 to 20 years

The useful lives of the Utility's property, plant and equipment are authorized by the CPUC. Depreciation rates include a component for the cost of asset retirement net of salvage value. The Utility has a separate rate component for the accrual of its recorded obligation for nuclear decommissioning which is included in depreciation, amortization, and decommissioning expense in the accompanying Consolidated Statements of Operations. The accrued net asset retirement obligation is included in accumulated depreciation and decommissioning in the accompanying Consolidated Balance Sheets.

Refer to the section "Accounting for the Impairment or Disposal of Long-Lived Assets" in this Note and Note 7 "Impairment, Write-offs, and Other Charges" for a discussion of impairment and the effect on Property, Plant and Equipment.

Nuclear Fuel

Property, plant and equipment includes nuclear fuel inventories. Stored nuclear fuel inventory is stated at weighted average cost. Nuclear fuel in the reactor is amortized based on the amount of energy output.

Capitalized Software Costs

PG&E Corporation capitalizes costs incurred during the application development stage of internal use software projects to property, plant and equipment. Capitalized software costs totaled $349 million at December 31, 2002, and $269 million at December 31, 2001, net of accumulated amortization of $154 million at December 31, 2002, and $112 million at December 31, 2001. PG&E Corporation amortizes capitalized software costs ratably over the expected lives of the projects ranging from 3 to 15 years, commencing operational use, in accordance with regulatory requirements.

Gains and Losses on Debt Extinguishments

Gains and losses on debt extinguishments 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 debt extinguishments associated with unregulated operations are recognized at the time such debt is reacquired, and upon adoption of SFAS No. 145 on July 1, 2002 are reported as interest expense unless they were determined to be unusual and infrequent, in which case they would be reported as extraordinary gains or losses.

Fair Value of Financial Instruments

The fair value of a financial instrument represents the amount at which the instrument could be exchanged in a current transaction between willing parties, other than in a forced sale or liquidation. Significant differences can occur between the fair value and carrying amount of financial instruments that are recorded at historical amounts.

PG&E Corporation used the following methods and assumptions in estimating fair value disclosures for financial instruments:

- The fair values of cash and cash equivalents, restricted cash and deposits, net accounts receivable, short-term borrowings, debt in default, and accounts payable, approximate their carrying values as of December 31, 2002, and 2001;
- The fair value of the Utility's debt, for which no market quotations are readily available, is obtained from third-party experts with extensive experience in the fair valuation of such instruments. The fair value of a small portion of the Utility's debt is determined using the present value of future cash flows; and
- The fair values of nuclear decommissioning funds, rate reduction bonds, the Utility's preferred stock, and the Utility's 7.90 percent deferrable interest subordinated debentures are determined based on quoted market prices.

Due to the illiquid nature and limited demand for PG&E NEG's long-term debt, the estimated fair value at December 31, 2002, was not able to be determined. At December 31, 2001, PG&E NEG's long-term receivables had a carrying value of $536 million and estimated fair value of $467 million. At December 31, 2001, PG&E NEG's long-term debt had a carrying value of $3.4 billion and an estimated fair value of $3.5 billion.

The carrying amount and fair value of PG&E Corporation's and the Utility's financial instruments are as follows (the table below excludes financial instruments with fair values that approximate their carrying values, as these instruments are presented on the Consolidated Balance Sheets):

(in millions)	At December 31,			
	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Nuclear decommissioning funds (Note 13):				
Utility	$1,335	$1,335	$1,337	$1,337
Long-term debt (Note 4):				
PG&E Corporation	1,000	1,000	1,000	1,000
Utility	4,820	4,631	5,153	4,975
Rate reduction bonds (Note 5):				
Utility	1,450	1,580	1,740	1,811
Utility preferred stock with mandatory redemption provisions (Note 10):	137	132	137	109
7.90 Percent cumulative quarterly income preferred securities (Note 4)	–	–	300	246
7.90 Percent deferrable interest subordinated debentures (Note 4)	300	275	–	–

Regulation and Statement of Financial Accounting Standards No. 71

PG&E Corporation and the Utility account for the financial effects of regulation in accordance with SFAS No. 71. SFAS No. 71 applies to regulated entities whose rates are designed to recover the costs of providing service. 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 also regulated by the FERC.

SFAS No. 71 provides for the recording of regulatory assets and liabilities when certain conditions are met. Regulatory assets represent the capitalization of incurred costs that would otherwise be charged to expense when it is probable that the incurred costs will be included for ratemaking purposes in the future. Regulatory liabilities represent rate actions of a regulator that will result in amounts that are to be credited to customers through the ratemaking process.

If portions of the Utility's or PG&E GTN's operations no longer become subject to the provisions of SFAS No. 71, a write-off of related regulatory assets and liabilities would be required, unless some form of transition cost recovery continues through rates established and collected for the remaining regulated operations.

Regulatory Assets

Regulatory assets comprise the following:

(in millions)	Balance at December 31, 2002	2001
Rate reduction bond assets	$1,346	$1,636
Unamortized loss, net of gain, on reacquired debt	299	322
Regulatory assets for deferred income tax	229	188
Other, net	137	137
Total Utility regulatory assets	2,011	2,283
PG&E GTN	42	36
Total PG&E Corporation regulatory assets	$2,053	$2,319

Regulatory assets are charged to expense during the period that the costs are reflected in regulated revenues.

The Utility's regulatory asset related to rate reduction bonds is amortized simultaneously with the amortization of the rate reduction bonds, and will be fully recovered by the end of 2007. The Utility's regulatory asset related to the unamortized loss, net of gain, on reacquired debt will be recovered over the remaining original amortization period of the reacquired debt over periods ranging from 1 to 24 years. The Utility's regulatory assets related to deferred income tax will be recovered over the period of reversal of the accumulated deferred taxes to which they relate. Based on current regulatory ratemaking and income tax laws, the Utility expects to recover deferred income tax-related regulatory assets over periods ranging from 1 to 39 years.

In general, the Utility does not earn a return on regulatory assets where the related costs do not accrue interest. At December 31, 2002, the Utility did not earn a return on regulatory assets related to deferred income taxes of $229 million.

Regulatory Liabilities

Regulatory Liabilities comprise the following:

(in millions)	Balance at December 31, 2002	2001
Employee benefit plans	$1,102	$1,133
Public purpose programs	182	218
Rate reduction bonds	102	17
Other	75	117
Total Utility regulatory liabilities	1,461	1,485
PG&E GTN	14	12
Total PG&E Corporation regulatory liabilities	$1,475	$1,497

The Utility's regulatory liabilities related to employee benefit plan expenses represent the cumulative differences between expenses recognized for financial accounting purposes and expenses recognized for ratemaking purposes. These balances will be charged against expense to the extent that future financial accounting expenses exceed amounts recoverable for regulatory purposes. The Utility's regulatory liabilities related to public purpose programs represent revenues designated for public purpose program costs that are expected to be incurred in the future. The Utility's regulatory liability for rate reduction bonds represents the deferral of over-collected revenue associated with the rate reduction bonds that the Utility expects to return to ratepayers in the future.

Regulatory Balancing Accounts

Sales balancing accounts accumulate differences between recorded revenues and revenues the Utility is authorized to collect through rates. Cost balancing accounts accumulate differences between recorded costs and costs the Utility is authorized to recover through rates. Under-collections that are probable of recovery are recorded as regulatory balancing account assets. Over-collections are recorded as regulatory balancing account liabilities. The Utility's regulatory balancing accounts accumulate balances until they are refunded to or received from Utility customers through authorized rate adjustments.

As a result of the California energy crisis discussed in Note 2, the Utility could no longer conclude that power-generation and procurement-related balancing accounts meet the requirements of SFAS No. 71. However, the Utility continues to record balancing accounts associated with its electricity and gas distribution and transmission businesses.

In 2002, the CPUC ordered the Utility to create certain electric balancing accounts to track specific electric-related costs but has not yet determined the recovery method for these costs. In the decisions ordering the creation of these balancing accounts, the CPUC indicated that the recovery method of these amounts would be determined in the future. Because the Utility cannot conclude that the amounts in these balancing accounts are considered probable of recovery in future rates, the Utility has reserved these balances by recording a charge against earnings. As of December 31, 2002, the reserve for these balances was $136 million.

The Utility's current regulatory balancing account assets comprise the following:

(in millions)	Balance at December 31, 2002	2001
Gas Revenue Balancing Accounts	$65	$42
Gas Cost Balancing Accounts	33	25
Electric Distribution Cost Balancing Accounts	–	8
Total	$98	$75

The Utility's current regulatory balancing account liabilities comprise the following:

(in millions)	Balance at December 31, 2002	2001
Gas Revenue Balancing Accounts	$ 4	$ 31
Gas Cost Balancing Accounts	226	178
Electric Transmission and Distribution Revenue Balancing Accounts	98	151
Electric Transmission Cost Balancing Accounts	32	-
Total	$360	$360

The Utility expects to collect from or refund to its ratepayers the balances included in current balancing accounts receivable and payable within the next twelve months. Regulatory balancing accounts that the Utility does not expect to collect or refund in the next twelve months are included in non-current regulatory assets and liabilities.

Revenue Recognition

Revenues are recorded in accordance with the Securities and Exchange Commission (SEC) Staff Accounting Bulletin (SAB) No. 101, "Revenue Recognition," as amended.

Energy commodities and services 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. Electric utility revenues, which are comprised of generation, transmission, and distribution services, are billed to the Utility's customers at the CPUC-approved "bundled" electricity rate. Gas utility revenues, which are comprised of transmission and distribution services, are also billed at CPUC-approved rates. Utility revenues are recognized as gas and electricity are delivered, and include amounts for services rendered but not yet billed at the end of each year.

As discussed in Note 2, since January 2001, the California Department of Water Resources (DWR) has purchased electricity on behalf of the Utility's customers to cover the amount of electricity needed by the Utility's customers that could not be met by the Utility's purchased power contracts and retained generation facilities. Under California law, the DWR is deemed to sell the electricity directly to the Utility's retail customers, not to the Utility. Therefore, the Utility is a pass-through entity for transactions between its customers and the DWR. Although charges for electricity provided by the DWR are included in the amounts the Utility bills its customers, the Utility deducts from electric revenues amounts passed through to the DWR. The pass-through amounts are based on the DWR's CPUC-approved revenue requirement and are excluded from the Utility's electric revenues in its Consolidated Statements of Operations.

In accordance with EITF 98-10 and SFAS No. 133, certain energy trading contracts that are not designated as hedging instruments or as normal purchase and sale contracts, are recorded at fair value using mark-to-market accounting, which records a change in fair value as income (or a charge) on the income statement, and correspondingly adjusts the fair value of the instrument on the balance sheet. Effective January 1, 2003, all non-derivative energy trading contracts that were marked to market under EITF 98-10 will be accounted for using the cost method. Please refer to the Adoption of New Accounting Policies section of this note for additional information.

Revenues from trading activities are reported on a net basis in operating revenues for both realized and unrealized gains (and losses). Realized revenues and costs of sales from non-trading activities are reported on a gross basis as operating revenues and operating expenses, respectively.

Accounting for Price Risk Management Activities

PG&E Corporation, primarily through its subsidiaries, engages in price risk management activities for both non-trading and trading purposes. Non-trading activities are conducted to optimize and secure the return on risk capital deployed within PG&E NEG's existing asset and contractual portfolio. Because of the Utility's credit rating downgrade and subsequent bankruptcy, risk management activities have been limited to forward and option contracts related to the Utility's natural gas portfolio and the continuation of power forward contracts that were in existence prior to the bankruptcy.

PG&E Corporation conducts trading activities principally through its unregulated lines of business. Trading activities are conducted to generate profit, create liquidity, and maintain a market presence. Net open positions often exist or are established due to PG&E NEG's assessment of and response to changing market conditions.

PG&E NEG is significantly reducing their energy trading operations.

Derivatives associated with both non-trading and trading activities include forward contracts, futures, swaps, options, and other contracts.

Derivative instruments associated with non-trading activities are accounted for at fair value in accordance with SFAS No. 133 and ongoing interpretations of the FASB's DIG. Derivative and other financial instruments associated with trading activities in electric and other energy commodities are accounted for at fair value in accordance with SFAS No. 133 and EITF 98-10, subject to the transition requirements of the rescission of EITF 98-10 discussed above.

Both non-trading and trading derivatives are classified as price risk management assets and price risk management liabilities in the accompanying Consolidated Balance Sheets. Non-trading derivatives, or any portion thereof, that are not effective hedges are adjusted to fair value through income. For non-trading derivatives that are effective hedges, changes in the fair value are recognized in accumulated other comprehensive income (loss) until the hedged item is recognized in earnings. Derivatives associated with trading activities are adjusted to fair value through income, subject to the effects of the rescission of EITF 98-10 discussed above.

Net realized gains or losses on non-trading derivative instruments for the year ended December 31, 2002, were included in various lines on the PG&E Corporation Consolidated Statements of Operations, including energy commodities and services revenue, cost of energy commodities and services, interest income or interest expense, and other income, (expense), net. Changes in the market value of the trading contracts, resulting primarily from newly originated transactions and the impact of commodity prices or interest rate movements, are recognized in operating income in the period of change. On an unrealized and a realized basis, PG&E Corporation now recognizes trading contracts on a net basis as previously described in this Note.

As described more fully in this Note under *Change in Estimate Due to Changes in Certain Fair Value Assumptions*, for non-trading and trading contracts, models are used to estimate the fair value of derivatives and other contracts that are accounted for as derivative contracts. Gross mark-to-market value is estimated using the midpoint of quoted bid and ask prices for liquid periods and, for illiquid periods, using the midpoint of the marginal cost curve and the forecast curve. Interpolation methods are used for intermediate periods when broker quotes are intermittent. The gross mark-to-market valuation is then adjusted for time value of money, creditworthiness of contractual counterparties, market liquidity in future periods, and other adjustments necessary to determine fair value.

PG&E Corporation engages in non-trading activities to hedge the impact of market fluctuations on energy commodity prices, interest rates, and foreign currencies. Before the implementation of SFAS No. 133, PG&E Corporation and the Utility accounted for hedging activities under the deferral method, whereby unrealized gains and losses on hedging transactions were deferred. When the underlying item settled, PG&E Corporation and the Utility recognized the gain or loss from the hedge instrument in operating income. In instances where the anticipated correlation of price movements did not occur, hedge accounting was terminated and future changes in the value of the derivative were recognized as gains or losses. If the hedged item was sold, the value of the associated derivative was recognized in income.

Effective January 1, 2001, PG&E Corporation and the Utility adopted SFAS No. 133 that requires that all derivatives, as defined, are recognized on the balance sheet at fair value. PG&E Corporation's transition adjustment to implement SFAS No. 133 on January 1, 2001, resulted in a non-material decrease to earnings and an after-tax decrease of $333 million to accumulated other comprehensive income. The Utility's transition adjustment to implement SFAS No. 133 resulted in a non-material decrease to earnings and an after-tax $90 million positive adjustment to accumulated other comprehensive loss. These transition adjustments, which relate to hedges of interest rate, foreign currency, and commodity price risk exposure, were recognized as of January 1, 2001, as a cumulative effect of a change in accounting principle.

PG&E Corporation and the Utility also have derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business. These derivatives are exempt from the requirements of SFAS No. 133 under the normal purchase and sales exception, and are not reflected on the balance sheet at fair value. The FASB has approved two interpretations issued by the DIG that changed the definition of normal purchases and sales for certain power contracts. As previously described in this Note under "*Changes to Accounting for Certain Derivative Contracts*," PG&E Corporation implemented these interpretations on April 1, 2002.

To qualify for the normal purchases and sales exemption from SFAS No. 133, a contract must have pricing that is deemed to be clearly and closely related to the asset to be delivered under the contract. In 2001, the FASB approved another interpretation issued by the DIG that clarifies how this requirement applies to certain commodity contracts. In applying this new DIG guidance, PG&E Corporation determined that one of its derivative commodity contracts no longer qualifies for normal purchases and sales treatment, and must be marked-to-market through earnings. The cumulative effect of this change in accounting principle increased earnings by approximately $9 million (after-tax).

Stock-Based Compensation

PG&E Corporation and the Utility account for stock-based compensation using the intrinsic value method in accordance with the provisions of APB No. 25, as allowed by SFAS No. 123, as amended by SFAS No. 148. Under the intrinsic value method, PG&E Corporation and the Utility do not recognize any compensation expense, as the exercise price of all stock options is equal to the fair market value at the time the options are granted. Had compensation expense been recognized using the fair value-based method under SFAS No. 123, PG&E Corporation's pro forma consolidated earnings (loss) and earnings (loss) per share would have been as follows:

(in millions, except per share amounts)	Year ended December 31,		
	2002	2001	2000
Net earnings (loss):			
As reported	$ (874)	$1,099	$(3,364)
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(20)	(23)	(10)
Proforma	$ (894)	$1,076	$(3,374)
Basic earnings (loss) per share:			
As reported	$(2.36)	$ 3.03	$ (9.29)
Proforma	$(2.41)	$ 2.96	$ (9.32)
Diluted earnings (loss) per share:			
As reported	$(2.36)	$ 3.02	$ (9.29)
Proforma	$(2.41)	$ 2.96	$ (9.32)

Had compensation expense been recognized using the fair value-based method under SFAS No. 123, the Utility's pro forma consolidated earnings (loss) and earnings (loss) per share would have been as follows:

(in millions, except per share amounts)	Year ended December 31,		
	2002	2001	2000
Net earnings (loss):			
As reported	$1,794	$1,015	$(3,483)
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(7)	(7)	(5)
Proforma	$1,787	$1,008	$(3,488)

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) reports a measure for accumulated changes in equity of an enterprise that results from transactions and other economic events other than transactions with shareholders. PG&E Corporation's and the Utility's accumulated other comprehensive income (loss) consists principally of changes in the market value of certain cash flow hedges with the implementation of SFAS No. 133 on January 1, 2001, as well as foreign currency translation adjustments.

Reclassifications

Certain amounts in the 2001 and 2000 financial statements have been reclassified to conform to the 2002 presentation. These reclassifications did not affect the consolidated net income of either PG&E Corporation or the Utility for the years presented.

NOTE 2: THE UTILITY CHAPTER 11 FILING

Electric Industry Restructuring

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

For the seven-month period from June 2000 through December 2000, wholesale electric prices in California averaged $0.18 per kilowatt-hour (kWh). During this period, the Utility's retail electric rates were frozen and provided only approximately $0.05 per kWh to pay for the Utility's electricity costs.

The frozen rates were designed to allow the Utility to recover its authorized utility costs and, to the extent the frozen rates generated revenues in excess of the Utility's authorized utility costs, recover its transitions costs. During the California energy crisis, frozen rates were insufficient to cover the Utility's electricity procurement and other costs. Because the Utility could no longer conclude that its under-collected electricity procurement and remaining transition costs were probable of recovery, the Utility charged $6.9 billion to expense for these costs at December 31, 2000. The Utility's inability to recover procurement costs from customers ultimately resulted in billions of dollars in defaulted debt and unpaid bills and caused the Utility to file a voluntary petition for relief under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court on April 6, 2001.

In January 2001, the CPUC increased electric rates by $0.01 per kWh, and in March 2001 by another $0.03 per kWh, and restricted use of these surcharge revenues to "ongoing procurement costs" and "future power purchases." The Utility had recorded a regulatory liability for these $0.01 and $0.03 surcharge revenues when such surcharges exceeded ongoing procurement costs.

Although the CPUC authorized the $0.03 per kWh surcharge in March 2001, the Utility did not begin collecting the revenues until June 2001. As a result, in May 2001, the CPUC authorized the Utility to collect an additional $0.005 per kWh in revenues for 12 months to make up for the time lag in collection of the $0.03 surcharge revenues. Although the collection of this "half-cent" surcharge was originally scheduled to end on May 31, 2002, the CPUC issued a resolution ordering the Utility to continue collecting the half-cent surcharge until further consideration by the CPUC and to record the surcharge revenues in a balancing account. The Utility had recorded a regulatory liability for the $0.005 per kWh (half-cent) surcharge revenues billed subsequent May 31, 2002. The regulatory liabilities for the $0.01 per kWh and $0.03 per kWh surcharge revenues in excess of ongoing procurement costs, and half-cent surcharge revenues billed after May 31, 2002, totaled $222 million as of September 30, 2002, and $65 million as of December 30, 2001.

In November 2002, the CPUC approved a decision modifying the restrictions on the use of revenues generated by the surcharges to permit the revenues to be used for the purpose of securing or restoring the Utility's reasonable financial health, as determined by the CPUC. The CPUC will determine in other proceedings how the surcharge revenues can be used, whether there is any cost or other basis to support specific surcharge levels, and whether the resulting rates are just and reasonable. After the CPUC determines when the AB 1890 rate freeze ended, the CPUC will determine the extent and disposition of the Utility's under-collected costs, if any, remaining at the end of the rate freeze. If the CPUC determines that the Utility recovered revenues in excess of its transition costs or in excess of other permitted uses, the CPUC may require the Utility to refund such excess revenues.

In a case currently pending before it relating to the CPUC's settlement with Southern California Edison (SCE), another California investor-owned utility (IOU), the Supreme Court of California is considering whether the CPUC has the authority to enter into a settlement which allows SCE to recover under-collected procurement and transition costs in light of the provisions of AB 1890. The Utility cannot predict the outcome of this case or whether the CPUC or others would attempt to apply any ruling to the Utility. If the Utility is ordered to refund material amounts to ratepayers, the Utility's financial condition and results of operations would be materially adversely affected.

In December 2002, the CPUC issued a decision authorizing the Utility to stop tracking amounts related to the $0.01 and $0.03 surcharge revenues in a separate regulatory liability account and instead record them as a reduction to unrecovered transition costs. As a result, in January 2003, the Utility filed a letter with the CPUC requesting to withdraw its regulatory liability account used to track the $0.01 and $0.03 surcharge revenues in excess of ongoing procurement costs.

Based on this December 2002 CPUC decision and an agreement between the CPUC and SCE, in which SCE was allowed to use its half-cent surcharge to offset its California Department of Water Resources (DWR) revenue requirement, the Utility reversed its regulatory liabilities totaling $222 million related to the $0.01 and $0.03 per kWh surcharge revenues in excess of ongoing procurement costs, and half-cent surcharge revenues billed subsequent to May 31, 2002 during the fourth quarter of 2002. (Of this amount, $157 million was originally recorded as a regulatory liability during 2002; and as such, the reversal of this amount has no impact on current year earnings.)

During 2001, the price of wholesale electricity stabilized. As a result, the Utility's total generation-related electric revenues were greater than its generation-related costs. In 2001, this resulted in additional earnings of $458 million (after-tax), which represented a partial recovery of previously written-off under-collected purchased power and transition costs, and included $327 million (after-tax) related to the market value of terminated bilateral contracts. During the year ended December 31, 2002, the Utility's total generation-related revenues exceeded its generation-related costs by approximately $1.4 billion (after-tax), which includes a net reduction of 2001 accrued purchased power costs of approximately $352 million (after-tax) and includes an offset of $218 million (after-tax) in additional pass-through revenues accrued in 2002 related to amounts to be remitted to the DWR in connection with the DWR's proposed amendment to the CPUC's May 16, 2002, servicing order. (See further discussion below under "Electricity Purchases.") The outstanding balance of the Utility's under-collected purchased power and transition costs (which were originally $4.1 billion, after-tax) amounted to $2.2 billion and $3.6 billion (after-tax) at December 31, 2002, and 2001, respectively. The recovery of these remaining under-collected purchased power costs and transition costs will depend on a number of factors, including the ultimate outcome of the Utility's bankruptcy and future regulatory and judicial proceedings, including the outcome of the Utility's filed rate doctrine litigation. (The filed rate doctrine litigation refers to a lawsuit filed in November 2000 in the U.S. District Court for the Northern District of California by the Utility against the CPUC Commissioners, asking the court to declare that the federally approved wholesale electricity costs that the Utility has incurred to serve its customers are recoverable in retail rates under the federal filed rate doctrine.)

Under AB 1890, the rate freeze was scheduled to end on the earlier of March 31, 2002, or the date that the Utility recovered all of its generation-related transition costs as determined by the CPUC. However, in January 2002, the CPUC issued a decision finding that new California legislation, AB 6X, had materially affected the implementation of AB 1890. The CPUC scheduled further proceedings to address the impact of AB 6X on the AB 1890 rate freeze for the Utility and to determine the extent and disposition of the Utility's remaining unrecovered transition costs. In its November 2002 decision regarding the surcharge revenues, discussed above, the CPUC reiterated that it had yet to decide when the rate freeze ended and the disposition of any under-collected costs remaining at the end of the rate freeze.

The CPUC and the Official Committee of Unsecured Creditors (OCC) filed an alternative plan of reorganization in the Utility's bankruptcy proceeding, proposing that the Utility's overall retail electric rates be maintained at current levels through January 31, 2003, in order to generate cash to repay in part the Utility's creditors under the CPUC's plan. (See "CPUC/OCC's Alternative Plan of Reorganization" below.) During the third quarter of 2002, the CPUC represented that since utilities are now required under state law, AB 6X, to retain their generating assets and the CPUC has regained its traditional rate authority over those assets, costs associated with those assets may be recovered by the utilities in the traditional way, under cost-based regulation. Based on these CPUC decisions and representations, the Utility believes it can continue to record revenues collected under its existing overall retail rates, subsequent to the statutory end of the rate freeze.

However, the CPUC's proceedings to consider the impact of AB 6X on the AB 1890 rate freeze and the disposition of the Utility's unrecovered transition costs are still pending, and it is possible that at some future date the CPUC, on its own initiative or in response to judicial decisions, including the California Supreme Court's consideration regarding the authority of the CPUC to enter into a settlement which allows SCE to recover under-collected procurement and transition costs in light of the provisions of AB 1890, may change its interpretation of law or otherwise seek to change the Utility's overall retail electric rates retroactively. The Utility has not provided reserves for potential refunds of any of these revenues as of December 31, 2002. As a result, any of the changes described above could materially affect the Utility's earnings.

In a March 2001 decision, the CPUC adopted an accounting proposal by The Utility Reform Network (TURN) that retroactively restates the way in which the Utility's transition costs are recovered. This retroactive change had the effect of extending the AB 1890 rate freeze and reducing the amount of past wholesale electricity costs that could be eligible for recovery from customers. The CPUC, the California Supreme Court, and the Bankruptcy Court denied the Utility's request for rehearing. The Utility is currently appealing this matter to the U.S. District Court for the Northern District of California. The Utility cannot predict the outcome of this matter.

Generation Divestiture

AB 6X, passed by the California Legislature in January 2001, prohibits utilities from divesting their remaining power plants before January 1, 2006. The Utility believes this law does not supersede or repeal an existing law requiring the CPUC to establish a market value for their remaining generating assets by the end of 2001, based on appraisal, sale or other divestiture. The Utility has filed comments on this matter with the CPUC. However, the CPUC has not yet issued a decision.

On January 17, 2002, the Utility filed an administrative claim with the State of California Victim Compensation and Government Claims Board (the Board) alleging that the new law violates the Utility's statutory rights under California's deregulation law (AB 1890). The Utility believes that it has been denied its right to the market value of its retained generating facilities of at least $4.1 billion. On March 7, 2002, the Board formally denied the Utility's claim. Having exhausted remedies before the Board, the Utility filed suit for breach of contract in the California Superior Court on September 6, 2002. On January 9, 2003, the Superior Court granted the State of California's request to dismiss the complaint finding that AB 1890 does not constitute a contract. The Utility has 60 days to file an appeal and intends to do so. The Utility cannot predict what the outcome of any of these proceedings will be or whether they will have a material adverse effect on its results of operations or financial condition.

Electricity Purchases

In January 2001, as wholesale electric prices continued to exceed retail rates, the major credit rating agencies lowered their ratings for the Utility and PG&E Corporation to non-investment grade levels. Consequently, the Utility lost access to its bank facilities and capital markets, and could no longer continue buying electricity to deliver to its customers. As a result, in the first quarter of 2001, the California Legislature and the Governor of California authorized the DWR to purchase electricity for the Utility's customers and to issue revenue bonds to finance electricity purchases (governed by AB 1X). Initially, the DWR indicated that it intended to buy electricity only at "reasonable prices" to meet the Utility's net open position, leaving the ISO to purchase the remainder in order to avoid blackouts. The ISO billed the Utility for its costs to purchase electricity to cover the amount of the Utility's net open position not covered by the DWR. In 2001, the Utility accrued approximately $1 billion for these ISO purchases for the period January 17, 2001, through April 6, 2001. However, in 2001, the FERC issued a series of orders directing the ISO to buy electricity only on behalf of creditworthy entities. In March 2002, the FERC denied an application for rehearing and reaffirmed its previous orders finding that the DWR is responsible for paying such ISO charges.

In February 2002, the CPUC approved decisions adopting rates for the DWR, and allowing the DWR to collect power charges and financing charges from ratepayers to provide the revenues needed by the DWR to procure electricity for the customers of the Utility and the other California IOUs for the two-year period ending December 31, 2002.

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

In October 2002, the DWR filed a proposed amendment to the CPUC's May 16, 2002, servicing order requesting changes to the calculation that determines the amount the Utility is required to pass through to the DWR. The DWR's proposed amendment changes the calculation that determines the amount of revenues that the Utility must pass-through to the DWR. This proposed amendment would also be used to true up previous amounts passed through to the DWR as well as future payments. Under its statutory authority, the DWR may request the CPUC to order utilities to implement such amendments, and the CPUC has approved such amendments in the past without significant change. In December 2002, the CPUC approved an operating order requiring the Utility to perform the operational, dispatch, and administrative functions for the DWR's allocated contracts beginning on January 1, 2003. The operating order, which applies prospectively, includes the DWR's proposed method of calculating the amount of revenues that the Utility must pass-through to the DWR. As a result, as of December 31, 2002, the Utility has accrued an additional $369 million (pre-tax) liability for pass-through revenues for electricity provided by the DWR to the Utility's customers.

In October 2002, the Utility filed a lawsuit in a California court asking the court to find that the DWR's revenue requirements had not been demonstrated to be "just and reasonable" (as required by AB 1X) and lawful, and that the DWR had violated the procedural requirements of AB 1X in making its determination. The Utility asked the court to order the DWR's revenue requirement determination be withdrawn as invalid, and that the DWR be precluded from imposing its revenue requirements on the Utility and its customers until it has complied with the law. No schedule has yet been set for consideration of the lawsuit.

Senate Bill 1976

Under AB 1X, the DWR is prohibited from entering into new agreements to purchase electricity to meet the net open position of the California IOUs after December 31, 2002. In September 2002, the Governor signed California Senate Bill (SB) 1976 into law. SB 1976 required that each California IOU submit, within 60 days after the CPUC allocated existing DWR contracts for electricity procurement to each California IOU, an electricity procurement plan to meet the residual net open position associated with that utility's customer demand. SB 1976 requires that each procurement plan include one or more of the following features:

- A competitive procurement process under a format authorized by the CPUC, with the costs of procurement obtained in compliance with the authorized bidding format being recoverable in rates;
- A clear, achievable, and quantifiable incentive mechanism that establishes benchmarks for procurement and authorizes the IOUs to procure electricity from the market subject to comparison with the CPUC-authorized benchmarks; or
- Upfront and achievable standards and criteria to determine the acceptability and eligibility for rate recovery of a proposed transaction and an expedited CPUC pre-approval process for proposed bilateral contracts to ensure compliance with the individual utility's procurement plan.

SB 1976 provides that the CPUC may not approve the procurement plan if it finds the plan contains features or mechanisms which would impair restoration of the IOU's creditworthiness or would lead to a deterioration of the IOU's creditworthiness. SB 1976 also indicates that procurement activities in compliance with an approved procurement plan will not be subject to after-the-fact reasonableness review. The CPUC is permitted to establish a regulatory process to verify and ensure that each contract was administered in accordance with its terms and that contract disputes that arise are resolved reasonably.

A central feature of the SB 1976 regulatory framework is its direction to the CPUC to create new electric procurement balancing accounts to track and allow recovery of the differences between recorded revenues and costs incurred under an approved procurement plan. The CPUC must review the revenues and costs associated with the Utility's electric procurement plan at least semi-annually and adjust rates or order refunds, as appropriate, to properly amortize the balancing accounts. Until January 1, 2006, the CPUC must establish the schedule for amortizing the over-collections or under-collections in the electric procurement balancing accounts so that the aggregate over-collections or under-collections reflected in the accounts do not exceed 5 percent of the IOU's actual recorded generation revenues for the prior calendar year, excluding revenues collected on behalf of the DWR. Mandatory semi-annual review and adjustment of the balancing accounts will continue until January 1, 2006, after which time the CPUC will conduct electric procurement balancing account reviews and adjust retail ratemaking amortization schedules for the balancing accounts as the CPUC deems appropriate and in a manner consistent with the requirements of SB 1976 for timely recovery of electricity procurement costs.

Allocation of DWR Electricity to Customers of the IOUs

Consistent with applicable law and CPUC orders, since 2001, the Utility and the other California IOUs have acted as the billing and collection agents for the DWR's sales of its electricity to retail customers. In September 2002, the CPUC issued a decision allocating the electricity provided under existing DWR contracts to the customers of the IOUs. This decision required the Utility, along with the other IOUs, to begin performing all the day-to-day scheduling, dispatch, and administrative functions associated with the DWR contracts allocated to the IOUs' portfolios by January 1, 2003.

Although the DWR retains legal and financial responsibility for these contracts, the DWR has stated publicly that it intends to transfer full legal title of, and responsibility for, the DWR electricity contracts to the IOUs as soon as possible. However, SB 1976 does not contemplate a transfer of title of the DWR contracts to the IOUs. In addition, the operating order issued by the CPUC in December 2002 implementing the Utility's operational and scheduling responsibility with respect to the DWR allocated contracts specifies that the DWR will retain legal and financial responsibility for the contracts and that the December 2002 order does not result in an assignment of the DWR allocated contracts. The Utility's proposed plan of reorganization prohibits the Utility from accepting, directly or indirectly, assignment of legal or financial responsibility for the DWR contracts. There can be no assurance that either the State of California or the CPUC will not seek to provide the DWR with authority to effect such a transfer of legal title in the future. The Utility has informed the CPUC, the DWR and the State that the Utility would vigorously oppose any attempt to transfer the DWR allocated contracts to the Utility without the Utility's consent.

Chapter 11 Filing

On April 6, 2001, the Utility filed for relief under Chapter 11 of the Bankruptcy Code. Under Chapter 11, the Utility is subject to the jurisdiction of the Bankruptcy Court, however the Utility has control of its assets and is authorized to operate its business as a debtor-in-possession. Subsidiaries of the Utility, including PG&E Funding, LLC (which holds rate reduction bonds) and PG&E Holdings, LLC (which holds stock of the Utility), are not included in the Utility's Chapter 11 filing. PG&E Corporation, the Utility's parent, and PG&E NEG have not filed for Chapter 11 and are not included in the Utility's Chapter 11 filing. PG&E Corporation, however, is a co-proponent of the Utility's proposed plan of reorganization.

In connection with the Utility's Chapter 11 filing, various parties have filed claims with the Bankruptcy Court. Through December 31, 2002, claims filed with the Bankruptcy Court totaled approximately $49.4 billion. Of the $49.4 billion of claims filed, claims for approximately $25.5 billion have been disallowed by the Bankruptcy Court due to objections submitted by the Utility or as a result of the claimants withdrawing their claims from the Bankruptcy Court. Of the remaining $23.9 billion of filed claims, pursuant to the Plan and alternative plan (discussed below), claims totaling approximately $6.6 billion are expected to pass through the bankruptcy proceeding and be determined in the appropriate court or other tribunal during the bankruptcy proceeding or after it concludes.

The Utility intends to object to approximately $4.3 billion of the remaining $23.9 billion of filed claims. These objections relate primarily to generator claims. Approximately $500 million of the $23.9 billion of filed claims are subject to pending Utility objections. The Utility has recorded its estimate of all valid claims at December 31, 2002, as $9.4 billion of Liabilities Subject to Compromise and $3.0 billion of Long-Term Debt. The Utility has paid certain claims authorized by the Bankruptcy Court, as discussed below, and reduced the amount of outstanding claims accordingly. In addition, since its Chapter 11 filing, the Utility has accrued interest on all claims the Utility considers valid. This additional interest accrual is not included in the original $49.4 billion of claims filed. The following schedule summarizes the activity of the Utility's Liabilities Subject to Compromise from the period of December 31, 2001 to December 31, 2002.

(in billions)

Liabilities Subject to Compromise at December 31, 2001	$11.4
Interest accrual for the year ended December 31, 2002	0.3
Claims paid pursuant to Bankruptcy Court orders	(1.4)
Claims and Interest authorized by the Bankruptcy Court to be paid (transferred to accounts payable or interest payable)	(0.2)
Reclassification of debt upon liquidation of trust holding solely Utility Subordinated Debentures (Note 4)	0.3
Reversal of first quarter 2001 ISO accrual	(1.0)
Liabilities Subject to Compromise at December 31, 2002	$ 9.4
Claims filed by PG&E Corporation and included in Liabilities Subject to Compromise	(0.2)
Liabilities Subject to Compromise at December 31, 2002, excluding claims payable to PG&E Corporation	$ 9.2

The balance of Liabilities Subject to Compromise increases and decreases due to a variety of factors. For example, disputed claims may be resolved or the Bankruptcy Court may authorize payment of certain claims.

The Bankruptcy Court has authorized the Utility to pay certain pre-petition claims and pre- and post-petition interest on certain claims prior to emerging from Chapter 11. Pursuant to Bankruptcy Court authorization, through December 31, 2002, approximately $901 million in principal and $60 million in interest had been paid to qualifying facilities (QFs). The Bankruptcy Court has also authorized the Utility to pay all undisputed creditor claims that amount to $5,000 or less and undisputed mechanics' lien and reclamation claims. At December 31, 2002, the majority of these payments had been made and totaled approximately $10 million. Also pursuant to Bankruptcy Court authorization, the Utility has paid approximately $1.3 billion through January 2, 2003, for pre- and post-petition interest on certain undisputed claims. The Utility also repaid advances and interest on advances of approximately $25 million, through January 2, 2003, to banks providing letters of credit backing pollution control bonds. In addition, the Utility has paid approximately $79 million in refunds for customer deposits, reimbursements for work performed by customers, and inspection fees for contracts related to gas and electric line extensions. A portion of these refunds, reimbursements, and inspection fees were paid as part of the Utility's normal business operations, and were not included in claims filed with the Bankruptcy Court.

As discussed above, the Bankruptcy Court has authorized payment of certain claims. These claims are therefore not included in the $9.4 billion of Liabilities Subject to Compromise, however the Utility is paying interest on these other claims at the various rates as described below. For certain claims, the Utility has identified receivable balances owed to the Utility from the claimant. These receivable balances may be settled as offsets to claims filed by the claimant, thereby reducing the amount of the claim and the interest ultimately payable to the claimant.

As specified in the Utility's proposed plan of reorganization (the Plan) described below, the Utility has agreed to pay pre- and post-petition interest on Liabilities Subject to Compromise at the rates set forth below, plus additional interest on certain claims as discussed below.

	Amount Owed (in millions)	Agreed Upon Rate (per annum)	
Commercial Paper Claims	$ 873	7.466%	
Floating Rate Notes	1,240	7.583%	(Implied yield of 7.690%)
Senior Notes	680	9.625%	
Medium-Term Notes	287	5.810% to 8.450%	
Revolving Line of Credit Claims	938	8.000%	
Majority of QFs	97	5.000%	
Other Claims	5,276	Various	
Liabilities Subject to Compromise at December 31, 2002	$9,391		

Since the Plan did not become effective on or before February 15, 2003, the interest rates for Commercial Paper Claims, Floating Rate Notes, Senior Notes, Medium-Term Notes, and Revolving Line of Credit Claims have been increased by 37.5 basis points, for periods on and after February 15, 2003. If the Plan does not become effective on or before September 15, 2003, the interest rates for these claims on and after such date will be increased by an additional 37.5 basis points. Finally, if the effective date does not occur on or before March 15, 2004, the interest rates for these claims on and after such date will be increased by an additional 37.5 basis points. For other claims, the Utility has recorded interest at the contractual or FERC-tariffed interest rate. When those rates do not apply, the Utility has recorded interest at the federal judgment rate.

The Utility has received approval from the Bankruptcy Court to make certain pre-petition principal payments on secured debt that has matured and has, at December 31, 2002, paid $333 million on this debt. At December 31, 2002, the Utility has $3 billion outstanding in pre-petition principal, secured debt. This debt is classified as Long-Term Debt in the Consolidated Balance Sheets.

The Bankruptcy Court has also authorized certain payments and actions necessary for the Utility to continue its normal business operations while operating as a debtor-in-possession. For example, the Utility is authorized to pay employee wages and benefits, certain QFs, interest on secured debt, environmental remediation expenses, and expenditures related to property, plant and equipment. In addition, the Utility is authorized to refund certain customer deposits, use certain bank accounts and cash collateral, and assume responsibility for various hydroelectric contracts.

Proposed Plan of Reorganization

The Utility and PG&E Corporation have jointly proposed a plan of reorganization, referred to as the Plan, which would allow the Utility to restructure its businesses and refinance the restructured businesses. The Plan is designed to align the Utility's existing businesses under the regulators that best match the business functions. Retail assets (natural gas and electricity distribution) would remain under the retail regulator, the CPUC. The wholesale assets (electric transmission, interstate natural gas transportation, and electric generation) would be placed under wholesale regulators, the FERC and the Nuclear Regulatory Commission (NRC). After this realignment, the retail-focused business would be a natural gas and electricity distribution company (Reorganized Utility), representing approximately 70 percent of the book value of the Utility's assets.

In contemplation of the Plan becoming effective, the Utility has created three new limited liability companies, the LLCs, which currently are owned by the Utility's wholly owned subsidiary, Newco Energy Corporation, or Newco. On the effective date of the Plan, the Utility would transfer substantially all the assets and liabilities primarily related to the Utility's electricity generation business to Electric Generation LLC, or Gen; the assets and liabilities primarily related to the Utility's electricity transmission business to ETrans LLC, or ETrans; and the assets and liabilities primarily related to the Utility's natural gas transportation and storage business to GTrans LLC, or GTrans.

The Plan proposes that on the effective date, the Utility would distribute to PG&E Corporation all of the outstanding common stock of Newco. Each of ETrans, GTrans, and Gen would continue to be an indirect wholly owned subsidiary of PG&E Corporation. Finally, on the effective date of the Plan or as promptly thereafter as practicable, PG&E Corporation would distribute all the shares of the Utility's common stock that it then holds to its existing shareholders in a spin-off transaction. After the spin-off, the Reorganized Utility would be an independent publicly held company. The common stock of the Reorganized Utility would be registered under federal securities laws and would be freely tradable by the recipients on the effective date or as soon as practicable thereafter. The Reorganized Utility would apply to list its common stock on the New York Stock Exchange. The Reorganized Utility would retain the name "Pacific Gas and Electric Company."

Although the Reorganized Utility would be legally separated from the LLCs, the Reorganized Utility's operations would remain connected to the operations of the LLCs after the effective date of the Plan. For example:

- The Reorganized Utility would rely on Gen for a significant portion of the electricity the Reorganized Utility needs to meet its electricity distribution customers' demand during the 12-year term of a power purchase and sale agreement between the Reorganized Utility and Gen, or the Gen power purchase and sale agreement.
- The Reorganized Utility would rely on ETrans for the Reorganized Utility's electricity transmission needs because the transmission lines proposed to be transferred to ETrans are currently the only transmission lines directly connected to the Utility's electricity distribution system.
- The Reorganized Utility would rely on GTrans for the Reorganized Utility's natural gas transportation needs because the facilities proposed to be transferred to GTrans are currently the only transportation facilities directly connected to the Utility's natural gas distribution system. In addition, the Reorganized Utility would rely on GTrans for a substantial portion of the Reorganized Utility's natural gas storage requirements for at least 10 years under a transportation and storage services agreement between the Reorganized Utility and GTrans, though the Utility does have storage options with third party providers to meet a portion of their requirements.
- The Reorganized Utility also would have significant operating relationships with the LLCs covering a range of functions and services.

Finally, the Reorganized Utility would continue to rely on its natural gas transportation agreement with PG&E GTN, for the transportation of western Canadian natural gas.

During 2002, the Utility undertook several initiatives to prepare for separation under the Plan. The Utility has spent approximately $43 million through December 31, 2002, on these initiatives.

The Plan proposes that allowed claims would be satisfied by cash, long-term notes issued by the LLCs or a combination of cash and such notes. Each of ETrans, GTrans, and Gen would issue long-term notes to the Reorganized Utility and the Reorganized Utility would then transfer the notes to certain holders of allowed claims. In addition, each of the Reorganized Utility, ETrans, GTrans, and Gen would issue "new money" notes in registered public offerings. The LLCs would transfer the proceeds of the sale of the new money notes, less working capital reserves, to the Utility for payment of allowed claims. The Plan also would reinstate nearly $1.59 billion of preferred stock and pollution control loan agreements.

On February 19, 2003, Standard & Poor's (S&P), a major credit rating agency, announced that it had re-affirmed its preliminary rating evaluation, originally issued in January 2002, of the corporate credit ratings of, and the securities proposed to be issued by the Reorganized Utility and the LLCs in connection with the implementation of the Utility Plan. Subject to the satisfaction of various conditions, S&P stated that the approximately $8.5 billion of securities proposed to be issued by the Reorganized Utility and the LLCs, as well as their corporate credit ratings, would be capable of achieving investment grade ratings of at least BBB-. In order to satisfy some of the conditions specified by S&P, on February 24, 2003, the Utility filed amendments to the Utility Plan with the Bankruptcy Court that, among other modifications:

- permit the Reorganized Utility and the LLCs to issue secured debt instead of unsecured debt,
- permit adjustments in the amount of debt the Reorganized Utility and the LLCs would issue so that additional new money notes could be issued if additional cash is required to satisfy allowed claims or to deposit in escrow for disputed claims and such debt can be issued while maintaining investment grade ratings, or so that less debt could be issued in order to obtain investment grade ratings or if less cash is required to satisfy allowed claims and be deposited into escrow for disputed claims,
- require Gen to establish a debt service reserve account and an operating reserve account,
- under certain circumstances, permit an increase in the amount of cash creditors receiving cash and notes will receive,
- permit the Utility's mortgage-backed pollution control bonds to be redeemed if the Reorganized Utility issues secured new money notes, and
- commit PG&E Corporation to contribute up to $700 million in cash to the Utility's capital from the issuance of equity or from other available sources, to the extent necessary to satisfy the cash obligations of the Utility in respect of allowed claims and required deposits into escrow for disputed claims, or to obtain investment grade ratings for the debt to be issued by the Reorganized Utility and the LLCs.

In addition to the amendments to the Plan, amendments to various filings at the FERC, and possibly other regulatory agencies, will be required in order to implement the changes to the Plan.

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

- The effective date of the Plan shall be on or before May 30, 2003;
- All actions, documents, and agreements necessary to implement the Plan shall have been effected or executed;
- PG&E Corporation and the Utility shall have received all authorizations, consents, regulatory approvals, rulings, letters, no-action letters, opinions, or documents that are determined by PG&E Corporation and the Utility to be necessary to implement the Plan;
- S&P and Moody's shall have established investment-grade credit ratings for each of the securities to be issued by the Reorganized Utility, ETrans, GTrans, and Gen of not less than BBB- and Baa3, respectively;
- The Plan shall not have been modified in a material way since the confirmation date; and
- The registration statements pursuant to which the new securities will be issued shall have been declared effective by the SEC, the Reorganized Utility shall have consummated the sale of its new securities to be sold under the Plan, and the new securities of each of ETrans, GTrans, and Gen shall have been priced

and the trade date with respect to each shall have occurred.

If one or more of the conditions described above have not occurred or been waived by May 30, 2003, the confirmation order would be vacated. The Utility's obligations with respect to claims and equity interests would remain unchanged.

PG&E Corporation and the Utility contend that bankruptcy law expressly preempts state law in connection with the implementation of a plan of reorganization. The Bankruptcy Court rejected this contention. PG&E Corporation and the Utility appealed the express preemption aspect of this decision to the U.S. District Court. The U.S. District Court reversed the Bankruptcy Court's ruling and remanded the case back to the Bankruptcy Court for further proceedings, ruling that the Bankruptcy Code expressly preempts "nonbankruptcy laws that would otherwise apply to bar, among other things, transactions necessary to implement the reorganization plan." The U.S. District Court entered judgment on September 19, 2002, and the CPUC and several other parties thereafter initiated an appeal to the U.S. Court of Appeals for the Ninth Circuit, which is pending.

The CPUC/OCC's Alternative Plan of Reorganization

The CPUC and the OCC have jointly proposed an alternative plan of reorganization for the Utility that does not call for realignment of the Utility's existing businesses. The alternative plan instead provides for the continued regulation of all of the Utility's current operations by the CPUC. The alternative plan proposes to satisfy all allowed creditor claims in full either through reinstatement or payment in cash, using a combination of cash on hand and the proceeds from the issuance of $7.3 billion of new senior secured debt and the issuance of $1.5 billion of new unsecured debt and preferred securities. The alternative plan proposes to establish a $1.75 billion regulatory asset, which would be amortized over ten years and would earn the full rate of return on rate base.

The CPUC/OCC Plan also provides that it would not become effective until the Utility and the CPUC enter into a "reorganization agreement" under which the CPUC promises to establish retail electric rates on an ongoing basis sufficient for the Utility to achieve and maintain investment grade credit ratings and to recover in rates (1) the interest and dividends payable on, and the amortization and redemption of, the securities to be issued under the alternative plan, and (2) certain recoverable costs (defined as the amounts the Utility is authorized by the CPUC to recover in retail electric rates in accordance with historic practice for all of its prudently incurred costs, including capital investment in property, plant and equipment, a return of capital and a return on capital and equity to be determined by the CPUC from time to time in accordance with its past practices).

PG&E Corporation and the Utility believe the alternative plan is not credible or confirmable. PG&E Corporation and the Utility do not believe the alternative plan would restore the Utility to investment grade status if the alternative plan were to become effective. Additionally, PG&E Corporation and the Utility believe the alternative plan would violate applicable federal and state law.

Confirmation Hearings

Solicitation of creditor votes began on June 17, 2002, and concluded on August 12, 2002. On September 9, 2002, an independent voting agent filed the voting results with the Bankruptcy Court. Nine of the ten voting classes under the Utility's proposed plan of reorganization approved the Plan. The alternative plan was approved by one of the eight voting classes under the alternative plan.

On November 6, 2002, the CPUC and the OCC filed an amended alternative plan and filed a motion asking the Bankruptcy Court to authorize the resolicitation of creditor votes and preferences. The Bankruptcy Court heard oral arguments on November 27, 2002. On February 6, 2003, the Bankruptcy Court issued an order denying the CPUC's and the OCC's request.

In determining whether to confirm either plan, the Bankruptcy Court will consider creditor and equity interests, plan feasibility, distributions to creditors and equity interests, and the financial viability of the reorganized entities. Various parties have filed objections to confirmation of either or both plans. PG&E Corporation and the Utility filed objections to the alternative plan stating their belief that the alternative plan is neither feasible nor confirmable for the reasons discussed above. The CPUC also filed an objection to the Plan.

The trial on confirmation of the alternative plan began on November 18, 2002. The trial on the Plan began on December 16, 2002, with objections common to both plans slated for trial during the Plan trial.

The Utility is unable to predict which plan, if any, the Bankruptcy Court will confirm. If either plan is confirmed, implementation of the confirmed plan may be delayed due to appeals, CPUC actions or proceedings, or other regulatory hearings that could be required in connection with the regulatory approvals necessary to implement that plan, and other events. The uncertainty regarding the outcome of the bankruptcy proceeding and the related uncertainty around the plan of reorganization that is ultimately adopted and implemented will have a significant impact on the Utility's future liquidity and results of operations. The Utility is unable at this time to predict the outcome of its bankruptcy case or the effect of the reorganization process on the claims of the Utility's creditors or the interests of the Utility's preferred shareholders. However, the Utility believes, based on information presently available to it, that cash and cash equivalents on hand at December 31, 2002, of $3.3 billion and cash available from operations will provide sufficient liquidity to allow it to continue as a going concern through 2003.

NOTE 3: PG&E NEG LIQUIDITY MATTERS

During 2002, adverse changes in the electric power and gas utility industry and energy markets affected PG&E Corporation, the Utility and PG&E NEG business including:

- Contractions and instability of wholesale electricity and energy commodity markets;
- Significant decline in generation margins (spark spreads) caused by excess supply and reduced demand in most regions of the United States;
- Loss of confidence in energy companies due to increased scrutiny by regulators, elected officials, and investors as a result of a string of financial reporting scandals;
- Heightened scrutiny by credit rating agencies prompted by these market changes and scandals which resulted in lower credit ratings for many market participants; and
- Resulting significant financial distress and liquidity problems among market participants leading to numerous financial restructurings and less market participation.

PG&E NEG has been significantly impacted by these changes in 2002. New generation came online while the economic recession reduced demand. This oversupply and reduced demand resulted in low spark spreads (the net of power prices less fuel costs) and depressed operating margins. These changes in the power industry have had a significant negative impact on the financial results and liquidity of PG&E NEG.

Before July 31, 2002, most of the various debt instruments of PG&E NEG and its affiliates carried investment-grade credit ratings as assigned by S&P and Moody's, two major credit rating agencies. Since July 31, 2002, PG&E NEG's rated entities have been downgraded several times. The result of these downgrades had left all of PG&E NEG's rated entities and debt instruments at below investment grade.

The downgrade of PG&E NEG's credit ratings impacts various guarantees and financial arrangements that require PG&E NEG to maintain certain credit ratings by S&P and/or Moody's. PG&E NEG's counterparties have demanded that PG&E NEG provide additional security for performance in the form of cash, letters of credit, acceptable replacement guarantees, or advanced funding of obligations. Other counterparties continue to have the right to make such demands. If PG&E NEG fails to provide this additional collateral within defined cure periods, PG&E NEG may be in default under contractual terms. In addition to agreements containing ratings triggers, other agreements allow counterparties to seek additional security for performance whenever such counterparty becomes concerned about PG&E NEG's or its subsidiaries' creditworthiness. PG&E NEG's credit downgrade constrains its access to additional capital and triggers increases in cost of indebtedness under many of its outstanding debt arrangements.

The credit downgrade also impacted PG&E NEG's and its subsidiaries' ability to service their financial obligations by putting constraints on the ability to move cash from one subsidiary to another or to PG&E NEG itself. PG&E NEG's subsidiaries must now independently determine, in light of each company's financial situation, whether any proposed dividend, distribution or intercompany loan is permitted and is in such subsidiary's interest.

PG&E NEG is currently in default under various recourse debt agreements and guaranteed equity commitments totaling approximately $2.9 billion. In addition, other PG&E NEG subsidiaries are in default under various debt agreements totaling approximately $2.5 billion, but this debt is non-recourse to PG&E NEG. On November 14, 2002, PG&E NEG defaulted on the repayment of the $431 million 364-day tranche of its Corporate Revolver. The amount outstanding under the two-year tranche of the Corporate Revolver is $273 million, the majority of which supports outstanding letters of credit. The default under the Corporate Revolver also constitutes a cross-default under PG&E NEG's (outstanding) (1) Senior Notes ($1 billion), (2) guarantee of the Turbine Revolver ($205 million), and (3) equity commitment guarantees for the GenHoldings credit facility ($355 million), for the La Paloma credit facility ($375 million) and for the Lake Road credit facility ($230 million). In addition, on November 15, 2002, PG&E NEG failed to pay a $52 million interest payment due under the Senior Notes.

PG&E Corporation continues to provide assistance to PG&E NEG, its subsidiaries and its lenders in their negotiations to establish a restructuring of PG&E NEG's commitments. However, if these negotiations prove unsuccessful and if lenders exercise their default remedies or if the financial commitments are not restructured, PG&E NEG and certain of its subsidiaries may be compelled to seek protection under or be forced into a proceeding under Chapter 11 of the Bankruptcy Code. Management does not expect the liquidity constraints of PG&E NEG and its subsidiaries will affect the financial condition of PG&E Corporation or the Utility.

Debt in Default and Long-Term Debt

The schedule below summarizes PG&E NEG's outstanding debt in default and long-term debts as of December 31, 2002, and 2001:

(in millions)	Maturity	Interest Rates	Outstanding Balance December 31, 2002	Outstanding Balance December 31, 2001
Debt in Default [1]				
PG&E NEG, Inc. Senior Unsecured Notes	2011	10.375%	$1,000	$1,000
PG&E NEG, Inc. Credit Facility – Tranche B (364 day)	11/14/02	Prime plus credit spread	431	330
PG&E NEG, Inc. Credit Facility – Tranche A (2-year facility with a $273 million total commitment)	8/23/03	Prime plus credit spread	42	–
Turbine and Equipment Facility	12/31/03	Prime plus credit spread	205	221
GenHoldings Construction Facility Tranche A	12/5/03	LIBOR plus credit spread	118	–
GenHoldings Construction Facility Tranche B	12/5/03	LIBOR plus credit spread	1,068	450
GenHoldings Swap Termination			50	–
Lake Road Construction Facility Tranche A	12/11/02	Prime plus credit spread	227	206
Lake Road Construction Facility Tranche B	12/11/02	Prime plus credit spread	219	198
Lake Road Construction Facility Tranche C		Prime plus credit spread	–	13
Lake Road Working Capital Facility	12/09/03	Prime plus credit spread	23	–
Lake Road Swap Termination	12/11/02		61	–
La Paloma Construction Facility Tranche A	12/11/02	Prime plus credit spread	367	319
La Paloma Construction Facility Tranche B	12/11/02	Prime plus credit spread	291	251
La Paloma Construction Facility Tranche C	12/11/02	Prime plus credit spread	20	18
La Paloma Construction Facility			29	–
La Paloma Swap Termination			79	–
Subtotal			4,230	3,006
Long-Term Debt				
PG&E GTN Senior Unsecured Notes	2005	7.10%	250	250
PG&E GTN Senior Unsecured Debentures	2025	7.80%	150	150
PG&E GTN Senior Unsecured Notes	2012	6.62%	100	–
PG&E GTN Medium Term Notes	Through 2003	6.96%	6	39
PG&E GTN Credit Facility	5/2/05	LIBOR plus credit spread	58	85
USGenNE Credit Facility	9/1/03	LIBOR plus credit spread	75	75
Plains End Construction Facility	9/6/06	LIBOR plus credit spread	56	23
Other non-recourse project term loans	Various	Principally LIBOR plus credit spread		100
Mortgage loan payable	2010	CP rate + 6.07%	7	7
Other	Various	Various	20	17
Subtotal			722	746
Total Debt in default and Long-term debt			$4,952	$3,752
Amounts classified as:				
Debt in default			$4,230	$ –
Long-term debt, classified as current			17	378
Long-term debt			630	3,299
Amount related to liabilities of operations held for sale, classified as current			75	75
Total Debt in default and Long-term debt			$4,952	$3,752

[1] Certain PG&E NEG long-term debt has been reclassified under debt in default above and has been classified as current liabilities in the accompanying Consolidated Balance Sheets. These instruments were not in default during 2001.

As of December 31, 2002, scheduled maturities of PG&E NEG debt in default and long-term debt were as follows:

(in millions)	
Three months ended March 31, 2003	$1,431
Three months ended June 30, 2003	-
Three months ended September 30, 2003	42
Three months ended December 31, 2003	2,757
Total debt in default	$4,230
2003	92
2004	3
2005	310
2006	52
2007	4
Thereafter	261
Total Long-term debt	$ 722

PG&E NEG Senior Unsecured Notes – On May 22, 2001, PG&E NEG completed an offering of $1 billion in senior unsecured notes (Senior Notes) and received net proceeds of approximately $972 million after bond debt discount and note issuance costs.

On November 15, 2002, PG&E NEG failed to pay a $52 million interest payment due on these notes. At December 31, 2002, PG&E NEG has an outstanding interest payment due on these notes of $65 million.

Credit Facilities – In August 2001, PG&E NEG arranged a $1.25 billion working capital and letter of credit facility consisting of a $750 million tranche with a 364-day term and a $500 million tranche with a two-year term. On October 21, 2002, the available commitments were reduced to $431 million and $279 million, respectively. As of December 31, 2002, $431 million had been drawn against the 364-day revolving credit facility and $42 million had been drawn against the two-year facility, in addition to $231 million of letters of credit issued under the two-year facility. At December 31, 2002, PG&E NEG had outstanding interest accrued on these facilities of $6 million.

PG&E NEG also has other revolving credit facilities held by subsidiaries. These facilities relate specifically to funding requirements of these entities and are not available to PG&E NEG. Under the terms of the various revolving credit facilities, the credit spread component of the interest rates and fees charged for borrowings was increased as a result of PG&E NEG's credit downgrades. PG&E NEG's credit downgrades did not trigger any acceleration of payments due under these long-term debt arrangements.

PG&E GTN Credit Facility – On May 2, 2002, PG&E GTN entered into a three-year $125 million revolving credit facility. At December 31, 2002, there was $58 million outstanding under this facility. The average weighted interest rate on the amount outstanding at December 31, 2002 is approximately 2.89 percent.

Turbine and Equipment Facility – In May 2001, PG&E NEG established a revolving credit facility of up to $280 million to fund turbine payments and equipment purchases associated with its generation facilities. The average weighted interest rate on the amount outstanding at December 31, 2002 is approximately 4.66 percent.

USGenNE Credit Facility – In August 2001, USGenNE entered into a credit and letter of credit facility that has a total commitment of $100 million of which $75 million have been drawn upon and $13 million supports letters of credit that have been issued and are outstanding at December 31, 2002. Total amounts outstanding under this facility, including any accrued interest are included in Liabilities of operations held for sale on the Consolidated Balance Sheets. See Note 6 Discontinued Operations. The average weighted interest rate on the amount outstanding is approximately 2.61 percent.

GenHoldings Construction Facility – In December 2001, PG&E NEG entered into a $1.075 billion 5-year non-recourse credit facility, which increased to $1.46 billion on April 5, 2002, for the GenHoldings I, LLC, (GenHoldings) portfolio of projects secured by the Millennium, Harquahala, Covert, and Athens projects. The facility was intended to be used to reimburse PG&E NEG and lenders for a portion of the construction costs already incurred on these projects and to fund a portion of the balance of the construction costs through completion.

GenHoldings has defaulted under its credit agreement by failing to make equity contributions to fund construction draws for the Athens, Harquahala, and Covert generating projects. Through December 31, 2002, GenHoldings has contributed $833 million of equity to the projects. Although PG&E NEG has guaranteed GenHoldings' obligation to make equity contributions, PG&E NEG has notified the GenHoldings lenders that it will not make further equity contributions on behalf of GenHoldings. In November and December 2002, the lenders executed waivers and amendments to the credit agreement under which they agreed to continue to waive until March 31, 2003, the default caused by GenHoldings' failure to make equity contributions. In addition, certain of these lenders agreed to increase their loan commitments to an amount sufficient to provide (1) the funds necessary to complete construction of the Athens, Covert and Harquahala facilities; and (2) additional working capital facilities to enable each project, including Millennium, to timely pay for its fuel requirements and to provide its own collateral to support natural gas pipeline capacity reservations and independent transmission system operator requirements. The November and December 2002 increased loan commitments are senior to the original liens and rank equally with each other but are senior to amounts loaned through and including the October credit extension. As a result, on November 25, 2002, the funding lenders paid GenHoldings' then pending draw request of approximately $75 million and on December 23, 2002, the funding lenders paid GenHoldings' then pending draw request of approximately $44 million.

In connection with the lenders' waiver of various defaults and additional funding commitments, PG&E NEG has agreed to cooperate with any reasonable proposal by the lenders regarding disposition of the equity in or assets of any or all of the PG&E NEG subsidiaries holding the Athens, Covert, Harquahala and Millennium projects. The amended credit agreement provides that an event of default will occur if the Athens, Covert, Harquahala and Millennium facilities are not transferred to the lenders or their designees on or before March 31, 2003. Such a default would trigger lender remedies, including the right to foreclose on the projects.

Under the waiver, PG&E NEG has re-affirmed its guarantee of GenHoldings' obligation to make equity contributions to these projects of approximately $355 million. Neither PG&E NEG nor GenHoldings currently expects to have sufficient funds to make this payment. The requirement to pay $355 million will remain an obligation of PG&E NEG that would survive the transfer of the projects.

Further, as a result of GenHoldings' failure to make required payments under the interest rate hedge contracts entered into by GenHoldings, the counterparties to such interest rate hedge contracts terminated the contracts during December 2002. Settlement amounts due by GenHoldings in connection with such terminated contracts are, in the aggregate, approximately $49.8 million.

Lake Road and La Paloma Construction Facilities – In September 1999 and March 2000, Lake Road and La Paloma (respectively) entered into Participation Agreements to finance the construction of the two plants. In 2001, subsequent to the issuance of the 1999 and 2000 financial statements, management determined that the assets and liabilities related to these leased facilities should have been consolidated. In November 2002 Lake Road and La Paloma defaulted on their obligations to pay interest and swap payments. In addition, as a result of PG&E NEG's downgrade to below investment-grade by both S&P and Moody's, PG&E NEG, as guarantor of certain debt obligations of Lake Road and La Paloma, became required to make equity contributions to Lake Road and La Paloma of $230 million and $375 million respectively. None of PG&E NEG, Lake Road or La Paloma have sufficient funds to make these payments.

As of December 4, 2002, PG&E NEG and certain subsidiaries entered into various agreements with the respective lenders for each of the Lake Road and La Paloma generating projects providing for (1) funding of construction costs required to complete the La Paloma facility; and (2) additional working capital facilities to enable each subsidiary to timely pay for its fuel requirements and to provide its own collateral to support natural gas pipeline capacity reservations and independent transmission system operator requirements, as well as for general working capital purposes. Lenders extending new credit under these agreements have received liens on the projects that are senior to the existing lenders' liens. These agreements provide, among other things, that the failure to transfer the Lake Road and La Paloma projects to the respective lenders by June 9, 2003 will constitute a default under the agreements. The failure to transfer the facilities would entitle the lenders to accelerate the new indebtedness and exercise other remedies.

In consideration of the lenders' forebearance and additional funding, PG&E NEG had previously agreed to cooperate, and cause its subsidiaries to cooperate, with any reasonable proposal regarding disposition of the ownership interests in and/or assets of the La Paloma project, on terms and conditions satisfactory to the lenders in their sole discretion.

The La Paloma and Lake Road projects have been financed entirely with debt. PG&E NEG has guaranteed the repayment of a portion of the project subsidiary debt in the approximate aggregate amounts of $374.5 million for La Paloma and $230 million for Lake Road, which amounts represent the subsidiaries' equity contribution in the projects. The lenders have accelerated the guaranteed portion of the debt and made a payment demand under the PG&E NEG guarantee. Neither the PG&E NEG subsidiaries nor PG&E NEG have sufficient funds to make these payments. The requirement to make the payments will remain an obligation of PG&E NEG that would survive the transfer of the projects.

Further, as a result of the La Paloma and Lake Road subsidiaries' failure to make required payments under the interest rate hedge contracts entered into by them, the counterparties to such interest rate hedge contracts have terminated the contracts. Settlement amounts due from the Lake Road and La Paloma project subsidiaries in connection with such terminated contracts are, in the aggregate, approximately $61 million for Lake Road and $79 million for La Paloma.

PG&E GTN Senior Unsecured Notes, Debentures and Medium-Term Notes

On May 31, 1995, PG&E GTN completed the sale of $400 million of debt securities through a $700 million shelf registration. PG&E GTN issued $250 million of 7.10 percent 10-year senior unsecured notes due June 1, 2005, and $150 million of 7.80 percent 30-year senior unsecured debentures due June 1, 2025. The 10-year notes were issued at a discount to yield 7.11 percent and the 30-year debentures were issued at a discount to yield 7.95 percent. At December 31, 2002, the unamortized debt discount balance for the notes and debentures were $0.1 million and $2.0 million, respectively. The 30-year debentures are callable after June 1, 2005, at the option of GTN. Both the senior unsecured notes and the senior unsecured debentures were downgraded during 2002 to a credit rating of CCC from Standard and Poor's and B1 from Moody's Investors Service.

On June 6, 2002, PG&E GTN issued $100 million of 6.62 percent Senior Notes due June 6, 2012. Proceeds were used to repay $90 million of debt on its revolving credit facility, and the balance retained to meet general corporate needs.

In addition, during 1995, $70 million of medium-term notes were issued at face values ranging from $1 million to $17 million. As at January 31, 2003 the medium-term notes carry a credit rating of CCC from Standard and Poor's and B1 from Moody's Investors Service. Medium-term notes totalling $33 million in 2002 and $31 million in

2001 matured and were accordingly extinguished. The remaining notes mature during 2003 and have an average interest rate of 6.96 percent.

Plains End Construction Facility – In September 2001, PG&E NEG established a facility for $69.4 million. The debt facility was used to fund the balance of construction costs for the Plains End project. The facility expires upon the earlier of five years after commercial operations have been declared or September 2007. The average weighted interest rate on the amount outstanding is approximately 5.17 percent.

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

Certain credit agreements contain, among other restrictions, customary affirmative covenants, representations and warranties and have cross-default provisions with respect to PG&E 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 PG&E NEG's property or assets; incurrence of indebtedness; entering into agreements limiting the right of any subsidiary of PG&E NEG to make payments to its shareholders; and certain transactions with affiliates. Certain credit agreements also require that PG&E NEG maintain a minimum ratio of cash flow available for fixed charges to fixed charges and a maximum ratio of funded indebtedness to total capitalization.

Letters of Credit

In addition to outstanding balances under the above credit facilities PG&E NEG has commitments available under these facilities and other facilities to issue letters of credit.

The following table lists the various facilities that have the capacity to issue letters of credit:

(in millions) Borrower	Maturity	Letter of Credit Capacity	Letter of Credit Outstanding December 31, 2002
PG&E NEG	8/03	$231	$231
USGenNE	8/03	25	13
PG&E Gen	12/04	7	7
PG&E ET	9/03	19	19
PG&E ET	11/03	35	34

NOTE 4: DEBT FINANCING

Debt in Default and Long-Term Debt

Debt in default and long-term debt that matures in one year or more from the date of issuance consisted of the following:

(in millions)	Balance at December 31,	
	2002	2001
Debt in Default: [1]		
PG&E NEG credit facilities in default		
Revolving credit facilities in default	$ 473	$ 330
PG&E NEG long-term debt in default		
Senior unsecured notes, 10.375%, due 2011	$1,000	$1,000
Term loans, various, 2002-2003	2,757	1,676
Total long-term debt in default	3,757	2,676
Total Debt in Default	$4,230	$3,006
Long-Term Debt:		
PG&E Corporation		
Lehman Loans due 2006, variable	$ 720	$ –
9.50% Convertible Subordinated Notes	280	–
General Electric and Lehman Loans due in 2003, variable	–	1,000
Discount	(24)	(96)
Total long-term debt, net of current portion	976	904
Utility		
First and refunding mortgage bonds:		
Maturity — Interest Rates		
2003-2005 — 5.875% to 6.250%	880	1,214
2006-2010 — 6.35% to 6.625%	85	85
2011-2026 — 5.85% to 8.80%	2,079	2,079
Principal amounts outstanding	3,044	3,378
Unamortized discount net of premium	(24)	(26)
Total mortgage bonds	3,020	3,352
Less: current portion	281	333
Total long-term debt, net of current portion	2,739	3,019
PG&E NEG		
Senior unsecured notes, 7.10%, due 2005	250	250
Senior unsecured debentures, 7.80%, due 2025	150	150
Senior unsecured notes, 6.62%, due 2012	100	–
Medium-term notes, 6.83% to 6.96%, thru 2003	6	39
Term loans, various, 2006	56	123
Amount outstanding under credit facilities	133	160
Other long-term debts	27	24
Sub-total	722	746
Less: current portion	17	48
Amount related to liabilities of Operations held for sale, current	75	75
Total long-term debt, net of current portion	630	623
Total Long-Term Debt	$4,345	$4,546
Long-Term Debt Subject to Compromise:		
Utility		
Senior notes, 9.63%, due 2005	680	680
Pollution control loan agreements, variable rates, due 2016-2026	614	614
Pollution control loan agreement, 5.35% fixed rate, due 2016	200	200
Unsecured medium-term notes, 5.81% to 8.45%, due 2003-2014	287	287
Deferrable interest subordinated debentures, 7.9%, due 2025	300	–
Other Utility long-term debt	19	20
Total Long-Term Debt Subject to Compromise	$2,100	$1,801

[1] Certain PG&E NEG long-term debt as of December 31, 2001 has been shown in the above schedule as debt in default above for comparative purposes. This long-term debt was not in default during 2001.

PG&E Corporation

PG&E Corporation entered in a credit agreement (Original Credit Agreement) with General Electric Capital Corporation (GECC) and Lehman Commercial Paper Inc. (LCPI) in 2001. During 2002, PG&E Corporation negotiated new terms to the Original Credit Agreement. In August 2002, PG&E Corporation made a voluntary prepayment of principal and interest totaling $607 million to the GECC portion of the debt. As a result of the prepayment, PG&E Corporation wrote off $83 million of unamortized loan fees and reversed $38 million of unamortized loan discount associated with unvested options, netting to a $45 million charge to interest expense. In relation to the remainder of the loan, PG&E Corporation also recorded $70 million of debt extinguishment losses to interest expense, as a result of new waiver extensions.

On October 18, 2002, PG&E Corporation entered into a Second Amended and Restated Credit Agreement (Credit Agreement) with Lehman Commercial Paper, Inc. (LCPI or, with other parties, the Lenders) with total principal amount of $720 million outstanding at December 31, 2002. The total principal amount includes $420 million previously retained under prior credit arrangements and $300 million representing new loans (New Loans), and collectively referred to as the Loans.

The New Loans were released from escrow to PG&E Corporation on January 17, 2003, concurrent with the payment of a funding fee of $9 million. The Loans are repayable in a single installment on September 2, 2006, unless repaid earlier in accordance with the Credit Agreement.

The interest rate under the Credit Agreement is Eurodollar Rate plus 10 percent, based upon interest periods of one, two, three, or six months, as selected each period by PG&E Corporation. Interest is payable quarterly or at the end of the selected interest period, whichever is shorter. On January 17, 2003, PG&E Corporation paid a first interest payment of $13 million and elected an initial interest period of six months.

In addition, the Credit Agreement provides for Payment-in-Kind (PIK) interest of 4 percent commencing upon receipt of the funds. PIK interest is not paid in cash but rather added to the principal amount of the loan at the start of each interest period.

Except for an option agreement (Option Agreement), granting certain lenders options to purchase common stock of PG&E & NEG, in conjunction with the prior March 1, 2002, Credit Agreement as amended (the Old Credit Agreement), amounts under the Credit Agreement are senior unsubordinated obligations of PG&E Corporation.

On September 3, 2002, General Electric Capital Corporation (GECC) gave notice to PG&E Corporation that it was exercising its right to sell (put) to PG&E Corporation its options representing 1.8 percent of PG&E NEG, which it had acquired in connection with the Old Credit Agreement. Under the terms of the option agreement, PG&E Corporation and GECC entered into an appraisal process to determine the value of the PG&E NEG options. On October 30, 2002, before the completion of the appraisal process, GECC cancelled by giving notice of cancellation of its put notice, which was accepted by PG&E Corporation. GECC no longer has the right to put these options to PG&E Corporation. On February 25, 2003, GECC exercised the options, which otherwise would have expired on March 1, 2003. Similar options representing 1.2 percent of PG&E NEG must also be exercised before March 1, 2003.

Under the Option Agreement discussed above, certain lenders were granted warrants to purchase certain quantities of PG&E NEG shares. These warrants are marked to market on a monthly basis. In the third quarter of 2002, PG&E Corporation recorded other income of $71 million, as a result of the change in market value of the PG&E NEG warrants during that period. As discussed above, the appraisal process to determine the value of PG&E NEG was not completed. If it is determined that PG&E NEG's value is greater than the value currently reflected in the mark-to market accounting, PG&E

Corporation would be required to incur a charge to earnings as a result of the increased valuation.

Security

The Loans are secured by a first priority security interest in the common stock of PG&E NEG and the common stock of the Utility, along with substantially all other assets of PG&E Corporation.

Other Terms

Under the terms of the Credit Agreement, PG&E Corporation is required to make an offer to repay the Loans (including prepayment fees) under various circumstances, which include a change in control of PG&E Corporation and a spin-off of the Utility in connection with a plan of reorganization.

As required by the Credit Agreement, PG&E Corporation retained an interest reserve of $76 million as of December 31, 2002, and upon receipt of the New Loans placed an additional $54 million into such interest reserve.

Restrictions

The Credit Agreement contains limitations, among other restrictions, on the ability of PG&E Corporation and certain of its subsidiaries to grant liens, consolidate, merge, purchase or sell assets, declare or pay dividends, incur indebtedness, or make advances, loans, and investments.

However, PG&E Corporation is permitted to dispose of PG&E NEG assets under certain circumstances. Any proceeds to PG&E Corporation from such permitted sales must be applied to prepay the Loans.

Events of Default and Mandatory Prepayments

The Credit Agreement contains certain events of default, including PG&E Corporation's failure to pay any indebtedness of $100 million or more. Upon an event of default, the Lenders are entitled to accelerate and declare the Loans immediately due and payable.

The Credit Agreement requires mandatory prepayments with the net cash proceeds from incurrence of additional indebtedness, issuance or sale of equity by PG&E Corporation or the Utility, sale of certain assets by PG&E Corporation, the Utility, or PG&E NEG; the receipt of condemnation or insurance proceeds, and distributions or dividends paid to PG&E Corporation or PG&E NEG.

Upon mandatory prepayment, PG&E Corporation must pay a prepayment fee calculated depending upon when the prepayment occurred.

PG&E Corporation Warrants

In connection with the Credit Agreement, PG&E Corporation also issued to the Lenders warrants to purchase 2,658,268 shares of common stock of PG&E Corporation, at an exercise price of $0.01 per share. These warrants expire on September 2, 2007, and are generally exercisable except when by their exercise the holder becomes, and has the intention to remain, the single largest common shareholder.

The fair market value of these warrants was estimated at the date of grant and recorded as a discount to long-term debt. At December 31, 2002, the discount was $24 million, net of accumulated discount amortization of $1 million.

In connection with the prior June 25th Amended and Restated Credit Agreement, PG&E Corporation issued warrants to the lenders to purchase 2,397,541 shares of common stock of PG&E Corporation, at an exercise price of $0.01 per share and with terms similar to the warrants described above. The unamortized discount related to these warrants and other deferred financing costs were charged to interest expense upon the voluntary repayment of $600 million principal and interest of approximately $6.7 million in August 2002.

PG&E Corporation has agreed to provide, following consummation of a plan of reorganization of the Utility, registration rights in connection with the shares issuable upon exercise of these warrants.

Use of Proceeds

PG&E Corporation will use the net proceeds of the New Loans, net of various interest reserve requirements, to fund corporate working capital and for general corporate purposes.

Convertible Subordinated Notes

On June 25, 2002, PG&E Corporation issued 7.50 percent Convertible Subordinated Notes (the Notes) due 2007 in the aggregate principal amount of $280 million. The Notes may be converted by the holders into 18,558,655 shares of the common stock of PG&E Corporation.

Concurrent with the October 18, 2002, financing described above, the Note Indenture was amended as follows:

- The cross default provisions related to PG&E NEG and its subsidiaries was deleted;
- The interest rate on the Notes increased to 9.50 percent from 7.50 percent;
- The maturity of the Notes was extended to June 30, 2010, from June 30, 2007; and
- PG&E Corporation provided the holders of the Notes with a one-time right to require PG&E Corporation to repurchase the Notes on June 30, 2007, at a purchase price equal to the principal amount plus accrued and unpaid interest (including any liquidated damages and pass-through dividends, if any).

Utility

First and Refunding Mortgage Bonds – First and refunding mortgage bonds are issued in series and bear annual interest rates ranging from 5.85 percent to 8.80 percent. 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. While in bankruptcy, the Utility is prohibited from making payments on the Mortgage Bonds, without permission from the Bankruptcy Court. The Bankruptcy Court approved the payment of $333 million of mortgage bonds maturing in March 2002 and has also approved the payment of interest in accordance with the terms of the bonds.

Included in the total mortgage bonds outstanding at December 31, 2002, and 2001, are $345 million of bonds held in trust for the California Pollution Control Financing Authority (CPCFA) with interest rates ranging from 5.85 percent to 6.63 percent 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 7.38 percent. The Utility used the net proceeds to repay short-term borrowings incurred to finance scheduled payments due to the PX for August 2000 power purchases and for other general corporate purposes. These notes contained interest rate adjustments dependent upon the Utility's unsecured debt ratings.

As a result of the Utility's credit rating downgrades, there was an interest rate adjustment of 1.75 percent on the $680 million senior notes. In addition, there was an interest premium penalty of 0.5 percent imposed on the senior notes due to the Utility's inability to make a public offering on April 30, 2001. Accordingly, the rate increased to 9.63 percent from 7.38 percent effective November 1, 2001. In 2001, the Utility's bankruptcy filing and failure to make payments on the senior notes were events of default. The senior notes have been classified as Liabilities Subject to Compromise in the Consolidated Balance Sheets at December 31, 2002, and 2001.

Pollution Control Loan Agreements – Pollution control loan agreements from the CPCFA totaled $814 million at December 31, 2002, and 2001.

Interest rates on $614 million of the loans are variable. For 2002, the variable interest rates ranged from 1.25 percent to 1.78 percent. These loans are subject to redemption by the holder under certain circumstances. They were secured primarily by irrevocable letters of credit (LOC) from certain banks, which based on terms negotiated in 2002, mature in 2003 through 2004. On March 1, 2001, a $200 million loan was converted to a fixed rate obligation with an interest rate of 5.35 percent.

In April and May 2001, four loans totaling $454 million were accelerated and the banks paid the amounts due under the LOCs. In the meantime, the Utility was unable to make interest payments due to the bankruptcy filing.

This resulted in like obligations from the Utility to the banks. Amounts outstanding at December 31, 2002, and 2001, under the pollution control agreements were classified as Liabilities Subject to Compromise in the Consolidated Balance Sheets at December 31, 2002 and 2001.

Medium-Term Notes – The Utility has outstanding $287 million of medium-term notes due from 2002 to 2014 with interest rates ranging from 5.81 percent to 8.45 percent, which are also in default. The outstanding principal amounts at December 31, 2002, and 2001, were classified as Liabilities Subject to Compromise in the accompanying financial statements.

7.90 Percent Deferrable Interest Subordinate Debentures

On November 28, 1995, PG&E Capital I (Trust), a wholly owned subsidiary of the Utility, issued 12 million shares of 7.90 percent Cumulative Quarterly Income Preferred Securities (QUIPS), with a total 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 a total 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 7.90 percent Deferrable Interest Subordinated Debentures (QUIDS) due 2025 issued by the Utility with a value of $309 million at maturity.

On March 16, 2001, the Utility postponed quarterly interest payments on the QUIDS until further notice in accordance with the bond's terms. The corresponding quarterly payments on the QUIPS, due on April 2, 2001, were similarly postponed.

Quarterly interest payments may be postponed up to 20 consecutive quarters under the terms of the bond agreement. According to the bond's terms, investors earn interest on the unpaid distributions at the rate of 7.90 percent. Upon liquidation or dissolution of the Utility, holders of the QUIPS would be entitled to the liquidation preference of $25 per share plus all accrued and unpaid interest thereon to the date of payment.

As discussed in Note 2, on March 27, 2002, the Bankruptcy Court issued an order authorizing the Utility to pay pre- and post-petition interest to holders of certain undisputed claims, including QUIPS, within ten business days after Bankruptcy Court approval of the Utility's disclosure statement.

The disclosure statement was approved on April 24, 2002. On May 6, 2002, the Utility made payments to holders of QUIPS representing interest accrued through February 28, 2002, and on March 31, 2002, the Utility made an additional interest payment for the one month ended March 31, 2002. On July 1, 2002, the Utility made an interest payment for the three months ended June 30, 2002, and since then has continued to make quarterly interest payments as scheduled.

On April 12, 2001, Bank One, N.A., as successor-in-interest to The First National Bank of Chicago (Property Trustee), gave notice that an event of default exists under the Trust Agreement due to the Utility's filing for Chapter 11 on April 6, 2001 (see Note 2). As a result of the event of default, the Trust Agreement required the Trust to be liquidated by the trustee by distributing the QUIDS, after satisfaction of liabilities to creditors of the Trust, to the holders of QUIPS. Pursuant to the Trustee's notice dated

April 24, 2002, the Trust was liquidated on May 24, 2002. Upon liquidation of the Trust, the former holders of QUIPS received a like amount of QUIDS. The terms and interest payments of the QUIDS correspond to the terms and interest payments of the QUIPS.

The QUIDS are included in financing debt classified as Liabilities Subject to Compromise on PG&E Corporation's and Utility's Consolidated Balance Sheets at December 31, 2002. The QUIPS are reflected as "Mandatory Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures" on PG&E Corporation's and the Utility's Consolidated Balance Sheets at December 31, 2001.

PG&E NEG

See Note 3 PG&E Liquidity Matters for discussions related to PG&E NEG's debt in default and long-term debt.

Repayment Schedule

At December 31, 2002, PG&E Corporation's combined aggregate amounts of maturing long-term debt are reflected in the table below:

(dollars in millions) **Expected maturity date**	**2003**	**2004**	**2005**	**2006**	**2007**	**Thereafter**	**Total**
PG&E Corporation[1]							
Long-term debt:							
Fixed rate obligations (9.50% Convertible Subordinated Notes)	$ –	$ –	$ –	$ –	$ –	$ 280	$ 280
Average interest rate						9.50%	9.50%
Variable rate obligation[2]	–	–	–	842	–	–	842
Utility:							
Long-term debt:							
Liabilities not subject to compromise:							
Fixed rate obligations	281	310	290	–	–	2,139	3,020
Average interest rate	6.25%	6.25%	5.88%	–	–	7.25%	6.92%
Liabilities subject to compromise:							
Fixed rate obligations[3]	173	54	696	1	1	261	1,186
Average interest rate	7.40%	7.51%	9.56%	9.45%	9.45%	5.95%	8.35%
7.90 Percent Deferrable Interest Subordinated Debentures	–	–	–	–	–	300	300
Variable rate obligations[4]	349	265	–	–	–	–	614
Rate reductions bonds	290	290	290	290	290	–	1,450
Average interest rate	6.36%	6.42%	6.42%	6.44%	6.48%	–%	6.42%
PG&E NEG:							
Long-term debt:							
Fixed rate obligations	6	–	250	–	–	250	506
Variable rate obligations	86	3	60	52	4	11	216
Average interest rate	6.41%	6.57%	6.92%	7.33%	7.31%	7.10%	6.95%
Total	$1,185	$ 922	$1,586	$1,185	$ 295	$3,241	$8,414

(1) Certain PG&E NEG Long-term debt has been reclassified under Long-term debt in default and has been reclassified as a current liability in the accompanying Consolidated Balance Sheets. The maturity of such debt in default is disclosed in Note 3 PG&E NEG Liquidity Matters.

(2) $720 million outstanding at December 31, 2002, with 4 percent interest compounded yields value of $842 million at maturity.

(3) $132 million out of the 2003 repayment amount matured in 2002 and 2001, and was unpaid.

(4) The expected maturity dates for pollution control loan agreements with variable interest rates are based on the maturity dates of the letters of credit securing the loans.

Credit Facilities and Short-Term Borrowings

The following table summarizes PG&E Corporation's lines of credit:

(in millions)	December 31, 2002	December 31, 2001
Credit Facilities Subject to Compromise:		
Utility		
5-year Revolving Credit Facility	$ 938	$ 938
Total Lines of Credit Subject to Compromise	938	938
Short-Term Borrowings Subject to Compromise:		
Utility		
Bank Borrowings – Letters of Credit for Accelerated Pollution Control Agreements	454	454
Floating Rate Notes	1,240	1,240
Commercial Paper	873	873
Total Short-Term Borrowings Subject to Compromise	2,567	2,567
Total Credit Facilities and Short-Term Borrowings Subject to Compromise	$3,505	$3,505

The total amount outstanding on the Utility's credit facilities was $938 million at December 31, 2002, and 2001. The total amount outstanding on the Utility's short-term borrowings was $2,567 million at December 31, 2002, and 2001. Due to the Utility's bankruptcy filing (see Note 2), both have been classified as Liabilities Subject to Compromise in the table above and on the Consolidated Balance Sheets for 2002 and 2001.

The weighted average interest rate on the short-term borrowings subject to compromise as of December 31, 2002, and 2001, was 7.47 percent and 7.53 percent.

Utility

Credit Facilities – At December 31, 2002, and 2001, the Utility had $938 million outstanding on a $1 billion five-year revolving credit facility. This facility was used to support the Utility's commercial paper program and other liquidity requirements. Non-payment of matured commercial paper in excess of $100 million in 2001 constituted an event of default under the credit facility and consequently the bank terminated its outstanding commitment. The outstanding balance is classified as Liabilities Subject to Compromise on the December 31, 2002, and 2001, Consolidated Balance Sheets.

Commercial Paper – The total amount of commercial paper outstanding at December 31, 2002, and 2001, was $873 million. The Utility has been in default on its commercial paper obligations since January 17, 2001. The weighted average interest rate on the Utility's commercial paper obligation as of December 31, 2002, and 2001, was 7.47 percent.

Floating Rate Notes – The Utility issued a total of $1,240 million of 364-day floating rate notes in November 2000, with interest payable quarterly. These notes were not paid on the maturity date of November 30, 2001. Non-payment of the floating rate notes was an event of default, entitling the floating rate note trustee to accelerate the repayment of these notes. However, the Utility is prohibited from paying liabilities incurred prior to its bankruptcy filing without Bankruptcy Court approval.

Bank Borrowing – Letters of Credit for Accelerated Pollution Control Bonds – As previously discussed in April and May 2001, four pollution control loan agreements totaling $454 million were accelerated by the note holders. These accelerations were funded by various banks under letter of credit agreements resulting in similar obligations from the Utility to the banks.

PG&E NEG

See Note 3 PG&E Liquidity Matters for discussions related to PG&E NEG's credit facilities and short-term borrowings.

NOTE 5: RATE REDUCTION BONDS

In December 1997, PG&E Funding LLC (Funding), a limited liability corporation wholly owned by and consolidated with the Utility, issued $2.9 billion of rate reduction bonds. The proceeds of the rate reduction bonds were used by PG&E Funding LLC to purchase from the Utility the right, known as "transition property," to be paid a specified amount from a non-bypassable charge levied on residential and small commercial customers (Fixed Transition Amount (FTA) charges). FTA charges are authorized by the CPUC pursuant to state legislation and will be paid by residential and small commercial customers until the rate reduction bonds are fully retired. FTA charges are collected by the Utility and remitted to Funding based on a transition property servicing agreement. On January 4, 2001, S&P lowered the Utility's short-term credit rating to A-3, and on January 5, 2001, Moody's lowered the Utility's short-term credit rating to P-3. As a result, on January 8, 2001, the Utility was required under the transition property servicing agreement to begin remitting to Funding on a daily basis FTA charges paid by ratepayers, as opposed to once a month, as had previously been required.

The rate reduction bonds have maturity dates ranging from 2003 to 2007, and bear interest at rates ranging from 6.36 percent to 6.48 percent. The bonds are secured solely by the transition property and there is no recourse to the Utility or PG&E Corporation.

The total amount of rate reduction bonds principal outstanding was $1,450 million at December 31, 2002, and $1,740 million at December 31, 2001. The scheduled principal payments on the rate reduction bonds for the years 2003 through 2007 are $290 million for each year. While Funding is a wholly owned consolidated subsidiary of the Utility, Funding is legally separate from the Utility. The assets of Funding 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 6: DISCONTINUED OPERATIONS

Discontinued Operations and Assets Held for Sale

USGen New England – In September 1998, USGen New England, Inc. (USGenNE) acquired the non-nuclear generating assets of the New England Electric System (NEES) for approximately $1.8 billion. These assets included:

- 2,344 megawatts (MW) of coal and oil fired power plants in Massachusetts;
- 1,166 MW of hydroelectric facilities in New Hampshire, Vermont, and Massachusetts;
- 495 MW of gas-fired power plants in Rhode Island;
- Above market power purchase agreements with support payments provided by NEES for the first nine years;
- Gas pipeline transportation contracts; and
- Transition wholesale load contracts known as Standard Offer Agreements.

Consistent with its previously announced strategy to dispose of certain merchant assets, in December 2002, the Board of Directors of PG&E Corporation approved management's plan for the proposed sale of USGenNE.

Under the provisions of SFAS No. 144, USGenNE is accounted for as an asset held for sale at December 31, 2002. This requires that the asset be recorded at the lower of fair value, less costs to sell or book value. Based on the current estimated fair value of a sale of USGenNE, PG&E NEG recorded a pre-tax loss of $1.1 billion, with no tax benefits associated with the loss, in the fourth quarter of 2002. It is anticipated that the sale of USGenNE assets will occur during 2003. This loss on sale as well as the operating results from USGenNE is being reported as discontinued operations in the Consolidated Financial Statements of PG&E Corporation at December 31, 2002.

Mountain View – On September 17 and 28, 2001, PG&E NEG purchased Mountain View Power Partners, LLC and Mountain View Power Partners II, LLC, respectively (collectively referred to as Mountain View). The two companies were merged on October 1, 2002.

These companies own 44 and 22 MW wind energy projects, respectively, near Palm Springs, California. PG&E NEG contracted with SeaWest for the operation and maintenance of the wind units. Total consideration for these two companies was $92 million. The power is sold to the DWR under a 10-year contract.

In December 2002, the Board of Directors of PG&E Corporation approved the sale of Mountain View. On December 18, 2002, a subsidiary of PG&E NEG entered into an agreement to sell Mountain View to Centennial Power, Inc. for $102 million.

Under the provisions of SFAS No. 144, Mountain View is accounted for as an asset held for sale at December 31, 2002. This requires that the asset be recorded at the lower of fair value, less costs to sell or book value. Based upon the current estimated proceeds from the sale of Mountain View, PG&E NEG will record an immaterial gain in the first quarter of 2003.

The operating results from Mountain View are reported as discontinued operations in the Consolidated Financial Statements of PG&E Corporation at December 31, 2002.

ET Canada – In December 2002, the proposed sale of PG&E Energy Trading Canada Corporation (ET Canada) to Seminole Gas Company Limited was approved. Based upon the sales price, PG&E Energy Trading Holdings Corporation, the direct owner of the shares of ET Canada recorded a $25 million pre-tax loss, with no tax benefits associated with the loss, on the disposition of ET Canada. The transaction is anticipated to close by the end of February or early March, 2003. Under the provisions of SFAS No. 144, the assets and liabilities of ET Canada have been classified as assets held for sale and reflected as discontinued operations in the Consolidated Financial Statements of PG&E Corporation at December 31, 2002.

The following table reflects the operating results of the combined USGenNE, Mountain View, and ET Canada before reclassification to discontinued operations:

(in millions)	Year ended December 31,		
	2002	2001	2000
Operating Revenues	$1,289	$943	$905
Operating Expenses			
Cost of commodity sales and fuel	993	486	483
Operations, maintenance, and management	243	246	236
Depreciation and amortization	71	66	64
Other operating expenses	1	-	-
Total operating expense	1,308	798	783
Operating Income (Loss)	(19)	145	122
Interest income	46	46	52
Interest expense	(2)	(4)	-
Other income (expense), net	(11)	(7)	-
Income Before Income Taxes	14	180	174
Income tax expense	3	73	75
Earnings from USGenNE, Mountain View, and ET Canada classified as Discontinued Operations	$ 11	$107	$ 99

The following table reflects the components of assets and liabilities of Operations held for sale of USGenNE, Mountain View, and ET Canada before reclassification to discontinued operations:

(in millions)	December 31,	
	2002	2001
ASSETS		
Current Assets		
Cash and cash equivalents	$ 32	$ 66
Accounts receivable–trade	300	398
Inventory	82	79
Price risk management	196	187
Prepaid expenses, deposits and other	97	14
Total current assets held for sale	707	744
Property, Plant and Equipment		
Total property, plant and equipment	799	1,906
Accumulated depreciation	(285)	(216)
Net property, plant and equipment [1]	514	1,690
Other Noncurrent Assets		
Long-term receivables [2]	319	455
Intangible assets, net of accumulated amortization of $37 million and $28 million	20	29
Price risk management	30	60
Other	33	20
Total noncurrent assets held for sale	916	2,254
TOTAL ASSETS HELD FOR SALE	$1,623	$2,998

(in millions)	December 31, 2002	December 31, 2001
LIABILITIES		
Current Liabilities		
Long-term debt, classified as current	$ 75	$ –
Accounts payable and accrued expenses	207	307
Price risk management	331	141
Out-of-market contractual obligations (3)	86	116
Other	–	6
Total current liabilities of operations held for sale	699	570
Noncurrent Liabilities		
Long-term debt	–	75
Deferred income taxes	–	187
Price risk management	272	51
Out-of-market contractual obligations (3)	501	683
Other noncurrent liabilities and deferred credit	20	6
Total noncurrent liabilities of operations held for sale	793	1,002
TOTAL LIABILITIES OF OPERATIONS HELD FOR SALE	1,492	1,572
NET ASSETS HELD FOR SALE	$ 131	$1,426

(1) Includes impairment charges made against property, plant and equipment as further discussed in Note 7 Impairments, Write-offs, and Other Charges

(2) *Long-Term Receivable* – USGenNE receives payments from a wholly owned subsidiary of NEES, related to the assumption by USGenNE in September 1998 of power supply agreements, which are payable monthly through January 2008. The long-term receivables are valued at the present value of the scheduled payments using a discount rate that reflects NEES' credit rating on the date of acquisition.

(3) *Out-of-Market Contractual Obligations* – Commitments contained in the underlying Power Purchase Agreements (PPAs), gas commodity and transportation agreements (collectively, the "Gas Agreements"), and Standard Offer Agreements, acquired by USGenNE in September 1998, were recorded at fair value, based on management's estimate of either or both the gas commodity and gas transportation markets and electric markets over the life of the underlying contracts, discounted at a rate commensurate with the risks associated with such contracts. Standard Offer Agreements reflect a commitment to supply electric capacity and energy necessary for certain NEES affiliates to meet their obligations to supply fixed-rate service. PPAs and Gas Agreements are amortized on a straight-line basis over their specific lives. The Standard Offer Agreements are amortized using an accelerated method since the decline in value is greater in earlier years due to increasing contract pricing terms designed to reduce demand for supply service over time.

Discontinued Operations of Energy Services – In December 1999, PG&E Corporation's Board of Directors approved a plan to dispose of PG&E Energy Services (PG&E ES), its wholly owned subsidiary, through a sale. The disposal has been accounted for as a discontinued operation and PG&E NEG's investment in PG&E ES was written down to its estimated net realizable value. In addition, PG&E NEG provided a reserve for anticipated losses through the date of sale. In 2000, $31 million (net of taxes) of actual operating losses were charged against the reserve. During the second quarter of 2000, PG&E 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, a portion of the PG&E ES business and assets was sold on July 21, 2000, for a total consideration of $18 million.

For the year ended December 31, 2000, an additional loss of $40 million, which includes an income tax benefit of $36 million, was recorded as actual losses in connection with the disposal, which exceeded the original 1999 estimate. 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 actual loss incurred.

NOTE 7: IMPAIRMENTS, WRITE-OFFS AND OTHER CHARGES

Impairments and Write-Offs

The following is a summary of impairments and write-offs incurred by PG&E NEG in continuing operations:

(in millions)	Quarter ended December 31, 2002	Year ended December 31, 2002
Assets to be Transferred to Lenders:		
GenHoldings projects .	1,147	$1,147
Lake Road and La Paloma projects . . .	452	452
Assets to be Abandoned:		
Impairment of Mantua Creek project	279	279
Impairment of Kentucky Hydro project	18	18
Impairment of Turbines and Other Related Equipment Costs	30	276
Impairment of Project Development Costs	57	76
Other Impairments, write-offs, and charges:		
Termination of Interest Rate Swaps in Lake Road, La Paloma, and GenHoldings projects	189	189
Impairment of Dispersed Generation Assets .	88	118
Impairment of Goodwill	–	95
Impairment of Southaven loan . . .	74	74
Impairment of Prepaid Rents related to Attala lease	43	43
Total Impairments, write-offs and other charges	2,377	$2,767

Impairment of GenHoldings I LLC Projects: GenHoldings, a subsidiary of PG&E NEG, is obligated under its credit facility to make equity contributions to fund construction of the Harquahala, Covert and Athens generating projects. This credit facility is secured by these projects in addition to the Millennium generating facility. GenHoldings defaulted under its credit agreement in October 2002 by failing to make equity contributions to fund construction draws for the Athens, Harquahala and Covert generating projects. Although PG&E NEG has guaranteed GenHoldings' obligation to make equity contributions of up to $355 million, PG&E NEG notified the GenHoldings' lenders that it would not make further equity contributions on behalf of GenHoldings. In November and December 2002, the lenders executed waivers and amendments to the credit agreement under which they agreed to continue to waive until March 31, 2003, the default caused by GenHoldings' failure to make equity contributions. In addition, certain of these lenders have agreed to increase their loan commitments to an amount sufficient to provide (1) the funds necessary to complete construction of the Athens, Covert and Harquahala facilities; and (2) additional working capital facilities to enable each project, including Millennium, to timely pay for its fuel requirements and to provide its own collateral to support natural gas pipeline capacity reservations and independent transmission operator requirements. The November and December increased loan commitments are rank equally with each other but are senior to amounts loaned through and including the October credit extension.

In consideration of the lenders' forbearance and additional funding, PG&E NEG and GenHoldings have agreed to cooperate with any reasonable proposal by the lenders regarding disposition of the equity in or assets of any or all of the GenHoldings subsidiaries holding the Athens, Covert, Harquahala, and Millennium projects in connection with the restructuring of PG&E NEG's and its subsidiaries' financial commitments to such lenders. The amended credit agreement provides that an event of default will occur if the Athens, Covert, Harquahala, and Millennium projects are not transferred to the lenders or their designees on or before March 31, 2003. Such a default would trigger lender remedies, including the right to foreclose on the projects. Under the waiver, PG&E NEG has re-affirmed its guarantee of GenHoldings' obligation to make equity contributions of approximately $355 million to these projects. Neither PG&E NEG nor GenHoldings currently expects to have sufficient funds to make this payment. The requirement to pay $355 million remains an obligation of PG&E NEG that would survive the transfer of the projects.

In accordance with the provisions of SFAS No. 144 the long-lived assets of GenHoldings at December 31, 2002 were tested for impairment. As a result of the test, the assets were determined to be impaired and were written-down to fair value. Based on the current estimated fair value of these assets, GenHoldings recorded a pre-tax loss from impairment of $1.147 billion in the fourth quarter of 2002.

Impairment of Lake Road and La Paloma Projects: On November 14, 2002, PG&E NEG defaulted under its equity commitment guarantees for the Lake Road and the La Paloma credit facilities. As of December 4, 2002, PG&E NEG and certain of its subsidiaries entered into agreements with respect to each of the Lake Road and La Paloma generating projects providing for (1) funding of construction costs required to complete the La Paloma facility; and (2) additional working capital facilities to enable each subsidiary to timely pay for its fuel requirements and to provide its own collateral to support natural gas pipeline capacity reservations and independent transmission system operator requirements, as well as for general working capital purposes. Lenders extending new credit under these agreements have received liens on the projects that are senior to the existing lenders' liens. These agreements provide, among other things, that the failure to transfer right, title and interest in, to and under the Lake Road and La Paloma projects to the respective lenders by June 9, 2003 will constitute a default under the agreements. The failure to transfer the facilities would entitle the lenders to accelerate the new indebtedness and exercise other remedies.

The Lake Road and La Paloma projects have been financed entirely with debt. PG&E NEG has guaranteed the repayment of a portion of the project subsidiary debt of approximately $230 million for Lake Road and $375 million for La Paloma, which amounts represent the subsidiaries' equity contribution in the projects. The lenders have demanded the immediate payment of these equity contributions. Neither the PG&E NEG subsidiaries nor PG&E NEG have sufficient funds to make these payments. The requirement to make the payments will remain an obligation of PG&E NEG that would survive the transfer of the projects.

In accordance with the provisions of SFAS No. 144, the long-lived assets of the Lake Road and La Paloma project subsidiaries at December 31, 2002 were tested for impairment. As a result of the test, these assets were determined to be impaired and were written-down to fair value. Based on the current estimated fair value of these assets, the Lake Road and La Paloma project subsidiaries recorded a pre-tax loss from impairment of approximately $186 million and $266 million, respectively, in the fourth quarter of 2002.

Impairment of Mantua Creek Project: The Mantua Creek project is a nominal 897 megawatt (MW) combined cycle merchant power plant located in the Township of West Deptford, New Jersey. Construction began in October 2001 and the project was 24 percent complete as of October 31, 2002. Due to liquidity concerns, PG&E NEG could no longer provide equity contributions to the project and efforts to sell the project were unsuccessful. Beginning in the fourth quarter of 2002, contracts with vendors were suspended or terminated to eliminate an increase in project costs. In December 2002, the project provided notices of termination to the Pennsylvania, New Jersey, Maryland Independent System Operator (PJM), and other significant counterparties. With all significant contracts terminated, PG&E NEG's subsidiary will abandon this project in early 2003. PG&E NEG's subsidiary has written-off the capitalized development and construction costs of $257 million at December 31, 2002. In addition, PG&E NEG has recorded an accrual of $22 million for charges and associated termination costs at December 31, 2002.

Impairment of Turbines and Other Related Equipment: To support PG&E NEG's electric generating development program, PG&E NEG subsidiaries had contractual commitments and options to purchase a significant number of combustion turbines and related equipment. PG&E NEG subsidiaries' commitment to purchase combustion turbines and related equipment exceeded the new planned development activities discussed herein. In the second quarter of 2002, these PG&E NEG subsidiaries recognized a pre-tax charge of $246 million. The charge consisted of the impairment of the previously capitalized costs associated with prior payments made under the terms of the turbine and equipment contracts in the amount of $188 million and an accrual of $58 million for future termination payments required under the turbine and related equipment contracts. In addition, at that time, the PG&E NEG subsidiaries retained capitalized prepayment costs associated with three development projects that were to be further developed or sold. In the fourth quarter of 2002, these PG&E NEG subsidiaries incurred an additional pre-tax charge of $30 million for the write-off of prior turbine prepayments associated with the impairment of the remaining development projects as discussed below.

In November 2002, subsidiaries of PG&E NEG reached agreement with General Electric Company (GEC) to terminate its master turbine purchase agreement and with General Electric International, Inc. (GEII) to terminate its master long-term service agreement. GEC and GEII have agreed to reduce the termination fees from approximately $34 million to approximately $22 million and to defer payment of the reduced fees to December 31, 2004. The costs to terminate this contract were accrued for in the second quarter of 2002 as discussed above.

Also in November 2002, Mitsubishi Power Systems, Inc. (MPS) notified PG&E NEG's subsidiary that it was terminating the turbine purchase agreement for failure to pay past due amounts and failure to collateralize PG&E NEG's guarantee. While PG&E NEG's subsidiary has disputed that such amounts were due before January and July 2003 and has asserted that a breach under PG&E NEG's guarantee did not give rise to a breach of the turbine purchase agreement, neither PG&E NEG nor its subsidiary intends to contest the termination. The costs to terminate this contract were accrued for in the second quarter of 2002, as discussed above. On January 31, 2003, a termination payment of $4.5 million was made with the remaining amount of $9.5 million expected to be paid in July 2003.

Termination of Interest Rate Swaps on Lake Road, La Paloma and GenHoldings Projects: As a result of the La Paloma and Lake Road project subsidiaries' failure to make required equity payments under interest rate hedge contracts entered into by them, the counterparties to such interest rate hedge contracts have terminated the contracts. Settlement amounts due from the Lake Road and La Paloma project subsidiaries in connection with such terminated contracts are, in the aggregate, $61 million and $78 million, respectively. Further, as a result of GenHoldings' failure to make required payments under interest rate hedge contracts entered into by GenHoldings, the counterparties to such interest rate hedge contracts terminated the contracts during December 2002. Settlement amounts due by GenHoldings in connection with such terminated contracts are, in the aggregate, approximately $50 million. The La Paloma and Lake Road project subsidiaries and GenHoldings incurred a pre-tax charge to earnings in the fourth quarter of 2002 for these amounts totaling $189 million.

Impairment of Dispersed Generation: PG&E NEG is seeking a buyer for PG&E Dispersed Generation LLC, Plains End LLC, Dispersed Properties LLC and 100 percent of the capital stock of Ramco Inc, (collectively, referred to as Dispersed Gen Companies or Dispersed Generation). In accordance with the provisions of SFAS No. 144, the long-lived assets of the Dispersed Gen Companies were tested for impairment. As a result of the test, these assets were determined to be impaired and were written-down to fair value. Based on the current estimated fair value (based on the estimated proceeds) of a sale, Dispersed Generation recorded a pre-tax loss from impairment of \$88 million in the fourth quarter of 2002. This is in addition to a pre-tax loss from impairment of \$30 million that was recorded in the third quarter of 2002, which related to certain equipment (turbines, generators, transformers, etc.) that was purchased and/or refurbished and held for future expansion at current Dispersed Generation facilities.

Impairment of Goodwill: SFAS No. 142 "Goodwill and Other Intangible Assets," requires that goodwill be reviewed at least annually for impairment. Due to significant adverse changes within the national energy markets, PG&E NEG and it subsidiaries elected to test its goodwill for possible impairment in the third quarter of 2002. Based upon the results of the fair value test, PG&E NEG and it subsidiaries recognized a goodwill impairment loss of \$95 million in the third quarter of 2002. The fair value of the segment was estimated using the discounted cash flows method. At December 31, 2002, there was no goodwill remaining at PG&E NEG and it subsidiaries.

Impairment of Development Costs: In the second quarter of 2002, PG&E NEG project subsidiaries recognized an impairment loss related to the capitalized costs associated with certain development projects. These PG&E NEG subsidiaries analyzed the potential future cash flow from those projects that it no longer anticipated developing and recognized an impairment of the asset value it was carrying for those projects. The aggregate pre-tax impairment charge recorded by these PG&E NEG subsidiaries for its development assets (excluding associated equipment) was \$19 million recorded in the second quarter of 2002. At that time, these PG&E NEG subsidiaries continued to develop or planned to sell three additional projects. These subsidiaries have ceased developing these projects and sought to sell the development assets. To date, these subsidiaries have been unsuccessful in selling these projects and have tested the capitalized costs associated with the projects for impairment at December 31, 2002. Based upon the results of these tests, an additional aggregate pre-tax impairment charge of approximately \$57 million was recorded by these subsidiaries for their development assets (excluding associated equipment costs as discussed above) in the fourth quarter of 2002. While these subsidiaries have impaired all of their development projects, they have not abandoned the permits or rights to these projects. It is anticipated that these permits and rights will be abandoned for all development projects in 2003.

Impairment of Southaven Power LLC Loan Receivable: PG&E Energy Trading- Power, L.P. (PG&E ET) signed a tolling agreement with Southaven Power LLC (Southaven) dated June 1, 2000, pursuant to which PG&E ET was required to provide credit support that meets certain requirements set forth in the agreement. PG&E ET satisfied this obligation by providing an investment-grade guarantee from PG&E NEG. The original maximum amount of the guarantee was \$250 million. However, this amount was reduced by approximately \$74 million, the amount of a subordinated loan that PG&E ET made to Southaven on August 31, 2002.

Southaven has advised PG&E ET that it believes an event of default under the tolling agreement has taken place with respect to the obligation for a guarantee because PG&E NEG is no longer investment-grade as defined in the agreement and because PG&E ET has failed to provide, within 30 days from the downgrade, substitute credit support that meets the requirements of the agreement. Under the tolling agreement, Southaven has the right to terminate the agreement and seek a termination payment. In addition, PG&E ET has provided Southaven with a notice of default with respect to Southaven's performance under the tolling agreement. If this default is not cured, PG&E ET has the right to terminate the agreement and seek recovery of a termination payment. On February 4, 2003, PG&E ET provided a notice of termination. Southaven has objected to the notice and has filed suit in connection with this matter. PG&E ET has recorded an impairment of the loan receivable due to the uncertainty associated with the recoverability of the loan, which was subordinate to the senior debt of the project and reliant upon operations of the plant under the terms of the tolling agreement.

Impairment of Prepaid Rents on Attala Lease: On May 7, 2002, Attala Generating Company LLC (Attala Generating), an indirect wholly owned subsidiary of PG&E NEG, completed a $340 million sale and leaseback transaction whereby it sold and leased back its approximately 526 MW generation facility located in Mississippi to a third-party special purpose entity.

PG&E NEG has provided a $300 million guarantee to support the payment obligations of another indirect wholly owned subsidiary, Attala Energy Company LLC (Attala Energy) under a tolling agreement entered into with Attala Generating. The payments under the 25-year term tolling agreement provide Attala Generating, as lessee, with sufficient cash flows during the term of the tolling agreement to pay rent under a 37-year lease and certain other operating costs. Due to current energy market conditions, Attala Energy is unable to make the payments under the tolling agreement and failed to make the required payment due on November 22, 2002 to Attala Generating. Failure to cure this payment default constituted an event of default under the tolling agreement as of November 27, 2002. Further, PG&E NEG's failure to pay maturing principal under its Corporate Revolver on November 14, 2002, became an event of default under the tolling agreement upon Attala Energy's failure to replace the PG&E NEG guarantee by December 16, 2002. On December 31, 2002, the tolling agreement terminated following notice of termination given by Attala Generating. The parties are currently determining the termination payment, if any, that Attala Energy would owe Attala Generating. Despite the termination of the tolling agreements, Attala Energy remains obligated to provide an acceptable guarantee or collateral to secure its obligations under the tolling agreement, including the payment of any termination payment that may be determined to be due.

No default has occurred under the related lease and Attala Generating timely made the $22.2 million lease payment due on January 2, 2003. However, the lease provides that failure to replace the tolling agreement with a satisfactory replacement tolling agreement within 180 days after the first default under the tolling agreement, which occurred on November 27, 2002, will constitute an event of default under the lease. After the termination payment has been determined in accordance with the tolling agreement and if Attala Energy or PG&E NEG both fail, or have failed, to provide security as required by the tolling agreement, the time period would not extend beyond the 60th day after such failure to provide security. Upon the occurrence of an event of default under the lease, the lessor would be entitled to exercise various remedies, including termination of the lease and foreclosure of the assets securing the lease. At December 31, 2002, Attala Generating wrote-off prepaid rental payments of $43 million due to the uncertainty of future cash flows associated with the lease.

Impairment of Kentucky Hydro Project: The Kentucky Hydro Generating Project consists of two run-of-river hydroelectric power plants located in Kentucky on the Ohio River. The project negotiated a turnkey, fixed price contract with VA Tech MCE Corporation (VA Tech) and issued a limited notice to proceed in August 2001. Beginning in the fourth quarter of 2002, all work on the project was suspended except for minimal expenditures to maintain the Federal Energy Regulatory Commission licenses. The termination cost due to VA Tech of approximately $14 million was fully paid. VA Tech terminated the contract effective December 6, 2002. As part of the settlement of PG&E NEG subsidiary's partnership arrangement, this subsidiary assigned its partnership interest to the original developer, W.V. Hydro, on February 7, 2003. PG&E NEG has written-off the capitalized development and construction costs and provided for all termination costs by recording a pre-tax charge of $18 million at December 31, 2002.

NOTE 8: ACQUISITIONS AND DISPOSALS

Sale of Interest in Hermiston – On November 4, 2002, affiliates of PG&E ET entered into an agreement to sell 49.9 percent of its ownership interest in Hermiston Generating Company, L.P. (HGC) to Sumitomo Corporation and Sumitomo Corporation of America. The buyer was granted an option to purchase, during the three-month period beginning 13 months immediately following the closing date, an additional 0.1 percent interest (at the fair market value at the date of exercise). HGC owns an undivided 50.01 percent interest in a 474 MW gas-fired generating plant in Hermiston, Oregon. The other 49.99 percent is owned by PacifiCorp, which also purchases the output of the plant under a long-term contract. The sale was completed on December 20, 2002, following the receipt of necessary regulatory approvals. PG&E NEG received $46 million in proceeds for the sale of HGC resulting in a pre-tax $11 million gain, after the sale of a net investment balance of $25 million and reversal of Other Comprehensive Income of $10 million. Gain from the sale of HGC is included in other operating expenses. Prior to this sale of partnership interest, PG&E NEG owned 100 of this partnership and was fully consolidating HGC into its results.

Sale of Development Assets – On July 10, 2001, PG&E NEG completed the sale of certain development assets, resulting in a pre-tax gain of $23 million.

Purchase and Closing of Spencer Station – On June 29, 2001, PG&E ET contracted to supply the full service power requirements of the city of Denton, Texas, for a period of five years beginning July 1, 2001. PG&E ET's supply obligation to the city was net of approximately 97 megawatts of generation entitlements retained by the city, plus 40 megawatts of purchased power that the city had assigned to PG&E ET for the summer of 2001. Another affiliate of PG&E NEG acquired a 178 megawatt generating station and two small hydroelectric facilities from the city. The total consideration was approximately $12 million for this transaction.

On November 5, 2002, PG&E NEG announced its plan to shut down its Spencer Station generating plant located in Denton, Texas. However, PG&E NEG did not shut down Spencer Station and instead sold Spencer Station to the City of Garland on February 13, 2003. In addition, PG&E ET has sold its obligation to supply the full service power requirements of the City of Denton. Based on the current fair value (based on the proceeds) of a sale of Spencer Station, PG&E NEG will record an immaterial gain in the first quarter of 2003.

Purchase of Attala – On September 28, 2000, PG&E NEG purchased for $311 million Attala Generating, which owns a gas-fired power plant that was under construction. Under the purchase agreement, PG&E NEG prepaid the estimated remaining construction costs, which were being managed by the seller. The project, which was approximately 82 percent complete as of December 31, 2000, began commercial service in June 2001. In connection with the acquisition, PG&E NEG also assumed industrial revenue bonds issued by the Mississippi Business Finance Corporation in the amount of $159 million, under an agreement that the seller would pay off the bonds. Accordingly, a $159 million receivable was recorded. At December 31, 2001, the seller had paid off the bonds. See Note 7 for a current status of this facility.

Sale of PG&E GTT – On January 27, 2000, PG&E NEG signed a definitive agreement with El Paso Field Services Company (El Paso) providing for the sale of the stock of PG&E GTT to El Paso, a subsidiary of El Paso Energy Corporation. On December 22, 2000, after receipt of governmental approvals, PG&E NEG completed the stock sale. The total consideration received was $456 million, less $150 million used to retire the PG&E GTT's short-term debt, and the assumption by El Paso of PG&E GTT's long-term debt having a book value of $564 million. PG&E Corporation's Consolidated Statements of Operations included $33 million of net income related to the year ended December 31, 2000.

NOTE 9: COMMON STOCK

PG&E Corporation

PG&E Corporation has authorized 800 million shares of no-par common stock of which 405 million shares were issued and outstanding at December 31, 2002, and 388 million at December 31, 2001.

PG&E Corporation repurchased $0.5 million of its common stock during the year ended December 31, 2001. The repurchases were made to satisfy obligations under the Dividend Reinvestment Plan. PG&E Corporation repurchased approximately $5,000 of its common stock during the year ended December 31, 2002. PG&E Corporation is precluded by the terms of the Credit Agreement from repurchasing any more of its common stock until the Loans are repaid.

On March 2, 2001, PG&E Corporation paid its suspended fourth quarter 2000 stock dividend of $0.30 per common share, declared by the Board of Directors on October 18, 2000, to shareholders of record as of December 15, 2000.

On January 2, 2003, the Board of Directors granted 1.6 million shares of PG&E Corporation restricted stock under the PG&E Corporation Long-Term Incentive Program. Over the period of four years, restrictions will lapse as to 20 percent of the total number of shares of restricted stock each year. Restrictions will lapse as to an additional 5 percent of the total number of shares of restricted stock each year, if PG&E Corporation is in the top quartile of its comparator group. This is measured by relative annual total shareholder return for the year ending immediately before each annual lapse date. (See Note 14.)

Utility

The Utility is authorized to issue 800 million shares of its $5 par value common stock. Of the total shares authorized, 321 million shares were issued and outstanding as of December 31, 2002, and 2001. PG&E Corporation and PG&E Holding LLC, a subsidiary of the Utility, hold all of the Utility's outstanding common stock.

The Utility did not repurchase any shares of its common stock during the year ended December 31, 2002, and 2001. In April 2000, PG&E Holdings LLC repurchased 11.9 million shares of the Utility's common stock at a cost of $275 million. At December 31, 2002, and 2001, the Utility held repurchased common stock totaled 19.5 million shares, at a cost of $475 million. The repurchased common stock is included as a reduction of stockholders' equity on the Utility's Consolidated Balance Sheets.

In October 2000, the Utility declared a $110 million common stock dividend to PG&E Corporation and PG&E Holding LLC. In January 2001, the Utility suspended payment of the declared dividend. The suspension was made so that the Utility could maintain its CPUC-authorized capital structure, which is the level of common and preferred equity the Utility may maintain in relation to its debt.

The Utility did not declare or pay common and preferred stock dividends in 2001 and 2002. Preferred stock dividends have a cumulative feature in which any preferred stock dividends not paid in any year must be made up in a later year before any dividends can be distributed to common stockholders. As a result, the Utility may not pay any dividends on its common stock until the cumulative preferred stock dividends and mandatory preferred sinking fund requirements are paid.

NOTE 10: PREFERRED STOCK

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 common stock. 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 PG&E Corporation, any of its subsidiaries, or its employee benefit plans) has acquired or obtained the right to acquire beneficial ownership of 15 percent 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 percent 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 acquirer) to purchase Units of Series A Preferred Stock having twice the market value of the initially fixed exercise price, i.e., at a 50 percent 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 million 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 $0.01 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 PG&E Corporation 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 PG&E Corporation to initiate such an acquisition through negotiations with PG&E Corporation's 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, PG&E Corporation. To the extent any potential acquirers 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, 2002, and 2001, the Utility had issued and outstanding 5,784,825 shares of non-redeemable preferred stock. Holders of the Utility's non-redeemable preferred stock 5.0 percent, 5.5 percent, and 6.0 percent series have rights to annual dividends per share ranging from $1.25 to $1.50.

At December 31, 2002, and 2001, 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. At December 31, 2002, annual dividends ranged from $1.09 to

$1.76 and redemption prices ranged from $25.75 to $27.25.

At December 31, 2002, the Utility's redeemable preferred stock with mandatory redemption provisions consisted of 3 million shares of the 6.57 percent series and 2.5 million shares of the 6.30 percent series. These series are redeemable at par value plus accumulated and unpaid dividends through the redemption date. The 6.57 percent series may be redeemed at the Utility's option on or after July 31, 2002. The 6.30 percent series may be redeemed at the Utility's option on or after January 31, 2004. These series of preferred stock are subject to mandatory redemption provisions entitling them to sinking funds providing for the retirement of the stock outstanding.

The redemption requirements for the Utility's redeemable preferred stock with mandatory redemption provisions are for the 6.57 percent series $4 million per year from 2002 through 2006, and $55 million in 2007, and for the 6.30 percent series, $3 million per year from 2004 through 2008, and $47 million in 2009.

Due to the California energy crisis, the Utility's Board of Directors did not declare the following regular preferred stock dividends normally payable 15 days after the three-month periods ended:

- January 31, 2001;
- April 30, 2001;
- July 31, 2001;
- October 31, 2001;
- January 31, 2002;
- April 30, 2002;
- July 31, 2002;
- October 31, 2002; and
- January 31, 2003.

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and an equal preference in dividend and liquidation rights. Accumulated and unpaid preferred stock dividends amounted to $50 million as of December 31, 2002, and $25 million as of December 31, 2001. 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 and mandatory preferred sinking fund payments are paid, the Utility may not pay any dividends on its common stock, nor may the Utility repurchase any of its common stock. A sinking fund sets aside funds for the future periodic retirement of the outstanding stocks.

Preferred Stock of PG&E NEG

Preferred stock of PG&E NEG consists of $58 million of preferred stock issued by a subsidiary of PG&E NEG. The preferred stock, with $100 par value, has a stated non-cumulative quarterly dividend of $3.35 per share, per quarter, and is redeemable when there is an excess of available cash. There were 549,594 shares of preferred stock outstanding at December 31, 2002, and 2001.

NOTE 11: PRICE RISK MANAGEMENT

As previously discussed, PG&E NEG is in the process of reducing and unwinding its trading positions. Additionally, asset hedge positions associated with the merchant plants will either remain with the assets or be terminated. PG&E NEG has significantly reduced their energy trading operations in an ongoing effort to raise cash and reduce debt. PG&E NEG's objective is to limit its asset trading and risk management activities to only what is necessary for energy management services to facilitate the transition of PG&E NEG's merchant generation facilities through their sale, transfer or abandonment process. PG&E NEG will then further reduce and transition to only retain limited capabilities to ensure fuel procurement and power logistics for PG&E NEG's retained independent power plant operations.

Non-Trading Activities

At December 31, 2002, PG&E Corporation had cash flow hedges of varying durations associated with commodity price risk, interest rate risk, and foreign currency risk, the longest of which extend through December 2011, March 2014, and December 2004, respectively.

The amount of commodity hedges included in Accumulated Other Comprehensive Income or Loss (OCI), net of tax, at December 31, 2002, was a loss of $27 million. The amount of interest rate hedges included in OCI, net of tax, at December 31, 2002, was a loss of $61 million. The amount of foreign currency hedges included in OCI, net of tax, at December 31, 2002, was a loss of $2 million.

PG&E Corporation's net derivative losses included in OCI at December 31, 2002, were $90 million, of which approximately $70 million is expected to be reclassified into earnings within the next 12 months based on the contractual terms of the contracts or the termination of the hedge position. The actual amounts reclassified from OCI to earnings will differ as a result of market price changes. The Utility did not have any cash flow hedges at December 31, 2002, or December 31, 2001. The Utility's ineffective portion of changes in amounts of cash flow hedges was immaterial for the year ended December 31, 2001.

The schedule below summarizes the activities affecting Accumulated Other Comprehensive Income (Loss), net of tax, from derivative instruments:

(in millions)	Year Ended December 31,			
	2002		2001	
	PG&E Corporation	Utility	PG&E Corporation	Utility
Derivative gains included in accumulated other comprehensive income at beginning of period	$ 36	$ –	$ –	$ –
Cumulative effect of adoption of SFAS No. 133	–	–	(243)	90
Net gain (loss) from current period hedging transactions and price changes	(139)	–	237	(5)
Net reclassification to earnings	13	–	42	(85)
Derivative gains (losses) included in accumulated other comprehensive income at end of period	(90)	–	36	–
Foreign currency translation adjustment	(3)	–	(5)	(2)
Other	–	–	(1)	–
Accumulated other comprehensive income (loss) at end of period	$ (93)	$ –	$ 30	$ (2)

For most non-trading activities, earnings are recognized on an accrual basis as revenues are earned and as expenses are incurred. Thus, most non-trading activities do not affect earnings on a mark-to-market basis. For example, the effective portion of contracts accounted for as cash flow hedges have no mark-to-market effect on earnings; these contracts are presented on a mark-to-market basis on the balance sheet in PRM assets and liabilities and OCI. Other non-trading contracts are exempt from the SFAS No. 133 fair value requirements under the normal purchases and sales exception and thus have no mark-to-market effect on earnings.

However, in a few instances, non-trading activities affect PG&E NEG's earnings on a mark-to-market basis. PG&E NEG recognizes the ineffective portion of the fair value of cash flow hedges in earnings. PG&E NEG also has certain derivative contracts, which, while they are meant for non-trading purposes, do not qualify for cash flow hedge accounting or for the normal purchases and sales exception to SFAS No. 133. These derivatives are reported in earnings on a mark-to-market basis. These contracts primarily consist of those derivative commodity contracts for which normal purchases and sales treatment was disallowed upon PG&E NEG's implementation of DIG C15 and C16 effective April 1, 2002 (see Note 1).

The effects on pre-tax earnings of non-trading activities that are reflected in income on a mark-to-market basis are as follows:

(in millions)	Year Ended December 31,	
	2002	2001
Ineffective portion of cash flow hedges	$ (2)	$ —
Earnings from discontinued cash flow hedges	(203)	—
Non-trading derivatives marked-to-market through earnings	(78)	19
Total	$(283)	$ 19

The $203 million pre-tax loss from discontinuance of cash flow hedges is primarily due to the interest rate hedges. Accounting hedge treatment was discontinued when certain PG&E NEG subsidiaries failed to make payments under their debt agreements and, therefore, the hedged transactions were no longer considered probable of occurrence. The $189 million loss in OCI relating to the interest rate hedges was reclassified to earnings, in accordance with the provisions of SFAS No. 133. (See further discussions in Note 3, *GenHoldings Construction Facility* and *Lake Road and La Paloma Construction Facilities*.) The remainder of the $203 million pre-tax loss relates to financial commodity hedges that were discontinued after the hedged transactions were no longer considered probable of occurrence.

Trading Activities

Unrealized gains and losses from trading activities, including the reversal of unrealized gains and losses previously recognized on contracts that go to settlement or delivery, are presented on a net basis in operating revenues. Realized gains and losses from trading activities also are presented on a net basis in operating revenues, beginning in the third quarter of 2002, as more fully described in Note 1.

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

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

PG&E Corporation's net gains (losses) on trading activities are as follows:

(in millions)	Year Ended December 31,		
	2002	2001	2000
Trading activities:			
Unrealized gains (losses), net	$ (74)	$(120)	$ 31
Realized gains, net	121	296	174
Total	$ 47	$ 176	$205

See Note 1 for a discussion of the rescission of EITF 98-10, which impacted the accounting for trading activities.

Price Risk Management Assets and Liabilities

PRM assets and liabilities on the accompanying PG&E Corporation Consolidated Balance Sheets reflect the aggregation of the fair values of outstanding contracts. These fair values are calculated on a mark-to-market basis for contracts that will be settled in future periods. PRM assets and liabilities at December 31, 2002, include amounts for trading and non-trading activities, as described below:

(in millions)	PRM Assets		PRM Liabilities		Net Assets (Liabilities)
	Current	Noncurrent	Current	Noncurrent	
December 31, 2002					
Trading activities	$351	$232	$(349)	$(236)	$ (2)
Non-trading activities:					
Cash flow hedges – offset to OCI	130	101	(155)	(69)	7
Derivatives marked to market through earnings	17	65	(2)	–	80
Total consolidated PRM Assets and Liabilities	$498	$398	$(506)	$(305)	$ 85

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

Credit Risk

Credit risk is the risk of loss that PG&E Corporation and the Utility would incur if counterparties failed to perform their contractual obligations (these obligations are reflected as Accounts Receivable–Customers, net; notes receivable included in Other Noncurrent Assets–Other; PRM assets; and Assets held for sale on the balance sheet). PG&E Corporation and the Utility conduct business primarily with customers or vendors, referred to as counterparties, in the energy industry. These counterparties include other investor-owned utilities, municipal utilities, energy trading companies, financial institutions, and oil and gas production companies located in the United States and Canada. This concentration of counterparties may impact PG&E Corporation's and the Utility's overall exposure to credit risk because their counterparties may be similarly affected by economic or regulatory changes or other changes in conditions.

PG&E Corporation and the Utility manage their credit risk in accordance with their respective Risk Management Policies. The policies establish processes for assigning credit limits to counterparties before entering into agreements with significant exposure to PG&E Corporation and the Utility. These processes include an evaluation of a potential counterparty's financial condition, net worth, credit rating, and other credit criteria as deemed appropriate, and are performed at least annually.

Credit exposure is calculated daily, and in the event that exposure exceeds the established limits, PG&E Corporation and the Utility take immediate action to reduce the exposure, or obtain additional collateral, or both. Further, PG&E Corporation and the Utility rely heavily on master agreements that require the counterparty to post security, referred to as credit collateral, in the form of cash, letters of credit, corporate guarantees of acceptable credit quality, or eligible securities if current net receivables and replacement cost exposure exceed contractually specified limits.

PG&E Corporation and the Utility calculate gross credit exposure for each counterparty as the current mark-to-market value of the contract (that is, the amount that would be lost if the counterparty defaulted today) plus or minus any outstanding net receivables or payables, prior to the application of the counterparty's credit collateral.

In 2002, PG&E Corporation's and the Utility's credit risk increased due in part to downgrades of some counterparties credit ratings to levels below investment grade. The downgrades increase PG&E Corporation's or the Utility's credit risk because any collateral provided by these counterparties in the form of corporate guarantees or eligible securities may be of lesser or no value. Therefore, in the event these counterparties failed to perform under their contracts, PG&E Corporation and the Utility may face a greater potential maximum loss. In contrast, PG&E Corporation and the Utility do not face any additional risk if counterparties' credit collateral is in the form of cash or letters of credit, as this collateral is not affected by a credit rating downgrade.

For the year ended December 31, 2002, PG&E Corporation and the Utility have recognized no losses due to the contract defaults or bankruptcies of counterparties. However, in 2001, PG&E Corporation terminated its contracts with a bankrupt company, which resulted in a pre-tax charge to earnings of $60 million related to trading and non-trading activities, after application of collateral held and accounts payable.

At December 31, 2002, and at December 31, 2001, PG&E Corporation had no single counterparty that represented greater than 10 percent of PG&E Corporation's net credit exposure. At December 31, 2002, the Utility had one investment-grade counterparty that represented 21 percent of the Utility's net credit exposure, and one below investment-grade counterparty that represented 11 percent of the Utility's net credit exposure. At December 31, 2001, the Utility had no single counterparty that represented greater than 10 percent of the Utility's net credit exposure.

The schedule below summarizes PG&E Corporation's and the Utility's credit risk exposure to counterparties that are in a net asset position, with the exception of exchange-traded futures (the exchange provides for contract settlement on a daily basis), as well as PG&E Corporation's and the Utility's credit risk exposure to counterparties with a greater than 10 percent net credit exposure, at December 31, 2002, and December 31, 2001:.

(in millions)	Gross Credit Exposure Before Credit Collateral (1)	Credit Collateral (2)	Net Credit Exposure (2)	Number of Counterparties >10%	Net Exposure of Counterparties >10%
At December 31, 2002					
PG&E Corporation	$1,165	$195	$970	–	$ –
Utility (3)	288	113	175	2	55
At December 31, 2001					
PG&E Corporation	$1,203	$207	$996	–	$ –
Utility (3)	271	127	144	–	–

(1) Gross credit exposure equals mark-to-market value (adjusted for applicable credit valuation adjustments), notes receivable, and net (payables) receivables where netting is allowed. Gross and net credit exposure amounts reported above do not include adjustments for time value, liquidity, or model.

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

(3) The Utility's gross credit exposure includes wholesale activity only. Retail activity and payables incurred prior to the Utility's bankruptcy filing are not included. Retail activity at the Utility consists of the accounts receivable from the sale of gas and electricity to millions of residential and small commercial customers.

At December 31, 2002, approximately $205 million, or 21 percent of PG&E Corporation's net credit exposure, was to entities that have credit ratings below investment grade. At December 31, 2002, approximately $64 million, or 37 percent of the Utility's net credit exposure was to entities that had credit ratings below investment grade. At December 31, 2001, approximately $244 million, or 25 percent of PG&E Corporation's net credit exposure, was to entities that had credit ratings below investment grade. At December 31, 2001, approximately $32 million, or 22 percent of the Utility's net credit exposure, was to entities that had credit ratings below investment grade. Investment grade is determined using publicly available information, i.e. rated at least Baa3 by Moody's and BBB- by S&P. If the counterparty provides a guarantee by a higher rated entity (e.g., its parent), the credit rating determination is based on the rating of its guarantor.

At December 31, 2002, approximately $65 million, or 7 percent of PG&E Corporation's net credit exposure was with counterparties at PG&E NEG that were not rated. At December 31, 2001, none of PG&E Corporation's net credit exposure was with counterparties at PG&E NEG that were not rated. Most counterparties with no credit rating are governmental authorities which are not rated, but which PG&E Corporation has assessed as equivalent to investment grade. Other counterparties with no credit rating are subject to an internal assessment of their credit quality and a credit rating designation.

PG&E Corporation's regional concentrations of credit exposure are to counterparties that conduct business primarily in the western United States and also to counterparties that conduct business primarily throughout North America. Additionally, the Utility's concentration of credit risk reflects its receivables from residential and small commercial customers in northern California. However, the risk of material loss due to nonperformance from these customers is not considered likely. Reserves for uncollectible accounts receivable are provided for the potential loss from nonpayment by these customers based on historical experience. The Utility has a net regional concentration of credit exposure totaling $175 million to counterparties that conduct business primarily throughout North America.

NOTE 12: INVESTMENTS IN AFFILIATES AND RELATED PARTY TRANSACTIONS

Investment in Unconsolidated Affiliates

Utility

The Utility has investments in unconsolidated affiliates, which are mainly engaged in the purchase of residential real estate property. The equity method of accounting is applied to the Utility's investment in these entities. Under the equity method, the Utility's share of equity income or losses of these entities is reflected as equity in earnings of affiliates. As of December 31, 2002, the Utility's recorded investment in these entities totaled $15 million. As a limited partner, the Utility's exposure to potential loss is limited to its investment in each partnership.

PG&E NEG

PG&E NEG has non-controlling investments in various power generation and other energy projects. The equity method of accounting is applied to such investments in affiliated entities, which include corporations, joint ventures and partnerships, due to the ownership structure preventing PG&E NEG from exercising control. Under this method, PG&E NEG's share of equity income or losses of these entities is reflected as revenue on the accompanying financial statements.

PG&E NEG's share of ownership in these affiliates ranges from 5 percent to 64 percent, and its net investment amounted to $403 million as of December 31, 2002, and $414 million as of December 31, 2001.

Net gains from the sale of interests in unconsolidated affiliates were $21 million during 2000, excluding PG&E NEG's pipeline interests that were sold as part of the GTT disposition. Amounts are included in other operating expenses. There were no sales of unconsolidated affiliates in 2002 or 2001.

The following table sets forth summarized financial information of PG&E NEG's investments in affiliates accounted for under the equity method for the years ended December 31, 2002, 2001, and 2000:

(in millions)	Year Ended December 31,		
Statement of Operations Data	**2002**	**2001**	**2000**
Revenues	$1,141	$1,150	$1,252
Income From Operations	418	482	491
Earnings Before Taxes	341	295	197
Equity in earnings from affiliates	48	79	65

	As of December 31,	
Balance Sheet Data	**2002**	**2001**
Current assets	$ 309	$ 306
Noncurrent assets	3,846	3,567
Total Assets	$4,155	$3,873
Current liabilities	$ 788	$ 274
Noncurrent liabilities	2,613	3,074
Equity	754	525
Total Liabilities and Equity	$4,155	$3,873

The reconciliation of the PG&E NEG's share of equity to investment balance is as follows:

(in millions)	As of December 31,	
	2002	**2001**
PG&E NEG's share of equity	$ 95	$112
Purchase premium over book value	126	131
Lease receivables and other investments	182	171
Investments in unconsolidated affiliates	$403	$414

The purchase premium over book value is being amortized over periods ranging from 16 to 35 years and is recorded through amortization expense. The yearly purchase premium amortization expenses were $7 million in 2002, $7 million in 2001, and $7 million in 2000.

Related Party Agreements and Transactions

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

(in millions)	Year ended December 31,		
	2002	**2001**	**2000**
Utility proceeds from:			
Administrative services provided to PG&E Corporation	$ 7	$ 6	$ 12
Gas reservation services provided to PG&E ET	9	11	12
Contribution in aid of construction received from PG&E NEG	2	5	3
Other	–	1	2
Trade Deposit due from PG&E GTNW	–	11	–

(in millions)	Year ended December 31,		
	2002	2001	2000
Utility payments for:			
Administrative services received from PG&E Corporation	$106	$127	$ 83
Interest on Debt to PG&E Corporation	8	3	3
Administrative services received from PG&E NEG	2	–	–
Gas commodity and transmission services received from PG&E ET	49	120	136
Interest on Debt to PG&E ET	2	–	–
Transmission services received from PG&E GTN	47	40	46
Trade Deposit due to ET	7	–	–

NOTE 13: NUCLEAR DECOMMISSIONING

Decommissioning of the Utility's nuclear power facilities is scheduled to begin, for ratemaking purposes, in 2015 and scheduled for completion in 2041. Nuclear decommissioning means (1) the safe removal of nuclear facilities from service, and (2) the reduction of 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 at Diablo Canyon Power Plant and Humboldt Bay Power Plant is $1.9 billion in 2002 dollars (or $8.4 billion in future dollars). This estimate is (1) based on a February 2002 decommissioning cost study, and (2) includes labor, materials, waste disposal and other costs. The Utility plans to fund these costs from independent decommissioning trusts, which receive annual contributions as discussed further below. The Utility estimates after-tax annual earnings, including realized gains and losses, on the tax-qualified decommissioning funds of 6.34 percent and non-tax-qualified decommissioning funds of 5.39 percent. 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, costs of labor, materials, and equipment. The estimated total obligation is being recognized proportionately over the license term of each facility.

At December 31, 2002, the total nuclear decommissioning obligation accrued was $1.3 billion and is included in accumulated depreciation and decommissioning on PG&E Corporation's and the Utility's Consolidated Balance Sheets.

On January 1, 2003, the Utility adopted SFAS No. 143. Under SFAS No. 143, the Utility will adjust its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. See Note 1 under Adoption of New Accounting Policies – Accounting for Asset Retirement Obligations.

On March 15, 2002, the Utility filed its 2002 Nuclear Decommissioning Cost Triennial Proceeding (NDCTP), seeking to increase its nuclear decommissioning revenue requirements for the years 2003 through 2005 based on the February 2002 cost study. The Utility's NDCTP seeks recovery of $24 million in revenue requirements relating to the Diablo Canyon Nuclear Decommissioning Trusts and $17.5 million in revenue requirements relating to the Humboldt Bay Power Plant Decommissioning Trusts. The NDCTP also seeks recovery of $7.3 million in CPUC-jurisdictional revenue requirements for Humboldt Bay Unit 3 operating and maintenance costs. These costs include the radiation protection, surveillance activities, security forces, and maintenance of security systems. The Utility proposes continuing to collect the revenue requirement through a non-bypassable charge in electric rates, and to record the revenue requirement and the associated revenues in the Nuclear Decommissioning adjustment mechanism balancing account. The balancing account would require the Utility to return to ratepayers any amounts collected as part of the Utility's nuclear decommissioning revenue requirement that were not contributed to the independent trusts.

Until post-rate freeze ratemaking is implemented, an increase in the Utility's nuclear decommissioning revenue requirements would reduce the amount of revenues available to offset electric generation costs, and would not have an impact on the Utility's results of operations.

The CPUC held hearings on the NDCTP in September 2002 and is scheduled to issue a final decision in April 2003.

For the year ended December 31, 2002, and December 31, 2001, annual nuclear decommissioning trust contributions collected in rates were $24 million and this amount was contributed to the trusts.

Amounts contributed to the funds, along with accumulated earnings, will be used exclusively for decommissioning and cannot be released from the trusts until authorized by the CPUC. Trust fund earnings increase the trust fund balance and the accumulated provision for decommissioning.

The CPUC has authorized the qualified trust to invest a maximum of 50 percent of its funds in publicly traded equity securities, of which up to 20 percent may be invested in publicly traded non-US securities. For the nonqualified trust, no more than 60 percent may be invested in publicly traded equities. The trusts are in compliance with the investment restrictions authorized by the CPUC.

In general, investment securities are exposed to various risks, such as interest rate, credit, and overall market volatility risks. Due to the level of risk associated with certain investment securities, it is reasonably possible that changes in the market values of investment securities could occur in the near term, and such changes could materially affect the trusts' current value.

The following table provides a summary of the amortized cost and fair value, based on quoted market prices, of the Utility's nuclear decommissioning trust funds:

(in millions)	Maturity Date	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
Year ended December 31, 2002					
U.S. government and agency issues	2003-2032	$ 423	$ 50	$ –	$ 473
Municipal bonds and other	2003-2034	185	12	(1)	196
Equity securities		394	281	(9)	666
Total		$1,002	$343	$(10)	1,335
Other assets					89
Other liabilities					(89)
Fair Value					$1,335
Year ended December 31, 2001					
U.S. government and agency issues	2002-2031	$ 437	$ 39	$ –	$ 476
Municipal bonds and other	2002-2034	218	14	(1)	231
Equity securities		371	347	(12)	706
Total		$1,026	$400	$(13)	1,413
Other assets					44
Other liabilities					(120)
Fair Value					$1,337

The cost of debt and equity securities sold is determined by specific identification. The following table provides a summary of the activity for the debt and equity securities:

(in millions)	Year Ended December 31,		
	2002	2001	2000
Proceeds received from sales of securities	$1,631	$751	$1,379
Gross realized gains on sales of securities held as available-for-sale	51	71	74
Gross realized losses on sales of securities held as available-for-sale	91	98	64

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 able to store on-site all spent fuel produced through approximately 2007. It is likely that an interim or permanent DOE storage facility will not be available for Diablo Canyon's spent fuel by 2007. Therefore, the Utility is examining its options for providing additional temporary spent fuel storage at Diablo Canyon or other facilities.

NOTE 14: EMPLOYEE BENEFIT PLANS

PG&E Corporation and its subsidiaries provide both qualified and nonqualified noncontributory defined benefit pension plans for their employees, retirees, and non-employee directors (referred to collectively as pension benefits). PG&E Corporation and its subsidiaries also 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). The following schedules aggregate all of PG&E Corporation's plans. All descriptions and assumptions of the pension benefits and other benefits discussed below are based on the Utility's plans since the Utility's plans represent the majority of all plan asset and benefit obligations.

The following schedule reconciles the plans' funded status to the prepaid or accrued benefit cost recorded on the Consolidated Balance Sheets. The plans' funded status is the difference between the fair value of plan assets and the benefit obligations.

(in millions)	Pension Benefits		Other Benefits	
	2002	2001	2002	2001
Change in benefit obligation				
Benefit obligation at January 1	$(6,087)	$(5,405)	$(1,065)	$(1,009)
Service cost for benefits earned	(140)	(128)	(25)	(21)
Interest cost	(438)	(420)	(77)	(74)
Actuarial loss	(415)	(408)	(107)	(12)
Participants paid benefits	–	–	(25)	(20)
Settlement	1	–	–	–
Benefits and expenses paid	298	274	74	71
Benefit obligation at December 31	$(6,781)	$(6,087)	$(1,225)	$(1,065)
Change in plan assets				
Fair value of plan assets at January 1	$ 7,175	$ 7,808	$ 915	$ 1,012
Actual return on plan assets	(690)	(364)	(149)	(70)
Company contributions	10	5	49	27
Plan participant contribution	–	–	25	20
Settlement	(8)	–	–	–
Benefits and expenses paid	(298)	(274)	(77)	(74)
Fair value of plan assets at December 31	$ 6,189	$ 7,175	$ 763	$ 915

(in millions)	Pension Benefits		Other Benefits	
	2002	2001	2002	2001
Funded Status				
Plan assets greater (lower) than benefit obligation	$ (592)	$ 1,088	$ (462)	$ (150)
Unrecognized prior service cost	313	358	13	14
Unrecognized net (gain) loss	1,205	(501)	179	(156)
Unrecognized net transition obligation	22	36	261	287
Prepaid (accrued) benefit cost	$ 948	$ 981	$ (9)	$ (5)
Utility's share:				
Plan assets greater (lower) than benefit obligation	$ (553)	$ 1,103	$ (448)	$ (147)
Prepaid (accrued) benefit costs	$ 974	$ 994	$ (11)	$ (6)

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:

(in millions)	Pension Benefits December 31,			Other Benefits December 31,		
	2002	2001	2000	2002	2001	2000
Service cost for benefits earned	$(140)	$(128)	$(119)	$(25)	$(21)	$(17)
Interest cost	(438)	(420)	(386)	(77)	(74)	(72)
Expected return on assets	596	645	679	76	83	91
Amortized prior service and transition cost	(59)	(55)	(55)	(28)	(28)	(28)
Amortization of unrecognized gain	5	83	183	4	21	32
Settlement (loss) gain	(7)	–	6	–	–	18
Benefit income (cost)	$ (43)	$ 125	$ 308	$(50)	$(19)	$ 24
Utility's share of benefit income (cost)	$ (37)	$ 127	$ 302	$(49)	$(19)	$ 7

Net benefit income (cost) was calculated using expected return on plan assets of 8.5 percent for both pension and other benefits.

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). The actual return on plan assets was below the expected return in 2002, 2001, and 2000.

Under SFAS No. 71, regulatory adjustments have been recorded in the Consolidated Statements of Operations and Consolidated Balance Sheets of the Utility to reflect the difference between Utility pension income for accounting purposes and Utility pension income for ratemaking, which is based on a funding approach. The CPUC has authorized the Utility to recover the costs associated with its other benefits 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 following actuarial assumptions were used in determining the plans' assets and benefit obligations and net benefit income (cost). Year-end assumptions are used to compute assets and benefit obligations, while prior year-end assumptions are used to compute net benefit income (cost).

	Pension Benefits December 31,			Other Benefits December 31,		
	2002	2001	2000	2002	2001	2000
Discount rate	6.75%	7.25%	7.50%	6.75%	7.25%	7.50%
Average rate of future compensation increases	5.00	5.00	5.00	5.00	5.00	5.00
Expected return on plan assets	8.10	8.50	8.50	(1)	8.50	8.50

(1) As of the end of 2002, PG&E Corporation changed the expected long-term rate of return on plan assets for various funded plans as follows:

Other Benefits:	
Defined Benefit – Medical Plan Bargaining	8.50%
Defined Benefit – Medical Plan Management	7.20%
Defined Benefit – Life Insurance Plan	8.10%

The assumed health care cost trend rate for 2003 is approximately 10.5 percent, grading down to an ultimate rate in 2008 and beyond of approximately 5.5 percent. 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	$ 8	$ (7)
Effect on post retirement benefits obligation	$72	$(67)

Defined Contribution 401(k) Benefits

PG&E Corporation and its subsidiaries also sponsor defined contribution pension plans more commonly referred to as 401(k) plans. These plans are qualified under applicable sections of the Internal Revenue Code. These plans provide for tax-deferred salary deductions and after-tax employee contributions as well as employer contributions. Employees designate the funds in which their contributions and any employer contributions are invested. Employer contributions include matching and/or basic contributions. For certain plans, matching employer contributions are automatically invested in PG&E Corporation common stock. Employees may reallocate matching employer contributions and accumulated earnings thereon to another investment fund or funds available to their plan at any time once they have been credited to their account. Employee contribution expense reflected in the accompanying PG&E Corporation's Consolidated Statements of Operations amounted to:

(in millions)

Year ended December 31,	Amounts
2002	$52
2001	48
2000	60

Long-Term Incentive Program

PG&E Corporation maintains a Long-Term Incentive Program (Program) that permits various stock-based incentive awards to be granted to non-employee directors, executive officers, and other employees of PG&E Corporation and its subsidiaries. The Stock Option Plan, the Performance Unit Plan, and the Non-Employee Director Stock Incentive Plan (each of which is a component of the Program) provide incentives based on PG&E Corporation's financial performance over time.

Stock Option Plan (SOP)

The SOP provides for grants of stock options to eligible participants with or without associated stock appreciation rights and dividend equivalents.

At December 31, 2002, 45,527,595 shares of PG&E Corporation common stock had been authorized for award under the SOP, with 14,507,614 shares still available under the SOP.

PG&E Corporation – Consolidated

Fair values of options granted in 2002, 2001, and 2000 under the Black-Scholes valuation method are as follows:

(1) Options granted in 2002 had weighted average fair value under the Black-Scholes valuation method of $6.61 per share for 211,712 shares;

(2) Options granted in 2001 were measured using two sets of assumptions deriving weighted average fair values of $6.01 per share for 5,736,300 options granted and $5.80 per share for 5,670,852 options granted at their respective date of grant; and

(3) Options granted in 2000 had weighted average fair values at their date of grant of $3.26.

Significant assumptions used in the Black-Scholes valuation method for shares granted in 2002, 2001 (two sets of assumptions), and 2000 were:

	2002	2001	2000
Expected stock price volatility	30.0%	33.00% & 29.05%	20.19%
Expected dividend yield	0%	0% & 4.35%	5.18%
Risk-free interest rate	4.65%	5.24% & 5.95%	6.10%
Expected life	10 years	10 years	10 years

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. Options outstanding at December 31, 2002, had option prices ranging from $11.80 to $34.25, and a weighted average remaining contractual life of 6.5 years.

The following table summarizes the consolidated SOPs activity at and for the years ended December 31:

(shares in millions)	2002		2001		2000	
	Shares	Weighted Average Option Price	Shares	Weighted Average Option Price	Shares	Weighted Average Option Price
Outstanding, beginning of year	34.1	$22.11	24.3	$25.90	16.4	$29.42
Granted during year	0.2	19.44	11.4	14.33	10.2	20.03
Exercised during year	(0.3)	23.65	(0.1)	31.96	(1.2)	23.52
Cancellations during year	(2.9)	27.61	(1.5)	23.55	(1.1)	26.57
Outstanding, end of year	31.1	22.22	34.1	22.11	24.3	25.90
Exercisable, end of year	15.5	27.05	10.9	27.86	6.3	27.73

The following summarizes information for options outstanding and exercisable at December 31, 2002. Of the outstanding options at December 31, 2002:

(1) 203,712 options had exercise prices ranging from $17.35 to $21.07 with a weighted average remaining contractual life of 9.04 years, of which none of the shares were exercisable;

(2) 9,974,652 options had exercise prices ranging from $9.75 to $19.56, with a weighted average remaining contractual life of 8.3 years, of which 189,700 shares were exercisable at a weighted average exercise price of $14.21; and

(3) 7,826,604 options had exercise prices ranging from $19.81 to $29.06, with a weighted average remaining contractual life of 6.8 years, of which 3,538,779 shares were exercisable at a weighted average exercise price of $19.96.

In addition, 3,593,775 options were granted on January 2, 2003, at an exercise price of $14.61, the then-current market price of PG&E Corporation common stock.

Utility

Fair values of options granted to purchase PG&E Corporation common stock in 2002, 2001, and 2000 under the Black-Scholes valuation method, using the same assumptions as above, are as follows:

(1) No options were granted in 2002;

(2) Options granted in 2001 were measured using two sets of assumptions deriving weighted average fair values of $6.01 per share for 2,057,500 options granted and $5.80 per share for 2,054,100 options granted at their respective date of grant; and

(3) Options granted in 2000 had weighted average fair values at their date of grant of $3.26.

In general, 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.

Options outstanding at December 31, 2002, had option prices ranging from $12.63 to $34.25, and a weighted average remaining contractual life of 7.4 years.

The following table summarizes the SOPs activity for the Utility at and for the years ended December 31:

(shares in millions)	2002		2001		2000	
	Shares	Weighted Average Option Price	Shares	Weighted Average Option Price	Shares	Weighted Average Option Price
Outstanding, beginning of year	12.7	$22.40	8.9	$26.31	6.8	$29.25
Granted during year	–	–	4.1	14.32	3.3	19.89
Exercised during year	(0.2)	23.60	(0.1)	31.96	(0.8)	24.81
Cancellations during year	(0.1)	23.73	(0.2)	24.44	(0.4)	26.95
Outstanding, end of year	12.4	22.37	12.7	22.40	8.9	26.31
Exercisable, end of year	5.9	27.74	4.0	28.81	4.0	28.98

The following summarizes information for options outstanding and exercisable at December 31, 2002. Of the outstanding options at December 31, 2002:

(1) 4,045,600 options, related to 2001 grants had exercise prices ranging from $12.63 to $16.01, with a weighted average remaining contractual life of 9.3 years, of which 60,800 options were exercisable at a weighted average exercise price of $13.57; and

(2) 2,921,124 options, related to 2000 grants, had exercise prices ranging from $19.81 to $26.31, with a weighted average remaining contractual life of 8.0 years, of which 1,009,499 options were exercisable at a weighted average exercise price of $19.90.

In addition, 2,029,725 options were granted on January 2, 2003, at an exercise price of $14.61, the then-current market price of PG&E Corporation common stock.

Performance Unit Plan (PUP)

Under the PUP, PG&E Corporation grants performance units to certain officers of PG&E Corporation and its subsidiaries. The performance units vest one-third in each of the three years following the year of grant. The number of performance units granted and the amount of compensation expense recognized in connection with the issuance of performance units during the years ended December 31, 2002, 2001, and 2000, were not material.

Non-Employee Director Stock Incentive Plan (NEDSIP)

Under the NEDSIP, each person who is a non-employee director on the first business day of the applicable calendar year is entitled to receive stock-based grants with a total aggregate equity value of $30,000, composed of:

(1) Restricted shares of PG&E Corporation common stock valued at $10,000 (based on the closing price of PG&E Corporation common stock on the first business day of the year); and

(2) A combination of non-qualified stock options and common stock equivalents with a total equity value of $20,000 based on equity value increments of $5,000.

The exercise price of stock options is equal to the fair market value of PG&E Corporation common stock on the date of grant. Restricted stock and stock options vest over a five-year period following the date of grant except:

(1) Upon a director's mandatory retirement from the Board;

(2) Upon a director's death or disability; or

(3) In the event of a change in control, in which cases the restricted stock and stock options will vest immediately.

The component of the NEDSIP representing stock options at December 31, 2002, 2001, and 2000, is included in the above data under SOP in accordance with APB No. 25 and SFAS No. 123, as amended by SFAS No. 148. The component of the NEDSIP representing expense recognized in connection with issuance of restricted stock and common stock equivalents during the years ended December 31, 2002, 2001, and 2000, was not material.

PG&E Corporation Supplemental Retirement Savings Plan (SRSP)

The SRSP provides supplemental retirement alternatives to eligible senior officers and key employees of PG&E Corporation and its subsidiaries by allowing participants to defer portions of their compensation, including salaries, amounts awarded under the PUP, and other incentive awards. The SRSP also provides a means for eligible participants to receive and invest employer contribution amounts exceeding contribution limits within the various defined contribution plans sponsored by PG&E Corporation and its subsidiaries. Under the employee-elected deferral component of the SRSP, eligible employees may defer all or part of their PUP (if eligible) and other incentive awards, and 5 to 50 percent of their monthly salary each month. Under the supplemental employer-provided retirement benefits component of the SRSP, eligible employees receive full employer matching and basic contributions in excess of limitations set out by the Internal Revenue Code as qualified under defined contribution 401(k) plans into a non-qualified account. A separate non-qualified account is maintained for each eligible employee to hold any deferred and/or employer-contributed amounts with investment options available for the employee's designation. PG&E Corporation recognizes any gain or loss from these investments and adjusts each employee account on a quarterly basis. Expense related to deferred amounts is recognized in the period in which it is earned by the employee and accrued until paid under the terms of the plan. Employer contribution expense and expenses related to gain or loss from investments of contributed and deferred amounts recognized in connection with the SRSP during the years ended December 31, 2001, and 2000, was not material. For the year ended December 31, 2002, the expense amounted to $3 million.

Executive Stock Ownership Program (ESOP)

The ESOP sets certain stock ownership targets for certain employees. The targets are set as a multiple of the employee's base salary and vary according to the employee. To the extent an employee achieves and maintains the stock ownership targets, the employee will be entitled to receive additional common stock equivalents called Special Incentive Stock Ownership Premiums (SISOPs) to be credited to his or her SRSP account. The SISOPs vest three years after the date of grant and are subject to forfeiture if the employee fails to maintain his or her respective stock ownership target. The amount of expense related to SISOPs granted including the net of appreciation and depreciation on the stock price of PG&E Corporation common stock for the years ended December 31, 2002, 2001, and 2000, was not material.

Restricted Stock Awards

In January 2003, PG&E Corporation awarded restricted shares of PG&E Corporation common stock to eligible employees of PG&E Corporation and its subsidiaries. The shares are granted with restrictions and are subject to forfeiture unless certain conditions are met. On January 2, 2003, 1.6 million shares of restricted stock were granted.

The restricted shares are issued at the grant date and are held in an escrow account. The shares become available to the employees as the restrictions lapse. In general, the restrictions lapse automatically over a period of four years at the rate of 20 percent per year, restrictions as to an additional 5 percent of the shares will lapse per year if PG&E Corporation is in the top quartile of its comparator as measured by relative annual total shareholder return for years ending immediately before each annual lapse date.

Retention Programs

PG&E Corporation implemented various retention mechanisms in 2001. These mechanisms awarded identified key personnel of

PG&E Corporation and its subsidiaries with lump-sum cash payments and/or units of Special Senior Executive Retention Grants.

The Special Senior Executive Retention Grants provide certain employees with phantom PG&E Corporation restricted stock units that, except in the event of a change in control, or on the employee's death or disability, vest no earlier than December 31, 2003. Vesting of one half of the awards is also dependent upon meeting certain performance measures.

The number of units of phantom stock granted under these mechanisms totaled 3,044,600 units in 2001. The phantom stock units are marked-to-market based on the market price of PG&E Corporation common stock, and amortized as a charge to income over a four-year period. The expense recognized in connection with these retention mechanisms, including cash payments and phantom restricted stock units totaled $12 million for the year ended December 31, 2002, and $29 million for the year ended December 31, 2001.

NOTE 15: INCOME TAXES

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

(in millions)	PG&E Corporation			Utility		
	Year Ended December 31,					
	2002	2001	2000	2002	2001	2000
Current	$ 478	$ 967	$(1,284)	$ 838	$ 902	$(1,224)
Deferred	(510)	(393)	(780)	351	(267)	(891)
Tax credits, net	(11)	(39)	(39)	(11)	(39)	(39)
Income tax (benefit) expense	$ (43)	$ 535	$(2,103)	$1,178	$ 596	$(2,154)

The following details net deferred income tax liabilities:

(in millions)	PG&E Corporation		Utility	
	Year ended December 31,			
	2002	2001	2002	2001
Deferred income tax assets:				
Customer advances for construction	$ 318	$ 252	$ 318	$ 252
Unamortized investment tax credits	105	110	105	110
Reserve for damages	268	254	268	254
Environmental reserve	162	161	162	161
ISO energy purchases	–	353	–	353
Impairments	1,162	–	–	–
Other	244	336	79	217
Total deferred income tax assets	$2,259	$ 1,466	$ 932	$1,347
Deferred income tax liabilities:				
Regulatory balancing accounts	$ 175	$ 369	$ 175	369
Property related basis differences	2,220	2,085	1,778	1,665
Income tax regulatory asset	134	83	134	83
Other	517	481	325	323
Total deferred income tax liabilities	3,046	3,018	2,412	2,440
Total net deferred income taxes liabilities	787	1,552	1,480	1,093
Classification of net deferred income taxes liabilities:				
Included in current liabilities	4	73	(5)	65
Included in noncurrent liabilities	783	1,479	1,485	1,028
Total net deferred income taxes liabilities	$ 787	$ 1,552	$1,480	$1,093

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

($ dollars in millions)	PG&E Corporation			Utility		
	Year Ended December 31,					
	2002	2001	2000	2002	2001	2000
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)	(45.5)	4.7	4.5	5.4	5.0	4.3
Effect of regulatory treatment of depreciation differences	(34.4)	1.8	(2.0)	1.2	1.7	(2.0)
Tax credits, net	83.8	(4.3)	0.7	(0.6)	(2.5)	0.7
Effect of foreign earnings at different tax rates	(15.6)	(0.1)	0.1	–	–	–
Stock sale differences	–	–	(1.4)	–	–	–
Stock sale valuation allowance	–	–	1.5		–	–
Other, net	20.0	(1.8)	(0.3)	(1.7)	(2.3)	0.1
Effective tax rate	43.3%	35.3%	38.1%	39.3%	36.9%	38.1%

At December 31, 2002, PG&E Corporation had $420 million of California net operating loss (NOL) carryforwards that will expire if not used by the end of 2012. The California Revenue and Taxation Code has suspended the use of NOL carryforwards for the tax years ending December 31, 2002, and December 31, 2003.

In 2002, PG&E Corporation established valuation allowances for state deferred tax assets associated with PG&E NEG's impairments and write-offs. A valuation allowance of $97 million was recorded in continuing operations with respect to these state deferred tax assets. In addition, a valuation allowance of $87 million was recorded in discontinued operations with respect to state deferred tax assets associated with impairments and write-offs reflected in discontinued operations. These valuation allowances were established due to the uncertainty in realizing tax benefits associated with the state deferred tax assets. PG&E Corporation could not determine that it was more likely than not that some portion or all of its state deferred tax assets would be realized.

In addition to the reserves above, PG&E NEG recorded additional valuation reserves on a stand-alone basis for federal deferred tax assets of $408 million related to continuing operations and $381 million related to discontinued operations. These reserves were eliminated in consolidation, as PG&E Corporation believes that it is more likely than not that these deferred tax benefits will be realized on a consolidated basis.

NOTE 16: COMMITMENTS AND CONTINGENCIES

Commitments

PG&E Corporation has substantial financial commitments in connection with agreements entered into supporting the Utility's and PG&E NEG's operating, construction, and development activities. PG&E NEG's commitments are discussed in Note 3.

Utility

Natural Gas Supply and Transportation Commitments – The Utility purchases natural gas directly from producers and marketers in both Canada and the United States. The composition of the portfolio of natural gas procurement contracts has fluctuated, generally based on market conditions.

The Utility also has long-term gas transportation service agreements with various Canadian and interstate pipeline companies. These companies are responsible for transporting the Utility's gas to the California border. The total demand charges that the Utility will pay each year may change due to changes in tariff rates. These agreements include provisions for payment of fixed demand charges for reserving firm pipeline capacity as well as volumetric transportation charges. The total demand and volumetric transportation charges the Utility incurred under these agreements were $101 million in 2002, $239 million in 2001, and $94 million in 2000.

At December 31, 2002, the Utility's obligations for natural gas purchases and gas transportation services are as follows:

(in millions)	
2003	$595
2004	138
2005	83
2006	26
2007	10
Thereafter	–
Total	$852

Since the Utility filed for bankruptcy and its credit rating is below investment grade, the Utility uses several different credit arrangements for the purpose of purchasing natural gas. The Utility has a $10 million standby letter of credit and pledges its gas customer accounts receivable. The core gas inventory will be pledged only if the Utility's gas customer accounts receivable are less than the amount that the Utility owes to the gas suppliers. As of December 31, 2002, the accounts receivable were sufficient. Therefore, the core gas inventory has not been pledged. The CPUC authorized the Utility to pledge its gas accounts receivable and core inventory, if necessary, until the earlier of:

- May 1, 2003; or
- 15 days after an upgrade of the credit rating of the Utility's mortgage bonds to at least BBB- by S&P or Baa3 by Moody's; or
- The effective date of a plan of reorganization; or
- The dismissal or conversion of the Utility's bankruptcy proceeding.

At December 31, 2002, the pledged amount for total gas accounts receivable was $513 million.

Power Purchase Agreements

Qualifying Facilities – The Utility is required by CPUC decisions to purchase energy and capacity from independent power producers that are qualifying facilities, or QFs, under the Public Utility Regulatory Policies Act of 1978, or PURPA. Pursuant to PURPA, the CPUC required California utilities to enter into a series of long-term power purchase agreements, or PPAs, with QFs and approved the applicable terms, conditions, price options and eligibility requirements. The PPAs with QFs require the Utility to pay for energy and capacity. Energy payments are based on the QF's actual electrical output and CPUC-approved energy prices, while capacity payments are based on the QF's total available capacity and contractual capacity commitment. Capacity payments may be reduced or increased if the facility fails to meet or, alternatively, exceeds performance requirements specified in the applicable PPAs. The Utility recovers its costs incurred from these contracts through electric revenues billed to the customers. Most of the PPAs with QFs expire on various dates through 2028. The Utility's PPAs with QFs accounted for approximately 25 percent of the 2002 electricity deliveries and approximately 21 percent of the 2001 electricity deliveries. There was no single agreement that accounted for more than 5 percent of the Utility's electricity deliveries in 2002 or 2001.

As a result of the energy crisis and the Utility's bankruptcy filing, a number of QFs requested the Bankruptcy Court to either (1) terminate their contracts requiring them to sell power to the Utility, or (2) have the contracts suspended for the summer of 2001 so the QFs could sell power at market rates to the Utility. The Bankruptcy Court ordered the QFs to directly negotiate with the Utility. In July 2001, 197 QFs elected to adopt CPUC-approved amendments to their PPAs to fix their energy payments at $0.054 per kWh for five years.

In December 2001, the Bankruptcy Court approved supplemental agreements between the Utility and most QFs to resolve the applicable interest rate to be applied to pre-petition amounts owed to QFs. The supplemental agreements (1) set the interest rate for pre-petition payables at 5 percent, (2) provide for a "catch-up payment" of all accrued and unpaid interest through the initial payment date, and (3) depending on the amount owed, provide for either (a) payment of the principal and interest amount of the pre-petition payable, or (b) payment in 6 or 12 monthly payments beginning on the last business day of the month during which the Bankruptcy Court approval was granted. In the event the effective date of a plan of reorganization occurs before the last monthly payment is made, the remaining unpaid principal and unpaid interest shall be paid on the effective date. The total amount the Utility owed to QFs when it filed for bankruptcy protection was approximately $1 billion. The principal payments to the QFs amounted to $901 million in 2002 and the interest payments amounted to $44 million in 2002 and $16 million in 2001.

Through December 31, 2002, 264 of 313 QFs have signed assumption and/or supplemental agreements. The Utility believes it will be able to enter into similar supplemental agreements with some of the remaining QFs.

Irrigation Districts and Water Agencies – The Utility has contracts with various irrigation districts and water agencies to purchase hydroelectric power. Under these contracts, the Utility must make (1) specified semi-annual minimum payments based on the irrigation districts' and water agencies' debt service requirements, whether or not any energy is supplied (subject to the supplier's retention of the FERC's authorization), and (2) variable payments for operation and maintenance costs incurred by the suppliers. These contracts expire on various dates from 2004 to 2031. The Utility's PPAs with irrigation districts and water agencies accounted for approximately 4 percent of the 2002 electricity deliveries and accounted for approximately 3 percent of the 2001 electricity deliveries.

Bilateral Power Purchase Contracts – Despite the lack of established criteria for cost recovery from the CPUC, the Utility entered into several bilateral forward electric contracts in October 2000 to stabilize the escalating costs of purchasing power. Several of these contracts were terminated by the other parties because either the Utility filed for bankruptcy or the Utility's credit rating declined to below investment grade. As stated in the contracts, the contracts must be settled at the market value on the termination date. The estimated (pre-tax) net gain on the terminated contracts of $552 million in 2001 was used to reduce the cost of electricity in the Utility's and PG&E Corporation's Consolidated Statements of Operations.

At December 31, 2002, the Utility had outstanding two bilateral forward electric contracts, which will expire in 2003. The undiscounted future minimum energy payments due under these contracts are $196 million in 2003. Under the normal purchases and sales accounting exemption of SFAS No. 133, the Utility does not recognize the cost of the bilateral contracts until the energy is delivered. At December 31, 2002, the outstanding bilateral contracts have an estimated negative market value of $36 million. This value would be recorded as a cost of electricity in the Consolidated Statements of Operations if these contracts failed to meet the normal purchases and sales exemption. The provisions of one of the contracts allows the other party to terminate the contract without penalty at fair value while the Utility is in a Chapter 11 bankruptcy filing. The Utility expects that the physical delivery of electricity will continue through the duration of the contract period and that the contracts will continue to meet the normal purchases and sales exemptions.

Other – California Senate Bill 1078, or SB 1078, requires private utilities to increase their renewable energy supplies by 1 percent a year until these supplies are 20 percent of their generation supply portfolio, provided sufficient funds are available to cover any above-market costs of renewables. Utilities must meet the 20 percent of their generation supply portfolio no later than 2017.

In November 2002, the Utility entered into four contracts with renewable energy suppliers that would obligate the Utility and the DWR upon the occurrence of certain conditions. Subsequently, in February 2003, one of the contracts was terminated. The terms of these contracts with the renewable energy suppliers are for five years commencing on or after January 1, 2003. The Utility will reimburse the DWR for the cost of the contracts in the first year or until the Utility attains an investment grade credit rating, whichever comes first. The Utility has proposed to recover the costs of these contracts through its Energy Resource Recovery Account.

The amount of energy received and the total payments made under QF, irrigation district and water agency, and bilateral PPAs were as follows:

(in millions, except gigawatt-hours)	Year ended December 31, 2002	2001	2000
Gigawatt-hours received	28,088	23,732	26,027
QF Energy payments	$1,051	$1,454	$1,549
QF Capacity payments	506	473	519
Irrigation district and water agency payments	57	54	56
Bilateral payments	196	155	53

At December 31, 2002, the undiscounted future expected PPA payments are as follows:

	QF		Irrigation District & Water Agency		Bilateral	Other		
(in millions)	Energy	Capacity	Operations & Maintenance	Debt Service	Energy	Energy	Capacity	Total
2003	$1,150	$ 530	$ 38	$ 28	$196	$ 14	$ 28	$ 1,984
2004	1,080	520	31	28	–	14	28	1,701
2005	960	490	26	26	–	14	28	1,544
2006	880	470	27	27	–	14	28	1,446
2007	830	450	28	27	–	14	28	1,377
Thereafter	5,000	2,800	524	168	–	–	–	8,492
Total	$9,900	$5,260	$674	$304	$196	$ 70	$140	$16,544

WAPA Sales Contract Commitments – In 1967, the Utility and the Western Area Power Administration, or WAPA, entered into a long-term power contract governing (1) the interconnection of the Utility's and WAPA's transmission systems, (2) the use of the Utility's transmission and distribution system by WAPA, and (3) the integration of the Utility's and WAPA's loads and resources. The contract gave the Utility access to surplus hydroelectric power at low prices and obligated the Utility to provide WAPA with electricity when its own resources were not sufficient to meet its requirements. The contract terminates on December 31, 2004.

As a result of California's electric industry restructuring in 1998, the Utility was required to procure the energy it needed to meet its own and WAPA's requirements from the Power Exchange. This caused the Utility to be exposed to market-based electric pricing rather than the cost of service-based electric pricing that had been presumed when the contract was executed. As a result, during the energy crisis, the Utility paid substantially more for the electricity it purchased on behalf of WAPA than it received for the sales of electricity to WAPA.

The costs going forward to procure power to fulfill the Utility's obligations to WAPA under the contract is uncertain. However, the Utility expects that the cost of meeting its obligation to WAPA may be greater than the price the Utility receives from WAPA under the contract. Under AB 1890, the Utility's retail ratepayers pay for this difference as a stranded power purchase cost. The amount of the difference between the Utility's cost to meet its obligations to WAPA and the revenues it receives from WAPA cannot be accurately estimated at this time since both the purchase price and the amount of electricity WAPA will need from the Utility through the end of the contract are uncertain. Though it is not indicative of future sales commitments or sales-related costs, WAPA's net amount purchased from the Utility is 3,619 GWh in 2002, 4,823 GWh in 2001, and 5,120 GWh in 2000.

Nuclear Fuel Agreements – The Utility has purchase agreements for nuclear fuel components and services for use in operating the Diablo Canyon generating facility. These agreements run from two to five years and are intended to ensure long-term fuel supply, but also permit the Utility the flexibility to take advantage of short-term supply opportunities. Deliveries under six of the eight contracts in place at the end of 2002 will end by 2005. In most cases, the Utility's nuclear fuel contracts are requirements-based and dependent on the Utility's continued operation of its Diablo Canyon generating plant.

At December 31, 2002, the undiscounted obligations under nuclear fuel agreements are as follows:

(in millions)	
2003	$ 59
2004	50
2005	12
2006	13
2007	14
Thereafter	65
Total	$213

Payments for nuclear fuel amounted to $70 million in 2002, $50 million in 2001, and $78 million in 2000.

The Utility relies on large, well-established international producers for its long-term agreements in order to diversify its commitments and ensure security of supply. Pricing terms are also diversified, ranging from fixed prices to base prices that are adjusted using published information.

Operating Leases

The Utility has entered into several operating lease agreements for office space. The leases expire on various dates between 2003 and 2009. At December 31, 2002, the approximate obligations under these operating lease agreements are as follows:

(in millions)	
2003	$ 9
2004	10
2005	9
2006	9
2007	9
Thereafter	9
Total	$55

The operating expenses related to the operating lease agreements for office space amounted $13 million in 2002, $11 million in 2001, and $12 million in 2000.

Other Commitments

Capital Infusion Agreement – The Utility has entered into Capital Infusion Agreements, which obligate the Utility to make scheduled payments to investment partnerships in return for a limited partnership interest. The CPUC has approved the Utility's investment in the non-regulated subsidiaries, which are mainly engaged in the purchase of residential real estate property. The Capital Infusion agreements are secured by the Utility's interest in the partnership and the Utility is fully responsible for its future obligations under these agreements. See discussion of unconsolidated subsidiaries in Note 1.

Under the agreements, the Utility is in default if the Utility (1) becomes insolvent or files for bankruptcy, or (2) fails to make any of its scheduled payments. While technically in default as of December 31, 2002, the Utility is current on all its payments and expects to make all future payments when they become due. The Utility believes the technical default will not result in a loss in the Utility's investment interest.

The Utility's contributions to the investment partnership amounted to $7 million in 2002, $9 million in 2001, and $4 million in 2000.

Diablo Canyon Power-Plant Turbines – The Utility has entered into a contract to retrofit its six low-pressure turbines at Diablo Canyon Unit 1 and Unit 2. These turbine retrofits will (1) improve reliability of the turbine equipment, (2) reduce maintenance costs, and (3) produce more electricity through improved efficiency. The installation of the turbine retrofits is expected to begin in Fall 2005. Progress payments for the turbines will begin in 2003 as certain milestones are reached. The Utility expects all costs incurred under the contract to be capitalized, and included in Property, Plant, and Equipment in the Consolidated Balance Sheets and amortized over the useful life of the asset.

Self-Generation Incentive Program – The CPUC directed the state's larger investor-owned utilities to fund load-control and self-generation initiatives at an annual cost of $138 million for four years beginning in 2001. The Utility's portion of the annual costs is $3 million for load control and $60 million for self-generation initiatives per year. Under the self-generation incentive portion, the Utility offers lump sum rebates to customers who install up to one-and-a-half megawatts of "clean" on-site distributed energy. As of December 31, 2002, the Utility has signed contracts with 54 customers. The Utility's estimated obligation under these contracts is $16 million. The Utility expects the majority of the contract obligations to be fulfilled in 2003 and payment obligations to be paid to the customers. However, customers have the option of extending the installment date by up to another 180 days due to unforeseen events (such as delays in equipment arrival, delays in permitting process, etc.), which would in turn delay the incentive payments.

The costs associated with the incentive portion of the self-generation program amounted to $7 million in 2002 with no similar costs incurred in 2001 and 2000.

The CPUC has stated that it will allow costs of this program which are not recovered during the rate freeze to be recorded in a balancing account and recovered after the rate freeze ends. The Utility receives no rate of return on its investment in these programs, and the CPUC has not addressed how these costs will be recovered. See discussion of the Utility's policy regarding balancing accounts in Note 1.

Telecommunications – The Utility has several cancelable contracts to support the Utility's local and long-distance telecommunication needs. The terms of the contracts require the Utility to give a one-year notice in order to terminate the service. Therefore, the Utility's future commitment is the annual amount, less any amount already paid.

The costs incurred under these contracts amounted to $7 million in 2002, $9 million in 2001, and $5 million in 2000.

At December 31, 2002, the future minimum payments related to other commitments as described above are as follows:

(in millions)	
2003	$ 51
2004	35
2005	30
2006	15
2007	2
Thereafter	2
Total	$135

PG&E NEG

PG&E NEG, through its subsidiaries, has entered into various long-term firm commitments. PG&E NEG and its subsidiaries are negotiating with the lenders, debtholders and other counterparties in an attempt to restructure these commitments. The ability of PG&E NEG and its subsidiaries to fund these commitments depends on the terms of any restructuring plan that may be agreed to by the appropriate parties. The following table identifies by year, the aggregate amounts of these commitments:

(in millions)	2003	2004	2005	2006	2007	Thereafter	TOTAL
Fuel Supply and Transportation Agreements	$ 105	$ 91	$ 91	$ 88	$ 75	$ 380	$ 830
Power Purchase Agreements	217	220	220	220	225	1,140	2,242
Operating Leases	70	79	79	81	84	807	1,200
Long Term Service Agreements	41	7	7	7	7	36	105
Payments in Lieu of Taxes	28	21	14	16	17	97	193
Construction Commitments	237	–	–	–	–	–	237
Tolling Agreements	62	62	62	62	62	482	792

Fuel Supply and Transportation Agreements – PG&E NEG, through various subsidiaries, has entered into gas supply and firm transportation agreements with various pipelines and transporters to provide fuel transportation services. Under these agreements, PG&E NEG must make specified minimum payments each month.

Power Purchase Agreements – USGenNE assumed rights and duties under several power purchase contracts with third party independent power producers as part of the acquisition of the New England Electric System (NEES) assets. As of December 31, 2002, these agreements provided for an aggregate of approximately 800 MW of capacity. USGen New England is required to pay to New England Power Company amounts due to third-party producers under the power purchase contracts.

Operating Leases – Various subsidiaries of PG&E NEG have entered into several operating lease agreements for generating facilities and office space. Lease terms vary between 3 and 48 years.

In November 1998, USGenNE entered into a $479 million sale-leaseback transaction whereby the subsidiary sold and leased back a pumped storage station under an operating lease.

On May 7, 2002, Attala Generating Company LLC, an indirect subsidiary of PG&E NEG, completed a $340 million sale and leaseback transaction whereby it sold and leased back its facility to a third party special purpose entity. The related lease is being accounted for as an operating lease. See Note 7 "Impairments, Write-offs, and Other Charges".

Operating lease expense amounted to $78 million, $54 million, and $70 million in 2002, 2001, and 2000, respectively.

Long Term Service Agreements – Various subsidiaries of PG&E NEG have entered into long-term service agreements for the maintenance and repair of certain of its combustion turbine or combined-cycle generating plants. These agreements are for periods up to 18 years.

Payments in Lieu of Property Taxes – Various subsidiaries of PG&E NEG have entered into certain agreements with local governments that provide for payments in lieu of property taxes for some of its generating facilities.

Construction Commitments – Various subsidiaries of PG&E NEG currently have projects (Athens, Covert, La Paloma, and Harquahala) under construction. PG&E NEG's construction commitments are generally related to the major construction agreements including the construction and other related contracts. Certain construction contracts also contain commitments to purchase turbines and related equipment.

Tolling Agreements

PG&E ET, entered into tolling agreements with several counterparties under which it, at its discretion, supplies the fuel to the power plants and then sells the plant's output in the competitive market. Payments to counterparties are reduced if the plants do not achieve agreed-upon levels of performance. The face amount of PG&E NEG's and its subsidiaries' guarantees relating to PG&E ET's tolling agreements is approximately $600 million. The tolling agreements currently in place are with (1) Liberty Electric Power, L.P. (Liberty) guaranteed by both PG&E NEG and PG&E GTN for an aggregate amount of up to $150 million; (2) DTE-Georgetown, LLC (DTE) guaranteed by PG&E GTN for up to $24 million; (3) Calpine Energy Services, L.P. (Calpine) for which no guarantee is in place; (4) Southaven Power, LLC (Southaven) guaranteed by PG&E NEG for up to $175 million; and (5) Caledonia Generating, LLC (Caledonia) guaranteed by PG&E NEG for up to $250 million.

Liberty – Liberty has provided notice to PG&E ET that the ratings downgrade of PG&E NEG constituted a material adverse change under the tolling agreement requiring PG&E ET to replace the guarantee and to post security in the amount of $150 million. PG&E ET has not posted such security. Liberty has the right to terminate the agreement and seek recovery of a termination payment. Under the terms of the guarantees to Liberty for the aggregate $150 million, Liberty must first proceed against PG&E NEG's guarantee, and can demand payment under PG&E GTN's guarantee only if (1) PG&E NEG is in bankruptcy or (2) Liberty has made a payment demand on PG&E NEG which remains unpaid five business days after the payment demand is made. In addition, PG&E ET has provided notices to Liberty of several breaches of the tolling agreement by Liberty and has advised Liberty that, unless cured, these breaches would constitute a default under the agreement. If these defaults remain uncured, PG&E ET has the right to terminate the agreement and seek recovery of a termination payment.

DTE – By letter dated October 14, 2002, DTE provided notice to PG&E ET that the downgrade of PG&E GTN constituted a material adverse change under the tolling agreement between PG&E ET and DTE and that PG&E ET was required to post replacement security within ten days. By letter dated October 23, 2002, PG&E ET advised DTE that because there had not been a material adverse change with respect to PG&E GTN within the meaning of the tolling agreement, PG&E ET was not required to post replacement security. If PG&E ET was required to post replacement security and it failed to do so, DTE would have the right to terminate the tolling agreement and seek recovery of a termination payment.

Calpine – The tolling agreement states that on or before October 15, 2002, Calpine was to have issued a full notice to proceed under its construction contract to its engineering, procurement and construction contractor for the Otay Mesa facility. On October 16, 2002, PG&E ET asked Calpine to confirm that it had issued this full notice to proceed and Calpine was not able to do so to the satisfaction of PG&E ET. Consequently, PG&E ET advised Calpine by letter dated October 30, 2002 that it was terminating the tolling agreement effective November 29, 2002. Calpine has indicated that this termination was improper and constituted a default under the agreement, but has not taken any further action.

Caledonia and Southaven Tolling Agreements. – PG&E ET signed a tolling agreement with Southaven Power, LLC (Southaven) dated as of June 1, 2000, under which PG&E ET is required to provide credit support as defined in the tolling agreement. PG&E ET satisfied this obligation by providing an investment-grade guarantee from PG&E NEG as defined in the tolling agreement. The amount of the guarantee as of January 31, 2003 does not exceed $175 million. By letter dated August 31, 2002, Southaven advised PG&E ET that it believed an event of default under the tolling agreement had taken place with respect to this obligation as PG&E NEG was no longer investment-grade as defined in the tolling agreement and because PG&E ET had failed to provide, within thirty days from the downgrade substitute credit support that met the requirement of the agreement. Southaven has the right to terminate the agreement and seek a termination payment. In addition, PG&E ET has provided Southaven with a notice of default respecting Southaven's performance under the tolling agreement concerning the inability of the facility to inject its output into the local grid. Southaven has not cured this default and on February 4, 2003, PG&E ET provided a notice of termination.

PG&E ET signed a tolling agreement with Caledonia Generating, LLC (Caledonia) dated as of September 20, 2000, under which PG&E ET is required to provide credit support as defined in the agreement. PG&E ET satisfied this obligation by providing an investment-grade guarantee from PG&E NEG as defined in the tolling agreement. The amount of the guarantee as of January 31, 2003 does not exceed $250 million. By letter dated August 31, 2002, Caledonia advised PG&E ET that it believed an event of default under the tolling agreement had taken place with respect to this obligation as PG&E NEG was no longer investment-grade as defined in the tolling agreement and because PG&E ET had failed to provide, within thirty days from the downgrade substitute credit support that met the requirement of the tolling agreement. Caledonia has the right to terminate the agreement and seek a termination payment. In addition, PG&E ET has provided Caledonia with a notice of default respecting Caledonia's performance under the agreement and concerning the inability of the facility to inject its output into the local grid. Caledonia has not cured this default and on February 4, 2003, PG&E ET provided a notice of termination.

On February 7, 2003, Southaven and Caledonia filed emergency petitions to compel arbitration or alternatively, a temporary restraining order and preliminary injunction with the Circuit Court for Montgomery County, Maryland. The Court has denied the relief requested and set the matter for hearing on February 27, 2003.

PG&E ET is not able to predict whether the counterparties will seek to terminate the agreements or whether the Court will grant the requested relief. Accordingly, it is not able to predict whether or the extent to which, these proceedings will have a material adverse effect on PG&E NEG's financial condition or results of operation.

Under each tolling agreement, determination of the termination payment is based on a formula that takes into account a number of factors including market conditions such as the price of power and the price of fuel. In the event of a dispute over the amount of any termination payment that the parties are unable to resolve by negotiation, the tolling agreement provides for mandatory arbitration. The dispute resolution process could take as long as six months to more than a year to complete. To the extent that PG&E ET did not pay these damages, the counterparties could seek payment under the guarantees for an aggregate amount not to exceed $600 million. PG&E NEG is unable to predict whether counterparties will seek to terminate their tolling agreements. PG&E NEG does not currently expect to be able to pay any termination payments that may become due.

Guarantees

PG&E NEG and certain subsidiaries have provided guarantees to approximately 232 counterparties in support of PG&E ET's energy trading and non-trading activities related to PG&E NEG's merchant energy portfolio in the face amount of $2.7 billion. Typically, the overall exposure under these guarantees is only a fraction of the face value of these guarantees, since not all counterparty credit limits are fully used at any time. As of December 31, 2002, PG&E NEG and its rated subsidiaries' aggregate exposure under these guarantees was approximately $83 million. The amount of such exposure varies daily depending on changes in market prices and net changes in position. In light of the downgrades, some counterparties have sought and others may seek replacement security to collateralize the exposure guaranteed by PG&E NEG and its various subsidiaries. PG&E GTN and PG&E ET have terminated the arrangements pursuant to which PG&E GTN provided guarantees on behalf of PG&E ET such that PG&E GTN will provide no new guarantees on behalf of PG&E ET.

At December 31, 2002, PG&E ET's estimated exposure not covered by a guarantee (excluding exposure under tolling agreements) is approximately $94 million.

To date, PG&E ET has met those replacement security requirements properly demanded by counterparties and has not defaulted under any of its master trading agreements although one counterparty has alleged a default. No demands have been made upon the guarantors of PG&E ET's obligations under these trading agreements. In the past, PG&E ET has been able to negotiate acceptable arrangements and reduce its overall exposure to counterparties when PG&E ET or its counterparties have faced similar situations. There can be no assurance that PG&E ET can continue to negotiate acceptable arrangements in the current circumstances. PG&E NEG cannot quantify with any certainty the actual future calls on PG&E ET's liquidity. PG&E NEG's and its subsidiaries' ability to meet these calls on their liquidity will vary with market price volatility, uncertainty with respect to PG&E NEG's financial condition and the degree of liquidity in the energy markets. The actual calls for collateral will depend largely upon counterparties' responses to the ratings downgrades, forbearance agreements, pre- and early-pay arrangements, the continued performance of PG&E NEG companies under the underlying agreements, whether counterparties have the right to demand such collateral, the execution of master netting agreements and offsetting transactions, changes in the amount of exposure, and the counterparties' other commercial considerations.

Other Guarantees

PG&E NEG has provided guarantees related to other obligations by PG&E NEG companies to counterparties for goods or services. PG&E NEG does not believe that it has significant exposure under these guarantees. The most significant of these guarantees relate to performance under certain construction and equipment procurement contracts. In the event PG&E NEG is unable to provide any additional or replacement security which may be required as a result of downgrades, the counterparty providing the goods or services could suspend performance or terminate the underlying agreement and seek recovery of damages. These guarantees represent guarantees of subsidiary obligations for transactions entered into in the ordinary course of business. Some of the guarantees relate to the construction or development of PG&E NEG's power plants and pipelines. These guarantees are described below.

PG&E NEG has issued guarantees for the performance of the contractors building the Harquahala and Covert power projects for up to $555 million. Any exposure under the guarantees for construction completion is mitigated by guarantees in favor of PG&E NEG from the constructor and equipment vendors related to performance, schedule and cost. The constructor and various equipment vendors are performing under their underlying contracts.

PG&E NEG has issued $100 million of guarantees to the constructor of the Harquahala and Covert projects to cover certain separate cost-sharing arrangements. Failure to perform under those separate cost-sharing arrangements or the related guarantees would not have an impact on the constructor's obligations to complete the Harquahala and Covert projects pursuant to the construction contracts. However, in the event that the construction contractor incurs certain unreimbursed project costs or cost overruns, the contractor could assert a claim against PG&E NEG's subsidiary or PG&E NEG under its guarantees. PG&E NEG believes that the construction contractor as of the date can validly assert no claim hereof.

PG&E NEG has provided a $300 million guarantee to support a tolling agreement that a wholly owned subsidiary, Attala Energy Company LLC, has entered into with another wholly owned subsidiary, Attala Generating. See discussion in Note 7 under "Impairments, Write-offs, and Other Charges."

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

Contingencies

PG&E Corporation

PG&E Corporation has entered into contractual obligations with healthcare providers to coordinate the payment of healthcare costs for PG&E Corporation and PG&E NEG. In the event that PG&E NEG is unable to fund future healthcare costs, PG&E Corporation could be in the position of funding these costs. PG&E NEG's annual healthcare costs in 2002 were approximately $21 million.

As further disclosed below, PG&E Corporation has guaranteed the Utility's reimbursement obligation associated with certain surety bonds and the Utility's obligation to pay workers' compensation claims.

Utility

Nuclear Insurance – The Utility has several types of nuclear insurance for its Diablo Canyon Power Plant, or DCPP, and Humboldt Bay Power Plant, or HBPP. The Utility has insurance coverage for property damages and business interruption losses as a member of Nuclear Electric Insurance Limited, or NEIL. NEIL is a mutual insurer owned by utilities with nuclear facilities. Under this insurance, if a nuclear generating facility insured by NEIL suffers severe losses and those losses exceed the resources of NEIL, the Utility may be responsible for additional premiums of up to $32 million to cover property damages and business interruption for DCPP and up to $1.4 million to cover property damages for HBPP.

Under federal law, the Price-Anderson Act are public liability claims from a nuclear incident limited to $9.5 billion. As required by the Act, the Utility has purchased the maximum available public liability insurance of $300 million for DCPP. The balance of the $9.5 billion of liability protection is covered by a loss-sharing program (secondary financial protection) among utilities owning nuclear reactors. Under the Act, secondary financial protection is required for all reactors of 100 MW or higher. If a nuclear incident results in costs in excess of $300 million, then the Utility may be responsible for up to $88 million per reactor with payments in each year limited to a maximum of $10 million per incident until the Utility has fully paid its share of the liability. Since the Utility has two nuclear reactors, of over 100 MW, the Utility may be assessed up to $176 million per incident with payments in year limited to a maximum of $20 million per incident. The Price-Anderson Act expired on August 1, 2002. By the terms of the act itself, the provisions of the act will remain in effect until Congress renews the act. The current draft of the bill to renew this act would increase the maximum assessment per nuclear incident per unit to $99 million from $88 million, with payments in each year limited to a maximum of $15 million per nuclear incident per unit, increased from $10 million.

Additionally, the Utility has purchased $53.3 million of private liability insurance for HBPP and has a $500 million indemnification from the Nuclear Regulatory Commission for public liability arising from nuclear incidents covering liabilities in excess of the $53.3 million of private liability insurance for HBPP.

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

In February 2001, several surety companies provided cancellation notices because of the Utility's financial situation. The DIR has not agreed to release the canceling sureties from their obligations for claims occurring prior to the cancellation and has continued to apply the cancelled bond amounts, totaling $185 million, towards the $365 million amount of collateral. The Utility was able to supplement the difference through three additional active surety bonds totaling $180 million. At December 31, 2002, the cancelled bonds have not impacted the Utility's self-insured status under California law. PG&E Corporation has guaranteed the Utility's reimbursement obligation associated with these surety bonds and the Utility's underlying obligation to pay workers' compensation claims.

Environmental Matters – The Utility may be required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under the Comprehensive Environmental Response Compensation and Liability Act and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous materials. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if the Utility 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 likely clean-up costs can be reasonably estimated. The Utility reviews its remediation liability on a quarterly basis for each site that may be exposed to remediation responsibilities. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring, and site closure using (1) current technology, (2) enacted laws and regulations, (3) experience gained at similar sites, and (4) the probable level of involvement and financial condition of other potentially responsible parties. Unless there is a better estimate within this range of possible costs, the Utility records the lower end of this range.

The Utility had an undiscounted environmental remediation liability of $331 million at December 31, 2002, and $295 million at December 31, 2001. The $331 million accrued at December 31, 2002, includes (1) $138 million related to the pre-closing remediation liability associated with divested generation facilities, and (2) $193 million related to remediation costs for those generation facilities that the Utility still owns, manufactured gas plant sites, gas gathering sites, and compressor stations. Of the $331 million environmental remediation liability, the Utility has recovered $188 million through rates charged to its customers, and expects to recover approximately $84 million of the balance in future rates. The Utility also is recovering its costs from insurance carriers and from other third parties whenever it is possible.

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. The Utility estimates the upper limit of the range using assumptions least favorable to the Utility, which is based upon a range of reasonably possible outcomes. The Utility's future cost could increase to as much as $444 million if (1) the other potentially responsible parties are not financially able to contribute to these costs, (2) the extent of contamination or necessary remediation is greater than anticipated, or (3) the Utility is found to be responsible for clean-up costs at additional sites.

On June 28, 2001, the Bankruptcy Court authorized the Utility to continue its hazardous waste remediation program and to expend (1) up to $22 million in hazardous substance remediation programs and procedures in each calendar year in which the Chapter 11 case is pending; and (2) any additional amounts in emergency situations involving post-petition releases or threatened releases of hazardous substances subject to the Bankruptcy Court's specific approval.

The California Attorney General, on behalf of various state environmental agencies, filed claims in the Utility's bankruptcy proceeding for environmental remediation at numerous sites totaling approximately $770 million. For most if not all of these sites, the Utility is in the process of remediation in cooperation with the relevant agencies and other parties responsible for contributing to the clean-up in the normal course of business. Since the Utility's proposed plan of reorganization provides that the Utility intends to respond to these types of claims in the regular course of business, and since the Utility has not argued that the bankruptcy proceeding relieves the Utility of its obligations to respond to valid environmental remediation orders, the Utility believes the claims seeking specific cash recoveries are invalid.

PG&E NEG

PG&E NEG has substantial financial contingencies in addition to the environmental matters discussed below. See Note 3 PG&E NEG Liquidity Matters for further discussion on PG&E NEG's financial contingencies.

Environmental Matters

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

As a result of the EPA Information Request and environmental regulatory initiatives by the Commonwealth of Massachusetts, USGenNE is exploring ways to achieve significant reductions of sulfur dioxide and nitrogen oxide emissions. Additional requirements for the control of mercury and carbon dioxide emissions also will be forthcoming as part of these regulatory initiatives. Management believes that USGenNE would meet these requirements through installation of controls at the Brayton Point and Salem Harbor plants and estimates that capital expenditures on these environmental projects could approximate $348 million over the next four years. To date, PG&E NEG has incurred expenditures related to these projects of $15.7 million. These estimates are currently under review and it is possible that actual expenditures may be higher. Based on an emission control plan filed for Brayton Point under the regulations implementing these initiatives, the Massachusetts Department of Environmental Protection (DEP) ruled that Brayton Point is required to meet the newer, more stringent emission limitations for sulfur dioxide and nitrogen oxide by 2006. The DEP has ruled that Salem Harbor must satisfy these limitations by 2004. Although it is USGenNE's current intention to appeal DEP's ruling that Salem Harbor must comply with the new regulations by 2004, in the absence of a successful appeal of the DEP's ruling, the compliance date for Salem Harbor remains October 2004. USGenNE will not be able to operate Salem Harbor unless it is in compliance with these emission limitations. PG&E NEG believes that it is impossible to meet the October 2004 deadline. Therefore, it may not be able to operate the facility after that deadline.

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

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

PG&E NEG's existing power plants are subject to federal and state water quality standards with respect to discharge constituents and thermal effluents. Three of the fossil-fueled plants owned and operated by USGenNE (Salem Harbor, Manchester Street, and Brayton Point) are operating pursuant to National Pollutant Discharge Elimination System (NPDES) permits that have expired. For the facilities whose NPDES permits have expired, permit renewal applications are pending, and all three facilities are continuing to operate under existing terms and conditions until new permits are issued. On July 22, 2002, the EPA and DEP issued a draft NPDES permit for Brayton Point that, among other things, substantially limits the discharge of heat by Brayton Point into Mount Hope Bay. Based on its initial review of the draft permit, USGenNE believes that the draft permit is excessively stringent. It is estimated that USGenNE's cost to comply with the new permit conditions could be as much as $248 million through 2006, but this is a preliminary estimate. There are various administrative and judicial proceedings that must be completed before the draft NPDES permit for Brayton Point becomes final and these proceedings are not expected to be completed during 2003. In addition, it is possible that the new permits for Salem Harbor and Manchester Street may also contain more stringent limitations than prior permits and that the cost to comply with the new permit conditions could be greater than the current estimate of $4 million. In addition, the issuance of any final NPDES permits may be affected by the EPA's proposed regulations under Section 316(b) of the Clean Water Act.

On March 27, 2002, the Rhode Island Attorney General notified USGenNE of their belief that Brayton Point "is in violation of applicable statutory and regulatory provisions governing its operations...", including "protections accorded by common law" respecting discharges from the facility into Mount Hope Bay. He stated that he intends to seek judicial relief "to abate these environmental law violations and to recover damages..." within the next 30 days. The notice purportedly was provided pursuant to section 7A of chapter 214 of Massachusetts General Laws. PG&E NEG believes that Brayton Point is in full compliance with all applicable permits, laws, and regulations. The complaint has not yet been filed or served. In early May 2002, the Rhode Island Attorney General stated that he did not plan to file the action until the EPA issues a draft Clean Water Act NPDES permit for Brayton Point. The EPA issued this draft permit on July 22, 2002, and the Rhode Island Attorney General has since stated he has no intention of pursuing this matter until he reviews USGenNE's response to the draft permit which was submitted on October 4, 2002. Management is unable to predict whether he will pursue this matter and, if he does, the extent to which it will have a material adverse effect on PG&E NEG's financial condition or results of operation.

On April 9, 2002, the EPA proposed regulations under Section 316(b) of the Clean Water Act for cooling water intake structures. The regulations would affect existing power generation facilities using over 50 million gallons per day, typically including some form of "once-through" cooling. Brayton Point, Salem Harbor, and Manchester Street are among an estimated 539 plants nationwide that would be affected by this rulemaking. The proposed rule calls for a set of performance standards that vary with the type of water body and that are intended to reduce impacts to aquatic organisms. The final regulations are scheduled to be promulgated in February 2004. The extent to which they may require additional capital investment will depend on the timing of the NPDES permit proceedings for the affected facilities. It is possible that the regulations may allow greater flexibility in achieving specified permit limits and thereby reduce the cost of compliance.

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

PG&E NEG began the activities during 2000, and is expected to complete them in 2003. PG&E NEG incurred expenditures related to these agreements of $5.4 million in 2000, $2.6 million in 2001, and $4.7 million in 2002. In addition to the costs previously incurred, PG&E NEG maintains a reserve in the amount of $6 million relating to its estimate of the remaining environmental expenditures to fulfill its obligations under these agreements. PG&E NEG has deferred costs associated with capital expenditures and has set up a receivable for amounts it believes are probable of recovery from insurance proceeds.

PG&E NEG believes that it may be required to spend up to approximately $608 million, excluding insurance proceeds, through 2008 for environmental compliance to continue operating these facilities. This amount may change, however, and the timing of any necessary capital expenditures could be accelerated in the event of a change in environmental regulations or the commencement of any enforcement proceeding against PG&E NEG. PG&E NEG has not made any commitments to spend these amounts. In the event PG&E NEG does not spend required amounts as of each facility's compliance deadline to maintain environmental compliance, PG&E NEG may not be able to continue to operate one or all of these facilities.

Global climate change is a significant environmental issue that is likely to require sustained global action and investment over many decades. PG&E Corporation has been engaged on the climate change issue for several years and is working with others on developing appropriate public policy responses to this challenge. PG&E Corporation continuously assesses the financial and operational implications of this issue; however, the outcome and timing of these initiatives are uncertain.

There are six greenhouse gases. The Utility and PG&E NEG emit varying quantities of these greenhouse gases, including carbon dioxide and methane, in the course of their operations. Depending on the ultimate regulatory regime put into place for greenhouse gases, PG&E Corporation's operations, cash flows and financial condition could be adversely affected. Given the uncertainty of the regulatory regime, it is not possible to predict the extent to which climate change regulation will have a material adverse effect on the Utility's or PG&E NEG's financial condition or result of operations.

PG&E NEG and the Utility are taking numerous steps to manage the potential risks associated with the eventual regulation of greenhouse gases, including but not limited to preparing inventories of greenhouse gas emissions, voluntarily reporting on these emissions through a variety of state and federal programs, engaging in demand side management programs that prevent greenhouse gas emissions, and supporting market-based solutions to the climate change challenge.

Legal Matters

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

Chromium Litigation

There are 15 civil suits pending against the Utility in several California state courts. One of these suits also names PG&E Corporation as a defendant. One additional civil suit, *Kearney v. Pacific Gas and Electric Company*, was filed against the Utility and PG&E Corporation after the Utility's bankruptcy filing and was dismissed without prejudice while the plaintiffs sought the right to file and pursue late claims in the Bankruptcy Court. In the *Kearney* case, the Bankruptcy Court ruled that the six adult plaintiffs could not file untimely bankruptcy claims against the Utility. The court also ruled that the 24 minor plaintiffs could file untimely bankruptcy claims against the Utility. The suits allege personal injuries, wrongful death, and loss of consortium and seek compensatory and punitive damages based on claims arising from alleged exposure to chromium in the vicinity of the Utility's gas compressor stations at Hinkley and Kettleman, California, and the area of California near Topock, Arizona. Currently, there are approximately 1,200 plaintiffs in the chromium litigation cases.

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

In the case of *Adams v. Pacific Gas and Electric Company and Betz Chemical Company*, after a hearing on July 17, 2002, the state court dismissed 35 plaintiffs with prejudice because their claims are barred by the statute of limitations. The state court dismissed another 65 plaintiffs without prejudice, so these plaintiffs may attempt to prove that their claims are not barred by the statute of limitations. Thirty of these plaintiffs filed a Fourth Amended Complaint on October 16, 2002. The other 35 plaintiffs who were given leave to amend have been dismissed with prejudice for failure to amend.

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

The Utility has recorded a reserve in its financial statements in the amount of $160 million for these matters. PG&E Corporation and the Utility believe that, after taking into account the reserves recorded at December 31, 2002, the ultimate outcome of this matter will not have a material adverse impact on PG&E Corporation's or the Utility's financial condition or future results of operations.

Natural Gas Royalties Litigation

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

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

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

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

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

Federal Securities Lawsuit

On April 16, 2001, a complaint was filed against PG&E Corporation and the Utility in the U.S. District Court for the Central District of California. The Utility was subsequently dismissed, due to its Chapter 11 bankruptcy filing. By order entered on or about May 31, 2001, the case was transferred to the U.S. District Court for the Northern District of California. On August 9, 2001, plaintiff filed a first amended complaint in the U.S. District Court for the Northern District of California. An executive officer of PG&E Corporation also has been named as a defendant. The first amended complaint, purportedly brought on behalf of all persons who purchased PG&E Corporation common stock or certain shares of the Utility's preferred stock between July 20, 2000, and April 9, 2001, claimed that the defendants caused PG&E Corporation's Consolidated Financial Statements for the second and third quarters of 2000 to be materially misleading in violation of federal securities laws as a result of recording as a deferred cost and capitalizing as a regulatory asset the under-collections that resulted when escalating wholesale energy prices caused the Utility to pay far more to purchase electricity than it was permitted to collect from customers. On January 14, 2002, the District Court granted the defendants' motion to dismiss the plaintiffs' first amended complaint, finding that the complaint failed to state a claim in light of the public disclosures by PG&E Corporation, the Utility, and others regarding the under-collections, the risk that they might not be recoverable, the financial consequences of non-recovery, and other information from which analysts and investors could assess for themselves the probability of recovery.

On February 4, 2002, the plaintiffs filed a second amended complaint that, in addition to containing many of the same allegations as were in the first amended complaint, contains many of the same allegations that appear in the California Attorney General's complaint discussed below. The plaintiffs sought an unspecified amount of compensatory damages, plus costs and attorneys' fees. On March 11, 2002, the defendants filed a motion to dismiss the second amended complaint. After a hearing held on June 24, 2002, the District Court issued an order on June 25, 2002, granting the defendants' motion to dismiss the second amended complaint. The dismissal is with prejudice, prohibiting the plaintiffs from filing a further complaint. On November 15, 2002, the plaintiffs filed an appeal in the United States Court of Appeals for the Ninth Circuit, advancing substantially the same arguments that the District Court had rejected previously. Defendants filed their answer to the appeal on January 2, 2003.

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

Order Instituting Investigation (OII) into Holding Company Activities and Related Litigation

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

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

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

The holding companies have filed petitions for review of both the CPUC's capital requirements and jurisdiction decisions in several state appellate courts, and the utilities also have filed petitions for review of the capital requirements decision with the California appellate courts. The CPUC moved to consolidate all proceedings in the San Francisco state appellate court and requested that the court extend the deadline by which the CPUC must file its responses to the petitions for review until after the consolidation occurred. The CPUC's request for consolidation was granted and all of the petitions are now before the First Appellate District in San Francisco, California.

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

Among other allegations, the Attorney General alleged that, through the Utility's bankruptcy proceedings, PG&E Corporation and the Utility engaged in unlawful, unfair, and fraudulent business practices in alleged violation of California Business and Professions Code Section 17200 by seeking to implement the transactions contemplated in the proposed Plan of Reorganization filed in the Utility's bankruptcy proceeding. The complaint also seeks restitution of assets allegedly wrongfully transferred to

PG&E Corporation from the Utility. On February 8, 2002, PG&E Corporation filed a notice of removal in the Bankruptcy Court to transfer the Attorney General's complaint to the Bankruptcy Court. On February 15, 2002, PG&E Corporation filed a motion to dismiss the lawsuit, or in the alternative, to stay the suit with the Bankruptcy Court. Subsequently, the Attorney General filed a motion to remand the action to state court. In June 2002, the Bankruptcy Court held that federal law preempted the Attorney General's allegations concerning PG&E Corporation's participation in the Utility's bankruptcy proceedings. The Bankruptcy Court directed the Attorney General to file an amended complaint omitting these allegations and remanded the amended complaint to the San Francisco Superior Court. Both parties have appealed the Bankruptcy Court's remand order. The appeal and cross-appeal are pending in the U.S. District Court for the Northern District of California.

On August 9, 2002, the Attorney General filed its amended complaint in the San Francisco Superior Court, omitting the allegations concerning PG&E Corporation's participation in the Utility's bankruptcy proceedings. PG&E Corporation and the directors named in the complaint have filed a motion to strike certain allegations of the amended complaint. Those motions are pending.

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

After removing the city's action to the Bankruptcy Court on February 8, 2002, PG&E Corporation filed a motion to dismiss the complaint. Subsequently, the City filed a motion to remand the action to state court. In June 2002, the Bankruptcy Court issued an Amended Order on Motion to Remand stating that the Bankruptcy Court retained jurisdiction over the causes of action for conversion and unjust enrichment, finding that these claims belong solely to the Utility and cannot be asserted by the City and County, but remanding the Section 17200 cause of action to state court. Both parties have appealed the Bankruptcy Court's remand order. The appeal and cross-appeal are pending in the U.S. District Court for the Northern District of California.

Following remand, PG&E Corporation brought a motion to strike. This motion is pending. PG&E Corporation also moved to coordinate this case with the Section 17200 case brought by Cynthia Behr, which is discussed below. That motion was granted.

In addition, a third case, entitled *Cynthia Behr v. PG&E Corporation, et al.*, was filed on February 14, 2002 by a private plaintiff (who also has filed a claim in bankruptcy) in Santa Clara Superior Court also alleging a violation of California Business and Professions Code Section 17200. The Behr complaint also names the directors of PG&E Corporation and the Utility as defendants. The allegations of the complaint are similar to the allegations contained in the Attorney General's complaint but also include allegations of fraudulent transfer and violation of the California bulk sales laws. Plaintiff requests the same remedies as the Attorney General's case and in addition requests damages, attachment, and restraints upon the transfer of defendants' property. On March 8, 2002, PG&E Corporation filed a notice of removal in the Bankruptcy Court to transfer the complaint to the Bankruptcy Court. Subsequently, the plaintiff filed a motion to remand the action to state court. In its June 2002 ruling mentioned above as to the Attorney General's and the City's cases, the Bankruptcy Court retained jurisdiction over Behr's fraudulent transfer claim and bulk sales claim, finding them to belong to the Utility's estate. The Bankruptcy Court remanded Behr's Section 17200 claim to the Santa Clara Superior

Court. Both parties have appealed the Bankruptcy Court's remand order. The appeal and cross-appeal are pending in the U.S. District Court for the Northern District of California.

Following remand, PG&E Corporation moved to have the Behr case coordinated with the City's case described above. That motion was granted, and the Behr case will now proceed in San Francisco Superior Court.

PG&E Corporation and the Utility believe that they have complied with applicable statutes, CPUC decisions, rules, and orders. Neither the Utility nor PG&E Corporation, however, can predict what the outcome of the CPUC's investigation will be or whether the outcome will have a material adverse effect on their results of operations or financial condition. PG&E Corporation believes that the allegations of the complaints are without merit and will vigorously respond to and defend the litigation. PG&E Corporation cannot predict whether the outcome of the litigation will have a material adverse effect on its results of operations or financial condition.

William Ahern, et al. v. Pacific Gas and Electric Company

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

Recorded Liability for Legal Matters

In accordance with SFAS No. 5, "Accounting for Contingencies," PG&E Corporation makes a provision for a liability when it is both probable that a liability has been incurred and the amount of the loss can be reasonably estimated. These provisions are reviewed quarterly and adjusted to reflect the impacts of negotiations, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular case. In 2001, the Utility increased its provision for legal matters due to a significant case that had a potential material financial impact on the Utility. In 2002, the Utility adjusted its provision again due to the settlement of that case without any damages awarded to the other parties.

The provision for legal matters is included in PG&E Corporation's and the Utility's other noncurrent liabilities in the Consolidated Balance Sheets. The following table reflects the current year's activity to the recorded liability for legal matters for the Utility:

(in millions)	2002	2001
Beginning balance, January 1,	$209	$185
Provision for liabilities	27	7
Payments	(5)	(2)
Adjustments	(29)	19
Ending balance, December 31,	$202	$209

NOTE 17: SEGMENT INFORMATION

PG&E Corporation has identified three reportable operating segments based on similarities in the following characteristics:

- Economic characteristics;
- Products and services;

- Types of customers;
- Methods of distribution;
- Regulatory environment; and
- How information is reported to and used by PG&E Corporation's chief operating decision maker.

The Utility is one reportable operating segment and the other two are part of PG&E NEG. These three reportable operating segments provide products and services and are subject to different forms of regulation or jurisdictions. PG&E Corporation's reportable segments are described below:

Utility – provides natural gas and electric service in Northern and Central California.

PG&E NEG's Integrated Energy & Marketing Activities – engages in the generation, transport, marketing and trading of electricity, various fuels and other energy-related commodities throughout North America.

PG&E NEG's Interstate Pipeline Operations – owns, operates and develops interstate natural gas transmission pipeline facilities which run from Canada/United States border to the California/Oregon border.

In December 2002, the Board of PG&E Corporation approved the sale of USGenNE and Mountain View. The sale transaction for Mountain View was closed on January 31, 2003. Both entities have been accounted for as assets held for sale at December 31, 2002, and the operating results are being reported as discontinued operations.

During 2000, PG&E NEG disposed of PG&E ES and PG&E GTT through a sale.

Segment information for the years 2002, 2001, and 2000, is as follows:

		PG&E National Energy Group [1]					
(in millions)	Utility	Total PG&E NEG	Integrated Energy & Marketing Activities	Interstate Pipeline Operations	PG&E NEG Eliminations	PG&E Corporation, Eliminations and Other [2]	Total
2002							
Operating revenues [3]	$10,505	$ 1,990	$ 1,817	$ 206	$ (33)	$ -	$12,495
Intersegment revenues [4]	9	85	38	47	-	(94)	-
Total operating revenues	10,514	2,075	1,855	253	(33)	(94)	12,495
Depreciation, amortization, and decommissioning	1,193	116	70	46	-	-	1,309
Interest income	74	18	17	4	(3)	40	132
Interest expense	(988)	(202)	(136)	(35)	(31)	(264)	(1,454)
Income tax provision (benefit) [5]	1,178	(656)	(1,186)	44	486	(565)	(43)
Income (loss) from continuing operations	1,794	(2,225)	(1,722)	79	(582)	374	(57)
Net income (loss)	1,794	(3,423)	(2,417)	79	(1,085)	755	(874)
Capital expenditures	1,546	1,485	1,294	191	-	1	3,032
Total assets at year-end [6]	24,551	7,945	7,550	1,341	(946)	1,200	33,696
2001 [7]							
Operating revenues [2]	10,450	1,760	1,560	206	(6)	-	12,210
Intersegment revenues [4]	12	160	120	40	-	(172)	-
Total operating revenues	10,462	1,920	1,680	246	(6)	(172)	12,210
Depreciation, amortization, and decommissioning	896	101	54	42	5	5	1,002
Interest income	123	40	25	7	8	4	167
Interest expense	(974)	(134)	(71)	(37)	(26)	(101)	(1,209)
Income tax provision (benefit) [5]	596	(16)	(47)	34	(3)	(45)	535
Income (loss) from continuing operations	990	67	(5)	76	(4)	(74)	983
Net income (loss)	990	183	111	76	(4)	(74)	1,099
Capital expenditures	1,343	1,426	1,324	102	-	4	2,773
Total assets at year-end [6]	25,269	10,298	8,891	1,251	156	396	35,963
2000 [7]							
Operating revenues [2]	9,623	2,945	1,873	1,066	6	-	12,568
Intersegment revenues [4]	14	182	136	46	-	(196)	-
Total operating revenues	9,637	3,127	2,009	1,112	6	(196)	12,568
Depreciation, amortization, and decommissioning	3,511	79	38	41	-	5	3,595
Interest income	186	28	26	(3)	5	-	214
Interest expense [8]	(619)	(155)	(64)	(90)	(1)	(14)	(788)
Income tax provision (benefit) [5]	(2,154)	55	22	37	(4)	(4)	(2,103)
Income (loss) from continuing operations	(3,508)	93	5	78	10	(8)	(3,423)
Net income (loss)	(3,508)	152	104	78	(30)	(8)	(3,364)
Capital expenditures [9]	1,245	1,089	1,074	15	-	-	2,334
Total assets at year-end [6] [9]	21,988	13,967	12,419	1,204	344	197	36,152

(1) Income from equity method investees for Integrated Energy & Marketing were $48 million in 2002, $79 million in 2001, and $65 million in 2000.

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

(3) Operating revenues and expenses reflect the adoption during 2002 of a new accounting policy implementing a change from gross to net method of reporting revenues and expenses on trading activities. Prior year amounts for trading activities have been reclassified to conform with the new net presentation.

(4) Intersegment revenues are recorded at market prices, but the Utility uses rate set by the CPUC and PG&E NEG's Interstate Pipeline Operations uses rate set by the FERC.

(5) Income tax expense for the Utility was computed on a stand-alone basis. The balance of the consolidated income tax provision was allocated among PG&E Corporation and PG&E NEG.

(6) PG&E Corporation assets exclude its investments in subsidiaries.

(7) Prior periods amounts have been restated to reflect the reclassification of USGenNE, Mountain View, and ET Canada operating results to discontinued operations.

(8) PG&E Corporation allocated its interest expense to subsidiaries in 2000.

(9) "PG&E Corporation Eliminations and Other" column includes capital spending of zero million in 2000 and total assets of $1 million at December 31, 2000, for the discontinued operations of PG&E ES.

QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

Quarter ended	(in millions, except per share amounts)			
	December 31	September 30	June 30	March 31
2002				
PG&E CORPORATION				
Operating revenues [1]	$ 2,968	$ 3,654	$ 2,938	$ 2,935
Operating income (loss) [2][3]	(1,949)	998	782	1,301
Income (loss) from continuing operations [2][3]	(1,417)	459	278	623
Net income (loss) [2]	(2,189)	466	218	631
Earnings (Loss) per common share from continuing operations, basic	(3.72)	1.23	0.76	1.71
Earnings (Loss) per common share from continuing operations, diluted	(3.72)	1.17	0.75	1.69
Common stock price per share				
High	14.18	17.75	23.75	23.66
Low	8.17	8.00	16.35	18.86
UTILITY				
Operating revenues	$ 2,398	$ 2,949	$ 2,714	$ 2,453
Operating income	547	1,059	1,059	1,248
Net income	227	527	469	596
Income available for common stock	221	520	463	590
2001				
PG&E CORPORATION				
Operating revenues [1]	$ 3,017	$ 3,489	$ 2,752	$ 2,952
Operating income (loss) [2][3]	1,051	1,527	1,404	(1,391)
Income (Loss) from continuing operations [2][3]	506	747	718	(988)
Net income (loss) [2]	529	771	750	(951)
Earnings (Loss) per common share from continuing operations, basic	1.39	2.06	1.98	(2.72)
Earnings (Loss) per common share from continuing operations, diluted	1.38	2.05	1.98	(2.72)
Common stock price per share				
High	20.10	17.45	12.54	20.94
Low	14.96	11.66	6.50	8.38
UTILITY				
Operating revenues	$ 2,654	$ 2,937	$ 2,309	$ 2,562
Operating income (loss)	1,134	1,428	1,336	(1,420)
Net income (loss)	563	744	702	(994)
Income (Loss) available for (allocated to) common stock	557	737	696	(1,000)

(1) Operating revenues and operating expenses reflect the adoption during the third quarter of 2002 of a new accounting policy implementing a change from gross to net method of reporting revenues and expenses on trading activities. All prior period amounts for trading activities have been reclassified to conform to the new net presentation.

(2) In December 2002, the Board of Directors of PG&E Corporation approved the sale of USGenNE, Mountain View, and ET Canada. These entities have been accounted for as assets held for sale at December 31, 2002. The operating results have been excluded from continuing operations and reported as discontinued operations for all periods presented. A loss on

disposal of USGenNE and ET Canada of $767 million, net of income taxes of $381 million, was recorded for the quarter ended December 31, 2002. The earnings (loss) from operations of USGenNE, Mountain View, and ET Canada for quarters ending March 31, June 30, September 30, and December 31, 2002, were $8 million, $1 million, $7 million and ($5) million, respectively. The earnings from operations for the same periods in 2001 were $37 million, $32 million, $24 million, and $14 million, respectively.

(3) Amounts have been restated to reflect the reclassification of USGenNE, Mountain View, and ET Canada operating results to discontinued operations. Operating income and income from continuing operations previously reported for the first three quarters in 2002 were $1,306 million and $631 million, $774 million and $279 million, and $1,005 million and $466 million, respectively. Operating income (loss) and income (loss) from continuing operations previously reported for the quarters ended March 31, June 30, September 30, and December 31, 2001, were ($1,340) million and ($951) million, $1,447 million and $750 million, $1,552 million and $771 million, and $1,077 million and $520 million, respectively.

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 (the "Company") and of Pacific Gas and Electric Company (a Debtor-in-Possession) and subsidiaries (the "Utility") as of December 31, 2002 and 2001, and the related consolidated statements of operations, cash flows and common stockholders' equity of the Company and the related consolidated statements of operations, cash flows and stockholders' equity of the Utility for each of the three years in the period ended December 31, 2002. These financial statements are the responsibility of the respective managements of the Company and of the Utility. Our responsibility is to express an opinion on these financial statements based on our audits.

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 consolidated financial statements present fairly, in all material respects, the respective consolidated financial position of the Company and of the Utility as of December 31, 2002 and 2001, and the respective results of their consolidated operations and cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 of the Notes to the Consolidated Financial Statements, during 2002, the Company adopted new accounting standards to account for goodwill and intangible assets, impairment of long-lived assets, discontinued operations, gains and losses on debt extinguishment and certain derivative contracts. Additionally, during 2002, the Company changed the method of reporting gains and losses associated with energy trading contracts from the gross method to the net method and retroactively reclassified the consolidated statements of operations for 2001 and 2000. During 2001, as discussed in Note 1 of the Notes to the Consolidated Financial Statements, the Company and the Utility adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," and the Company adopted certain interpretations issued by the Derivatives Implementation Group of the Financial Accounting Standards Board.

The accompanying consolidated financial statements have been prepared on a going concern basis of accounting. As discussed in Notes 1 and 2 of the Notes to the Consolidated Financial Statements, the Utility, a subsidiary of the Company, has incurred power purchase costs substantially in excess of amounts charged to customers in rates. On April 6, 2001, the Utility sought protection from its creditors by filing a voluntary petition under provisions of Chapter 11 of the U.S. Bankruptcy Code. Additionally, as discussed in Note 3 of the Notes to the Consolidated Financial Statements, PG&E National Energy Group, a subsidiary of the Company, has defaulted on various debt and financing obligations. These matters raise substantial doubt about the ability of the Company and of the Utility to continue as going concerns. Managements' plans in regard to these matters are also described in Notes 2 and 3 of the Notes to the Consolidated Financial Statements. The respective consolidated financial statements do not include any adjustments that might result from the outcome of these uncertainties.

DELOITTE & TOUCHE LLP
San Francisco, California
February 24, 2003

RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

PG&E Corporation and Pacific Gas and Electric Company (the Utility) management are responsible for the integrity of the accompanying consolidated financial statements. The financial 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 consolidated financial statements included herein 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 of PG&E Corporation meets regularly with management, internal auditors, and Deloitte & Touche LLP, 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]

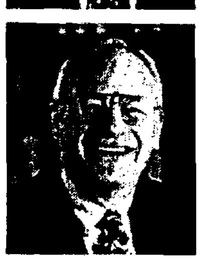
David R. Andrews
Senior Vice President Government Affairs, General Counsel, and Secretary, PepsiCo, Inc.

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, Retired, Kaiser Foundation Health Plan, Inc. and Kaiser Foundation Hospitals

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

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

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

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

(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.

Advisory Director of PG&E Corporation and Pacific Gas and Electric Company

Leslie S. Biller
Vice Chairman and Chief Operating Officer, Retired, Wells Fargo & Company

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

Executive Committees

Subject to certain limits, may exercise the powers and perform the duties of the Boards of Directors.

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 and accounting practices, internal controls, external and internal auditing programs, business ethics, and compliance with laws, regulations, and policies that may have a material impact on the Consolidated Financial Statements. Satisfy themselves as to the independence and competence of the independent public accountants, select and appoint the firm of independent public accountants to audit PG&E Corporation's and Pacific Gas and Electric Company's accounts, and pre-approve all auditing and non-audit services provided by the independent public accountants.

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

Finance Committee

Reviews financial and capital investment policies and objectives and specific actions required to achieve those objectives, long-term financial and investment plans and strategies, annual financial plans, dividend policy, short-term and long-term financing plans, proposed capital expenditures, proposed divestitures, major commercial and investment banking, financial consulting, and other financial relations, and risk management activities. Annually reviews a five-year financial plan that incorporates PG&E Corporation's business strategy goals, as well as an annual budget that reflects elements of the approved five-year plan.

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

Nominating, Compensation, and Governance Committee

Recommends candidates for nomination as directors and reviews the composition, performance, and compensation of the Boards of Directors. Reviews corporate governance matters, including the Corporate Governance Guidelines of PG&E Corporation and Pacific Gas and Electric Company. Reviews employment, compensation, and benefits policies and practices, and long-range 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 that could significantly affect the interests of customers, shareholders, or employees, policies and practices with respect to those issues, and significant societal, governmental, and environmental trends and issues that may affect the operations of PG&E Corporation, Pacific Gas and Electric Company, or their respective subsidiaries.

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

(1) 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.

PG&E Corporation Officers

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

Peter A. Darbee
Senior Vice President and Chief Financial Officer

P. Chrisman Iribe
Senior Vice President

Christopher P. Johns
Senior Vice President and Controller

Thomas B. King
Senior Vice President

L. E. Maddox
Senior Vice President

Daniel D. Richard, Jr.
Senior Vice President, Public Affairs

Gordon R. Smith
Senior Vice President

G. Brent Stanley
Senior Vice President, Human Resources

Bruce R. Worthington
Senior Vice President and General Counsel

Leroy T. Barnes, Jr.
Vice President and Treasurer

Leslie H. Everett
Vice President and Assistant to the Chairman

David S. Gee
Vice President, Strategic Planning

DeAnn Hapner
Vice President, Special Projects

Steven L. Kline
Vice President, Federal Governmental and Regulatory Relations

Greg S. Pruett
Vice President, Corporate Communications

Gabriel B. Togneri
Vice President, Investor Relations

PG&E National Energy Group Officers

Thomas B. King
President

P. Chrisman Iribe
Executive Vice President

L. E. Maddox
Executive Vice President

Pacific Gas and Electric Company Officers

Robert D. Glynn, Jr.
Chairman of the Board

Gordon R. Smith
President and Chief Executive Officer

Kent M. Harvey
Senior Vice President, Chief Financial Officer, and Treasurer

Roger J. Peters
Senior Vice President and General Counsel

James K. Randolph
Senior Vice President and Chief of Utility Operations

Daniel D. Richard, Jr.
Senior Vice President, Public Affairs

Gregory M. Rueger
Senior Vice President, Generation and Chief Nuclear Officer

Shareholder Information

For financial and other information about PG&E Corporation and Pacific Gas and Electric Company, please visit our websites, www.pgecorp.com and www.pge.com, respectively.

If you have questions about your PG&E Corporation common stock account or Pacific Gas and Electric Company preferred stock account, please write or call Mellon Investor Services:

Mellon Investor Services

P.O. Box 3310 (Securities Transfer)
P.O. Box 3315 (General Correspondence)
P.O. Box 3316 (Change of Address)
P.O. Box 3317 (Lost Certificate Replacement)
P.O. Box 3338 (Dividend Reinvestment)
South Hackensack, NJ 07606

Toll-free Telephone Services: 1.800.719.9056
Website: www.melloninvestor.com

If you have general questions about PG&E Corporation or Pacific Gas and Electric Company, please write or call the Corporate Secretary's Office:

Corporate Secretary

Linda Y.H. Cheng
PG&E Corporation
One Market, Spear Tower
Suite 2400
San Francisco, CA 94105-1126
415.267.7070
Fax 415.267.7268

Securities analysts, portfolio managers, or other representatives of the investment community should write or call the Investor Relations Office:

Vice President, Investor Relations

Gabriel B. Togneri
PG&E Corporation
One Market, Spear Tower
Suite 2400
San Francisco, CA 94105-1126
415.267.7080
Fax 415.267.7265

PG&E Corporation

General Information
415.267.7000

Pacific Gas and Electric Company

General Information
415.973.7000

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, 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

The 7.90% Cumulative Quarterly Income Preferred Securities (QUIPS) were converted on May 24, 2002, to 7.90% Deferrable Interest Subordinated Debentures (QUIDS). For additional information on QUIDS, please refer to Note 4 of the "Notes to the Consolidated Financial Statements" section of this report.

Stock Held in Brokerage Accounts ("Street Name")

When you purchase your stock and it is held for you by your broker, the shares are listed with Mellon Investor Services in the broker's name, or "street name." Mellon Investor Services does not know the identity of the individual shareholders who hold their shares in this manner. They simply know that a broker holds a number of shares which may be held for any number of investors. If you hold your stock in a street name account, you receive all tax forms, publications, and proxy materials through your broker. If you are receiving unwanted duplicate mailings, you should contact your broker to eliminate the duplications.

Lost or Stolen Stock Certificates

If you hold stock in your own name and your stock certificate has been lost, stolen, or in some way destroyed, you should notify Mellon Investor Services immediately.

(1) Local newspaper symbols may vary.

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

Date: April 16, 2003
Time: 10:00 a.m.

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

A joint notice of the annual meetings, joint proxy statement, and proxy card are being mailed with this annual report on or about March 21, 2003, to all shareholders of record as of February 18, 2003.

10-K Report

If you would like a copy of the 2002 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.