April 10, 2003

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

| | | |
|---|---|---|
| In the Matter of: | ) | |
| | ) | Docket No. 72-26-ISFSI |
| Pacific Gas and Electric Co. | ) | |
| | ) | ASLBP No. 02-801-01-ISFSI |
| (Diablo Canyon Power Plant Independent Spent Fuel Storage Installation) | ) | |
| | ) | |

# EXHIBITS TO SUMMARY OF FACTS, DATA, AND ARGUMENTS ON WHICH PACIFIC GAS AND ELECTRIC COMPANY WILL RELY AT THE SUBPART K ORAL ARGUMENT

William V. Manheim, Esq.
Richard F. Locke, Esq.
PACIFIC GAS & ELECTRIC COMPANY
77 Beale Street, B30A
San Francisco, CA 94105
(415) 973-6628

David A. Repka, Esq.
Brooke D. Poole, Esq.
WINSTON & STRAWN
1400 L Street, N.W.
Washington, DC 20005-3502
(202) 371-5700

COUNSEL FOR PACIFIC GAS AND ELECTRIC COMPANY

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SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

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FORM 10-K/A

Amendment No. 1

(Mark One)

/X/ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2002
or

/ / TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from
to

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| Commission File Number | Exact Name of Registrant as specified in its charter | State of Incorporation | IRS Employer Identification Number |
|---|---|---|---|
| 1-12609 | PG&E CORPORATION | California | 94-3234914 |
| 1-2348 | PACIFIC GAS AND ELECTRIC COMPANY | California | 94-0742640 |

Pacific Gas and Electric Company
77 Beale Street
P.O. Box 770000
San Francisco, California
(Address of principal executive offices)
94177
(Zip Code)
(415) 973-7000
(Registrant's telephone number, including area code)

PG&E Corporation
One Market, Spear Tower
Suite 2400
San Francisco, California
(Address of principal executive offices)
94105
(Zip Code)
(415) 267-7000
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

| Title of Each Class | Name of Each Exchange on Which Registered |
|---|---|
| PG&E Corporation<br>Common Stock, no par value<br>Preferred Stock Purchase Rights | New York Stock Exchange and Pacific Exchange |
| Pacific Gas and Electric Company<br>First Preferred Stock, cumulative, par value $25 per share:<br>Redeemable: 7.04%, 5% Series A, 5%, 4.80%, 4.50%, 4.36%<br>Mandatorily Redeemable: 6.57%, 6.30%<br>Nonredeemable: 6%, 5.50%, 5% | American Stock Exchange and Pacific Exchange |

| | |
|---|---|
| 7.90% Deferrable Interest Subordinated Debentures | American Stock Exchange and Pacific Exchange |

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes /X/ No / /

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. /X/

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes /X/ No / /

Aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 28, 2002, the last business day of the second fiscal quarter:

| | |
|---|---|
| PG&E Corporation Common Stock | $6,559 million |
| Common Stock outstanding as of February 1, 2003: | |
| PG&E Corporation: | 407,576,505 |
| Pacific Gas and Electric Company: | Wholly owned by PG&E Corporation |

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the documents listed below have been incorporated by reference into the indicated parts of this report, as specified in the responses to the item numbers involved.

| | |
|---|---|
| (1) Designated portions of the combined Annual Report to Shareholders for the year ended December 31, 2002 | Part I (Item 1), Part II (Items 5, 6, 7, 7A, and 8), Part IV (Item 15) |
| (2) Designated portions of the Joint Proxy Statement relating to the 2003 Annual Meeting of Shareholders | Part III (Items 10, 11, 12, and 13) |

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## Explanatory Note

This Amendment No. 1 on Form 10-K/A to PG&E Corporation's and Pacific Gas and Electric Company's joint Annual Report on Form 10-K the for the year ended December 31, 2002 filed with the Securities and Exchange Commission on February 27, 2003 (Form 10-K), is being filed to make certain typographical and tabulation corrections in the following items:

Part I, Item 1. Business

Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations--In response to this item PG&E Corporation and Pacific Gas and Electric Company incorporated by reference the Management's Discussion and Analysis of Financial Condition and Results of Operations appearing in the combined 2002 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company. The portions of the combined 2002 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company that were incorporated by reference were filed as Exhibit 13 to the Form 10-K. Corrections have been made to the sections entitled "Credit Facility Summary," "Cash Flows," "Results of Operations" and "Taxation Matters" of Management's Discussion and Analysis of Financial Condition and Results of Operations. An amended Exhibit 13 is filed with this Amendment No. 1 which is incorporated by reference in response to Item 7.

Part II, Item 8. Financial Statements and Supplementary Data--In response to this item PG&E Corporation and Pacific Gas and Electric Company incorporated by reference the Consolidated Financial Statements for each of PG&E Corporation and Pacific Gas and Electric Company and the Notes to Consolidated Financial Statements appearing in the combined 2002 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company. These portions of the combined 2002 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company that were incorporated by reference were filed as Exhibit 13 to the Form 10-K. Corrections have been made to Notes 1, 3, 11, 12, 15 and 16 to the Consolidated Financial Statements. An amended Exhibit 13 is filed with this Amendment No. 1 which is incorporated by reference in response to Item 8.

Part IV, Item 15. Exhibits, Financial Statement Schedules, and Reports on Form 8-K--The following amended exhibit is being re-filed with this Amendment No. 1:

> Exhibit 13--The following portions of the 2002 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company are included: "Selected Financial Data," "Management's Discussion and Analysis of Financial Condition and Results of Operations," "Independent Auditors' Report," "Responsibility for Consolidated Financial Statements," financial statements of PG&E Corporation entitled "Consolidated Statements of Operations," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Common Stockholders' Equity," financial statements of Pacific Gas and Electric Company entitled "Consolidated Statements of Operations," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," "Consolidated Statements of Stockholders' Equity," "Notes to Consolidated Financial Statements," and "Quarterly Consolidated Financial Data (Unaudited)"

PG&E Corporation and Pacific Gas and Electric Company believe that these changes are not material to their financial condition, results of operations or cash flows.

Except as described above, no other changes have been made to the Annual Report on Form 10-K filed on February 27, 2003. This Amendment No. 1 does not update any other disclosures to reflect developments since the original date of filing.

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## GLOSSARY OF TERMS

| | |
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| AB 1890 | Assembly Bill 1890, the California electric industry restructuring legislation |
| BACT | Best available control technology |
| BCAP | Biennial Cost Allocation Proceeding |
| bcf | billion cubic feet |
| BFM | block forward market |
| BTA | best technology available |
| Btu | British thermal unit |
| CCAA | California Clean Air Act |
| CEC | California Energy Commission |
| CEQA | California Environmental Quality Act |
| CERCLA | Comprehensive Environmental Response, Compensation, and Liability Act |
| core customers | residential and smaller commercial gas customers |
| core subscription customers | noncore customers who choose bundled service |
| CPIM | core procurement incentive mechanism |
| CPUC | California Public Utilities Commission |
| Diablo Canyon | Diablo Canyon Nuclear Power Plant |
| DOE | United States Department of Energy |
| DWR | California Department of Water Resources |
| EMF | electric and magnetic fields |

| | |
|---|---|
| EPA | United States Environmental Protection Agency |
| FERC | Federal Energy Regulatory Commission |
| GRC | General Rate Case |
| Humboldt Unit 3 | Humboldt Bay Power Plant (Unit 3) |
| HWRC | hazardous waste remediation costs |
| IPP | independent power producer |
| IOU or IOUs | investor owned utility or utilities |
| ISO | Independent System Operator |
| KV | Kilovolts |
| KVa | kilovolt-amperes |
| KW | Kilowatts |
| Mcf | thousand cubic feet |
| MDt | thousand decatherms |
| MMcf | million cubic feet |
| MW | Megawatts |
| MWh | megawatt-hour |
| noncore customers | industrial and larger commercial gas customers |
| NPDES | National Pollutant Discharge Elimination System |
| NRC | Nuclear Regulatory Commission |
| ORA | Office of Ratepayer Advocates, a division of the California Public Utilities Commission |
| PG&E Energy | PG&E NEG's integrated energy and marketing segment |
| PG&E ET | PG&E Energy Trading Holdings Corporation and its subsidiaries |
| PG&E Gen LLC | PG&E Generating Company, LLC and its affiliates |
| PG&E GTC | PG&E Gas Transmission Corporation and its subsidiaries |
| PG&E GTN | PG&E Gas Transmission, Northwest Corporation |
| PG&E NBP | PG&E North Baja Pipeline, LLC |
| PG&E NEG | PG&E National Energy Group, Inc. |
| PG&E Pipeline | PG&E NEG's interstate pipeline operations |
| PURPA | Public Utility Regulatory Policies Act of 1978 |
| PX | California Power Exchange |
| QF | qualifying facility |
| RCRA | Resource Conservation and Recovery Act |
| RTO | regional transmission organization |
| TCBA | Transition Cost Balancing Account |
| throughput | the amount of natural gas transported through a pipeline system |
| TRA | Transition Revenue Account |
| TURN | The Utility Reform Network |
| USGenNE | USGen New England, Inc. |



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# PART I

## ITEM 1. Business.

## GENERAL

### Corporate Structure and Business

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

Pacific Gas and Electric Company was incorporated in California in 1905. Effective January 1, 1997, the Utility and its subsidiaries became subsidiaries of PG&E Corporation, which was incorporated in 1995. In the holding company reorganization, the Utility's outstanding common stock was converted on a share-for-share basis into PG&E Corporation common stock. The Utility's debt securities and preferred stock were unaffected and remain as outstanding securities of Pacific Gas and Electric Company. The Utility filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code in the Bankruptcy Court for the Northern District of California 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 Utility is regulated primarily by the California Public Utilities Commission, or CPUC, and the Federal Energy Regulatory Commission, or FERC.

PG&E NEG, headquartered in Bethesda, Maryland, was incorporated on December 18, 1998, as a wholly owned subsidiary of PG&E Corporation. Shortly thereafter, PG&E Corporation contributed various subsidiaries to PG&E NEG. PG&E NEG and its subsidiaries are principally located in the United States and Canada. PG&E NEG's principal subsidiaries include: PG&E Generating Company, LLC, and its subsidiaries, or PG&E Gen; PG&E Energy Trading Holdings Corporation and its subsidiaries, or PG&E ET; and PG&E Gas Transmission Corporation and its subsidiaries, or PG&E GTC, which includes PG&E Gas Transmission, Northwest Corporation and its subsidiaries, or PG&E GTN, and North Baja Pipeline, LLC, or NBP. PG&E NEG also has other less significant subsidiaries.

The principal executive office of PG&E Corporation is located at One Market, Spear Tower, Suite 2400, San Francisco, California 94105, and its telephone number is (415) 267-7000. The principal executive office of Pacific Gas and Electric Company is located at 77 Beale Street, P.O. Box 770000, San Francisco, California 94177, and its telephone number is (415) 973-7000. PG&E Corporation, the Utility, and PG&E NEG each file various reports with the Securities and Exchange Commission, or the SEC. The reports that PG&E Corporation and the Utility file with the SEC are available free of charge on both PG&E Corporation's website, www.pge-corp.com, and the Utility's website, www.pge.com. PG&E NEG's reports also are available free of charge on PG&E Corporation's website, www.pge-corp.com.

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: economics, 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 "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2002 Annual Report to Shareholders and in Note 17 of the "Notes to Consolidated Financial Statements" of the 2002 Annual Report to Shareholders, which information is incorporated by reference into this report.

As result of the sustained downturn in the power industry during 2002, 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



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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. 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 if 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 U.S. Bankruptcy Code. PG&E Corporation does not expect that the liquidity constraints at PG&E NEG and its subsidiaries will affect the financial condition of PG&E Corporation or the Utility.

The consolidated financial statements of PG&E Corporation incorporated in this report reflect the accounts of PG&E Corporation, the Utility, PG&E NEG, and other wholly owned and controlled subsidiaries. The separate consolidated financial statements of the Utility reflect the accounts of the Utility and its wholly owned and controlled subsidiaries.

As of December 31, 2002, PG&E Corporation had approximately $34 billion in assets. Of this amount, Pacific Gas and Electric Company had $25 billion in assets. PG&E Corporation generated approximately $12 billion in operating revenues for 2002. Of this amount, the Utility generated $11 billion in operating revenues for 2002.

As of December 31, 2002, PG&E Corporation and its subsidiaries and affiliates had 21,814 employees (including 19,575 employees of the Utility). Of the Utility's employees, approximately 13,000 are covered by collective bargaining agreements with three labor unions: the International Brotherhood of Electrical Workers, Local 1245, AFL-CIO, or IBEW; the Engineers and Scientists of California, IFPTE Local 20, AFL-CIO and CLC, or ESC; and the International Union of Security Officers/SEIU, Local 24/7, or IUSO. The collective bargaining agreements with IBEW and ESC remain in effect until the earlier of December 31, 2003 or the date on which a new agreement is completed, and the agreement with the IUSO expires on February 28, 2003. The Utility currently is in negotiations for renewal of the collective bargaining agreements with IBEW and ESC and is beginning negotiations with IUSO.

Proposed Plans of Reorganization of the Utility

The Utility will not emerge from bankruptcy until a plan of reorganization has been confirmed by the Bankruptcy Court and the confirmed plan has been implemented. A plan sets forth the means for satisfying both claims against and equity interests in a debtor.

The Utility and PG&E Corporation submitted a proposed plan of reorganization, described below as the Utility Plan. The CPUC submitted a competing proposed plan of reorganization. During the summer of 2002, holders of claims against, and equity interests in, the Utility were requested to vote whether to accept or reject the competing plans. On September 9, 2002, an independent voting agent announced that nine of the ten voting classes under the Utility Plan approved the Utility Plan. The CPUC's plan was approved by one of the eight voting classes under the CPUC's plan. In August 2002, 10 days after the voting period ended, the CPUC and the Official Committee of Unsecured Creditors, or OCC, announced that the OCC had joined the CPUC to support a modified alternative plan of reorganization. On August 30, 2002, the CPUC and the OCC jointly submitted an amended plan of reorganization to the Bankruptcy Court (the CPUC/OCC Plan).

The Bankruptcy Court began confirmation hearings in November 2002 to determine whether to confirm the Utility Plan, the CPUC/OCC Plan, or neither plan. The Bankruptcy Court currently has scheduled trial dates through March 2003.

The Utility Plan. The Utility Plan proposes to restructure the Utility's current businesses and to refinance the restructured businesses so that all allowed creditor claims would be paid in full with interest. The Utility Plan is designed to align the businesses under the regulators that best match the business functions. Assets used in the retail distribution business would remain under the retail regulator, the CPUC, and assets used in the wholesale electric generation and transmission, and interstate natural gas transportation, would be placed under wholesale



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regulators, the FERC and the Nuclear Regulatory Commission, or NRC. After this alignment, the retail-focused, state-regulated business would be a natural gas and electricity distribution company, the Reorganized Utility, representing approximately 70% of the book value of the Utility's assets. The Utility would retain four small generating facilities. The wholesale businesses, electric transmission, interstate gas transmission, and generation, would be federally regulated as to price, terms, and conditions of service.

In contemplation of the Utility 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 Utility 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 Utility also would enter into agreements under which the Utility, Gen, ETrans and GTrans would allocate responsibility and indemnification for liabilities that survive the bankruptcy.

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

* the Utility would rely on Gen for a significant portion of the electricity the Utility needed to meet its electricity distribution customers' demand during the 12-year term of a power purchase and sale agreement between the Utility and Gen, or the Gen power purchase and sale agreement.

* The Utility would rely on ETrans for the 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 Utility would rely on GTrans for the 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 Utility would rely on GTrans for a substantial portion of the Utility's natural gas storage requirements for at least 10 years under a transportation and storage services agreement between the Utility and GTrans, though the Utility does have storage options with third party providers to meet a portion of their requirements.

* The Utility also would have significant operating relationships with the LLCs covering a range of functions and services.

* Finally, the Utility would continue to rely on its natural gas transportation agreement with PG&E Gas Transmission Northwest Corporation, or PG&E GTN, for the transportation of western Canadian natural gas.

The Utility Plan also proposes that on the effective date of the Utility Plan 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 Utility 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 Utility would be an independent publicly held company. The Utility would retain the name "Pacific Gas and Electric Company."

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 Utility will 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 Utility Plan currently 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



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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 CPUC/OCC Plan. The CPUC/OCC Plan does not call for realignment of the Utility's businesses, but instead provides for the continued regulation of all of the Utility's current operations by the CPUC. The CPUC/OCC Plan proposes to reinstate nearly $1 billion of preferred stock and pollution control bonds and satisfy remaining creditor claims in full in cash, using a combination of cash on hand and the proceeds of the issuance of $7.3 billion of new senior secured debt, $1.5 billion of unsecured notes and preferred securities. The CPUC/OCC Plan proposes to establish a $1.75 billion regulatory asset that would be amortized over 10 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 it would 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 CPUC/OCC Plan, and (2) certain recoverable costs (defined as the amounts that 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 CPUC/OCC Plan is not credible or confirmable. PG&E Corporation and the Utility do not believe the CPUC/OCC Plan would restore the Utility to investment grade status if it were to become effective. Additionally, PG&E Corporation and the Utility believe the CPUC/OCC Plan would violate applicable federal and state law.

Risk Factors

This report includes forward-looking statements that are necessarily subject to various risks and uncertainties. These statements are based on current expectations and assumptions which management believes are reasonable and on information currently available to management. These forward-looking statements are identified by words such as "estimates," "expects," "anticipates," "plans," "believes," "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



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

*
what costs the 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 undercollected 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 undercollected 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 due to an overcollection of such 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 Plan, 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.

Utility's Operating Environment. The amount of operating income and cash flows that 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 (i.e., those customers who choose an alternative energy provider);



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* the demand for and pricing of 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 damage to the Utility's assets or operations, to the extent not covered by insurance.

Legislative and Regulatory Environment. PG&E Corporation's, the Utility's, and PG&E NEG's businesses may be impacted by legislative or regulatory changes affecting the electric and natural gas industries in the United States.

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 FERC, and

* the outcome of the CPUC's pending investigation into whether the California investor-owned utilities, or 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 operations and financial condition 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;

* the outcome of pending environmental matters or proceedings;

* 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.

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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;

* the volatility of commodity fuel and electricity prices, and the effectiveness of risk management policies and procedures designed to address volatility; and

* the ability of counterparties to satisfy their financial commitments and the impact of counterparties' nonperformance on PG&E NEG's liquidity.

Efforts to Restructure PG&E NEG's Indebtedness. Whether PG&E NEG and certain of its subsidiaries seek protection under or be forced into a proceeding under the U.S. 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 operations 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 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 USGen 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 is 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; 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,



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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 results or outcomes currently sought or expected.

## REGULATION

Various aspects of PG&E Corporation's and its subsidiaries' businesses, including the Utility, are subject to a complex set of energy, environmental, and other governmental laws and regulations at the federal, state and local levels. This section summarizes some of the more significant laws and regulations affecting PG&E Corporation's business at this time.

### Regulation of PG&E Corporation

PG&E Corporation and its subsidiaries are exempt from all provisions, except Section 9(a)(2), of the Public Utility Holding Company Act of 1935, or the Holding Company Act. At present, PG&E Corporation has no expectation of becoming a registered holding company under the Holding Company Act. On July 7, 2001, the California Attorney General, or the AG, filed a petition with the SEC requesting the SEC to review and revoke PG&E Corporation's exemption from the Holding Company Act and to begin fully regulating the activities of PG&E Corporation and its affiliates. The AG's petition requested the SEC to hold a hearing on the matter as soon as possible, and requested a response from the SEC no later than September 5, 2001. On August 7, 2001, PG&E Corporation responded in detail to the AG's petition demonstrating that PG&E Corporation met the SEC's criteria for the intrastate exemption. On October 4, 2001, the AG filed a "supplement" to its petition requesting that the SEC consider additional issues and to set the matter for hearing. PG&E Corporation responded to the supplement on October 30, 2001, and once again demonstrated that there was no basis for action by the SEC. In comments filed on November 14, 2002 on PG&E Corporation's 9(a)(2) filing made with the SEC in connection with the implementation of the Utility Plan, the AG reiterated the arguments made in its July 7, 2001 and October 4, 2001 filings with the SEC. In its response filed with the SEC on January 24, 2003, PG&E Corporation responded to those arguments and demonstrated that there was no basis for SEC action with respect to those issues. To date, the SEC has neither instituted an investigation nor ordered hearings regarding the matters raised in the AG's petition.

PG&E Corporation is not a public utility under the laws of California and is not subject to regulation as such by the CPUC. However, the CPUC approval authorizing Pacific Gas and Electric Company to form a holding company was granted subject to various conditions related to finance, human resources, records and bookkeeping, and the transfer of customer information. As further discussed below, in January 2002, the CPUC issued a decision asserting that it maintains jurisdiction to enforce the conditions against PG&E Corporation and similar holding companies and to modify, clarify or add to the conditions. The financial conditions provide that

* the Utility is precluded from guaranteeing any obligations of PG&E Corporation without prior written consent from the CPUC,

* the Utility's dividend policy must continue to be established by the Utility's Board of Directors as though Pacific Gas and Electric Company were a stand-alone utility company,

* 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, must be given first priority by PG&E Corporation's Board of Directors (the "first priority condition"), and

* the Utility must maintain on average its CPUC-authorized utility capital structure, although it shall have an opportunity to request a waiver of this condition if an adverse financial event reduces the Utility's equity ratio by 1% or more.



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The CPUC also has adopted complex and detailed rules governing transactions between California's natural gas local distribution and electric utility companies and their non-regulated affiliates. The rules permit non-regulated affiliates of regulated utilities to compete in the affiliated utility's service territory, and also to use the name and logo of their affiliated utility, provided that in California the affiliate includes certain designated disclaimer language which emphasizes the separateness of the entities and that the affiliate is not regulated by the CPUC. The rules also address the separation of regulated utilities and their non-regulated affiliates and information exchange among the affiliates. The rules prohibit the utilities from engaging in certain practices that would discriminate against energy service providers that compete with the utility's non-regulated affiliates. The CPUC also has established specific penalties and enforcement procedures for affiliate rules violations. Utilities are required to self-report affiliate rules violations.

On April 3, 2001, the CPUC issued an order instituting an investigation 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, 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' actions to "ringfence" their unregulated subsidiaries. The CPUC will also determine whether additional rules, conditions, or changes are needed to adequately protect ratepayers and the public from dangers of abuse stemming from the holding company structure. The CPUC will investigate whether it should modify, change, or add conditions to the holding company decisions, make further changes to the holding company structure, alter the standards under which the CPUC determines whether to authorize the formation of holding companies, otherwise modify the decisions, or recommend statutory changes to the California legislature. As a result of the investigation, the CPUC may impose remedies, prospective rules, or conditions, as appropriate. PG&E Corporation and the Utility believe that they have complied with applicable statutes, CPUC decisions, rules, and orders.

On January 9, 2002, the CPUC issued two decisions in its pending investigation. In one decision, the CPUC, for the first time, adopted a broad interpretation of the first priority condition and concluded that the condition, if such acquisition would impair the utility's ability to fulfill its obligation to serve or to operate in a prudent and efficient manner.

In the other 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 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. The CPUC stated that PG&E Corporation was being dismissed so that an appropriate legal forum; i.e., the state court action discussed below, could decide expeditiously whether adoption of the Utility's proposed plan of reorganization would violate the first priority condition.

On January 10, 2002, the AG filed a complaint in the San Francisco Superior Court against PG&E Corporation and its directors, as well as against the directors of the Utility, based on allegations of unfair or fraudulent business acts or practices in violation of California Business and Professions Code Section 17200. Among other allegations, the AG alleges that PG&E Corporation violated the various conditions established by the CPUC in decisions approving the holding company formation. After the AG's complaint was filed, two other complaints containing substantially similar allegations were filed by the City and County of San Francisco and by a private plaintiff. For more information, see "Item 3--Legal Proceedings" below.

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 can predict what the outcomes of the CPUC's investigation, the AG's petition to the SEC, and the related litigation will be or whether the outcomes will have a material adverse effect on their results of operations or financial condition.



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## Regulation of Pacific Gas and Electric Company

### Federal Regulation

The FERC. The FERC is an independent agency within the U.S. Department of Energy, or the DOE. The FERC regulates the interstate sale and transportation of natural gas, the transmission of electricity in interstate commerce and the sale for resale of electricity in interstate commerce. The FERC regulates electric transmission rates and access, interconnections, operation of the California Independent System Operator, or ISO, and the terms and rates of wholesale electric power sales. The ISO has responsibility for providing open access transmission service on a non-discriminatory basis, meeting applicable reliability criteria, planning transmission system additions, and assuring the maintenance of adequate reserves and is subject to FERC regulation of tariffs and conditions of service. In addition, the FERC has jurisdiction over the Utility's electric transmission revenue requirements and rates. Further, most of the Utility's hydroelectric facilities are subject to licenses issued by the FERC.

In an effort to support the development of competitive markets, the FERC announced in its Order 2000 a policy of promoting regional transmission organizations, or RTOs, which would perform specified functions similar to the ISO. Under the FERC's Order 2000, RTOs would generally span areas where multiple utilities may have operated in the past in order to enhance the efficiency of power markets, for example, by eliminating duplicative charges from one transmission system to the next in a region. Order 2000 encourages utilities owning transmission systems to form RTOs on a voluntary basis. The Utility is a participant in the ISO; however, the FERC has not yet approved the ISO's status as a RTO under Order 2000.

In the FERC's proposal for a standard market design, the FERC has proposed additional changes to the open access transmission tariff initially established under the FERC's Order 888 to standardize transmission service and wholesale electric market design to address undue discrimination in interstate transmission services. The FERC has proposed that all public utilities with open access transmission tariffs file modifications to their tariffs to conform to the FERC's standard. These proposed changes would require all independent transmission providers or RTOs to participate in a regional planning process for grid upgrades and expansion to ensure grid reliability. The FERC proposed approving participant funding of certain new facilities, meaning those who would directly benefit from those facilities would be required to pay for them. PG&E Corporation filed comments on November 15, 2002 supporting the goals of the FERC's proposal, and is continuing to participate in the rulemaking process as it moves forward.

The ISO issued its own Comprehensive Market Design Proposal to effect changes to the structure and operation of the California electricity market. Implementation of the first phase of the proposal, automated market mitigation procedures, occurred in the fourth quarter of 2002, with subsequent phases to address real-time economic dispatch, integrated forward markets, locational marginal pricing, and congestion management scheduled to occur in 2003 and 2004.

In a separate proceeding, the FERC has proposed that all transmission providers use standard interconnection procedures and a standard agreement for generator interconnections. The generator interconnection rules, if adopted as proposed, would require the Utility to update and construct additional facilities based on decisions by new generators, and would preclude the Utility from disclaiming consequential damages for any claims or limiting the Utility's liability for its negligence in any new generator interconnection agreements. The FERC has also held that transmission providers, like the Utility, must upgrade existing facilities or construct new facilities to interconnect with new generators, and that while generators will generally be responsible for initially funding the costs of such facilities, some of which costs over time must be refunded by the Utility and recovered in the Utility's rates. The FERC recently held that generators are entitled to a credit for the cost of network upgrades which they funded even if the FERC previously had accepted agreements which directly assigned to the generators responsibility for the cost of those upgrades.

In response to the unprecedented increase in wholesale electricity prices, 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 like those in 2000 and 2001. These orders established a cap on bids for real-time electricity and ancillary services of $250/MWh and established various automatic mitigation procedures. Recently, in the FERC's standard market design proposed rules, 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 power sales. 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. The FERC has asserted that it would not order refunds for periods before October 2, 2000, because under a federal statute it can only consider ordering refunds as far back as 60 days after a complaint for overcharges was filed. The first complaint for overcharges was filed with the FERC in August 2000. These hearings, in which various parties, including the Utility and the State of California, which is seeking up to $8.9 billion in refunds for electricity overcharges on behalf of buyers, including the Utility, were concluded in October 2002. However, an August 21, 2002, order from the U. S. Court of Appeals for the Ninth Circuit ordered the FERC to allow the California parties "to adduce additional evidence of market manipulation by various sellers...." In November 2002, the FERC gave parties until February 28, 2003 to submit more evidence and conduct fact-finding on whether California's energy market was manipulated. On December 17, 2002, a FERC administrative law judge issued a ruling permitting the California parties to conduct discovery of potential market manipulation affecting California ISO and PX markets within all 14 western states and parts of Canada comprising the Western Electricity Coordinating Council to support claims for refunds. The judge also ruled new evidence is admissible on market manipulation and artificially inflated prices for natural gas, the chief fuel used to generate electricity.

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 power.

After the final round of evidence-gathering ends, the FERC commissioners must decide whether to uphold or change the initial decision. It is uncertain when the FERC will issue a decision.

The NRC. The NRC oversees the licensing, construction, operation, and decommissioning of nuclear facilities, including the Diablo Canyon Nuclear Power Plant (Diablo Canyon) and the retired nuclear generating unit at Humboldt Bay Unit 3. NRC regulations require extensive monitoring and review of the safety, radiological, environmental and security aspects of these facilities.

State Regulation

The CPUC. The CPUC has jurisdiction to set retail rates and conditions of service for the Utility's electric distribution, gas distribution, and gas transmission services in California. The CPUC also has jurisdiction over the Utility's sales of securities, dispositions of utility property, energy procurement on behalf of its electric and gas retail customers, rate of return, rates of depreciation, and certain aspects of the Utility's siting and operation of its electric and gas transmission and distribution systems. Ratemaking for retail sales from the Utility's remaining generation facilities is under the jurisdiction of the CPUC. To the extent such power is sold for resale into wholesale markets, however, it is under the ratemaking jurisdiction of the FERC. The CPUC also conducts various reviews of utility performance and conducts investigations into various matters, such as deregulation, competition, and the environment, in order to determine its future policies. The CPUC consists of five members appointed by the Governor of California and confirmed by the California State Senate for six-year terms.

The CEC. The California Energy Resources Conservation and Development Commission, also called the California Energy Commission, or the CEC, makes electricity-demand forecasts for the state and for specific service territories. Based upon these forecasts, the CEC determines additional energy sources and conservation program needs. The CEC has jurisdiction over the siting and construction of new thermal electric generating facilities 50 MW and greater in size. The CEC sponsors alternative-energy research and development projects, promotes energy conservation programs, and maintains a statewide plan of action in case of energy shortages. In addition, the CEC certifies power plant sites and related facilities within California. The CEC also administers funding for public purpose research and development, and renewable technologies programs.

California Legislature. The California Legislature also has an active role in the regulation of California IOUs. Over the last several years, the Utility's operations have been significantly affected by statutes passed by the California Legislature.

Assembly Bill 1890--California Electric Industry Restructuring. In 1998, California implemented Assembly Bill 1890, or AB 1890, which mandated the restructuring of the California electric industry 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 CPUC also issued many decisions to implement electric industry restructuring. Electric industry restructuring included the following components:



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The Rate Freeze and Transition Cost Recovery--Beginning January 1, 1997, electric rates for all customers were frozen at the level in effect on June 10, 1996, except that on January 1, 1998, rates for residential and small commercial customers were reduced by a further 10% and frozen at that level. The rate freeze for each IOU was supposed to end when that IOU had recovered its eligible "transition" costs (costs of utility generation-related assets and obligations that were expected to become uneconomic under the new competitive generation market structure), but not later than March 31, 2002. Under limited circumstances, some transition costs could be recovered after the transition period. Costs eligible for recovery as transition costs, as determined by the CPUC, include (1) above-market sunk costs associated with utility generating facilities that are fixed and unavoidable and that were included in customer rates on December 20, 1995, and future unavoidable above-market firm obligations, such as costs related to plant removal, (2) costs associated with pre-existing long-term contracts to purchase power at then above-market prices from qualifying facilities, or QFs, and other power suppliers, and (3) generation-related regulatory assets and obligations. Frozen rates were designed to recover authorized utility costs and, to the extent the frozen rates generated revenues in excess of authorized utility costs, recover the Utility's transition costs. Transition costs also were to be recovered by other revenue sources including (1) the portion of the market value of generation assets sold by the Utility or market valued by the CPUC that is in excess of book value, (2) revenues from energy sales from the utilities' remaining electric generation facilities that exceeded the allowed revenue requirements for the utilities' costs to generate or obtain such electricity, and (3) revenues provided after the end of the transition period for rate reduction bond principal repayments to recover deferred transition costs associated with the financed 10% rate reduction and issuance of the rate reduction bonds to finance such reduction.

For the first two years of the transition period, the revenues from frozen retail rates exceeded the generation costs included in retail rates. Based on the resulting net revenues and other revenue sources used to recover transition costs, it appeared that the Utility's transition costs would be recovered before March 31, 2002, thus allowing the rate freeze to end sooner than the statutory end date. Although the Utility informed the CPUC in late 2000 that it had satisfied the statutory conditions for ending the rate freeze by no later than August 31, 2000, the CPUC adopted changes to its regulatory accounting rules in March 2001 that had the effect of changing the classification of costs recovered in the Utility's regulatory balancing accounts and reversing the Utility's prior collection of transition costs.

In June 2000, wholesale electricity prices began to increase and reached unprecedented levels in November 2000 and later months. During the California energy crisis, frozen rates were insufficient to cover the Utility's electricity procurement and other costs. By December 31, 2000, the Utility had accumulated approximately $6.9 billion in undercollected purchased power and transition costs that the CPUC would not allow the Utility to collect from its customers. Because the Utility could no longer conclude that such costs were probable of recovery, the Utility charged this $6.9 billion to earnings during 2000.

In the first quarter of 2001, the CPUC authorized the Utility to begin collecting energy surcharges totaling $0.04 per kWh (composed of a $0.01 per kWh surcharge in January and a $0.03 per kWh surcharge approved in March). 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 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 CPUC restricted the use of these surcharge revenues to pay for the Utility's "ongoing procurement costs" and "future power purchases." Due to these surcharges, the Utility has been collecting revenues in excess of its ongoing costs of utility service enabling the Utility to partially recover its undercollected power procurement and transition costs previously written off. The amount of undercollected power procurement and transition costs has been reduced to approximately $2.2 billion (after-tax) at December 31, 2002.



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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 (which the CPUC states ended no later than March 31, 2002), the CPUC will determine the extent and disposition of the Utility's undercollected 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, the Supreme Court of California is considering whether the CPUC has the authority to enter into a settlement which allows Southern California Edison to recover undercollected 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.

Direct Access --AB 1890 gave the Utility's customers the choice of continuing to buy electricity from the California IOUs or buying electricity from independent power generators or retail electricity suppliers beginning April 1, 1998. Customers who choose to buy their electricity from independent power generators or retail electricity suppliers are called direct access customers. Most of the Utility's customers continued to buy electricity through the Utility. On September 20, 2001, the CPUC, pursuant to AB 1X, suspended the right of retail end-use customers to acquire direct access service, preventing additional customers from entering into contracts to purchase electricity from alternative energy providers. In a subsequent decision issued on March 21, 2002, the CPUC decided to allow all customers with direct access contracts entered into on or before September 20, 2001 to remain on direct access. The CPUC has established an exit fee, or non-bypassable charge, on those direct access customers to avoid a shift of costs from direct access customers to bundled service customers. For more information, see "Electric Ratemaking--Electric Procurement--Direct Access" below.

The Power Exchange, the Independent System Operator, and the Buy/Sell Requirement --AB 1890 called for the creation of the California Power Exchange, or the PX. The PX provided an auction process, intended to be competitive, to establish hourly transparent market clearing prices for electricity in the markets operated by the PX. The PX operated the following energy markets:

* the day-ahead market where market participants purchased power for their customers' needs for the following day,
* the day-of market where market participants purchased power needed to serve their customers on the same day, and
* the block forward market, or BFM, that matched bids to buy a specific amount of power for one month (and later one-quarter and annual terms) with offers to sell power for the same period in advance of the contracted delivery date.

This short-term spot market approach represented a dramatic shift from the existing pricing approach based on a portfolio of short and longer-term contracts. At the time the PX was formed and in several subsequent decisions, the CPUC ruled that prices paid by utilities to the PX under the CPUC's "buy-sell" mandate were presumed to be prudent and reasonable for the purpose of recovery in retail rates.

AB 1890 also called for the creation of the ISO to exercise centralized operational control of the statewide transmission grid. The California IOUs were obligated to transfer control, but not ownership, of their transmission systems to the ISO. The ISO is responsible for ensuring the reliability of the transmission grid and keeping momentary supply and demand in balance. The PX market was augmented by a spot "real-time" market maintained by the ISO. If enough power was not purchased and scheduled to meet the actual real-time demands for power being placed on the transmission system, then the ISO was authorized under its FERC-approved tariffs to purchase and provide the electricity from any other sources within or outside of California, often at high rates, to make up the difference in order to keep the electrical grid operating reliably. The ISO billed the PX for such power deficiencies, and the PX in turn billed the IOUs to the extent the IOUs were unable to purchase sufficient supply from the PX for their retail customers.

The PX's BFM provided the Utility a limited opportunity to hedge against prices in the PX day-ahead market only; it did not enable the Utility to hedge against ISO real-time market prices. In July 1999, the Utility obtained CPUC authority to participate in the BFM and the Utility subsequently entered into several BFM contracts.



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Due to the January 2001 downgrades in the Utility's credit ratings and the Utility's alleged failure to post collateral for all market transactions, the PX suspended the Utility's market trading privileges as of January 19, 2001. Further, the PX sought to liquidate the Utility's BFM contracts for the purchase of power. On February 5, 2001, the Governor, acting under California's Emergency Services Act, seized the Utility's BFM contracts for the benefit of the State. Under the Act, the State must pay the Utility the reasonable value of the contracts, although the PX may seek to recover monies that the Utility owes to the PX from any proceeds realized from those contracts. The Utility subsequently filed a complaint against the State to recover the value of the seized contracts. This litigation is still pending.

Divestiture and Market Valuation of Generation Assets --The structure of the transition to a fully competitive generation market established by AB 1890 also required all of the Utility's generation assets to be market valued, if not through sale, then through appraisal or other divestiture. Under AB 1890, the CPUC was required to complete market valuation of all generation assets by December 31, 2001. Under AB 1890, once an asset had been market valued, it was no longer subject to rate regulation by the CPUC. The market valuation process was intended to be an integral and essential step in recovering transition costs and measuring whether the transition period had ended. The transition costs eligible for recovery were to be calculated by netting above-market assets against below-market assets. Once market valuation had occurred, the end of the rate freeze date was to be computed retroactively to the point at which all transition costs had been recovered. To date, the only assets of the Utility that the CPUC has valued have been those that were divested through sale, except with respect to the Utility's Hunters Point power plant, which the CPUC ruled had no market value. The Utility timely submitted proposed market valuations of retained generation facilities, so that those facilities could be valued by the CPUC and no longer subject to CPUC regulation. In August 2000, the Utility submitted an interim market valuation of $2.8 billion for its hydroelectric generation facilities. Additionally, in June and December 2000, the Utility submitted testimony to the CPUC providing a market valuation of its hydroelectric facilities of $4.1 billion.

In 1995, in anticipation of the transition to a competitive wholesale electric market, the CPUC ordered the California IOUs to file plans to divest at least 50% of their fossil fuel-fired generation assets. Moreover, as an incentive to sell the remainder of the Utility's generation assets, the CPUC reduced the return on equity that the Utility could earn on any retained generation asset substantially below its otherwise authorized return to a level equivalent to 90% of the Utility's embedded cost of debt (or 6.77%). The Utility sold virtually all of its fossil-fuel fired and geothermal generation capacity with CPUC authorization and approval. By January 2000, the Utility owned only its large nuclear power generating facility at Diablo Canyon, its hydroelectric generation facilities, and two smaller, older fossil facilities. As the amount of the Utility's own generation resources decreased, the Utility was forced to rely on power supplied by third-party power producers through the PX to meet the electricity demands of its customers.

Assembly Bill 1X--California Department of Water Resources. In late December 2000 and early January 2001, the Utility's creditworthiness deteriorated and it was no longer able to comply with the ISO's creditworthiness criteria, spelled out in the ISO tariff, for scheduling third-party power transactions through the ISO. The Utility was unable to continue financing its wholesale power purchases in light of its downgraded credit ratings. On January 17, 2001, the Governor of California signed an order declaring an emergency and authorizing the California Department of Water Resources, or the DWR, to purchase power to maintain the continuity of supply to retail customers. On February 1, 2001, the Governor signed Assembly Bill 1X, or AB 1X, to authorize the DWR to purchase power and sell that power directly to the utilities' retail end-use customers. AB 1X also required the Utility to deliver the power purchased by the DWR over its distribution systems and to act as a billing and collection agent on behalf of the DWR, without taking title to such power or reselling it to its customers.

AB 1X allows the DWR to recover, as a revenue requirement, among other things: (1) amounts necessary to pay for the power and associated transmission and related services, (2) amounts needed to pay the principal and interest on bonds issued to finance the purchase of power, (3) administrative costs, and (4) certain other amounts associated with the program. AB 1X authorizes the CPUC to set rates to cover the DWR's revenue requirements (but prohibits the CPUC from increasing electric rates for residential customers who use less power than 130% of their existing baseline quantities).

Assembly Bill 6X--Prohibition on Disposition of Retained Utility-Owned Generating Assets. In January 2001, the California legislature also enacted AB 6X, which prohibits disposition of utility-owned generating facilities before January 1, 2006. On December 21, 2001, the assigned CPUC Commissioner issued a ruling for comment in which she expressed her opinion that the requirement of AB 1890 to market value retained generation by December 31, 2001 had been superseded by AB 6X. On January 15, 2002, the Utility filed its comments on the



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proposal stating that AB 6X did not relieve the CPUC of its statutory obligation to market value the retained generation by December 31, 2001. The CPUC has not yet issued a decision on this matter.

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 the surcharge revenues, discussed above, the CPUC reiterated that it had yet to decide when the rate freeze ended and the disposition of any undercollected 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 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 $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.

Senate Bill 1976--Resumption of Procurement. Under AB 1X, the DWR was prohibited from entering into new electricity purchase contracts and from purchasing electricity on the spot market after December 31, 2002. In September 2002, the Governor signed California Senate Bill 1976, or SB 1976, into law. SB 1976 required the CPUC to allocate electricity subject to existing DWR contracts among the customers of the California IOUs, including the Utility's customers. Each IOU had to submit, within 60 days of the CPUC's allocation of the existing DWR contracts, a proposed electricity procurement plan to the CPUC specifying the date that the IOU intends to resume procurement of electricity for its retail customers.

As part of the resumption of the procurement function, each IOU would procure electricity for that portion of its customers' needs that is not covered by the combination of the allocation of electricity from existing DWR contracts to that IOU's customers and the IOU's own electric resources and contracts (referred to as the residual net open position).

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 from the market subject to comparison with the CPUC-authorized benchmarks; and/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.

The CPUC must review each procurement plan but SB 1976 provides that the CPUC may not approve a procurement plan if it finds the plan contains features or mechanisms that would impair restoration of the IOU's creditworthiness or would lead to a deterioration of the IOU's creditworthiness. A procurement plan approved by the CPUC must accomplish the following objectives, among others:

* Enable the IOU to fulfill its obligation to serve its customers at just and reasonable rates;
* Eliminate the need for after-the-fact reasonableness review of actions in compliance with an approved procurement plan, including resulting electricity procurement contracts and related expenses, subject to verification and assurance that each contract was administered in accordance with the terms of the contract and that contract disputes that arise are resolved reasonably; and
* Moderate the price risk associated with serving its customers by authorizing the IOU to enter into financial and other electricity-related product contracts.

SB 1976 requires the CPUC to:

* create electric procurement balancing accounts to track and allow recovery

of the differences between recorded revenues and costs incurred under an approved procurement plan;

* review the revenues and costs associated with the IOU's procurement plan at least semi-annually and adjust rates or order refunds as necessary; and



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* establish the schedule for amortizing the overcollections or undercollections in the electric procurement balancing accounts at least through January 1, 2006, so that the aggregate overcollection or undercollection reflected in the accounts does not exceed 5% of the IOU's actual recorded generation revenues for the prior calendar year, excluding revenues collected on behalf of the DWR.

On September 19, 2002, the CPUC issued a decision allocating electricity subject to the DWR contracts to the generation portfolios of the three California IOUs for operational and scheduling purposes, with the DWR retaining legal title and financial reporting and payment responsibilities associated with these contracts. The IOUs will, however, become responsible for scheduling and dispatch of the quantities subject to the allocated contracts and for many administrative functions associated with those contracts.

On October 24, 2002, the CPUC issued a decision establishing an accelerated schedule for submission and approval of procurement plans for each California IOU with a view to these utilities resuming procurement responsibility for their net open position on January 1, 2003. On December 19, 2002, the CPUC adopted, in large part but with modifications, the Utility's revised 2003 interim procurement plan. The CPUC also authorized the IOUs to extend their planning into the first quarter of 2004 and directed them to hedge their 2004 first quarter residual net short positions with transactions entered into in 2003. The Utility is required to submit its long-term procurement plan covering the next 20 years by April 1, 2003.

In December 2002, the CPUC determined that the maximum risk of potential disallowance each IOU should face for all of its procurement activities should be limited to twice its annual administrative costs of managing procurement activities. The Utility anticipates that its annual administrative costs of managing procurement activities will be approximately $18 million in 2003.

On January 1, 2003, the California IOUs resumed the function of procuring electricity to meet their customers' residual net open position and became responsible for the operational and scheduling functions associated with the DWR contracts allocated to their customers. The IOUs continue to act as billing and collection agents for the DWR.

Local Regulation, Licenses and Permits

Pacific Gas and Electric Company obtains a number of permits, authorizations, and licenses in connection with the construction and operation of its generating plants, transmission lines, and gas compressor station facilities. Discharge permits, various Air Pollution Control District permits, U.S. Department of Agriculture-Forest Service permits, FERC hydroelectric facility and transmission line licenses, and NRC licenses are the most significant examples. Some licenses and permits may be revoked or modified by the granting agency if facts develop or events occur that differ significantly from the facts and projections assumed in granting the approval. Furthermore, discharge permits and other approvals and licenses are granted for a term less than the expected life of the associated facility. Licenses and permits may require periodic renewal, which may result in additional requirements being imposed by the granting agency. The Utility currently has eight hydroelectric projects and one transmission line project undergoing FERC license renewal.

The Utility has over 520 franchise agreements with various cities and counties that allow the Utility to install, operate and maintain its electric, natural gas, oil, and water facilities in the public streets and roads. In exchange for the right to use public streets and roads, the Utility pays annual fees to the cities and counties under the franchises. Franchise fees are computed according to statute depending on whether the particular franchise was granted under the Broughton Act or the Franchise Act of 1937; however, there are 38 "charter cities" that can set a fee of their own determination. The Utility also periodically obtains permits, authorizations, and licenses in connection with distribution of electricity and natural gas. Pursuant to the permits, licenses, and franchises, the Utility has rights to occupy and/or use public property for the operation of its business and to conduct certain operations.

The Utility's operations and assets are also regulated by a variety of other federal, state, and local agencies.

Regulation of PG&E National Energy Group, Inc. Businesses

Federal Regulation

The rates, terms, and conditions of the wholesale sale of power by the generating facilities owned or leased by PG&E NEG through PG&E Generating Company LLC, its subsidiaries and affiliates, and of power contractually controlled by them is subject to FERC jurisdiction under the Federal Power Act. Various PG&E NEG subsidiaries and affiliates have FERC-approved market-based rate schedules and accordingly have been granted waivers of



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many of the accounting, record keeping, and reporting requirements imposed on entities with cost-based rate schedules. This market-based rate authority may be revoked or limited at any time by the FERC.

PG&E NEG-affiliated projects are also subject to other differing federal regulatory regimes. Those qualifying as qualifying facilities, or QFs, under the Public Utility Regulatory Policies Act of 1978, or PURPA, are exempt from the Holding Company Act, certain rate filings, and accounting, record keeping, and reporting requirements that the FERC otherwise imposes and from certain state laws. Others qualify as Exempt Wholesale Generators under the National Energy Policy Act of 1992. These generators are not regulated under the Holding Company Act, but are subject to FERC and state regulation, including rate approval.

The FERC also regulates the rates, terms, and conditions for electric transmission in interstate commerce. Tariffs established under FERC regulation provide PG&E NEG with the necessary access to transmission lines which enables PG&E NEG to sell the energy PG&E NEG produces into competitive markets for wholesale energy. In April 1996, the FERC issued an order requiring all public utilities to file "open access" transmission tariffs. Some utilities are seeking permission from the FERC to recover costs associated with stranded investments through add-ons to their transmission rates. To the extent that the FERC will permit these charges, the cost of transmission may be significantly increased and may affect the cost of PG&E NEG operations.

The FERC also licenses all of PG&E NEG's hydroelectric and pumped storage projects. These licenses, which are issued for 30 to 50 years, will expire at different times between 2002 and 2020. The relicensing process often involves complex administrative processes that may take as long as 10 years. The FERC may issue a new license to the existing licensee, issue a license to a new licensee, order that the project be taken over by the federal government (with compensation to the licensee), or order the decommissioning of the project at the owner's expense.

PG&E NEG's natural gas transmission business is also subject to FERC jurisdiction. Certificates of public convenience and necessity have been obtained from the FERC for construction and operation of the existing pipelines and related facilities and properties, construction and operation of the North Baja Pipeline, and construction and operation on the PG&E GTN pipeline currently underway. An application has also been filed with the FERC to construct a further expansion on PG&E GTN. The rates, terms, and conditions of the transportation and sale (for resale) of natural gas in interstate commerce is subject to FERC jurisdiction. As necessary, PG&E NEG subsidiaries and affiliates file applications with the FERC for changes in rates and charges that allow recovery of costs of providing services to transportation customers. An October 1999 order permits individually negotiated rates in certain circumstances.

The U.S. Department of Energy, or DOE, also regulates the importation of natural gas from Canada and exportation of power to Canada.

State and Other Regulations

In addition to federal laws and regulation, PG&E NEG businesses are also subject to various state regulations. First, public utility regulatory commissions at the state level are responsible for approving rates and other terms and conditions under which public utilities purchase electric power from independent power projects. As a result, power sales agreements, which PG&E NEG affiliates enter into with such utilities, are potentially subject to review by the public utility commissions, through the commissions' power to approve utilities' rates and cost recoveries. Second, state public utility commissions also have the authority to promulgate regulations for implementing some federal laws, including certain aspects of PURPA. Third, some public utility commissions have asserted limited jurisdiction over independent power producers. For example, in New York the state public utility commission has imposed limited requirements involving safety, reliability, construction, and the issuance of securities by subsidiaries operating assets located in that state. Fourth, state regulators have jurisdiction over the restructuring of retail electric markets and related deregulation of their electric markets. Finally, states may also assert jurisdiction over the siting, construction, and operation of PG&E NEG's generation facilities.

In addition, the National Energy Board of Canada and the Canadian gas-exporting provinces issue licenses and permits for removal of natural gas from Canada. The Mexican Comision Reguladoro de Energia, or CRE, issues various licenses and permits for the importation of gas into Mexico. These requirements are similar to the requirements of the U.S. Department of Energy for the importation and exportation of gas.

Other regulatory matters are described throughout this report. For a discussion of environmental regulations to which PG&E Corporation and its subsidiaries are subject, see the section entitled "Environmental Matters" below.

## COMPETITION

Historically, energy utilities operated as regulated monopolies within specific service territories where they were essentially the sole suppliers of natural gas and electricity services. Under this model, the energy utilities owned and operated all of the businesses necessary to procure, generate, transport, and distribute energy. These services were priced on a combined, or "bundled" basis, with rates charged by the energy companies designed to include all of the costs of providing these services. Under traditional cost-of-service regulation, there is a regulatory compact in which the utilities undertake a continuing obligation under state law to serve their customers, in return for which the utilities are authorized to charge regulated rates sufficient to recover their costs of service, including timely recovery of their operating expenses and a reasonable return on their invested capital. The objective of this regulatory policy was to provide universal access to safe and reliable utility services. Regulation was designed in part to take the place of competition and ensure that these services were provided at fair prices. In recent years, energy utilities faced intensifying pressures to "unbundle," or price separately, those activities that are no longer considered natural monopoly services. The most significant of these were the commodity components--electricity and natural gas.

The driving forces behind these competitive pressures have been customers who believe they can obtain energy at lower unit prices and competitors who want access to those customers. Regulators and legislators responded to these customers and competitors by providing for more competition in the energy industry. Regulators and legislators required utilities to unbundle rates in order to allow customers to compare unit prices of the utilities and other providers when selecting their energy service provider.

### The Electric Industry

As discussed above, in 1998, California implemented AB 1890, which mandated the restructuring of the California electric industry 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.

During the first two years of the transition period, the revenues from frozen retail rates exceeded the generation costs included in retail rates. Beginning in June 2000, wholesale prices for electricity in California began to increase. Prices moderated somewhat in the fall of 2000, before increasing to unprecedented levels in mid-November of 2000 and later months. Revenues from the Utility's frozen retail rates were insufficient to recover the cost of purchasing wholesale power. In January 2001, as wholesale power prices continued to far 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 the capital markets, and could no longer continue buying power to deliver to its customers. As a result, the California legislature authorized the DWR to purchase electricity for the Utility's customers. The DWR's authority to enter into new contracts or purchase power on the spot market expired on December 31, 2002. On January 1, 2003, the California IOUs resumed procuring power to cover their retail customers' residual net open position.

The FERC's policy has supported the development of a competitive electric generation sector. The FERC's Order 888, issued in 1996, established standard terms and conditions for parties seeking access to regulated utilities' transmission grids. The FERC's subsequent Order 2000, issued in 1999, established national standards for RTOs and advanced the view that a regulated, unbundled transmission sector should facilitate competition in both wholesale electric generation and retail electricity markets. The FERC's more recent standard market design proposal continues to uphold this view.

The Utility faces increased competition in the electricity distribution function as a result of the construction of duplicate distribution facilities to service specific existing or new customers, potential municipalization of the Utility's existing distribution facilities by a local government or district, self-generation by the Utility's customers, and other forms of competition that may result in stranded investment capital, loss of customer growth and additional barriers to cost recovery. If the number of Utility customers declines due to these forms of competition and the Utility's rates are not increased in a timely manner to allow the Utility to fully recover its investment and procurement costs, the Utility's financial condition and results of operations could be materially adversely affected.

The Natural Gas Industry

FERC Order 636, issued in 1992, required interstate pipeline companies to divide their services into separate gas commodity sales, transportation, and storage services. Under Order 636, interstate gas pipelines must provide transportation service regardless of whether the customer (often a local gas distribution company) buys the gas commodity from the pipeline.



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In August 1997, the CPUC approved the Gas Accord settlement agreement, or Gas Accord, which restructured the Utility's gas services and its role in the gas market through 2002. Among other matters, the Gas Accord unbundled the rates for the Utility's gas transportation services from the rates for its distribution services. As a result, the Utility's customers may buy gas directly from competing suppliers and purchase transportation-only and distribution-only services from the Utility. The Utility's industrial and larger commercial customers, or noncore customers, now purchase their gas from producers, marketers and brokers. Substantially all residential and smaller commercial customers, or core customers, buy gas as well as transmission and distribution services from the Utility as a bundled service.

Although the Gas Accord originally was scheduled to expire on December 31, 2002, the Utility filed an application to extend the Gas Accord for two years, known as the Gas Accord II Application, or Gas Accord II. In August 2002, the CPUC approved a settlement agreement among the Utility and other parties that provided for a one-year extension through 2003 of the Utility's existing gas transportation and storage rates and terms and conditions of service, 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 insofar as they relate to the second year of the two-year application. In January 2003, the Utility filed an application proposing Gas Accord II rates for 2004. For more information about the Gas Accord and regulatory changes affecting the California natural gas industry, see "Utility Operations--Ratemaking Machanisms--Gas Ratemaking" below.

The Utility competes with other natural gas pipeline companies for transportation customers into the southern California market on the basis of transportation rates, access to competitively priced supplies of natural gas and the quality and reliability of transportation services. The most important competitive factor affecting the Utility's market share for transportation of gas to the southern California market is the total cost of western Canadian gas, including transportation costs, delivered to southern California from the

Utility's transportation system relative to the total cost of gas, including transportation costs, delivered to southern California on other pipeline systems from supply basins in the southwestern United States and Rocky Mountains. In general, when the total cost of western Canadian gas increases, the Utility's market share in southern California decreases. In addition, Kern River Pipeline Company expects to complete a major expansion of its pipeline system in 2003 that will increase its capacity to deliver natural gas into the southern California market by approximately 900 million cubic feet, or MMcf, per day. As a result of Kern River's expansion, the volume of gas that the Utility delivers to the southern California market may decrease in the short term. The Utility also competes for storage services with other third party storage providers, primarily in northern California. The most important competitive factors affecting the Utility's market share are overall product design and pricing terms.

From time to time, existing pipeline companies propose to expand their pipeline systems for delivery of natural gas into northern and central California. Although the record gas-fired electric generation gas demands in late 2000 and 2001 spurred several new natural gas pipeline proposals for northern and central California, many of the power generation projects have been cancelled or delayed, making it difficult for sponsors of the various gas pipeline projects to acquire enough firm capacity commitments to go forward with construction.

Electric Generation and Natural Gas Transmission

During 2002, adverse changes in the national energy markets affected 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.

PG&E NEG has been significantly impacted by these adverse changes. 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 energy industry have had a significant negative impact on the financial results and liquidity of PG&E NEG as discussed in Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations."



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Competitive factors may also affect the results of PG&E NEG's operations including new market entrants (e.g. construction by others of more efficient generation assets), retirements, and a participant's number of years and extent of operations in a particular energy market. PG&E NEG's Generation Business competes against a number of other participants in the merchant energy industry including Mirant, Calpine, Duke Energy, Reliant, AES, and NRG. Competitive factors relevant to this industry include financial resources, credit quality, development expertise, insight into market prices, conditions and regulatory factors, and community relations. PG&E NEG's competitors have greater financial resources than PG&E NEG does and have a lower cost of capital.

When economic circumstance force fuel suppliers into bankruptcy, fuel supply contracts are at risk of being terminated, especially if the current market prices are substantially higher than the prices committed to in long-term contracts. Under such circumstances, PG&E NEG is at risk for having its power sales agreements and fuel supply agreements uncoupled. As states review the need for electric industry restructuring, there is a risk that current contracts are found to be too expensive and attempts may be made to abrogate such contracts.

PG&E NEG's Pipeline Business competes with other pipeline companies for transportation customers on the basis of transportation rates, access to competitively priced gas supply and growing markets, and the quality and reliability of transportation services. The competitiveness of a pipeline's transportation services to any market is generally determined by the total delivered natural gas price from a particular natural gas supply basin to the market served by the pipeline. The cost of transportation on the pipeline is only one component of the total delivered cost.

PG&E NEG's transportation service on the PG&E GTN pipeline accesses supplies of natural gas primarily from western Canada and serves markets in the Pacific Northwest, California and Nevada. PG&E NEG must compete with other pipelines for access to natural gas supplies in western Canada. PG&E NEG's major competitors for transportation services for western Canadian natural gas supplies include TransCanada Pipelines, Alliance Pipeline, Southern Crossing Pipeline and Northern Border Pipeline Company and Westcoast Energy Gas Transmission.

The three markets PG&E NEG serves may access supplies from several competing basins in addition to supplies from western Canada. Historically, natural gas supplies from western Canada have been competitively priced on the PG&E GTN pipeline in relation to natural gas supplied from the other supply regions serving these markets. Supplies transported from western Canada on the PG&E GTN pipeline compete in the California market with Rocky Mountain natural gas supplies delivered by Kern River Gas Pipeline and Southwest natural gas supplies delivered by Transwestern Pipeline Company, El Paso Natural Gas and Southern Trails Pipeline. In the Pacific Northwest market, supplies transported from western Canada on the PG&E GTN pipeline compete with Rocky Mountain gas supplies delivered by Northwest Pipeline Corporation and with British Columbia supplies delivered by Westcoast Transmission Company for redelivery by Northwest Pipeline Corporation.

Transportation service on NBP provides access to natural gas supplies from both the Permian basin, located in western Texas and southeastern New Mexico, and the San Juan basin, primarily located in northwestern New Mexico. The North Baja system delivers gas to Gasoducto Bajanorte Pipeline, at the Baja California--California border, which transports the gas to markets in northern Baja California, Mexico. While there are currently no direct competitors to deliver natural gas to NBP's downstream markets, the pipeline may compete with fuel oil which is an alternative to natural gas in the operation of some electric generation plants in the North Baja region. Moreover, NBP's market is near locations of interest for liquefied natural gas development companies who may be interested in delivering foreign natural gas supplies to the area.

Overall, PG&E NEG's transportation volumes are also affected by other factors such as the availability and economic attractiveness of other energy sources. Hydroelectric generation, for example, may become available based on ample snowfall and displace demand for natural gas as a fuel for electric generation. Finally, in providing interruptible and short-term transportation service, PG&E NEG competes with release capacity offered by shippers holding firm contract capacity on PG&E NEG's pipelines.

## UTILITY OPERATIONS

The Utility is the principal provider of electricity and natural gas distribution and transmission services in northern and central California. The Utility's service territory covers 70,000 square miles, serving 4.8 million electricity customers and 4.0 million natural gas customers.

### Ratemaking Mechanisms

In setting the retail rates for the Utility's electric and natural gas utility services, the CPUC first determines the Utility's revenue requirements. The components of revenue requirements for electric and natural gas utility service include depreciation, expenses, taxes, and return on investment, as applicable, for distribution, transmission/



transportation, generation/procurement, and public purpose programs. The CPUC then allocates the revenue requirements among customer classes (mainly residential, commercial, industrial, and agricultural) and sets specific rates designed to produce the required revenue. The concept underpinning the determination of revenue requirements and rates is to allow a utility a fair opportunity to recover its reasonable costs of providing adequate utility service, including a reasonable rate of return of and on its investment in utility facilities.

The primary revenue requirement proceeding is the general rate case, or GRC. In the GRC, the CPUC authorizes the Utility to collect from ratepayers an amount known as "base revenues" to recover basic business and operational costs for its natural gas and electricity operations. The general rate case sets annual revenue requirement levels for a three-year rate period. The CPUC authorizes these revenue requirements in general rate case proceedings generally every three years based on a forecast of costs for the first or "test" year. The Utility's pending general rate case request is for test year 2003. For the remaining two years of a general rate case period, the Utility has indicated that it intends to apply for annual increases in base revenues (known as attrition rate adjustments) to reflect inflation and increases in invested capital. After authorizing the revenue requirement, the CPUC allocates revenue requirements among customer classes and establishes specific rate levels in separate proceedings.

Another major CPUC proceeding for determining revenue requirements is the annual cost of capital proceeding. Each year, the CPUC determines the adopted rate of return that the Utility may earn on its electric and gas distribution assets and recover from ratepayers. On November 7, 2002, the CPUC issued a final decision that retained the Utility's return on common equity at the current authorized level of 11.22%. This final decision also increased the Utility's authorized cost of debt to 7.57% from 7.26%, and held in place the current authorized capital structure of 48% common equity, 46.2% long-term debt, and 5.8% preferred equity. The final decision also holds open the proceeding to address the impact on the Utility's return on equity, costs of debt and preferred stock, and ratemaking capital structure of the implementation and financing of a bankruptcy plan of reorganization.

The return on the Utility's electric transmission-related assets is determined by the FERC. See "Electric Ratemaking" below. The return on the Utility's natural gas transmission and storage business was incorporated in rates established in the Gas Accord. See "Gas Ratemaking" below.

Electric Ratemaking

As required by AB 1890, electric rates for all customers were frozen at the level in effect on June 10, 1996, and, beginning January 1, 1998, rates for residential and small commercial customers were further reduced by 10%. In the first quarter of 2001, the CPUC authorized the Utility to begin collecting energy surcharges totaling $0.04 per kWh (composed of a $0.01 per kWh surcharge approved in January and a $0.03 per kWh surcharge approved in March). 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 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 CPUC initially restricted the use of these surcharge revenues to pay for the Utility's "ongoing procurement costs" and "future power purchases."

Under AB 1890, the rate freeze was supposed to end on the earlier of March 31, 2002, or when the Utility had recovered its eligible transition costs. Most transition costs must be recovered during a transition period that ends the earlier of December 31, 2001, or when the Utility had recovered its eligible transition costs. The Utility repeatedly has advised the CPUC that it had recovered all of its transition costs and has asked the CPUC to recognize that the rate freeze already has ended for the Utility's customers. After the rate freeze, changes in the Utility's electric revenue requirements in general will be reflected in rates. However, the CPUC has not yet determined that the rate freeze has ended for the Utility's customers.

After the CPUC has determined when the Utility's rate freeze ended, the Utility expects the CPUC to set rates to recover:

* the Utility's approved utility cost components,
* the cost of energy sold to customers, and
* the DWR's revenue requirement allocated to the Utility's customers.

The Utility refers to this structure as "bottoms-up" billing. At this time, the Utility does not know when or under what conditions the CPUC will determine that the Utility's rate freeze has ended and the Utility will begin bottoms-up billing or to which periods these rates would apply.



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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 undercollections 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.

Electric Distribution.

2003 General Rate Case. On November 8, 2002, the Utility filed its 2003 general rate case application requesting an increase in electric revenue requirements of $447 million over the current authorized amount of $2.269 billion to maintain current service levels to existing customers, and to adjust for wages and inflation. The Utility also indicated that it will seek an attrition rate adjustment increase for 2004 and 2005. The attrition rate adjustment mechanism is designed to avoid a reduction in earnings in years between general rate cases to reflect increases in rate base and expenses. The CPUC has ruled that the revenue requirements to be determined in the Utility's 2003 general rate case will be effective January 1, 2003, even though the CPUC will not issue a final decision on the 2003 GRC until 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 administrative law judge presiding over the 2003 GRC has adopted a schedule for this proceeding that includes a target date of February 5, 2004.

2002 Attrition Rate Adjustment Request. In the 2003 GRC, the CPUC asked parties to comment on the Utility's need for a 2002 attrition rate adjustment. The Utility informed the CPUC in November 2001 that the Utility would need a 2002 attrition rate adjustment to recover escalating electric and gas distribution service costs. In April 2002, the CPUC issued a ruling authorizing any attrition rate adjustment that ultimately may be granted to become effective as of April 22, 2002. In June 2002, the Utility filed its 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.

Baseline Allowance Increase. On April 9, 2002, the CPUC issued a decision that required the Utility to increase baseline allowances for certain residential customers by May 1, 2002. An increase to a customer's baseline allowance increases the amount of their monthly usage that will be covered under the lowest possible rate and that is exempt from surcharges. The decision deferred consideration of corresponding rate changes until a later phase of the proceeding and ordered the Utility to track the undercollections associated with these baseline quantity changes in an interest-bearing balancing account. The Utility estimates the annual revenue shortfall to be approximately $96 million for electricity service, and $6 million for natural gas service. The total electricity revenue shortfall estimated for the period May through December 2002 was $70 million.

In the second phase of the proceeding, the CPUC will consider issues involving demographic revisions to baseline allowances, a special allowance for well water pumping, revisions applicable to usage at vacation homes, and changes to baseline territories or seasons. The resolution of these issues could result in an additional revenue shortfall of approximately $102 million spread out over three to five years. Hearings on these issues concluded in September 2002 and a final CPUC decision is expected to be issued in early 2003. The Utility has charged the electricity revenue shortfall to earnings and will continue to charge the shortfall to earnings. This charge reduces revenue available to recover the Utility's previously written-off undercollected power procurement costs and transition costs.

Electric Transmission

Electric transmission revenues, and both wholesale and retail transmission rates, are subject to authorization by the FERC. The Utility has two sources of transmission revenues, those from charges under its transmission owner tariff, or TO Tariff, and those from charges under specific contracts with existing wholesale transmission customers that pre-date the Utility's participation in the ISO. Customers that receive transmission services under such pre-existing contracts, referred to as existing transmission contract customers, or ETC customers, are charged individualized rates based on the terms of their respective contracts. The Utility's ETC customers include various municipal utilities and state and federal agencies. These customers typically own and operate distribution systems that carry electricity to municipal, state or federal facilities, such as city halls, and the water pumps along the



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California aqueduct. The Utility's municipal utility ETC customers distribute electricity to municipal facilities and, in many cases to the homes and businesses of retail electricity customers located inside their municipality.

Under the FERC's regulatory regime, the Utility is able to file a new base transmission rate case under the Utility's TO Tariff whenever the Utility deems it necessary to increase its rates. The Utility is typically able to charge new rates, subject to refund, before the outcome of the FERC ratemaking review process.

The Utility's TO Tariff includes two rate components: (1) base transmission rates (from which the Utility derives the majority of its transmission revenues) which are intended to recover the Utility's operating and maintenance expenses, depreciation and amortization expenses, interest expense, tax expense and return on equity and (2) the rates the Utility charges its TO Tariff customers to recover various bills the Utility receives from the ISO for reliability service costs, and the ISO's transition charge associated with the ISO's high-voltage blended rate methodology.

Transmission Owner Rate Cases. On January 29, 2003, the FERC approved a settlement filed by the Utility that allows the Utility to recover $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 in TO Tariff electric transmission rates. During that period, somewhat higher rates were collected, subject to refund. As a result of the approval, the Utility will refund $30 million it had accrued for potential refunds related to the 14-month period ended May 30, 1999. In April 2000, the FERC approved a settlement that permitted the Utility to recover $329 million on an annual basis in TO Tariff electric transmission rates retroactively for the 10-month period from May 31, 1999 to March 31, 2000. In September 2000, the FERC approved another settlement that permitted the Utility to recover $352 million annually in TO Tariff electric transmission rates and made this retroactive to April 1, 2000. Further, in July 2001, the FERC approved another settlement that permits the Utility to collect $379 million annually in TO Tariff electric transmission rates retroactive to May 6, 2001. The transmission rates charged to TO Tariff 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.

On January 13, 2003, the Utility filed an application requesting to recover $545 million in electric retail transmission rates annually, a 44% increase over the revenue requirement currently in effect. The requested increase is mainly attributable to significant capital additions made to the Utility's 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%. The January 13 filing date will allow proposed rates to go into effect, subject to refund, no later than August 13, 2003.

The Utility recovers certain ISO costs described below in balancing accounts. In general, for each of these types of costs, the difference between the ISO's actual charges and revenues collected by the Utility and the forecasted costs will be used to either offset or increase the specific revenue requirement for such costs for the next period when the Utility files an annual balancing account rate case related to such costs.

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Reliability Services Costs--The ISO bills the Utility for reliability services based on payments that the ISO makes to generators under reliability must-run contracts and for locational out-of-market calls required to support reliability of the transmission system. The Utility charges its customers rates designed to recover these reliability service charges, without mark-up or service fees. The Utility records these customer charges as operating revenue, and records a corresponding expense under its cost of power line item to reflect the fact that the Utility must pass this revenue on to the ISO. Costs and revenues related to reliability services are tracked in the reliability services balancing account.
*
Transition Charges--Beginning on January 1, 2001, the Utility pays the ISO's high-voltage blended transmission rate which is higher than the Utility-specific high-voltage transmission rate. The difference between the ISO's rate and the Utility's rate is tracked in the Utility's transmission access charge balancing account and will be collected once frozen retail rates are changed by the CPUC.

Grid Management Costs. The ISO also bills the Utility for grid management services attributable to the Utility's ETC customers. These grid management services costs are passed on to the Utility's ETC customers through the Grid Management Charge Tariff. The Utility records grid management costs billed by the ISO in operating and maintenance expenses and passes these costs to its ETC customers, without mark-up or service fees, subject to refund pending the outcome of the FERC ratemaking review process expected to take place in the first half of 2003.

Scheduling Coordinator Costs. The Utility serves as the scheduling coordinator to schedule transmission with the ISO for its ETC customers. The ISO bills the Utility for providing certain services associated with these



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contracts. These ISO charges are referred to as the "scheduling coordinator costs." These costs historically have been tracked in the transmission revenue balancing account, or TRBA, in order for the Utility to recover these costs from its TO Tariff customers. In 2002, the FERC ruled that the Utility should refund to TO Tariff customers the scheduling coordinator costs that the Utility collected from them. As of December 31, 2002, TO Tariff customers had already paid the Utility $107 million for these costs.

In January 2000, the FERC accepted a filing by the Utility to establish a separate tariff to allow the Utility to recover both the shortfall and future scheduling coordinator costs from its ETC customers. The FERC has authorized the separate tariff, subject to refund, which has been challenged by ETC customers. 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.

Electric Generation

The CPUC has approved a 2002 revenue requirement of $3 billion for recovery of costs of generation that the Utility retains, including purchased power expenses, depreciation, operating expenses, taxes, and return on investment, based on the net regulatory value of generation assets as of December 31, 2000. The Utility's retained generation costs incurred in 2002 are subject to reasonableness review. A pending proposal by The Utility Reform Network, or TURN, a non-profit organization representing small utility customers, would continue this treatment. Before 2002, these costs have been forecast as with other costs in the general rate case, with rates set to recover the forecast, regardless of actual cost.

The Utility's 2003 revenue requirement for retained generation is being considered in the Utility's 2003 general rate case proceeding. The Utility's 2003 general rate case application, as updated on February 20, 2003, requested an increase in non-fuel generation revenue requirements of $149 million from $872 million, the amount currently authorized. This requested revenue requirement excludes the Utility's estimated fuel and procurement costs recorded in the Energy Resource Recovery Account, or ERRA, and the DWR's power charges.

Electric Procurement

2001 Annual Transition Cost Proceeding: Review of Reasonableness of Electric Procurement. On January 11, 2002, as directed by the CPUC, the Utility filed a report at 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 the 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 power 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, an administrative law judge of the CPUC is asserting jurisdiction to review the reasonableness of the Utility's wholesale electricity purchases from the PX and ISO in the proceeding. A report from the CPUC's Office of Ratepayer Advocates regarding the Utility's procurement activities for the covered period is due April 28, 2003. It is possible that this proceeding could result in some disallowance of the Utility's costs incurred during the 2000-2001 period associated with its purchases from the PX and ISO markets.

Energy Resource Recovery Account, or ERRA. As of January 1, 2003, the California IOUs have resumed procuring electricity to meet the amount of their customers' electricity needs that cannot be met with utility-owned generation, electricity supplied under QF and other contracts, and electricity allocated to their customers under the DWR contracts. Effective January 1, 2003, the Utility established the Energy Resource Recovery Account, or ERRA, to record and recover electricity costs, excluding the DWR's power contract costs, associated with the Utility's authorized procurement plan. Electricity costs recorded in ERRA include, but are not limited to, fuel costs for retained generation, QF contracts, inter-utility contracts, ISO charges, irrigation district contracts and other power purchase agreements, bilateral contracts, forward hedges, pre-payments and 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 authorized the Utility to file an expedited trigger application at any time that its forecast indicates the undercollection in the ERRA will be in excess of 5% of the Utility's recorded generation revenues for the prior year excluding amounts collected for the DWR. The Utility currently estimates that its 5% threshold amount will be



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approximately $224 million. When filing an expedited trigger application, the CPUC has directed the Utility to propose an amortization period of not less than 90 days for the undercollected amount to insure timely recovery. The CPUC has approved, on a preliminary basis, a starting ERRA revenue requirement of $2.035 billion for the Utility.

On February 3, 2003, the Utility filed its 2003 ERRA forecast application requesting that the CPUC reset the Utility's 2003 ERRA revenue requirement to $1.413 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.

Qualifying Facilities and Other Existing Bilateral Agreements. Costs of the Utility's existing contracts with qualifying facilities and other electricity providers are passed through to ratepayers dollar for dollar as approved by the CPUC in the retained generation ratemaking proceeding for 2002 and generation procurement proceeding for 2003. See "Electric Generation" and "Electric Resource Recovery Account" discussions, above.

Direct Access. To avoid a shift of costs from direct access customers to bundled customers, the CPUC has established a direct access cost responsibility surcharge, or CRS, to implement utility-specified non-bypassable charges on direct access customers for their share of the bond costs and power costs incurred by the DWR and above-market cost related to the Utility's own generation resources and power contracts. The decision establishes four components comprising the CRS:

* DWR Bond Charge. This charge is applicable to all direct access customers, except customers who were on direct access before the DWR began purchasing power and have continued to remain on direct access since the DWR began purchasing power (continuous direct access customers). The bond charge for direct access customers will include amounts accruing since November 15, 2002. The actual amount of this charge on direct access customers is being determined in the DWR bond charge allocation proceeding.

* DWR Electricity Charge for the September 21, 2001, through December 31, 2002 Period. This charge is applicable to direct access customers who previously took bundled service at any time on or after February 1, 2001. The charge is designed to recover direct access customers' share of the DWR's procurement costs between September 21, 2001, and December 31, 2002. Since bundled customers already have paid this amount to the DWR, these charges collected from direct access customers would reduce the amount of bundled customers' bills remitted to the DWR.

* DWR Electricity Charge for Future DWR Costs. This charge is applicable to direct access customers who previously took bundled service at any time on or after February 1, 2001. This charge is designed to recover direct access customers' share of the uneconomic portion of the DWR's procurement costs for 2003 and thereafter. This charge will be adjusted on an annual basis or more frequently if the DWR's revenue requirement is adjusted more frequently.

* The Utility's Procurement and Generation Charge. This charge is applicable to all direct access customers regardless of the date on which a customer switched to direct access. This charge is designed to recover direct access customers' share of the ongoing uneconomic portion of the Utility's generation and procurement costs. This charge will be based on an estimate of above-market costs for the Utility's procurement contracts and qualifying facility arrangements, which in turn is based on a $0.043 per kWh benchmark for 2003. This benchmark for determining above-market costs will be updated annually.

The decision imposes a cap on the CRS of $0.027 cents per kWh which was implemented on January 1, 2003. The CPUC has indicated that it will establish an expedited review schedule to determine whether the cap should be adjusted and has set a goal of reaching a decision on whether this cap should be adjusted, and whether trigger mechanisms for adjusting the cap would be established, by July 1, 2003.



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Funds remitted under the CRS will be applied first to the DWR bond charges, second to the DWR electricity charges, and third 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 undercollection of DWR charges, the shortfall would have to be remitted to DWR from bundled customers' funds. Interest on undercollections will be assessed at the DWR's bond interest rate on an interim basis while the CPUC examines a long-term plan for financing the CRS. 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.

DWR Revenue Requirements, Servicing Order and Operating Order. The CPUC has adopted rates for the DWR that allow the DWR to collect electricity and bond-related charges from ratepayers to recover what it spent to procure electricity for the customers of the California IOUs during 2001 and 2002. The recovery is being financed partially through a statewide revenue requirement allocated among the three California IOUs and partially through the DWR's November 2002 issuance of $11.3 billion in revenue bonds, which will be repaid by the customers of the three California IOUs through the bond charge discussed 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 $2.6 billion related to 2001 power charges and approximately $1.8 billion related to 2002 power charges. In December 2002, the CPUC issued a decision allocating approximately $2 billion of the DWR's 2003 power charge-related revenue requirements to the Utility's customers. This revenue requirement includes the variable costs of the DWR contracts allocated to the Utility's customers by an earlier decision in September 2002. The DWR plans to submit a revised 2003 power charge-related revenue requirement to the CPUC in late March 2003. A separate proceeding will consider a revision or true-up for the revenue requirements remitted to the DWR for 2001 and 2002 costs, once final 2002 cost data is available. This true-up proceeding is scheduled for April 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 that 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.

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 performed 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. 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 2001 and 2002.

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



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and conditions under which the Utility will administer the DWR allocated contracts and requires the Utility to dispatch all 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.

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 order, 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 review, nor is it responsible for a review of 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.

DWR Bond Charges. On October 24, 2002, the CPUC approved a decision that, in part, imposes bond charges to recover the DWR's bond costs from most bundled customers effective November 15, 2002, although the decision found that the Utility would not need to increase customers' overall rates to incorporate the bond charge. The DWR bond charge also will be imposed on all direct access customers, as described above. On December 30, 2002, the CPUC adopted a 2003 bond charge of $0.005 per kWh to start January 6, 2003. The Utility expects to accrue DWR bond-related charges of approximately $336 million during the 12 months ended 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 undercollected purchase power costs and transition costs.

Gas Ratemaking

Natural Gas Distribution

The Utility's 2003 general rate case, or GRC, application requested an increase in natural gas distribution revenue requirements of $105 million over the currently authorized amount of $894 million, to maintain current service levels to existing customers, and to adjust for wages and inflation. The Utility also indicated that it will seek an attrition rate adjustment increase for 2004 and 2005. The attrition rate adjustment mechanism is designed to avoid a reduction in earnings in years between general rate cases to reflect increases in rate base and expenses. The CPUC has ruled that the revenue requirements to be determined in the Utility's 2003 general rate case will be effective January 1, 2003, even though the CPUC will not issue a final decision on the 2003 GRC until after that date. The Utility cannot predict what amount of revenue requirements, if any, the CPUC will authorize for the 2003 through 2005 period, nor when such decision will be made.

Gas distribution costs and balancing account balances are allocated to customers in the Biennial Cost Allocation Proceeding, or BCAP. The BCAP normally occurs every two years and is updated in the interim year for



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purposes of amortizing any accumulation in the balancing accounts. Balancing accounts for gas distribution and public purpose program revenue requirements accumulate differences between authorized revenue requirements and actual base revenues. In April 2000, the Utility filed its 2000 BCAP application to cover the period January 1, 2000 through December 31, 2002, requesting a decrease in the annual base revenue requirement of $132 million compared to the authorized revenue requirement of $941 million at the time the application was filed. On November 8, 2001, the CPUC issued a decision approving the Utility's BCAP settlement filed in October 2000. The decision adopted a decrease in annual base revenue requirements of $113 million, effective January 1, 2002. The adopted BCAP rates were implemented on January 1, 2002. At the end of 2002, the Utility filed an annual true-up of balancing accounts and other gas transportation rate changes that went into effect January 1, 2003. This filing increased core and noncore transportation rates and revenue requirements by $103 million resulting from the annual true-up, changes authorized in the second year of the BCAP, an increase in the 2002 California Alternate Rates for Energy administration budget, the adopted 2003 cost of capital, an increase in the low income energy efficiency program budget for 2003, the increase in the CPUC reimbursement account fee, and the extension of the Gas Accord.

Natural Gas Transportation and Storage

The Utility's interstate and Canadian natural gas transportation agreements are governed by tariffs which detail rates, rules and terms of service for the provision of natural gas transportation services to the Utility on interstate and Canadian pipelines. These tariffs are approved by the FERC in a FERC ratemaking review process and by the Alberta Energy and Utilities Board and the National Energy Board for Canadian tariffs.

Since March 1998, the natural gas transportation and storage services that the Utility has obtained over its owned pipelines have been governed by the rates, terms and conditions approved by the CPUC in the Gas Accord and Gas Accord II settlement agreements through 2003, or, together, the Gas Accord. The Gas Accord separated, or "unbundled," the Utility's natural gas transportation and storage services from its distribution services, changed the terms of service and rate structure for natural gas transportation and storage services, fixed natural gas transportation and storage rates and allowed core customers to purchase natural gas from competing suppliers.

On January 13, 2003, the Utility filed an amended Gas Accord II application with the CPUC proposing to permanently retain the Gas Accord market structure, and requesting a $55 million increase in the Utility's rates for gas transmission and storage for 2004, or in the case of certain storage provisions from April 1, 2004, to March 31, 2005.

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 undercollections 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.

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. If the Utility were unable to renew or replace existing transportation contracts at the beginning or throughout the Gas Accord II period, or the Utility were to renew or replace those contracts on less favorable terms than adopted by the CPUC, or if overall demand for transportation and storage services were less than adopted by the CPUC in setting rates, the Utility may experience a material reduction in operating revenues. In either case, the Utility's financial condition and results of operations could be adversely affected.

Natural Gas Procurement

The Gas Accord also established the core procurement incentive mechanism, or CPIM, which is used to determine the reasonableness of the Utility's cost of procuring natural gas for the Utility's customers. The Gas Accord II settlement agreement extended the CPIM for one year. 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 locations where the Utility typically purchases natural gas. If costs fall within a range, or tolerance band currently 99% to 102%, around the benchmark, they are considered reasonable and fully recoverable in customer rates. Ratepayers and shareholders share costs and savings outside the tolerance band.



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The Utility sets the core natural gas procurement rate monthly based on the forecasted costs of natural gas and core pipeline capacity and storage costs. The Utility reflects the difference between actual natural gas procurement costs and forecasted natural gas procurement costs in several gas procurement balancing accounts, with under-and overcollections taken into account in subsequent monthly rates.

Any awards associated with the CPIM normally are reflected annually in the purchased natural gas balancing account after the close of the CPIM period, which is the 12-month period ending October 31. These awards are not included in earnings until approval by the CPUC. On December 17, 2002, the CPUC's Office of Ratepayer Advocates submitted its report agreeing with the Utility's CPIM performance for the period November 2000 through October 2001. The Utility requested that the CPUC approve a shareholder award of $7.7 million to be effective February 1, 2003. The CPUC has not acted on the Utility's request. In accordance with the Gas Accord, the Utility stopped providing procurement service to noncore customers in March 2001. During the winter of 2000/2001 when there was a steep increase in gas commodity prices, many noncore customers switched to core service in order to receive procurement service from the Utility. In 2002, the Utility filed a request with the CPUC to limit the number of noncore customers that could switch to core service because the Utility was concerned that large increases in its gas supply portfolio demand would raise prices for all other core procurement customers, and obligate the Utility to reinforce its pipeline system to provide core service reliability on a short-term basis to serve this new load. Consistent with rules adopted for southern California gas utilities in 2002, the Utility has requested that electric generation, cogeneration, enhanced oil recovery and refinery customers be prohibited from electing core service and that remaining noncore customers elect core service for a minimum five-year term.

On June 27, 2002, the CPUC opened a proceeding in response to a FERC order authorizing marketers in California to turn back up to 725 million cubic feet per day of firm capacity on the El Paso Pipeline Company, or El Paso, interstate pipeline. The first phase of the proceeding dealt with rules for the major California utilities to obtain El Paso turned-back capacity not subscribed to by other California replacement shippers. On July 17, 2002, the CPUC ordered utilities to obtain such capacity, and stated that if the utilities complied with this order that they would also receive full recovery for costs associated with existing capacity rights on interstate pipelines. The Utility obtained 204 MDth/day of capacity on El Paso in compliance with the CPUC decision. On December 19, 2002, the CPUC found that the Utility had met the objectives, terms and conditions set forth in the CPUC's July 17, 2002 order. The CPUC authorized the Utility to recover all costs associated with the subscription to El Paso pipeline capacity on an equal-cents-per-therm basis from core and noncore customers, subject to reallocation in a later phase of the proceeding. The Utility filed core and noncore transportation rates proposed to be effective March 2003 to recover $47.1 million of annual El Paso costs and costs previously incurred through December 2002. The CPUC also ordered the Utility to continue to treat Transwestern pipeline charges and brokering credits under its core procurement incentive mechanism, or CPIM. The Transwestern costs not currently authorized under the CPIM will be addressed in the second phase of this proceeding. On February 7, 2003, the Utility filed its proposal requesting full recovery of the Transwestern costs and El Paso turned back capacity costs from core customers and inclusion of these costs in its CPIM.

Public Purpose Programs

The Utility continues to administer and/or fund several state-mandated public purpose programs. In December 2002, the CPUC authorized the Utility to fund electric energy efficiency, low-income energy efficiency, research and development, and renewable energy resources programs in the amount of $232 million. The costs will be recovered in electric rates following the rate design phase of the Utility's 2003 general rate case. The CPUC also has authorized the Utility to collect $46 million in gas rates to fund gas energy efficiency, low-income energy efficiency, and research and development programs.

The Utility also provides the California Alternate Rates for Energy, or CARE, low-income discount rate, a rate subsidy paid for by the Utility's other customers, which is currently about $107 million per year.

The CPUC is responsible for authorizing the programs, funding levels, and cost recovery mechanisms for the Utility's operation of both the cost-effective energy efficiency and low-income energy efficiency programs. The CEC administers both the electric public interest research and development program and the renewable energy program on a statewide basis. In 2002, the Utility transferred $99 million to the CEC for these two programs.

Until 2002, the Utility was eligible to receive incentives for administering the energy efficiency program activities. The Utility files an annual earnings claim each year in the annual earnings assessment proceeding, which is the forum for stakeholders to comment on and for the CPUC to evaluate the Utility's claim. Earned incentives can be collected over as long as a 10-year period. In 2002, the CPUC eliminated the opportunity for the IOUs to



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earn incentives on their 2002 energy efficiency programs, replacing it with a mechanism keeping up to 15% of the energy efficiency expenditures subject to refund if the programs unreasonably miss targets or expenditures are unreasonably high. The CPUC has also declined to allow the IOUs the opportunity to earn incentives on the 2003 energy efficiency programs. This decision does not affect the mechanism to recover incentives in connection with energy efficiency programs for previous years.

In May 2000, 2001, and 2002, the Utility filed its annual applications claiming incentives totaling to approximately $106 million. In early 2002, the CPUC requested and received briefs on whether the incentive mechanism giving rise to $74 million of the $106 million should be modified to reduce the earnings potential. The CPUC has not yet acted on any of these applications or ruled on the incentive mechanism issue, but has scheduled a prehearing conference to begin the process for addressing the claims.

In October 2002, the CPUC opened a rulemaking to implement the nonbypassable gas public purpose program surcharge mandated by state legislation in 2001. The legislation requires all California gas users, even those users who are not utility customers, to fund public purpose energy efficiency, low-income energy efficiency, research and development, and CARE rate subsidies for qualifying low-income utility customers. The funds are collected by a surcharge on gas consumption, with utilities, many non-utility customers, and interstate pipelines remitting the surcharge revenues to the State Board of Equalization. These funds are allocated to the gas public purpose programs by the CPUC. The CPUC rulemaking proceeding will formalize the processes for administering the gas consumption surcharge as well as identifying appropriate programs and funding levels for public purpose gas research and development programs.

## ELECTRIC UTILITY OPERATIONS

### Electric Distribution

The Utility's electric distribution network extends throughout all or a portion of 47 of California's 58 counties, comprising most of northern and central California. The Utility's network consists of approximately 117,955 circuit miles of distribution lines (of which approximately 20% are underground and 80% are overhead) and 730 distribution substations. The Utility's distribution network connects to an electric transmission system at approximately 975 points of contact. This contact between the Utility's distribution network and the transmission system typically occurs at distribution substations where transformers and switching equipment reduce the high-voltage transmission levels at which the electric transmission system transmits electricity, ranging from 60 kilovolts to 500 kilovolts, or kV, to lower voltages, ranging from 4 kV to less than 60 kV, suitable for distribution to customers. The distribution substations serve as the central hubs of the distribution system and consist of transformers, voltage regulation equipment, protective devices and structural equipment. Emanating from each substation are primary and secondary distribution lines connected to local transformers and switching equipment which link distribution lines and provide delivery to end-users. In some cases, the Utility sells electricity from its distribution lines or facilities to entities such as municipal and other utilities that then resell the electricity. In certain cases, the distribution system is directly connected to generation facilities.

Electric Distribution Operating Statistics

In 2002, the Utility's electric distribution business delivered a total of approximately 78,230 gigawatt-hours, or GWh, of electricity to approximately 4.8 million electric distribution customers in our service territory, including 21,031 GWh purchased by the DWR and 7,433 GWh provided by direct access service providers.



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The following table shows the Utility's operating statistics (excluding subsidiaries) for electric energy sold or delivered, including the classification of sales and revenues by type of service.

| | 2002 | 2001 | 2000 | 1999 | 1998 |
|---|---|---|---|---|---|
| Customers (average for the year): | | | | | |
| Residential | 4,171,365 | 4,165,073 | 4,071,794 | 4,017,428 | 3,962,318 |
| Commercial | 483,946 | 484,430 | 471,080 | 474,710 | 469,136 |
| Industrial | 1,249 | 1,368 | 1,300 | 1,151 | 1,093 |
| Agricultural | 78,738 | 81,375 | 78,439 | 85,131 | 85,429 |
| Public street and highway lighting | 24,119 | 23,913 | 23,339 | 20,806 | 18,351 |
| Other electric utilities | 5 | 5 | 8 | -- | 14 |
| Total | 4,759,422 | 4,756,164 | 4,645,960 | 4,599,226 | 4,536,341 |
| Deliveries (in GWh): | | | | | |
| Residential | 27,435 | 26,840 | 28,753 | 27,739 | 26,846 |
| Commercial | 31,328 | 30,780 | 31,761 | 30,426 | 28,839 |
| Industrial (1) | 14,729 | 16,001 | 16,899 | 16,722 | 16,327 |
| Agricultural (1) | 4,000 | 4,093 | 3,818 | 3,739 | 3,069 |
| Public street and highway lighting | 674 | 418 | 426 | 437 | 445 |
| Other electric utilities | 64 | 241 | 266 | 167 | 2,358 |
| California Department of Water Resources Allocation (2001 and 2002 only) | (21,031) | (28,640) | | | |
| Total energy delivered (2) | 57,199 | 49,733 | 81,923 | 79,230 | 77,884 |
| Revenues (in thousands): | | | | | |
| Residential (3) | $ 3,641,582 | $ 3,364,466 | $3,007,675 | $2,961,788 | $2,891,424 |
| Commercial (3) | 4,468,465 | 3,925,218 | 2,693,316 | 2,837,111 | 2,793,336 |

| | 2002 | 2001 | 2000 | 1999 | 1998 |
|---|---|---|---|---|---|
| Industrial (3) | 1,275,033 | 1,312,280 | 509,486 | 863,951 | 933,316 |
| Agricultural (3) | 531,983 | 520,855 | 385,961 | 391,876 | 350,445 |
| Public street and highway lighting | 73,423 | 59,875 | 43,403 | 49,209 | 51,195 |
| Other electric utilities | 10,028 | 39,420 | 26,269 | 16,501 | 50,166 |
| Subtotal | 10,000,514 | 9,222,114 | 6,666,110 | 7,120,436 | 7,069,882 |
| California Department of Water Resources pass-through revenues | (2,056,037) | (2,172,666) | -- | -- | -- |
| Miscellaneous | 193,519 | 240,276 | 194,947 | 162,105 | 161,156 |
| Regulatory balancing accounts | 39,578 | 36,494 | (6,765) | (50,780) | (40,408) |
| Total electricity operating revenues | $ 8,177,574 | $ 7,326,217 | $6,854,292 | $7,231,761 | $7,190,630 |

| | 2002 | 2001 | 2000 | 1999 | 1998 |
|---|---|---|---|---|---|
| Other Data: | | | | | |
| Average annual residential usage (kWh) | 6,577 | 6,463 | 7,062 | 6,905 | 6,776 |
| Average billed revenues (cents per kWh): | | | | | |
| Residential | 13.27 | 12.50 | 10.46 | 10.68 | 10.77 |
| Commercial | 14.26 | 12.68 | 8.48 | 9.32 | 9.69 |
| Industrial (1) | 8.66 | 7.78 | 3.02 | 5.17 | 5.72 |
| Agricultural (1) | 13.30 | 12.55 | 10.11 | 10.48 | 11.42 |
| Net plant investment per customer ($) | 2,105 | 2,018 | 1,969 | 2,388 | 2,705 |

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(1)
The deliveries per kWh and average billed revenues per kWh include electricity provided to direct access customers who procure their own supplies of electricity.

(2)
Of the 78,230 GWh the Utility delivered in 2002, 49,766 GWh were procured or generated by the Utility (excluding energy loss and net deliveries to the Western Area Power Administration), 7,433 GWh were procured by direct access service providers and 21,031 GWh were procured by the DWR. Of the 78,373 GWh the Utility delivered in 2001, 45,751 GWh were procured or generated by the Utility (excluding energy loss and net deliveries to the Western Area Power Administration), 3,982 GWh were procured by the Utility's direct access customers and delivered by the Utility and 28,640 GWh were procured by the DWR and delivered by the Utility.

(3)
Revenues include direct access revenues, but exclude direct access credits.



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Electric Resources

The Utility's sources of electricity delivered to customers during 2002 were as follows: 11.31% from the Utility's hydroelectric assets, 19.60% from the Utility's nuclear facilities at Diablo Canyon, 1.02% from the Utility's fossil-fuel fired plants, 33.86% from QFs and other power suppliers, and 25.28% from power procured on behalf of customers by the DWR and 8.93% from power procured by direct access service providers.

Retained Generation

At December 31, 2002, the Utility's generation facilities, consisting primarily of hydroelectric and nuclear generating plants, had an aggregate net operating capacity of 6,420 megawatts, or MW. Except as otherwise noted below, at December 31, 2002, the Utility owned and operated the following generating plants, all located in California, listed by energy source:

| Generation Type | County Location | Number of Units | Net Operating Capacity kW |
|---|---|---|---|
| Hydroelectric: | | | |
| Conventional Plants | 16 counties in northern and central California | 107 | 2,684,200 |
| Helms Pumped Storage Plant | Fresno | 3 | 1,212,000 |
| Hydroelectric Subtotal | | 110 | 3,896,200 |
| Steam Plants: | | | |
| Humboldt Bay | Humboldt | 2 | 105,000 |
| Hunters Point (1) | San Francisco | 1 | 163,000 |
| Steam Subtotal | | 3 | 268,000 |
| Combustion Turbines: | | | |
| Hunters Point (1) | San Francisco | 1 | 52,000 |
| Mobile Turbines (2) | Humboldt | 2 | 30,000 |
| Combustion Turbines Subtotal | | 3 | 82,000 |
| Nuclear: | | | |
| Diablo Canyon | San Luis Obispo | 2 | 2,174,000 |
| Total | | 118 | 6,420,200 |

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(1)
In July 1998, the Utility reached an agreement with the City and County of San Francisco regarding the Hunters Point fossil-fuel fired power plant, which the ISO has designated as a "must-run" facility. The agreement expresses the Utility's intention to retire the plant when it is no longer needed by the ISO.

(2)
Listed to show capability; subject to relocation within the system as required.

(3)
One mobile turbine (15 MW) is not currently connected to the system. Hunters Point Units 2 and 3 (214 MW) were converted to synchronous condenser operations during 2001.

The Utility is interconnected with electric power systems in the Western Electricity Coordinating Council, which includes 14 western states, Alberta and British Columbia, Canada, and parts of Mexico.

Hydroelectric Generation Assets. The Utility's hydroelectric system consists of 110 generating units at 68 powerhouses, including a pumped storage facility, with a total generating capacity of 3,896 MW. The system includes 99 reservoirs, 76 diversions, 174 dams, 184 miles of canals, 44 miles of flumes, 135 miles of tunnels, 19 miles of pipe, and 5 miles of natural waterways. The system also includes 84 permits and licenses 94 contracts for water rights and 164 statements of water diversion and use.

Diablo Canyon Nuclear Power Plant. Diablo Canyon consists of two nuclear power reactor units, each capable of generating up to approximately 26 million kWh of electricity per day. Diablo Canyon Units 1 and 2 began commercial operation in May 1985 and March 1986, respectively. The operating license expiration dates for Diablo Canyon Units 1 and 2 are September 2021 and April 2025, respectively. As of December 31, 2002, Diablo Canyon Units 1 and 2 had achieved lifetime capacity factors of 82.45% and 85.35%, respectively.



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The table below outlines Diablo Canyon's refueling schedule for the next five years. Diablo Canyon refueling outages typically are scheduled every 19 to 21 months. The schedule below assumes that a refueling outage for a unit will last approximately 35 days, depending on the scope of the work required for a particular outage. The schedule is subject to change in the event of unscheduled plant outages.

| | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|
| Unit 1 | | | | | |
| Refueling | | March | October | | April |
| Startup | | April | November | | May |
| Unit 2 | | | | | |
| Refueling | February | October | | April | |
| Startup | March | November | | May | |

The Utility has purchase contracts for, and inventories of, uranium concentrates, uranium hexafluoride, and enriched uranium, as well as one contract for fuel fabrication. Based on current Diablo Canyon operations forecasts and a combination of existing contracts and inventories, the requirements for uranium supply, conversion of uranium to uranium hexafluoride, and the requirement for the enrichment of the uranium hexafluoride to enriched uranium, will be met through 2004. The fuel fabrication contract for the two units will supply their requirements for the next five operating cycles of each unit. In most cases, the Utility's nuclear fuel contracts are requirements-based, with the Utility's obligations linked to the continued operation of Diablo Canyon.

The Utility has insurance coverage for property damage and business interruption losses as a member of Nuclear Electric Insurance Limited, or NEIL. NEIL is a mutual insurer owned by utilities with nuclear generating facilities. Under these insurance policies, if the nuclear generating facility of a member utility suffers a loss due to a prolonged accidental outage, the Utility may be subject to maximum retrospective premium assessments of $25 million with respect to property damage and $8 million with respect to business interruption losses per year if losses exceed the resources of NEIL.

Effective November 15, 2001, in the event that one or more acts of terrorism cause property damage under any of the nuclear insurance policies issued by NEIL within 12 months from the date the first property damage occurs, the maximum recovery under all the nuclear insurance policies will be an aggregate of $3.24 billion, plus the additional amount recovered by NEIL for the losses from reinsurance, indemnity, and any other applicable sources. Under the Terrorism Risk Insurance Act of 2002, NEIL would be entitled to receive substantial reinsurance for an act caused by a foreign terrorist. The Terrorism Risk Insurance Act of 2002 expires on December 31, 2005.

The Price-Anderson Act, as amended by Congress in 1988, limits public liability claims that could arise from a nuclear incident to a maximum of $9.5 billion per incident. The Utility has purchased primary insurance of $300 million for the Diablo Canyon Power Plant for public liability claims resulting from a nuclear incident. The Utility has secondary financial protection that provides an additional $9.2 billion of coverage, as required by the Price-Anderson Act. Under the Price-Anderson Act, secondary financial protection is required for all nuclear electrical generation reactors having a rated operating capacity of at least 100 MW. There are 105 currently licensed reactors having a rated capacity in excess of 100 MW, including Diablo Canyon's Units 1 and 2. The Price-Anderson Act provides for loss sharing among utilities owning nuclear generating facilities if a costly incident occurs. If a nuclear incident results in claims in excess of $300 million, the Utility may be assessed up to $176 million per incident, with payments in each year limited to a maximum of $20 million per incident. The Utility also has $53.3 million of private liability insurance for Humboldt Bay Power Plant, where the Utility has a shutdown nuclear unit. In addition, the Utility has a $500 million indemnification from the NRC for public liability arising from nuclear incidents covering liabilities in excess of the $53.3 million of private liability insurance for Humboldt Bay Power Plant. 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.

Allocation of DWR Electricity to the California Investor-Owned Utilities

Under the authority of AB 1X, the DWR entered into 35 long-term electricity procurement contracts, representing in the aggregate an average annual capacity of 10,780 MW over the next seven years. The California



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IOUs act as billing and collection agents for the DWR's sales of its electricity to retail customers. The DWR's authority under AB 1X to enter into new electricity procurement arrangements expired on December 31, 2002.

In September 2002, the CPUC issued a decision that allocates the electricity provided through the DWR contracts among the customers of the three California IOUs. The DWR allocation generally consists of electricity quantities under contracts with specified delivery points in the Utility's service territory. The power available under the contracts is to be dispatched in conjunction with the IOU's existing resources on a least-cost basis, with surplus energy sales allocated pro rata between the DWR and the IOU's resources based on their relative amounts of generation. Some of the DWR contracts are firm commitments requiring the DWR to make purchases of specified quantities of electricity, others give the DWR the option as to whether to purchase the quantity of electricity set forth in the contract, and others have a combination of mandatory and optional purchases. Of the 19 DWR contracts allocated to the Utility, 11 involve mandatory purchase commitments, for a total average capacity of 3,010 MW, and the remaining 8 contracts involve optional purchase commitments, for a total average capacity of 1,610 MW.

The September 2002 CPUC decision orders the DWR to allocate its variable costs on a contract-by-contract basis. The allocation of both fixed and variable costs was decided in the annual DWR revenue requirement proceeding described above.

The California IOUs began performing all the day-to-day scheduling, dispatch and administrative functions associated with the DWR contracts allocated to their portfolios on January 1, 2003. The DWR retains legal title to electricity purchased under the allocated contracts as well as financial reporting and payment responsibility associated with these contracts. The IOUs continue to act as billing and collection agents for the DWR.

Although the IOUs will be held to a reasonableness standard in their scheduling and dispatch decision-making and their administration of the DWR contracts, the CPUC has determined that the maximum risk of potential disallowance each IOU should face for all of its procurement activities, including the operation and dispatch of DWR's contracts, should be limited to twice the IOU's annual administrative costs of managing procurement activities. The Utility anticipates that its annual administrative costs of managing procurement activities will be approximately $18 million in 2003. 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 on December 19, 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 19, 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.

Qualifying Facility Agreements

The Utility is required by CPUC decisions to purchase electric 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 QF long-term power purchase agreements and approved the applicable terms, conditions, price options, and eligibility requirements. The agreements require the Utility to pay for energy and capacity. Energy payments are based on the QF project's actual electrical output and capacity payments are based on the QF project'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 power purchase agreements.

As of December 31, 2002, the Utility had agreements with 285 QFs for approximately 4,200 MW. The 4,200 MW consist of 2,600 MW from cogeneration projects, 700 MW from wind projects and 900 MW from other projects, including biomass, waste-to-energy, geothermal, solar and hydroelectric. Power purchase agreements for 2,100 MW expire between 2003 and 2015 while agreements for an additional 1,600 MW expire between 2015 and 2028. Power purchase agreements for 500 MW have no specific expiration date and will terminate upon exercise of a termination option by the QF. QF power purchase agreements accounted for approximately 25% of the Utility's 2002 deliveries and no single agreement accounted for more than 5% of its electricity deliveries.

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In August 2002, the CPUC ordered the IOUs to offer transitional standard offer no. 1 contracts, or TS01 contracts, to certain QFs whose power purchase agreements with the IOU had expired or were about to expire. The term of these transitional contracts will end when the IOU fully implements its CPUC-approved long-term procurement plan or on December 31, 2003, whichever occurs first. The Utility signed TS01 contracts with nine QFs. These new contracts have been approved by the Bankruptcy Court and the CPUC and became effective on January 1, 2003.

Since December 2001, the Bankruptcy Court has 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

* set the interest rate for pre-petition payables at 5%,

* provide for a "catch-up payment" of all accrued and unpaid interest through the initial payment date, and

* depending on the amount owed, either (a) provide for the immediate payment of the principal and interest amount of the pre-petition payables or (b) payment in 12 or 6 equal monthly payments beginning on the last business day of the month during which Bankruptcy Court approval was granted.

If the effective date of the Utility's Plan occurs before the last monthly payment is made, the remaining unpaid principal and unpaid interest would be paid on the effective date. Additionally, since January 2002, the Utility has entered into agreements with additional QFs to assume their power purchase agreements, which agreements also contained the same interest and payment terms contained in the supplemental agreements described above. At December 31, 2002, $901 million in principal and $60 million in interest have been paid to the QFs. Through December 31, 2002, 264 of 313 QFs have signed assumption and/or supplemental agreements. The Utility believes that some of the remaining QFs also will wish to enter into similar supplemental agreements.

Renewable Resource Energy Contracts

An August 22, 2002, the CPUC issued a decision requiring the California IOUs to contract for electricity from renewable resources for an additional 1% each year beginning January 1, 2003, until a 20% renewable resource portfolio is achieved by no later than 2017. Interim renewable resources contracts should range from 5 to 15 year terms. In addition, the CPUC decision determined that any renewable resources contract prices that meet or are less than a provisional benchmark of 5.37 cents per kWh will be deemed reasonable, although prices above the benchmark also may be pre-approved for cost recovery through the pre-approval process adopted in the decision. The Utility currently estimates that the annual 1% increase in renewable resource electricity in its portfolio will initially require between 80 and 100 MW of additional renewable capacity to be added per year. On September 16, 2002, the Utility issued a request for offers to meet the 1% annual renewable resource requirement and on November 15, 2002, the Utility submitted the offers selected to the CPUC for approval. These submissions, which the CPUC approved in December 2002, will meet the Utility's renewable resource requirement for 2003.

Other Third-Party Power Agreements

The Utility also has contracts with various irrigation districts and water agencies to purchase hydroelectric power. Under these contracts, the Utility must make specified semi-annual minimum payments whether or not any energy is supplied (subject to the supplier's retention of the FERC's authorization) and variable payments for operation and maintenance costs incurred by the suppliers. These contracts expire on various dates from 2004 to 2031. Costs associated with these contracts to purchase power are eligible for recovery by the Utility as transition costs through the collection of the non-bypassable competition transition charge. At December 31, 2002, the undiscounted future minimum payments under these contracts are approximately $32.9 million for each of the years 2003 and 2004 and a total of $247 million for periods thereafter. Irrigation district and water agency deliveries in the aggregate accounted for approximately 4.24% of the Utility's 2002 electric power requirements.

The Utility also has two power purchase agreements representing an aggregate of 450 MW, both of which expire at the end of 2003. The Utility's minimum payments due under these contracts are $196 million for 2003.



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The amount of electric power received and the total payments made under QF, irrigation district, water agency, and bilateral agreements are as follows:

| | 2002 | 2001 | 2000 | 1999 | 1998 |
|---|---|---|---|---|---|
| Gigawatt-hours received | 28,088 | 23,732 | 26,027 | 25,910 | 25,994 |
| Energy payments (in millions) | $ 1,051 | $ 1,454 | $ 1,549 | $ 837 | $ 943 |
| Capacity payments (in millions) | $ 506 | $ 473 | $ 519 | $ 539 | $ 529 |
| Irrigation district and water agency payments (in millions) | $ 57 | $ 54 | $ 56 | $ 60 | $ 53 |
| Bilateral contract payments | $ 196 | $ 155 | $ 53 | 0 | 0 |

Western Area Power Administration. 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) WAPA's use of the Utility's transmission and distribution system, and (3) the integration of the Utility's and WAPA's loads and resources. The contract gave the Utility access to surplus hydroelectric generation and obligates the Utility to provide WAPA with electricity when its own resources are 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 electric power that it needed to meet its own and WAPA's requirements from the PX. This caused the Utility to be exposed to market-based energy pricing rather than the cost of service-based energy pricing that had been presumed when the contract was executed. As a result, the Utility paid substantially more for the energy it purchased on behalf of WAPA than it received for the sales of energy to WAPA. The cost 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 will be greater than the price that the Utility receives from WAPA under the contract. In part, the amount of electricity the Utility will be required to deliver to WAPA depends on the amount of electricity available from WAPA's hydroelectric resources. 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 energy 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 was 3,619 GWh in 2002, 4,823 GWh in 2001, and 5,120 GWh in 2000.

Electric Transmission

To transmit electricity to load centers, the Utility, at December 31, 2002, owned approximately 18,605 circuit miles of interconnected transmission lines operated at voltages of 60 kV to 500 kV and transmission substations having a capacity of approximately 47,596 megavolt-amperes (MVA), including spares, and excluding power plant interconnection facilities. Electricity is distributed to customers through approximately 118,033 circuit miles of distribution system and distribution substations having a capacity of approximately 24,020 MVA. For the year ended December 31, 2002, the Utility sold 104,499,158 MWh to its bundled retail customers and transmitted 7,433,238 MWh to direct access customers.

In connection with electric industry restructuring, in 1998 the IOUs relinquished to the ISO control, but not ownership, of their transmission facilities. The FERC has jurisdiction over the transmission facilities, and revenue requirements and rates for transmission service are set by the FERC. The ISO commenced operations on March 31, 1998. The ISO, regulated by the FERC, controls the operation of the transmission system and provides open access transmission service on a nondiscriminatory basis. As control area operator, the ISO also is responsible for assuring the reliability of the transmission system.

In 1998, the FERC approved the forms of agreements for Reliability Must-Run, or RMR, service that have been entered into between RMR facility owners and the ISO to ensure grid reliability and avoid the exercise of local market power. The costs of RMR contracts attributed to supporting the Utility's historic transmission control area are charged to the Utility as a Participating Transmission Owner, or PTO. These costs, which were approximately $311 million in 2002, are currently recovered from the Utility's retail customers and, subject to FERC filings to be made by March 31, 2003, wholesale transmission customers.

In March 2000, the ISO filed an application with the FERC seeking to establish its own Transmission Access Charge (TAC) as directed in AB 1890. The FERC accepted the ISO's TAC filing, subject to refund, but suspended the proceeding to allow interested parties to enter into settlement discussions. After settlement discussions proved unsuccessful, in December 2002 FERC set the case for hearing. In late December 2000, the ISO made a further



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implementation filing, also accepted by the FERC subject to refund, to establish specific TAC rates which was triggered by a transmission-owning municipality's application to become a new PTO. The ISO's TAC methodology provides for transition to a uniform statewide high voltage transmission rate, based on the revenue requirements of all PTOs associated with facilities operated at 200 kV and above. The TAC methodology also requires the IOUs, such as the Utility, to pay during a ten-year transition period a charge based on certain costs incurred by new PTOs resulting from joining the ISO and the cost differential from these higher-cost systems being included in the ISO controlled transmission grid. The Utility's obligation for this cost shift is proposed to be capped at $32 million per year.

The Utility has been working closely with the ISO to continue expanding the capacity on the Utility's electric transmission system. One segment of the transmission system proposed to be addressed by the Utility are the transmission facilities known as Path 15, which is located in the southern portion of the Utility's service area, and serves as part of the primary transmission path between northern California and southern California. At times, the current facilities cannot accommodate all low-cost power intended to be transmitted between southern California and northern California. (For transmission purposes, the Diablo Canyon Nuclear Power Plant is located south of Path 15.) This transmission constraint historically has resulted in significant wholesale power price differentials between northern and southern California, with relatively high power prices in northern California and relatively low power prices in southern California.

Following an analysis of the economic benefits of relieving transmission system constraints performed by the ISO, the Utility agreed to participate in a project sponsored by WAPA to upgrade the transfer capability of Path 15. The project entails construction of a new 84 mile, 500 kV transmission line by WAPA between two of the Utility's existing substations. The Utility has agreed to interconnect WAPA's new 500 kV line at the Utility's substations by installing necessary substation equipment and to modify other portions of its transmission system. WAPA will own and operate the new 500 kV line with financing provided by Trans-Elect, Inc., an independent electric transmission company. All participants in the WAPA-sponsored project have agreed to turn over operational control of the transmission system upgrade to the ISO upon completion of the project. In January 2002, the Utility received Bankruptcy Court approval to participate in the WAPA project including spending up to $75 million under its current five-year plan for the substation and system modifications necessary to interconnect to WAPA's new line. In May 2002, the FERC approved a letter agreement between the participants outlining ownership, financing and cost recovery associated with the project. The Utility is in the process of negotiating additional agreements with the project participants to develop schedules and coordinate construction of the project and for the coordinated operation and interconnection of the project with its existing facilities. The Utility's expenditure commitment is contingent upon WAPA meeting construction milestones.

The Utility's investment in its transmission system has been growing substantially over the past several years. The Utility made an additional capital investment of approximately $374 million in its transmission system in 2002 and plans to make an additional capital investment of approximately $504 million in 2003. Through the ISO's Long-Term Grid Planning Process, the Utility files annually with the ISO its transmission system upgrade and expansion plans and provides the ISO and other interested parties the opportunity to review and modify the Utility's planned upgrades and expansions.

## GAS UTILITY OPERATIONS

The Utility owns and operates an integrated gas transmission, storage, and distribution system in California that extends throughout all or a portion of 38 of California's 58 counties and includes most of northern and central California. In 2002, the Utility served approximately 3.9 million natural gas distribution customers.

At December 31, 2002, the Utility's system consisted of approximately 6,300 miles of transmission pipelines, three gas storage facilities, and approximately 38,944 miles of gas distribution lines. The Utility's Line 400/401 interconnects with PG&E GTN's natural gas transmission system. The PG&E GTN pipeline begins at the border of British Columbia, Canada and Idaho, and extends through northern Idaho, southeastern Washington, and central Oregon, and ends on the Oregon-California border where it connects with the Utility's Line 400/401. The Utility's Line 400/401 has a capacity at the border of approximately 2 billion cubic feet, or Bcf. The Utility's Line 300, which connects to the U.S. Southwest pipeline systems (Transwestern, El Paso, Questar, and Kern River) owned by third parties has a capacity at the California/Arizona border of 1,140 MMcf per day. The Utility's underground gas storage facilities located at McDonald Island, Los Medanos, and Pleasant Creek, have a total working gas capacity of 100 Bcf.



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Through the interconnection with other interstate pipelines, the Utility can receive natural gas from all the major natural gas basins in western North America, including basins in western Canada, the southwestern United States, and the Rocky Mountains, as well as natural gas fields in California.

Since 1991, the CPUC has divided the Utility's natural gas customers into two categories--core and noncore customers. This classification is based largely on a customer's annual natural gas usage. The core customer class is comprised mainly of residential and smaller commercial natural gas customers. The noncore customer class is comprised of industrial and larger commercial natural gas customers. In 2002, core customers represented over 99% of the Utility's total customers and 41% of its total natural gas deliveries while noncore customer comprised less than 1% of its total customers and 59% of its total natural gas deliveries.

The Utility provides natural gas delivery services to all its core and noncore customers. Core customers can purchase gas from third-party suppliers or can elect to have the Utility provide both delivery service and natural gas supply. Where the Utility provides both supply and delivery, the Utility refers to the service as "bundled service." The Utility offers transmission, distribution, and storage services as separate and distinct services to its non-core customers. These customers have the opportunity to select from a menu of services offered by the Utility and to pay only for the services that they use. Access to the transmission system is possible for all gas marketers and shippers, as well as non-core end-users. The Utility's core customers can select the commodity gas supplier of their choice, but the Utility continues to purchase gas as a regulated supplier for those core customers who do not select another supplier. Currently, over 99% of core customers, representing over 97% of core market demand, choose to receive bundled services from the Utility. The Utility ended its core subscription service in March 2001.

The Utility earns a return on its investment in natural gas distribution facilities. Customers pay a volumetric distribution rate that reflects the Utility's costs to serve each customer class. The Utility has regulatory balancing accounts for core customers designed so that the Utility's results of operations over the long term are not affected by their consumption levels. Results of operations can, however, be affected by noncore consumption levels because there are no similar regulatory balancing accounts related to noncore customers. Approximately 97% of the Utility's natural gas base revenues are recovered from core customers and 3% are recovered from noncore customers. The Utility Gas Accord II application for 2004 requests 100% balancing account treatment for noncore gas distribution revenues.

The Utility's peak day send-out of natural gas on its integrated system in California during the year ended December 31, 2002 was 4,077MMcf. The total volume of natural gas throughput during 2002 was approximately 749,981 MMcf, of which 733,585 MMcf was sold or transported to direct end-use or resale customers, 15,298 MMcf was used by the Utility primarily for its fossil-fuel fired electric generating plants, and 1,098 MMcf was transported off-system as customer-owned natural gas.

The California Gas Report, which presents the outlook for natural gas requirements and supplies for California over a long-term planning horizon, is prepared annually by the California electric and gas utilities. A comprehensive biennial report is prepared in even-numbered years. A supplemental report is prepared in intervening odd-numbered years updating recorded data for the previous year. The 2002 California Gas Report updated the Utility's annual gas requirements forecast for the years 2002 through 2022, forecasting average annual growth in gas throughput served by the Utility of approximately 1.8%. The gas requirements forecast is subject to many uncertainties and there are many factors that can influence the demand for natural gas, including weather conditions, level of economic activity, conservation, and amount and location of electric generation. The 2003 report is due to be filed July 1, 2003, and will include recorded data for 2002.



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Gas Operating Statistics

The following table shows Pacific Gas and Electric Company's operating statistics (excluding subsidiaries) for gas, including the classification of sales and revenues by type of service:

| | 2002 | 2001 | 2000 | 1999 | 1998 |
|---|---|---|---|---|---|
| Customers (average for the year): | | | | | |
| Residential | 3,738,524 | 3,705,141 | 3,642,266 | 3,593,355 | 3,536,089 |
| Commercial | 206,953 | 205,681 | 203,355 | 203,342 | 200,620 |
| Industrial | 1,819 | 1,764 | 1,719 | 1,625 | 1,610 |
| Other gas utilities | 5 | 6 | 6 | 4 | 5 |
| Total | 3,947,301 | 3,912,592 | 3,847,346 | 3,798,326 | 3,738,324 |
| Gas supply--thousand cubic feet (Mcf) (in thousands): | | | | | |
| Purchased from suppliers in: | | | | | |
| Canada | 210,716 | 209,630 | 216,684 | 230,808 | 298,125 |
| California | 19,533 | 10,425 | 32,167 | 18,956 | 17,724 |
| Other states | 67,878 | 76,589 | 75,834 | 107,226 | 122,342 |
| Total purchased | 298,127 | 296,644 | 324,685 | 356,990 | 438,191 |
| Net (to storage) from storage | (218) | (27,027) | 19,420 | (980) | (14,468) |
| Total | 297,909 | 269,617 | 344,105 | 356,010 | 423,723 |
| Pacific Gas and Electric Company use, losses, etc. (1) | 16,394 | (939) | 62,960 | 47,152 | 129,305 |
| Net gas for sales | 281,515 | 270,556 | 281,145 | 308,858 | 294,418 |
| Bundled gas sales--Mcf (in thousands): | | | | | |
| Residential | 202,141 | 197,184 | 210,515 | 233,482 | 223,706 |
| Commercial | 78,812 | 72,528 | 66,443 | 70,093 | 66,082 |
| Industrial | 563 | 831 | 4,146 | 5,255 | 4,616 |
| Other gas utilities | 0 | 13 | 41 | 28 | 14 |
| Total | 281,516 | 270,556 | 281,145 | 308,858 | 294,418 |

| | | | | | |
|---|---|---|---|---|---|
| Transportation only--Mcf (in thousands): | | | | | |
| Vintage system (Substantially all Industrial) (2) | 508,090 | 646,079 | 606,152 | 484,218 | 396,872 |
| Revenues (in thousands). | | | | | |
| Bundled gas sales: | | | | | |
| Residential | $1,379,036 | $2,307,677 | $1,680,745 | $1,542,705 | $1,414,313 |
| Commercial | 499,214 | 783,080 | 513,080 | 448,655 | 426,299 |
| Industrial | 2,447 | 15,904 | 35,347 | 24,638 | 24,634 |
| Other gas utilities | 829 | 2 | 0 | 77 | 1,072 |
| Bundled gas revenues | 1,881,526 | 3,106,663 | 2,229,172 | 2,016,075 | 1,866,318 |
| Transportation only revenue: | | | | | |
| Vintage system (Substantially all Industrial) | $ 308,212 | $ 365,550 | $ 324,319 | $ 267,544 | $ 232,038 |
| PG&E Expansion (Line 401) | 8,275 | 9,380 | 13,392 | 19,091 | 42,194 |
| Transportation service only revenue | 316,487 | 374,930 | 337,711 | 286,635 | 274,232 |
| Miscellaneous | 126,415 | (92,531) | 84,526 | (47,311) | 41,364 |
| Regulatory balancing accounts | 11,431 | (253,476) | 131,762 | (259,648) | (448,351) |
| Operating revenues | $2,335,859 | $3,135,586 | $2,783,171 | $1,995,751 | $1,733,563 |

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(1)
Includes fuel for Pacific Gas and Electric Company's fossil-fuel fired generating plants.

(2)
Does not include on-system transportation volumes transported on the PG&E Expansion of 382 MMcf, 259 MMcf, 4,833 MMcf, 1,251 MMcf, and 34,169 MMcf for 2002, 2001, 2000, 1999, and 1998, respectively.



| | 2002 | 2001 | 2000 | 1999 | 1998 |
|---|---|---|---|---|---|
| Selected Statistics: | | | | | |
| Average annual residential usage (Mcf) | 54.1 | 53.2 | 59 | 65 | 63 |
| Heating temperature--% of normal (1) | 104.6 | 105.1 | 101.2 | 108.5 | 93.0 |
| Average billed bundled gas sales revenues per Mcf: | | | | | |
| Residential | $ 6.82 | $11.70 | $ 7.98 | $ 6.61 | $ 6.32 |
| Commercial | 6.33 | 10.80 | 7.72 | 6.40 | 6.45 |
| Industrial | 4.35 | 19.15 | 8.53 | 4.69 | 5.36 |
| Average billed transportation only revenue per Mcf: | | | | | |
| Vintage system | 0.61 | 0.56 | 0.54 | 0.66 | 0.66 |
| PG&E Expansion (Line 401) | 7.54 | 1.78 | 2.04 | 0.53 | 0.54 |
| Net plant investment per customer (2) | $1,006 | $ 970 | $1,003 | $1,011 | $1,040 |

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(1)
Over 100% indicates colder than normal.

Natural Gas Supplies

The Utility purchases natural gas directly from producers and marketers in both Canada and the United States. The composition of the Utility's portfolio of natural gas procurement contracts has fluctuated, generally based on market conditions. The Utility's CPUC-approved core procurement incentive mechanism, or CPIM, uses published monthly and daily natural gas prices for determining the Utility's benchmark price. During the year ended December 31, 2002, the Utility purchased approximately 298,127 Mcf of natural gas from approximately 54 suppliers. Substantially all this supply was purchased under contracts with a term of less than one year. The Utility's largest individual supplier represented approximately 9.4% of the Utility's total natural gas purchases during the year ended December 31, 2002.

Approximately 70% of the Utility's natural gas supplies come from western Canada. The Utility has firm transportation agreements for western Canadian natural gas with TransCanada NOVA Gas Transmission, Ltd. and TransCanada PipeLines Ltd., B.C. System. These systems transport the natural gas to the U.S. and Canadian border, where it enters the transportation pipeline of PG&E GTN near Kingsgate, British Columbia. Approximately 28% of the Utility's natural gas supplies come from the southwestern United States and the Rocky Mountains. The Utility has firm transportation agreements with Transwestern Pipeline Company and El Paso Natural Gas Company to transport this natural gas to interconnections with the Utility's gas transportation and storage system near Topock, Arizona.

The following table shows the total volume and average price of gas in dollars per thousand cubic feet (Mcf) purchased by the Utility from these sources during each of the last five years.

| | 2002 | | 2001 | | 2000 | | 1999 | | 1998 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Thousands of Mcf | Avg Price (1) | Thousands of Mcf | Avg Price (1) | Thousands of Mcf | Avg Price (1) | Thousands of Mcf | Avg Price (1) | Thousands of Mcf | Avg. Price (1) |
| Canada | 210,716 | $2 42 | 209,630 | $ 4 43 | 216,684 | $4.05 | 230,808 | $2 50 | 298,125 | $2 00 |
| California | 19,533 | 2.88 | 10,425 | 16 68 | 32,167 | 8.20 | 18,956 | 2.45 | 17,724 | 2 44 |
| Other states (substantially all U.S Southwest) | 67,878 | 3.04 | 76,588 | 10.41 | 75,835 | 5.99 | 107,227 | 2 42 | 122,342 | 2 62 |
| Total/Weighted Average | 298,127 | $2.59 | 296,643 | $ 6.40 | 324,686 | $4.92 | 356,991 | $2 47 | 438,191 | $2.19 |

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(1)
The average prices for Canadian and U.S. Southwest gas include the commodity gas prices, interstate pipeline demand or reservation charges, transportation charges, and other pipeline assessments, including direct bills allocated over the quantities received at the California border. Beginning March 1, 1998, the average price for gas also includes intrastate pipeline demand and reservation charges. These costs previously were bundled in gas 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 locations where the Utility typically purchases natural gas. If costs fall within a range, or tolerance band, currently between 99% to 102%, around the benchmark, they are considered reasonable and the Utility may fully recover them in customer rates. Ratepayers and shareholders share costs and savings outside the tolerance band.

### Natural Gas Gathering Facilities

The Utility's natural gas gathering system collects and processes natural gas from third-party wells in California. The natural gas is processed to remove various impurities from the natural gas stream and to odorize the natural gas so that it may be detected in the event of a leak. The facilities include approximately 510 miles of gas gathering pipelines as well as dehydration, separation, regulation, odorization and metering equipment located at approximately 60 stations. The natural gas gathering system is geographically dispersed and is located in 16 California counties. Approximately 190 MMcf per day of natural gas flows through the Utility's gas gathering system.

### Natural Gas Transportation and Storage Services Agreements

Since March 1998, the Utility's natural gas transportation and storage services have been governed by the rates, terms, and conditions approved by the CPUC in the Gas Accord. The Gas Accord separated, or "unbundled," the Utility's natural gas transportation and storage services from its distribution services, changed the terms of service and rate structure for natural gas transportation and storage services, and fixed natural gas transportation and storage rates. As required by the CPUC, in October 2001, the Utility filed an application with the CPUC requesting a two-year extension, without modification, of the Gas Accord. In August 2002, the CPUC approved a settlement agreement among the Utility and other parties that provided for a one-year extension of the Gas Accord. The Gas Accord II settlement left unresolved the issues raised in the application insofar as they relate to the second year of the two-year application.

Following the CPUC administrative law judge's rulings which required the Utility to also file a cost and rate proposal for 2004, the Utility filed an amended application, on January 13, 2003, which proposes, among other things, retention of the basic Gas Accord market structure, transmission and storage costs and rates for 2004, a 13.4% equity return for gas transmission and storage assets, a 1-in-10 reliability standard, and for the Utility to remain at risk for recovery of all transmission and storage facility costs. Testimony by interested parties is due by February 28, 2003, and rebuttal testimony by March 24, 2003, with hearings to begin on April 1, 2003.

The Utility has a number of arrangements for natural gas transportation services. These agreements include provisions for payment of fixed demand charges for reserving firm pipeline capacity as well as volumetric transportation charges. The total demand charges may change periodically as a result of changes in regulated tariff rates. Additionally, the forward market value for the firm capacity is subject to change. The Utility held hedge agreements for a portion of this forward value at the time it defaulted in April 2001, which caused the hedge counterparties to terminate their agreements and demand termination payments. The Utility recognized a total of $111 million in losses related to these terminated agreements in 2001. The combined charges the Utility incurred under the transportation agreements and hedge agreements, including losses on terminated contracts, were $101 million, $239 million, and $94 million in 2002, 2001, and 2000, respectively. These amounts include payments that the Utility made to PG&E GTN of $47 million, $40 million, $46 million in 2002, 2001, and 2000, respectively, which are eliminated in the consolidated financial statements of PG&E Corporation.

Under a firm transportation agreement with PG&E GTN that runs through October 31, 2005, the Utility currently retains capacity of approximately 610 MDth/d on the PG&E GTN system to support its core customers. The Utility has been able to broker its unused capacity on PG&E GTN's system, when not needed for core customers.

Pursuant to the CPUC's order requiring the utilities to subscribe for capacity on El Paso's pipeline, the Utility has obtained 204 MDth/day of El Paso capacity rights on interstate pipeline under three natural gas transportation agreements commencing on November 1, 2002. The costs are currently allocated to core and noncore customers subject to reallocation in a future CPUC proceeding.

The Utility may recover demand charges through the CPIM and through brokering activities.

The Utility may, upon prior notice, extend each of these natural gas transportation contracts for additional minimum terms ranging, depending on the particular contract, from 1 to 10 years with demand charges to be set by tariffs approved by Canadian regulators in the case of TransCanada NOVA Gas Transmission, Ltd. and TransCanada PipeLines Ltd., B.C. System and the FERC in all other cases. For the contracts under FERC jurisdiction, the Utility has a right of first refusal allowing the Utility to renew pipeline service agreements at the end of their terms. If another prospective shipper wants the capacity, the Utility would be required to match the competing bid with respect to both price and term. In the past, FERC policy required only that the existing shipper match the price and a term of up to five years. In a recent order on remand from an appellate court, the FERC removed the



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five-year cap on matching bids. Under the new FERC policy, the existing shipper must match the competing bid with respect to both price and term, with no limit on the number of years that the shipper's bid must match.

## PG&E NATIONAL ENERGY GROUP, INC.

PG&E NEG is currently focused on power generation and natural gas transmission in the United States. PG&E NEG reports its business segments as follows: interstate pipeline operations (or "Pipeline Business") and power generation also referenced as Integrated Energy and Marketing (or "Generation Business").

### Generation Business

In the Generation Business segment, PG&E NEG engages in the generation of electricity in the continental United States. As of December 31, 2002, PG&E NEG had ownership or leasehold interests in 16 operating generating facilities with a net generating capacity of 1,476 megawatts (MW), as follows:

| Number of Facilities | Net MW | Primary Fuel Type | % of Portfolio |
|---|---|---|---|
| 8 | 667 | Coal/Oil | 45 |
| 7 | 797 | Natural Gas | 54 |
| 1 | 12 | Wind | 1 |
| 16 | 1,476 | | 100 |

PG&E NEG provides operating and/or management services for 14 of these 16 owned and leased generating facilities. Plant operations are focused on maximizing the availability of a facility to generate power during peak energy price hours, improving operating efficiencies and minimizing operating costs while placing a heavy emphasis on safety standards, environmental compliance and plant flexibility. These generating facilities sell all or a majority of their electrical capacity and output to one or more third parties under long-term power purchase agreements tied directly to the output of that plant.

PG&E NEG holds interests in these projects through wholly owned indirect subsidiaries and typically manages and operates these facilities through an operation and maintenance agreement and/or a management services agreement. These agreements generally provide for management, operations, maintenance and administration for day-to-day activities, including financial management, billing, accounting, public relations, contracts, reporting and budgets. In order to provide fuel for PG&E NEG's independent power projects (IPPs), natural gas and coal supply commitments are typically purchased from third parties under long-term supply agreements.

The revenues generated from long-term power sales agreements usually consist of two components: energy payments and capacity payments. Energy payments are typically based on the facility's actual electrical output and capacity payments are based on the facility's total available capacity. Energy payments are made for each kilowatt-hour of energy delivered, while capacity payments, under most circumstances, are made whether or not any electricity is delivered. However, capacity payments may be reduced if the facility does not attain an agreed availability level. The average life of the power sales agreements is 15 years.



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Description of Generating Facilities

The following table provides information regarding each of PG&E NEG's owned or leased generating facilities, as of December 31, 2002, excluding assets to be abandoned and assets held for sale or use, such as the USGenNE facilities, Lake Road, La Paloma, Attala, and the GenHoldings projects:

| Generating Facility | State | Total MW (1) | Net Interest in Total MW (2) | Structure | Fuel | Primary Output Sales Method | Date of Commercial Operation | Contract Expiration |
|---|---|---|---|---|---|---|---|---|
| New England Region | | | | | | | | |
| MASSPOWER | MA | 267 | 35 | Owned | Natural Gas | Power Purchase Agreements | 1993 | 2008 & 2013 |
| Pittsfield | MA | 173 | 154 | Leased | Natural Gas | Power Purchase Agreements | 1990 | 2010 |
| Subtotal | | 440 | 189 | | | | | |
| Mid-Atlantic and New York Region | | | | | | | | |
| Selkirk | NY | 345 | 145 | Owned | Natural Gas | Power Purchase Agreements and Competitive Market | 1992 | 2008/2014 |
| Carneys Point | NJ | 245 | 123 | Owned | Coal | Power Purchase Agreements | 1994 | 2024 |
| Logan | NJ | 225 | 113 | Owned | Coal | Power Purchase Agreement | 1994 | 2024 |
| Northampton | PA | 110 | 55 | Owned | Waste Coal | Power Purchase Agreements | 1995 | 2020 |
| Panther Creek | PA | 80 | 44 | Owned | Waste Coal | Power Purchase Agreement | 1992 | 2012 |
| Scrubgrass | PA | 87 | 44 | Owned | Waste Coal | Power Purchase Agreement | 1993 | 2017 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Madison | NY | 12 | 12 | Owned | Wind | Competitive Market | 2000 | N/A |
| Subtotal | | 1,104 | 536 | | | | | |
| Midwest Region | | | | | | | | |
| Ohio Peakers | OH | 149 | 149 | Owned | Natural Gas | Competitive Market | 2001 | 2005 |
| Southern Region | | | | | | | | |
| Indiantown | FL | 330 | 116 | Owned | Coal | Power Purchase Agreement | 1995 | 2025 |
| Cedar Bay | FL | 258 | 165 | Owned | Coal | Power Purchase Agreement | 1994 | 2024 |
| Subtotal | | 588 | 281 | | | | | |
| Western Region | | | | | | | | |
| Hermiston | OR | 474 | 119 | Owned | Natural Gas | Power Purchase Agreement | 1996 | 2016 |
| Colstrip | MT | 40 | 7 | Owned | Waste Coal | Power Purchase Agreement | 1990 | 2025 |
| San Diego Peakers | CA | 84 | 84 | Owned | Natural Gas | Competitive Market | 2001 | 2003 |
| Plains End | CO | 111 | 111 | Owned | Natural Gas | Power Purchase Agreement | 2002 | 2012 |
| Subtotal | | 709 | 321 | | | | | |
| Total | | 2,990 | 1,476 | | | | | |

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(1)
Megawatts are based on winter output.

(2)
PG&E NEG's net interest in the total MW of an independent power project is the current percentage ownership or leasehold interest in the project affiliate and does not necessarily correspond to PG&E NEG's percentage of the project's expected cash flow.

Natural Gas Transmission Business

In its Pipeline Business segment, PG&E NEG owns, operates and develops natural gas pipeline facilities, including the pipeline owned by PG&E GTN, an interest in the Iroquois Gas Transmission System, and the North Baja pipeline.

The following table summarizes PG&E NEG's gas transmission pipelines:

| Pipeline Name | Location | In Service Date | Approx. Capacity (MMcf/d) | 2001 Load Factor | Length (miles) | Ownership Interest |
|---|---|---|---|---|---|---|
| PG&E GTN | ID, OR, WA | 1961 | 2,900 | 91% | 1,356 | 100.0% |
| Iroquois Gas Transmission System | NY, CT | 1991 | 850 | 88% | 375 | 5.2% |
| North Baja | AZ, CA | 2002/2003 | 500 | N/A | 80 | 100.0% |

PG&E GTN Pipeline System. The PG&E GTN pipeline consists of over 1,350 miles of natural gas transmission pipeline in the Pacific Northwest with a capacity of approximately 2.9 billion cubic feet of natural gas per day. This pipeline begins at the British Columbia-Idaho border, extends for approximately 612 miles through northern Idaho, southeastern Washington and central Oregon, and ends at the Oregon-California border, where it connects with other pipelines. The PG&E GTN pipeline commenced commercial operation in 1961 and has subsequently expanded various times through 2002. This pipeline is the largest transporter of Canadian natural gas into the United States. The mainline system of this pipeline is composed of two parallel pipelines (along with 21 miles of a third parallel line) with 13 compressor stations totaling approximately 513,400 horsepower and ancillary facilities which include metering and regulating facilities and a communication system. PG&E GTN has approximately 639 miles of 36-inch diameter gas transmission lines (612 miles of 36-inch diameter pipe and 27 miles of 36-inch diameter pipeline looping) and approximately 611 miles of 42-inch diameter pipe. The PG&E GTN system also includes two laterals off of its mainline system, the Coyote Springs Extension, which supplies natural gas to an electric generation facility owned by Portland General Electric Company and other customers, and the Medford Extension, which supplies natural gas to Avista Utilities and Pacificorp Power Marketing. The Coyote Springs Extension is composed of approximately 18 miles of 12-inch diameter pipe, originating at a point on the PG&E GTN mainline system approximately 27 miles south of Stanfield, Oregon and connecting to Portland General Electric's electric generation facility near Boardman, Oregon. The Medford Extension consists of approximately 22 miles of 16-inch diameter pipe and 66 miles of 12-inch diameter pipe and extends from a point on the PG&E GTN mainline system near Bonanza, in Southern Oregon, to interconnection points with Avista Utilities at Klamath Falls and Medford, Oregon.

PG&E GTN Interconnection With Other Pipelines. PG&E GTN's pipeline facilities interconnect with facilities owned by TransCanada PipeLines Ltd.'s B.C. System (TransCanada) and facilities owned by Foothills Pipe Lines South B.C. Ltd. (Foothills South B.C.) near the Idaho-British Columbia border. PG&E GTN's pipeline facilities also interconnect with the facilities owned by the Utility, at the Oregon-California border, with the facilities owned by Northwest Pipeline Corporation (Northwest Pipeline) in Northern Oregon and in Eastern Washington, and with the facilities owned by Tuscarora Gas Transmission Company (Tuscarora) in Southern Oregon. PG&E GTN also delivers gas along various mainline delivery points to two local gas distribution companies.

TransCanada PipeLines Ltd. and Foothills South B.C. Ltd. PG&E GTN's pipeline facilities interconnect with the facilities of TransCanada and Foothills South B.C. near Kingsgate, British Columbia. Through the TransCanada and Foothills South B.C. systems, PG&E GTN's customers have access to natural gas from the Western Canadian Sedimentary Basin. TransCanada's Alberta System delivers gas from production areas to provincial gas distribution utilities and to all provincial export points, including the interconnect at the Alberta-British Columbia border to TransCanada's B.C. System and Foothills South B.C. for delivery south into PG&E GTN's system at the British Columbia-Idaho border.

Northwest Pipeline Corporation. PG&E GTN's pipeline facilities interconnect with the facilities of Northwest Pipeline near Spokane and Palouse, Washington and near Stanfield and Klamath Falls, Oregon. Northwest Pipeline is an interstate natural gas pipeline which both delivers gas to and receives gas from PG&E GTN and competes with PG&E GTN for transportation of natural gas into the Pacific Northwest and California. Northwest Pipeline's gas transportation services are regulated by the FERC.

Tuscarora Gas Transmission Company. PG&E GTN's pipeline facilities interconnect with the facilities of Tuscarora near Malin, Oregon. Tuscarora is an interstate natural gas pipeline that transports natural gas from this interconnection to the Reno, Nevada area. Tuscarora's gas transportation services are regulated by the FERC.

Pacific Gas and Electric Company. PG&E GTN's pipeline interconnects with the Utility's gas transmission pipeline system at the Oregon-California border. The Utility's pipeline facilities deliver natural gas to customers in Northern and Central California and interconnect with other pipeline facilities at the California-Arizona border near Topock, Arizona. The Utility's gas transmission system is currently regulated by the CPUC. In April 2001, the Utility commenced a case under Chapter 11 of the U.S. Bankruptcy Code. As part of the Utility's proposed plan of reorganization, in November 2001, the Utility filed an application with the FERC requesting authorization to operate these facilities as a federally-regulated interstate pipeline system. In conjunction with that application, PG&E GTN filed an application with the FERC for authorization to abandon by sale to the Utility approximately 2.66 miles of 42-inch and 36-inch mainline pipe from the southernmost meter station in Oregon to the California border. The transaction implementing this abandonment closed into escrow on November 14, 2002, pending receipt of satisfactory authorizations from the FERC and the Bankruptcy Court.

PG&E GTN's Expansion Projects. PG&E GTN has completed its 2002 Expansion Project, expanding its system by approximately 217 million cubic feet (MMcf) per day. Approximately 40 MMcf per day of that expansion capacity was placed in service in November 2001 and the remaining capacity was placed in service in November 2002. The total cost of the expansion is approximately $127 million. One shipper, contractually



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committed to 175,000 decatherm (Dth) per day of capacity on this project, failed to provide PG&E GTN with adequate assurances of the shipper's ability to meet its obligations under its transportation contract. On October 25, 2002, PG&E GTN and that shipper terminated the transportation contract and PG&E GTN received $16.8 million from that shipper in settlement of the contract.

In response to changing market conditions, PG&E GTN reached agreement with all shippers contractually committed on a second expansion (2003 Expansion Project) to terminate their firm transportation precedent agreements. Accordingly, on October 10, 2002, PG&E GTN filed with the FERC a request to vacate its 2003 Expansion Project proceeding and deferred the project. To date, PG&E GTN has spent $5.4 million on the project. PG&E GTN is continuing necessary development activities and expects to refile an application with FERC when market conditions improve.

Related to the termination of the 2003 Expansion Project precedent agreements, all but one of the former 2003 Expansion shippers has committed to take capacity on PG&E GTN's system made available as a result of the 2002 shipper termination or capacity formerly held by Enron or other existing capacity on PG&E GTN's system. PG&E GTN anticipates that it will enter into additional contracts for capacity made available from these sources through open market sales. As of December 31, 2002, PG&E GTN had approximately 155,000 Dth per day of capacity available for subscription on a long-term basis.

North Baja Pipeline. North Baja Pipeline, LLC (NBP) owns an approximately 80-mile interstate natural gas pipeline with a capacity of 512 MDth of natural gas per day. The NBP system originates near Ehrenberg, in western Arizona, and traverses southern California to a point on the Baja California, Mexico-California border. The NBP system began limited commercial operation in September 2002 and includes a single compressor station at Ehrenberg, which has approximately 28,800 certificated horsepower and ancillary facilities which include metering and regulating facilities and a communication system. The NBP mainline system consists of approximately 12 miles of 36-inch diameter gas transmission line and 68 miles of 30-inch diameter pipe. This new pipeline will deliver natural gas to a pipeline being constructed by Sempra Energy International. The 135-mile Sempra pipeline will interconnect with PG&E NBP at the California-Mexico border and transport gas into Northern Mexico and Southern California.

North Baja System Interconnections with Other Pipelines

El Paso Natural Gas (EPNG) - NBP pipeline facilities interconnect with the facilities of EPNG near Ehrenberg, Arizona. EPNG is an interstate natural gas pipeline, with a pipeline network throughout west Texas, New Mexico and Arizona, that serves customers and other pipelines, including NBP, within those states. Through EPNG, NBP customers have access to gas primarily from the Permian and San Juan basins of Texas, New Mexico and Colorado. EPNG's transportation services are regulated by the FERC.

Gasoducto Bajanorte (GB) - NBP pipeline facilities interconnect with the facilities of GB at the Baja California, Mexico-California border near Ogilby, California. GB is the pipeline that receives gas from NPB for the purpose of delivering the gas to customers located in the northern portion of Baja California, Mexico. GB's transportation services are regulated by the Comision Reguladora de Energia, Mexico, a regulatory agency in Mexico with responsibilities similar to those of FERC as they relate to natural gas pipelines.

Iroquois Pipeline. PG&E NEG owns a 5.2% interest in the Iroquois Gas Transmission System, an interstate pipeline which extends 375 miles from the U.S.-Canadian border in northern New York through the State of Connecticut to Long Island, New York. This pipeline, which commenced operations in 1991, provides gas transportation service to local gas distribution companies, electric utilities and electric power generators, directly or indirectly through exchanges and interconnecting pipelines, throughout the Northeast. The Iroquois pipeline is owned by a partnership of six U.S. and Canadian energy companies, including affiliates of TransCanada Pipeline, Dominion Resources and Keyspan Energy. Iroquois has executed firm multi-year transportation services agreements totaling more than 1,000 MMcf per day. This pipeline also provides interruptible transportation services on an as available basis. On December 26, 2001, the FERC issued a certificate of public convenience and necessity authorizing Iroquois to expand its capacity by 220 MMcf per day of natural gas and extend the pipeline into the Bronx borough of New York City for a total investment of approximately $210 million. Iroquois also filed three additional applications with the FERC to expand its system capacity, and to extend the pipeline into Eastern Long Island.



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Natural Gas Transportation Services

Under the FERC's current policies, transportation services are classified as either firm or interruptible, and PG&E NEG's fixed and variable costs are allocated between these types of service for ratemaking purposes. PG&E GTN provides firm and interruptible transportation services to third party shippers on a nondiscriminatory basis. Firm transportation services means that the customer has the highest priority rights to ship a quantity of gas between two points for the term of the applicable contract. Firm transportation service customers pay both a reservation charge and a delivery charge. The reservation charge is assessed for a firm shipper's right to transport a specified maximum daily quantity of gas over the term of the shipper's contract, and is payable regardless of the actual volume of gas transported by the shipper. The delivery charge is payable only with respect to the actual volume of gas transported by the shipper. Interruptible transportation service shippers pay only a delivery charge with respect to the actual volume of gas transported by the shipper.

As of December 31, 2002, PG&E GTN had 93.1% of its available long-term capacity held among 48 shippers under long-term transportation contracts. The terms of these long-term firm contracts range between 1 and 40 years into the future, with a volume-weighted average remaining term of these agreements of approximately 11 years as of December 31, 2002. Approximately 95.9% of total transportation revenue was attributable to long-term contracts in 2002.

PG&E GTN also offers short-term firm and interruptible transportation services plus hub services, which allow customers the ability to park or borrow volumes of gas on its pipeline. If weather, maintenance schedules and other conditions allow, additional firm capacity may become available on a short-term basis. PG&E GTN provides interruptible transportation service when capacity is available. Interruptible capacity is provided first to shippers offering to pay the maximum rate and, if necessary, allocated on a pro-rata basis to shippers offering to pay the maximum rate. If capacity remains after maximum tariff nominations are fulfilled, PG&E GTN allocates discounted interruptible space on a highest to lowest total revenue basis.

In 2002, PG&E GTN provided transportation services to 70 customers. These services include capacity utilized via long-term firm, short-term firm, interruptible and hub services contracts. Short-term firm, interruptible and hub services accounted for approximately 4.1% of total transportation revenues in 2002. Approximately 92.8% of transported volumes were attributable to long-term contracts utilization in 2002. Short-term firm and interruptible volumes accounted for the remaining 4.8% and 2.4%, respectively.

The total quantities of natural gas transported on the PG&E GTN pipeline for the years ended December 31, 1998 through 2002 are set forth in the following table:

| Year | Quantities (MDth) |
|---|---|
| 1998 | 1,003,266 |
| 1999 | 925,118 |
| 2000 | 966,653 |
| 2001 | 963,126 |
| 2002 | 915,772 |

At December 31, 2002, 71.8% of North Baja's available long-term capacity was held under long-term firm transportation agreements. Contracts for the remaining long-term capacity on North Baja take effect in 2003, while long-term contracted capacities associated with some contracts increase between 2003 and 2006. At that time 100% of the available long-term capacity on North Baja will be dedicated to long-term contracts ranging between approximately 4 and 22 years into the future. As of December 31, 2002, the volume-weighted average remaining term of all long-term contracted capacities on North Baja was approximately 20 years.

As of December 31, 2002, NBP was providing transportation services for four customers, all of which had long-term firm service transportation agreements. In 2002, all volumes transported on North Baja were associated with long-term transportation service. The total quantity of natural gas transported on the North Baja pipeline (service commenced on the North Baja pipeline on September 1, 2002) through December 31, 2002, was 11,416 MDth.

Ratemaking

PG&E GTN's firm and interruptible transportation services have both maximum rates, which are based upon total costs (fixed and variable) and minimum rates, which are based upon the related variable costs. Rates for GTN were established in its 1994 rate case. Rates for North Baja were established in FERC's initial order certificating



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construction and operations of its system. The maximum and minimum rates for each service are set forth in tariffs on file with the commission. Both PG&E GTN and North Baja are allowed to vary or discount rates between the maximum and minimum on a non-discriminatory basis. Neither PG&E GTN nor North Baja have discounted long-term firm transportation service rates, but at times PG&E GTN discounts short-term firm and interruptible transportation service rates in order to maximize revenue. Both pipelines are also authorized to offer firm and interruptible service to shippers under individually negotiated rates. Such rates may be above the maximum rate or below the minimum rate, may vary from a straight-fixed-variable, or SFV, rate design methodology, and may be established with reference to a formula. Such negotiated rates may only be offered to the extent that, at the time the shipper enters into a negotiated rate agreement, that shipper had the option to receive the same service at the recourse rate, which is the maximum rate for that service under PG&E GTN's Tariff.

Both PG&E GTN's and NBP's recourse rates for firm service are designed on an SFV methodology. Under the SFV rate design, a pipeline company's fixed costs, including return on equity and related taxes, associated with firm transportation service are collected through the reservation charge component of the pipeline company's firm transportation service rates. Both pipelines also offer FERC-mandated capacity release mechanisms, under which firm shippers may release capacity to other shippers on a temporary or permanent basis. In the case of a capacity release that is not permanent, a releasing shipper remains responsible to the pipeline for the reservation charges associated with the released capacity. With respect to permanent releases of capacity, the releasing shipper is no longer responsible for the reservation charges associated with the released capacity if the replacement shipper meets the creditworthiness provisions of the pipeline's tariff and agrees to pay the full reservation fee.

Based on its 1994 rate case, PG&E GTN is permitted to recover approximately 97.0% of its fixed costs (as established in 1994) through reservation charges on long-term capacity. As of December 31, 2002, GTN had 93.1% of its available long-term capacity subscribed under long-term firm contracts.

Based on its initial FERC certificate, NBP is permitted to recover 98.1% of its fixed costs through reservation charges on long-term capacity. As of December 31, 2002, North Baja had 71.8% of its available long-term capacity subscribed under long-term contracts. Since these contracts are for fixed negotiated rates, North Baja will only recover a portion of its fixed costs in the initial years.



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ENVIRONMENTAL MATTERS

Environmental Matters

The following discussion includes certain forward-looking information relating to estimated expenditures for environmental protection measures and the possible future impact of environmental compliance. The information below reflects current estimates, which are periodically evaluated and revised. Future estimates and actual results may differ materially from those indicated below. These estimates are subject to a number of assumptions and uncertainties, including changing laws and regulations, the ultimate outcome of complex factual investigations, evolving technologies, selection of compliance alternatives, the nature and extent of required remediation, the extent of the facility owner's responsibility, and the availability of recoveries or contributions from third parties.

PG&E Corporation, the Utility, and various PG&E NEG affiliates (including USGen New England, Inc., or USGenNE), are subject to a number of federal, state, and local laws and regulations relating to the protection of the environment and human health and safety. These laws and requirements relate to a broad range of activities, including:

* the discharge of pollutants into air, water and soil;

* the identification, generation, storage, handling, transportation, disposal, record keeping, labeling, reporting of, and emergency response in connection with, hazardous, toxic and radioactive materials; and

* land use, including endangered species and habitat protection.

The penalties for violation of these laws and requirements can be severe, and may include significant fines, damages, and criminal or civil sanctions. They also may require, under certain circumstances, the interruption or curtailment of operations. To comply with all applicable laws and requirements, the Utility or PG&E NEG may need to spend substantial amounts from time to time to construct or acquire new equipment, acquire permits and/or marketable allowances or other emission credits for facility operations, modify or replace existing equipment and clean up or decommission waste disposal areas at their current or former facilities and at other third-party sites where they may have disposed of or recycled wastes. In the past the Utility generally has recovered the costs of complying with environmental laws and regulations in its rates. In 1994, the CPUC established a ratemaking mechanism for hazardous waste remediation costs under which the Utility is authorized to recover costs for environmental claims (e.g., for cleaning up facilities and sites to which the Utility has sent hazardous wastes) from ratepayers. That mechanism assigns 90% of the includable hazardous substance cleanup costs to Utility ratepayers and 10% to Utility shareholders without a review of the underlying costs. Expenditures to cover environmental costs in the future are likely to be significant; however, based on the Utility's past experience, PG&E Corporation and the Utility believe it will be able to recover most of these costs from ratepayers and its insurers. PG&E Corporation and the Utility cannot assure you, however, that these costs will not be material, or that the Utility will be able to recover its costs in the future.

Environmental Protection Measures

The estimated expenditures of PG&E Corporation's subsidiaries for environmental protection are subject to periodic review and revision to reflect changing technology and evolving regulatory requirements. It is likely that the stringency of environmental regulations will increase in the future.

Air Quality

The Utility's and PG&E NEG's generating plants are subject to numerous air pollution control laws, including the Federal Clean Air Act and similar state and local statutes. These laws and regulations cover, among other pollutants, those contributing to the formation of ground-level ozone, carbon monoxide, sulfur dioxide, or SO2, nitrogen oxide, or NOx, and particulate matter. Fossil fuel-fired electric utility plants are usually major sources of air pollutants and, therefore are subject to substantial regulation and enforcement oversight by the applicable governmental agencies.

Various multi-pollutant initiatives have been introduced in the U.S. Senate and House of Representatives, including Senate Bill 556 and House Resolutions 1256 and 1335. These initiatives include limits on the emissions of NOx, SO2, mercury, and carbon dioxide, or CO2. Certain of these proposals would allow the use of trading mechanisms to achieve or maintain compliance with the proposed rules.



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A multi-state memorandum of understanding dealing with the control of NOx air emissions from major emission sources was signed by the Ozone Transport Commission states in the Mid-Atlantic and Northeastern states. The memorandum of understanding and underlying state laws establish a regional three-phase plan for reducing NOx emissions from electric generating units and large industrial boilers within the Ozone Transport Region.

The NOx allowances available to each facility under the ozone season budget decreases as the program progresses and thus forces an overall reduction in NOx emissions. Under regulatory systems of this type, PG&E NEG may purchase NOx allowances from other sources in the area in addition to those that are allocated to PG&E NEG facilities, instead of installing NOx emission control systems. Depending on the market conditions, the purchase of extra allowances may minimize the total cost of compliance. During Phase 3, PG&E NEG will receive fewer allowances under a reduced NOx budget. PG&E NEG plans to meet the Phase 3 budget level for its Salem Harbor and Brayton Point generating facilities with a combination of allowance purchases and emission control technologies. PG&E NEG expects that the emission reductions to be required under regulations recently issued by the Commonwealth of Massachusetts, described below, significantly reduce its need for allowance purchases.

As a result of the Utility's divestiture of most of its fossil fuel-fired power plants and its geothermal generation facilities, the Utility's NOx emission reduction compliance costs have been reduced significantly. Pursuant to the California Clean Air Act and the Federal Clean Air Act, two of the local air districts in which the Utility owns and operates fossil fuel-fired generating plants have adopted final rules that require a reduction in NOx emissions from the power plants of approximately 90% by 2004 (with numerous interim compliance deadlines).

The Utility's Gas Accord authorized $42 million to be included in rates through 2002 for gas NOx retrofit projects related to natural gas compressor stations on the Utility's Line 300, which delivers gas from the Southwest. The Gas Accord II (the extension of the Gas Accord through 2003) provides for recovery of these costs in rates through 2003, and the Gas Accord II 2004 application requests recovery in rates through 2004. Other air districts are considering NOx rules that would apply to the Utility's other natural gas compressor stations in California. Eventually the rules are likely to require NOx reductions of up to 80% at many of these natural gas compressor stations.

Substantially all of these costs will be capital costs.

In addition, certain current regulatory initiatives, particularly at the federal level, could increase the Utility's and PG&E NEG's compliance costs and capital expenditures to comply with laws such as laws relating to emissions of carbon dioxide and other greenhouse gases, particulates, and various other pollutants. If enacted, these programs could require the Utility and PG&E NEG to install additional pollution controls, purchase emission allowances, or curtail operations. Although associated costs could be material, the Utility expects that it would be able to recover these costs from ratepayers. The Utility will be required to incur substantial capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining permits and approvals addressing air emission related issues.

The Federal Clean Air Act's acid rain provisions also require substantial reductions in SO2 emissions. Implementation of the acid rain provisions is achieved through a total cap on SO2 emissions from affected units and an allocation of marketable SO2 allowances to each affected unit. Operators of electric generating units that emit SO2 in excess of their allocations can buy additional allowances from other affected sources.

The EPA also has been conducting a nationwide enforcement investigation regarding the historical compliance of coal-fueled electric generating stations with various permitting requirements of the Federal Clean Air Act. Specifically, the EPA and the U.S. Department of Justice recently have initiated enforcement actions against a number of electric utilities, several of which have entered into substantial settlements for alleged Federal Clean Air Act violations related to modifications (sometimes more than 20 years ago) of existing coal-fired generating facilities. In May 2000, USGenNE received an Information Request from the EPA pursuant to Section 114 of the Federal Clean Air Act. The Information Request asked USGenNE to provide certain information relative to the compliance of USGenNE's Brayton Point and Salem Harbor Generating Stations with the Federal Clean Air Act. No enforcement action has been brought by the EPA to date. USGenNE has had very preliminary discussions with the EPA to explore a potential settlement of this matter. It is not possible to predict whether any such settlement will occur or, in the absence of a settlement, the likelihood of whether the EPA will bring an enforcement action.

In addition to the EPA, states may impose more stringent air emissions requirements. On May 11, 2001, the Massachusetts Department of Environmental Protection (DEP) issued regulations imposing new restrictions on emissions of NOx, SO2, mercury, and CO2 from existing coal- and oil-fired power plants. These restrictions will impose more stringent annual and monthly limits on NOx and SO2 emissions than currently exist and will take



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effect in stages, beginning in October 2004 if no permits are needed for the changes necessary to comply, and beginning in 2006 if such permits are needed. The regulations contemplate that affected parties will file compliance plans, based on which the DEP would decide whether these permits were required. In addition, mercury emissions are capped as a first step and must be reduced by October 2006 pursuant to standards to be developed. CO2 emissions are regulated for the first time and must be reduced from recent historical levels. USGenNE believes that compliance with the CO2 caps can be achieved through implementation of a number of strategies, including sequestrations and offsite reductions. Various testing and record keeping requirements also are imposed. The new Massachusetts regulations affect primarily USGenNE's Brayton Point and Salem Harbor generating facilities.

USGenNE filed its plan to comply with the new regulations with the DEP at the end of 2001. The DEP has ruled that Brayton Point is required to meet the newer, more stringent emission limitations for SO2 and NOX by 2006. It has also ruled that Salem Harbor is required to meet these limitations by 2004. Although USGenNE intends to appeal DEP's ruling that Salem Harbor must comply with the new reglations by 2004, in the absence of a successful appeal of DEP's ruling, the compliance date for Salem Harbor remains 2004. USGenNE will not be able to operate Salem Harbor unless it is in compliance with these emission limitations. USGenNE believes that it is impossible to meet the 2004 deadline. Consequently, it may be unable to operate the facility beyond the 2004 deadline. Through 2006, and assuming that USGenNE prevails in its appeal of the 2004 deadline, it may be necessary to spend approximately $266 million to comply with these regulations. It is possible that actual expenditures may be higher. USGenNE has not made any commitments to spend these amounts. In the event that USGenNE does not spend required amounts to meet each facility's compliance deadline, USGenNE may not be able to operate the facilities.

The EPA is required under the Federal Clean Air Act 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 Federal Clean Air Act required that they be promulgated by November 2000. Another provision in the Federal Clean Air Act 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. It is not possible to accurately quantify the economic impact of the future regulations until more details are available through the rulemaking process.

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 CO2 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 results 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.

Water Quality

The Federal Clean Water Act generally prohibits the discharge of any pollutants, including heat, into any body of surface water, except in compliance with a discharge permit issued by a state environmental regulatory agency and/or the EPA. All of PG&E NEG's facilities that are required to have such permits either have them or have timely applied for extensions of expired permits and are operating in substantial compliance with the prior permit. At this time, three of the fossil-fuel plants owned and operated by USGenNE (Manchester Street, Brayton Point, and Salem Harbor stations) are operating pursuant to permits that have expired. For the facilities whose water



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discharge permits (National Pollutant Discharge Elimination System, or NPDES permits) have expired, permit renewal applications are pending, and USGenNE anticipates that all three facilities will be able to continue to operate in substantial compliance with prior permits until new permits are issued. It is possible that the new permits may contain more stringent limitations than the prior permits.

At Brayton Point, unlike the Manchester Street and Salem Harbor generating facilities, PG&E NEG has agreed to meet certain restrictions that were not in the expired NPDES permit. In October 1996, the EPA announced its intention to seek changes in Brayton Point's NPDES permit based on a report prepared by the Rhode Island Department of Environmental Management, which alleged a connection between declining fish populations in Mt. Hope Bay and thermal discharges from the Brayton Point once-through cooling system. In April 1997, the former owner of Brayton Point entered into a Memorandum of Agreement, or MOA, with various governmental entities regarding the operation of the Brayton Point station cooling water systems pending issuance of a renewed NPDES permit. This MOA, which is binding on PG&E NEG, limits on a seasonal basis the total quantity of heated water that may be discharged to Mt. Hope Bay by the plant. While the MOA is expected to remain in effect until a new NPDES permit is issued, it does not in any way preclude the imposition of more stringent discharge limitations for thermal and other pollutants in a new NPDES permit and it is possible that such limitations will in fact be imposed. On July 22, 2002, the EPA and the DEP issued a draft NPDES permit for Brayton Point that, among other things, substantially limits the discharge of heat by Brayton Point into Mt. Hope Bay. USGenNE believes that the permit is excessively stringent and estimates that the cost to comply with it could be as much as $248 million through 2006. This is a preliminary estimate. There are various administrative and judicial proceedings that must be completed before the draft NPDES permit becomes final and these proceedings are not expected to be completed during 2003. In addition, the EPA, as well as local environmental groups, have previously expressed concern that the metal vanadium is not addressed at Brayton Point or Salem Harbor under the terms of the old NPDES permits and it may raise this issue in upcoming NPDES permit negotiations. Based upon the lack of an identified control technology, PG&E NEG believes it is unlikely that the EPA will require that vanadium be addressed pursuant to a NPDES permit. However, if the EPA does insist on including vanadium in the NPDES permit, PG&E NEG may have to spend a significant amount to comply with such a provision. If these more stringent discharge limitations are imposed, compliance with them could have a material adverse effect on PG&E NEG's financial condition, cash flows, and results of operations.

The Utility's existing power plants, including Diablo Canyon, also are subject to federal and state water quality standards with respect to discharge constituents and thermal effluents. The Utility's fossil fuel-fired power plants comply in all material respects with the discharge constituents standards and the thermal standards. Additionally, pursuant to Section 316(b) of the Federal Clean Water Act, the Utility is required to demonstrate that the location, design, construction, and capacity of power plant cooling water intake structures reflect the best technology available, or BTA, for minimizing adverse environmental impacts at its existing water-cooled thermal plants. The Utility has submitted detailed studies of each power plant's intake structure to various governmental agencies and each plant's existing intake structure was found to meet the BTA requirements.

The Diablo Canyon Power Plant employs a "once through" cooling water system that is regulated under a NPDES permit issued by the Central Coast Regional Water Quality Control Board, or the Central Coast Board. This permit allows Diablo Canyon to discharge the cooling water at a temperature no more than 22 degrees above ambient receiving water, and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, recreation, commercial/sport fishing, marine and wildlife habitat, shellfish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft cease and desist order alleging that, although the temperature limit has never been exceeded, Diablo Canyon's discharge was not protective of beneficial uses. In October 2000, the Central Coast Board and the Utility reached a tentative settlement of this matter pursuant to which the Central Coast Board has agreed to find that the Utility's discharge of cooling water from the Diablo Canyon plant protects beneficial uses and that the intake technology meets the BTA requirements. As part of the settlement, the Utility will take measures to preserve certain acreage north of the plant and will fund approximately $6 million in environmental projects related to coastal resources. The parties are negotiating the documentation of the settlement. The final agreement will be subject to public comment prior to final approval by the Central Coast Board and, once signed by the parties, will be incorporated in a consent decree to be entered in California Superior Court. A claim has been filed by the California Attorney General in the Utility's bankruptcy proceeding on behalf of the Central Coast Board seeking unspecified penalties and other relief in connection with Diablo Canyon's operation of its cooling water system.



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In December 1999, the Utility was notified by the purchaser of the Utility's former Moss Landing power plant that it had identified a cleaning procedure used at the plant that released heated water from the intake, and that this procedure is not specified in the plant's NPDES permit issued by the Central Coast Board. The purchaser notified the Central Coast Board of its findings. In March 2002, the Utility and the Central Coast Board reached a tentative settlement of this matter under which the Utility will fund approximately $5 million in environmental projects related to coastal resources. The final agreement will be subject to public comment and will be incorporated in a consent decree to be entered in the California Superior Court. The California Attorney General has filed a claim in the Utility's bankruptcy case to preserve the Board's claim.

Additionally, 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 (mgd), typically including some form of "once-through" cooling. The Utility's Diablo Canyon, Hunters Point, and Humboldt Bay power plants and PG&E NEG's Brayton Point, Salem Harbor, and Manchester Street generating facilities are among an estimated 539 plants nationwide that would be affected by this rulemaking. The proposed regulations call for a set of performance standards that vary with the type of water body and that are intended to reduce impacts to aquatic organisms. Significant capital investment may be required to achieve the standards if the regulations are adopted as proposed. The final regulations are scheduled to be issued in February 2004.

PG&E Corporation and the Utility believe the ultimate outcome of these matters will not have a material impact on their consolidated financial position or results of operations.

The issuance or modification of statutes, regulations, or water quality control plans at the federal, state, or regional level may impose increasingly stringent cooling water discharge requirements on the Utility's and PG&E NEG's power plants in the future. Costs to comply with new permit conditions required to meet more stringent requirements that might be imposed cannot be estimated at the present time.

Endangered Species

Many of the Utility's facilities and operations are located in or pass through areas that are designated as critical habitats for federal- or state-listed endangered, threatened, or sensitive species. The Utility may be required to incur additional costs or be subjected to additional restrictions on operations if additional threatened or endangered species are listed or additional critical habitats are designated near the Utility's facilities or operations.

Hazardous Waste Compliance and Remediation

The Utility's and PG&E NEG's facilities are subject to the requirements issued by the EPA under the Resource Conservation and Recovery Act, or RCRA, and the Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, along with other state hazardous waste laws and other environmental requirements. CERCLA and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, damages to natural resources, and the costs of required health studies. In the ordinary course of the Utility's operations, the Utility has generated, and continues to generate, waste that falls within CERCLA's definition of a hazardous substance and, as a result, has been and may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

The Utility and PG&E NEG assess, on an ongoing basis, measures that may need to be taken to comply with federal, state and local laws and regulations related to hazardous materials and hazardous waste compliance and remediation activities. The Utility and PG&E NEG have a comprehensive program to comply with hazardous waste storage, handling, and disposal requirements issued by the EPA under RCRA and CERCLA, along with other state hazardous waste laws and other environmental requirements.

The Utility has been, and may be, required to pay for environmental remediation at sites where the Utility has been, or may be, a potentially responsible party under CERCLA and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites, gas gathering sites, compressor stations and sites



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where the Utility stores and disposes of potentially hazardous materials. The Utility may be responsible for remediation of hazardous substances even if the Utility did not deposit those substances on the site.

Operations at the Utility's current and former power plants may have resulted in contaminated soil or groundwater. Although the Utility has sold most of its fossil fuel-fired and geothermal power plants in connection with electric industry restructuring, in many cases the Utility retained pre-closing environmental liability with respect to these plants under various environmental laws. The Utility currently is investigating or remediating several such sites with the oversight of various governmental agencies. In addition, the federal Toxic Substances Control Act regulates the use, disposal, and cleanup of polychlorinated biphenyls, or PCBs, which are used in certain electrical equipment. During the 1980s, the Utility initiated two major programs to remove from service all of the distribution capacitors and network transformers containing high concentrations of PCBs. These programs removed the vast majority of PCBs existing in the Utility's electric distribution system.

One part of the Utility's program is aimed at assessing whether and to what extent remedial action may be necessary to mitigate potential hazards posed by certain disposal sites and retired manufactured gas plant sites. During their operation in the late 1800s and early 1900s, manufactured gas plants produced lampblack and tar residues. The lampblack and tar residues are byproducts of a process that the Utility, its predecessor companies, and other utilities used as early as the 1850s to manufacture gas from coal and oil. As natural gas became widely available (beginning about 1930), the Utility's manufactured gas plants were removed from service. The residues that may remain at some sites contain chemical compounds that now are classified as hazardous. The Utility owns all or a portion of 28 manufactured gas plant sites. The Utility has a program, in cooperation with environmental agencies, to evaluate and take appropriate action to mitigate any potential health or environmental hazards at sites that are owned by the Utility. The Utility spent approximately $4 million in 2002 and expects to spend approximately $11 million in 2003 on such projects. The Utility expects that expenses will increase as remedial actions related to these sites are approved by regulatory agencies. In addition, approximately 68 other manufactured gas plants in the Utility's service territory are now owned by numerous third parties, and it is possible that the Utility may incur cleanup costs related to these sites in the future.

Under environmental laws such as CERCLA, the Utility has been or may be required to take remedial action at third-party sites used for the disposal of wastes from the Utility's facilities, or to pay for associated cleanup costs or natural resource damages. The Utility is currently aware of 8 such sites where investigation or cleanup activities are currently underway. For example, at the Geothermal Incorporated site in Lake County, California, the Utility has been directed to perform site studies and any necessary remedial measures by regulatory agencies. At the Casmalia disposal facility near Santa Maria, California, the Utility and several other generators of waste sent to the site have entered into a court-approved agreement with the EPA that requires the Utility and the other parties to perform certain site investigation and mitigation measures.

In addition, the Utility has been named as a defendant in several civil lawsuits in which plaintiffs allege that the Utility is responsible for performing or paying for remedial action at sites that the Utility no longer owns or never owned.

The cost of hazardous substance remediation ultimately undertaken by the Utility is difficult to estimate. It is reasonably possible that 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 records an environmental remediation liability when site assessments indicate remediation is probable and the Utility can estimate a range of reasonably likely cleanup costs. The Utility reviews its remediation liability quarterly for each identified site. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring, and site closure using current technology, enacted laws and regulations, experience gained at similar sites, and 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 costs at the lower end of this range. At December 31, 2002, the Utility expected to spend $331 million, undiscounted for the effect of future inflation, for hazardous waste remediation costs at identified sites, including divested fossil fuel-fired power plants, where such costs are probable and quantifiable. (Although the Utility has sold most of its fossil fuel-fired power plants, the Utility has retained pre-closing environmental liability with respect to these plants.) If other potentially responsible parties are not financially able to contribute to these costs or further investigation indicates that the extent of contamination or necessary remediation is greater than anticipated, the Utility's future cost could be as much as $469 million. The Utility estimated the upper limit of the range of costs using assumptions least favorable to the Utility based upon a range of reasonably possible



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outcomes. Costs may be higher if the Utility is found to be responsible for cleanup costs at additional sites or if identifiable possible outcomes change.

On June 26, 2001, the Bankruptcy Court authorized the Utility to spend

* up to $22 million in each calendar year in which the Chapter 11 case is pending to continue its hazardous substance remediation programs and procedures, and

* any additional amounts necessary in emergency situations involving post-petition releases or threatened releases of hazardous substances, if such excess expenditures are necessary in the Utility's reasonable business judgment to prevent imminent harm to public health and safety or the environment (provided that the Utility seeks the Bankruptcy Court's approval of such emergency expenditures at the earliest practicable time).

The California Attorney General, on behalf of various state environmental agencies, filed claims in the Utility's bankruptcy case for environmental remediation at numerous sites totaling approximately $770 million. For most if not all these sites, the Utility is in the process of remediating the sites in cooperation with the relevant agencies and others responsible for contributing to the cleanup or would be doing so in the future, in the normal course of business. The Utility's proposed plan of reorganization provides that either the Utility or the LLCs will satisfy 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.

USGenNE assumed the onsite environmental liability associated with its acquisition of electric generating facilities from New England Electric System in 1998, but did not acquire any off-site liability associated with the past disposal practices at the acquired facilities. PG&E NEG has obtained pollution liability and environmental remediation insurance coverage to limit, to a certain extent, the financial risk associated with the on-site pollution liability at all of its facilities. Recently, the EPA indicated that it might begin to regulate fossil fuel combustion materials, including types of coal ash, as hazardous waste under RCRA. If the EPA implements its initial proposals on this issue, USGenNE may be required to change its current waste management practices and expend significant resources on the increased waste management requirements caused by the EPA's change in policy.

During April 2000, an environmental group served various affiliates of PG&E NEG, including USGenNE, with a notice of intent to file a citizen's suit under RCRA. In September 2000, PG&E NEG signed a series of agreements with the Massachusetts Department of Environmental Protection and the environmental group to resolve these matters that require USGenNE to alter its existing wastewater treatment facilities at its Brayton Point and Salem Harbor generating facilities. USGenNE began the activities during 2000 and expects to complete them in 2003. USGenNE has incurred expenditures related to these agreements of approximately $4.7 million in 2002, $2.6 million in 2001 and $5.4 million in 2000. In addition to the costs incurred in 2000, 2001 and 2002, at December 31, 2002, USGenNE 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.

Potential Recovery of Hazardous Waste Compliance and Remediation Costs

To the extent the Utility knows or can estimate the costs of hazardous waste compliance and remediation costs, the Utility intends to seek recovery for these costs in its filed rates through the normal ratemaking proceedings before the CPUC.

In 1994, the CPUC established a ratemaking mechanism for hazardous waste remediation costs, or HWRC. That mechanism assigns 90% of the includable hazardous substance cleanup costs to utility ratepayers and 10% to utility shareholders, without a reasonableness review of such costs or of underlying activities. Under the HWRC mechanism, 70% of the ratepayer portion of the Utility's cleanup costs is attributed to its gas department and 30% is attributed to its electric department. Insurance recoveries are assigned 70% to shareholders and 30% to ratepayers until both are reimbursed for the costs of pursuing insurance recoveries. The balance of insurance recoveries is allocated 90% to shareholders and 10% to ratepayers until shareholders are reimbursed for their 10% share of cleanup costs. Any unallocated funds remaining are held for five years and then distributed 60% to ratepayers and 40% to shareholders over the next five years. The Utility can seek to recover hazardous substance cleanup costs under the HWRC in the rate proceeding that it deems most appropriate. In connection with electric industry restructuring, the HWRC mechanism may no longer be used to recover electric generation-related cleanup costs for contamination caused by events occurring after January 1, 1998.



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For each divested generation facility for which the Utility retained environmental remediation liabilities, the plant's decommissioning cost estimate was adjusted by the Utility's estimated forecast of environmental remediation costs. (The buyers assumed the non-environmental decommissioning liability for these plants.) The CPUC ordered that excess recoveries of environmental and non-environmental decommissioning accruals related to the divested plants be used to offset other transition costs. As of December 31, 2002, the Utility had recovered from ratepayers approximately $138 million for environmental decommissioning accrual related to the divested plants. This amount will earn interest at 3% per year that will be used to meet the future environmental remediation costs for the divested plants. The net decommissioning accruals recovered from ratepayers attributable to the non-environmental liability for the divested plants was approximately $50 million. Because the Utility no longer has this non-environmental decommissioning liability, it has used this excess recovery amount to reduce other transition costs.

The $331 million accrued environmental remediation liability at December 31, 2002, mentioned above, includes

* $138 million related to the pre-closing remediation liability, discounted to present value at 7%, associated with divested generation facilities (see further discussion in the "Generation Divestiture" section of Note 2 of the Notes to the Consolidated Financial Statements of the 2002 Annual Report to Shareholders), and

* $193 million related to remediation costs for those generation facilities, manufactured gas plant sites, gas gathering sites, and compressor stations that the Utility still owns.

Of the $331 million environmental remediation liability, the Utility has recovered $188 million through rates, and expects to recover another $84 million in future rates. The Utility is seeking recovery of the remainder of its costs from insurance carriers and from other third parties as appropriate.

The ultimate amount of recovery from insurance coverage, either in the aggregate or with respect to a particular site, cannot be quantified at this time. Insurance recoveries are subject to the HWRC mechanism discussed above.

Nuclear Fuel Disposal

Under the Nuclear Waste Policy Act of 1982, or Nuclear Waste Act, the U.S. Department of Energy, or the DOE, is responsible for the transportation and ultimate long-term disposal of spent nuclear fuel and high-level radioactive waste. Under the Nuclear Waste Act, utilities are required to provide interim storage facilities until permanent storage facilities are provided by the federal government. The Nuclear Waste Act mandates that one or more such permanent disposal sites be in operation by 1998. Consistent with the law, the Utility signed a contract with the DOE providing for the disposal of the spent nuclear fuel and high-level radioactive waste from the Utility's nuclear power facilities beginning not later than January 1998. However, due to delays in identifying a storage site, the DOE has been unable to meet its contract commitment to begin accepting spent fuel by January 1998. Further, under the DOE's current estimated acceptance schedule for spent fuel, Diablo Canyon's spent fuel may not be accepted by the DOE for interim or permanent storage before 2010, at the earliest. At the projected level of operation for Diablo Canyon, the Utility's facilities are sufficient to store on-site all spent fuel produced through approximately 2007 while maintaining the capability for a full-core off-load. It is likely that an interim or permanent DOE storage facility will not be available for Diablo Canyon's spent fuel by 2007. In December 2001, the Utility filed a request with the NRC for a license to build a dry cask storage system to store spent fuel at Diablo Canyon, pending disposal or storage at a DOE facility. A hearing in this proceeding is scheduled for May 2003.

In February 2002, the DOE formally recommended, and President Bush approved, Yucca Mountain, Nevada as the site for a permanent spent fuel repository. The State of Nevada vetoed this site but the U.S. Congress overrode this veto with a House of Representatives vote in May 2002 and a Senate vote in July 2002, and the bill was subsequently signed by President Bush. As a result, the State of Nevada has filed a number of suits in various federal courts to stop the NRC's licensing of the site. If Yucca Mountain is ultimately determined to be acceptable as the repository site, the DOE will proceed with the licensing and eventual construction of the repository and may begin receipt of spent fuel as early as 2010. However, considerable uncertainty exists regarding the time frame under which the DOE will begin to accept spent fuel for storage or disposal. If Yucca Mountain is completed by 2010, the earliest Diablo Canyon's spent fuel would be accepted by Yucca Mountain for storage or disposal would be 2018.



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In July 1988, the NRC gave final approval to the Utility to store radioactive waste from the retired nuclear generating unit Humboldt Unit 3 at the plant until 2015 before ultimately decommissioning the unit. The Utility has agreed to remove all spent fuel when the federal disposal site is available. In 1988, the Utility completed the first step in the decommissioning of Humboldt Bay Unit 3 and placed the unit into a custodial mode of decommissioning called SAFSTOR. This is a condition of monitored safe storage in which the unit will be maintained until the spent nuclear fuel is removed from the spent fuel pool and the facility is dismantled. The used fuel assemblies currently are stored in metal racks submerged in a pool of water, i.e., a wet storage pool. The specially designed storage pool is constructed of steel-reinforced concrete and lined with stainless steel. The Utility currently is exploring licensing and permitting of an on-site dry cask storage facility. Transfer of spent fuel to a dry cask facility would allow early decommissioning of Humboldt Bay Unit 3. The Utility anticipates that if it were licensed to employ an on-site dry cask storage facility, it would receive a 20-year initial license with the opportunity to receive a 20-year renewal term.

Nuclear Decommissioning

The Utility's nuclear power facilities are scheduled to begin, for ratemaking purposes, decommissioning 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, based on a February 2002 site study, is $1.9 billion in 2002 dollars (or $8.4 billion in future dollars). The Utility's future estimate is based upon its 2001 estimated obligation assuming an annual escalation rate of 5.5% for decommissioning costs. This estimate includes labor, materials, waste disposal charges, and other costs. A contingency of 40% to capture engineering, regulatory, and business environment changes is included in the total estimated obligation. The Utility plans to fund these costs from independent decommissioning trusts, which receive annual contributions discussed further below. The Utility estimates after-tax annual earnings, including realized gains and losses, on the tax-qualified decommissioning funds of 6.34% and on non-tax-qualified decommissioning funds of 5.39%. 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.

Since January 1, 1998, nuclear decommissioning costs, which are not transition costs, have been recovered from customers through a non-bypassable charge that will continue until those costs are fully recovered. Recovery of decommissioning costs may be accelerated to the extent possible under the rate freeze. For the year ended December 31, 2002, annual nuclear decommissioning trust contributions collected in rates were $24 million and this amount was contributed to the trusts.

The CPUC has established a Nuclear Decommissioning Costs Triennial Proceeding to determine the decommissioning costs and to establish the annual revenue requirement and attrition factors over subsequent three-year periods. On March 15, 2002, the Utility filed its 2002 Nuclear Decommissioning Cost Triennial Proceeding application seeking to increase its nuclear decommissioning revenue requirements for the years 2003 through 2005 and to begin decommissioning of Humboldt Bay Unit 3 in 2006, instead of 2015. The Utility estimates a total decommissioning cost of approximately $299 million, stated in 2002 dollars, for Humboldt Bay Unit 3 presuming that the CPUC approves this earlier decommissioning schedule. The Utility 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 Utility also seeks recovery of $7.3 million in CPUC-jurisdictional revenue requirements for Humboldt Bay Unit 3 SAFSTOR 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 non-bypassable charge in electric rates, and to record the revenue requirement and the associated revenues in a balancing account. The CPUC held hearings on the application in September 2002 and is scheduled to issue a final decision in April 2003.

Decommissioning costs recovered in rates are placed in external trust funds. These funds, along with accumulated earnings, will be used exclusively for decommissioning and dismantling nuclear facilities. The trusts maintain substantially all of their investments in debt and equity securities. All earnings on the funds held in the trusts, net of authorized disbursements from the trusts and management and administrative fees, are reinvested. Monies may not be released from the external trusts until authorized by the CPUC. At December 31, 2002, the Utility had accumulated external trust funds with an estimated liquidation value of $1.3 billion, based on quoted market prices and net of deferred taxes on unrealized gains, to be used for the decommissioning of the Utility's nuclear facilities.



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Compressor Station Litigation

Several lawsuits have been filed against Pacific Gas and Electric Company seeking damages from alleged chromium contamination at the Utility's Hinkley, Topock, and Kettleman Compressor Stations. See Item 3 "Legal Proceedings--Compressor Station Chromium Litigation" below for a description of the pending litigation.

Electric and Magnetic Fields

Electric and magnetic fields, or EMFs, naturally result from the generation, transmission, distribution and use of electricity. In January 1991, the CPUC opened an investigation into potential interim policy actions to address increasing public concern, especially with respect to schools, regarding potential health risks that may be associated with EMFs from utility facilities. In its order instituting the investigation, the CPUC acknowledged that the scientific community has not reached consensus on the nature of any health impacts from contact with EMFs, but went on to state that a body of evidence has been compiled that raises the question of whether adverse health impacts might exist.

In November 1993, the CPUC adopted an interim EMF policy for California energy utilities that, among other things, requires California energy utilities to take no-cost and low-cost steps to reduce EMFs from new and upgraded utility facilities. California energy utilities were required to fund an EMF education program and an EMF research program managed by the California Department of Health Services. As part of its effort to educate the public about EMFs, the Utility provides interested customers with information regarding the EMF exposure issue. The Utility also provides a free field measurement service to inform customers about EMF levels at different locations in and around their residences or commercial buildings.

In October 2002, the California Department of Health Services released its report, based primarily on its review of studies by others, evaluating the possible risks from electric and magnetic fields to the CPUC and the public. The report's conclusions contrast with other recent reports by authoritative health agencies in that the California Department of Health Services' report has assigned a higher probability to the possibility that there is a causal connection between EMF exposures and a number of diseases and conditions, including childhood leukemia, adult leukemia, amyotrophic lateral sclerosis, and miscarriages.

It is not yet clear what actions the CPUC will take to respond to this report. Possible outcomes include, but are not limited to, continuation of current policies and imposition of more stringent measures to mitigate EMF exposures. The Utility cannot estimate the costs of such mitigation measures with any certainty at this time. However, such costs could be significant, depending on the particular mitigation measures undertaken, especially if relocation of existing power lines ultimately is required.

The Utility currently is not involved in third-party litigation concerning EMFs. In August 1996, the California Supreme Court held that homeowners are barred from suing utilities for alleged property value losses caused by fear of EMFs from power lines. The Court expressly limited its holding to property value issues, leaving open the question as to whether lawsuits for alleged personal injury resulting from exposure to EMFs are similarly barred. The Utility was a defendant in civil litigation in which plaintiffs alleged personal injuries resulting from exposure to EMFs. In January 1998, the appeals court in this matter held that the CPUC has exclusive jurisdiction over personal injury and wrongful death claims arising from allegations of harmful exposure to EMFs and barred plaintiffs' personal injury claims. Plaintiffs filed an appeal of this decision with the California Supreme Court. The California Supreme Court declined to hear the case.

Low Emission Vehicle Programs

In December 1995, the CPUC issued its decision in the Low Emission Vehicle (LEV) proceeding, which approved approximately $42 million in funding for the Utility's LEV program for the six-year period beginning in 1996. The LEV program expired on December 20, 2001. On January 23, 2002, the CPUC approved bridge funding of $7 million for the LEV program. On March 25, 2002, the Utility requested that the CPUC approve funding for the continuation of its LEV program. The other California utilities filed similar requests. In June 2002, the CPUC determined that issues related to research, development and demonstration, and customer education would be heard in the LEV proceeding, but that issues related to fleet vehicle acquisition, fueling and charging infrastructure, and operation and maintenance of Utility infrastructure would be addressed in the Utility's 2003 General Rate Case. Hearings in the LEV proceeding were held in August 2002. The 2003 General Rate Case was filed in November 2002. The Utility has requested funding of $5 million in the LEV proceeding and approximately $7.4 million for LEV-related costs in the 2003 General Rate Case. On December 19, 2002, LEV interim funding of



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$7 million was extended pending the CPUC's final decisions in both the LEV proceedings and the General Rate Case. A final decision in the LEV proceeding is expected by the end of March 2003.

ITEM 2. Properties.

Information concerning Pacific Gas and Electric Company's electric generation units, electric and gas transmission facilities, and electric and gas distribution facilities is included in response to Item 1 "Business." All of the Utility's real properties and substantially all of the Utility's personal properties are subject to the lien of an indenture that provides security to the holders of the Utility's First and Refunding Mortgage Bonds.

The Utility's corporate headquarters consist of approximately 1.7 million square feet of owned office space located in several buildings in San Francisco, California. In addition to owned office space, the Utility leases approximately 628,000 square feet of office space from third parties in San Francisco. In addition to this corporate office space, the Utility owns or has obtained the right to occupy and/or use real property comprising its electric and natural gas distribution facilities, natural gas gathering facilities, and generation facilities, all which are described above under "Electric Utility Operations" and "Gas Utility Operations." The Utility occupies or uses real property that it does not own chiefly through various leases, easements, rights-of-way, permits, or licenses from private landowners or governmental authorities. The Utility also owns or leases approximately 184 other facilities, including service centers, customer service offices, material distribution centers, training/conference centers, and office space, totaling 5.9 million square feet in the aggregate.

Information concerning properties and facilities owned by PG&E NEG and other PG&E Corporation subsidiaries is included in the discussion under the heading of this report entitled "PG&E National Energy Group, Inc."

ITEM 3. Legal Proceedings.

See Item 1 "Business" for other proceedings pending before governmental and administrative bodies. In addition to the following legal proceedings, PG&E Corporation and Pacific Gas and Electric Company are subject to routine litigation incidental to their business.

Pacific Gas and Electric Company Bankruptcy

On April 6, 2001, Pacific Gas and Electric Company filed a voluntary petition for relief under the provisions of Chapter 11 of the U.S. Bankruptcy

Code, or Bankruptcy Code, in the U.S. Bankruptcy Court for the Northern District of California, or Bankruptcy Court. Pursuant to Chapter 11 of the U.S. Bankruptcy Code, the Utility retains control of its assets and is authorized to operate its business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court. For more information about the Utility's financial condition and the factors leading up to the filing for bankruptcy protection, see "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 2 of the 2002 Annual Report to Shareholders, which portions are incorporated herein by reference and filed as Exhibit 13 to this report.

Bankruptcy law imposes an automatic stay to prevent parties from making certain claims or taking certain actions that would interfere with the estate or property of a Chapter 11 debtor. In general, the Utility may not pay pre-petition debts without the Bankruptcy Court's permission. Under the Bankruptcy Code, the Utility has the right to reject or assume executory contracts (contracts that require material future performance). Since the filing, the Bankruptcy Court has approved various requests by the Utility to permit the Utility to carry on its normal business operations (including payment of employee wages and benefits, refunds of certain customer deposits, use of certain bank accounts and cash collateral, the assumption of various hydroelectric contracts with water agencies and irrigation districts, and the continuation of environmental remediation and capital expenditure programs) and to fulfill certain post-petition obligations to suppliers and creditors.

On April 9, 2001, the Utility filed a complaint in the Bankruptcy Court against the CPUC and its Commissioners requesting that the court declare that any attempt by the CPUC to implement or enforce the regulatory accounting changes approved by the CPUC on March 27, 2001 would violate the automatic stay imposed by bankruptcy law, and asking the Court to enjoin implementation or enforcement of such accounting changes. On June 1, 2001, the Bankruptcy Court issued a decision denying the Utility's request for an injunction and granted the CPUC's motion to dismiss the complaint. Although the Court held that the Eleventh Amendment to the U.S. Constitution did not bar the Utility's suit against the individual Commissioners, the Court concluded that the Utility was not entitled to a stay or an injunction to prevent implementation and enforcement of the regulatory



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accounting order. First, the Court held that, assuming the Bankruptcy Code provision imposing an automatic stay on pre-petition proceedings might ordinarily apply (an issue that the Court expressly declined to decide), the Court determined that the Commissioners were acting pursuant to their police and regulatory power when issuing the order. Accordingly, the Court found that the CPUC's March 27, 2001 order was exempt from the automatic stay provision pursuant to a statutory exemption for the commencement or continuation of an action or proceeding by a governmental unit to enforce such governmental unit's police and regulatory power. Second, the Court held that the Utility had not shown any actual or threatened violation of federal law sufficient to warrant injunctive relief, nor did the balance of equities favor an injunction. The Utility has appealed the Bankruptcy Court's decision to the U.S. District Court for the Northern District of California, and the CPUC and its Commissioners cross-appealed. The appeals have been deemed related to, and therefore have been assigned to the same district court judge as, the appeals discussed below in the Utility's complaint filed against the CPUC Commissioners.

The Utility and PG&E Corporation have jointly proposed a proposed plan of reorganization, the Utility Plan, that proposes to restructure the Utility's current businesses and to refinance the restructured businesses so that all allowed creditor claims would be paid in full with interest. For a description of the Utility Plan, see Item 1 "Business" above and Note 2 of the Notes to Consolidated Financial Statements appearing in the 2002 Annual Report to Shareholders.

On November 30, 2001, the Utility and PG&E Corporation on behalf of its subsidiaries ETrans, GTrans, and Gen, filed various applications with the FERC seeking approval to implement the transactions proposed under the Utility's Plan. For additional information about the proposed Plan and the regulatory approvals required to implement the Plan, see Note 2 of the Notes to Consolidated Financial Statements appearing in the 2002 Annual Report to Shareholders.

On January 25, 2002, the Bankruptcy Court held a hearing to consider arguments as to whether the Bankruptcy Court has the power to preempt various California state and local laws as requested in the Utility Plan, and whether such preemption would violate the sovereign immunity of the State of California and its agencies, including the CPUC. On February 7, 2002, the Bankruptcy Court issued an order concluding that bankruptcy law does not permit express preemption, but it could permit implied preemption under certain circumstances. It also concluded that the Utility Plan as drafted violated sovereign immunity because it seeks affirmative relief against the State and the CPUC, but that if the Utility Plan and disclosure statement were amended, then the Utility Plan would overcome the sovereign immunity defense. Otherwise, the Utility and PG&E Corporation would have to prove that there had been a waiver of sovereign immunity. The Bankruptcy Court rejected PG&E Corporation's and the Utility's argument that Section 1123(a)(5) of the Bankruptcy Code expressly authorized the Bankruptcy Court to preempt any state law to confirm and effectuate a plan of reorganization. Instead, the Bankruptcy Court interpreted Section 1123(a)(5) to permit preemption of a state law where it had been shown that enforcing the state law at issue would be an obstacle to the accomplishment and execution of the full purposes of the bankruptcy laws. The Bankruptcy Court stated that whether a restructuring (i.e., the disaggregation of the Utility's businesses as proposed in the Utility Plan) is necessary for a feasible reorganization is an issue to be determined at the confirmation hearing.

In its February 7, 2002, the Bankruptcy Court held that "the Plan could be confirmed if Proponents are able to establish with particularity the requisite elements of implied preemption." The Bankruptcy Court stated that PG&E Corporation and the Utility must show facts that would lead the Bankruptcy Court to find that the "application of those laws to the facts of [the Debtor's] proposed reorganization are economic in nature rather than directed at protecting public safety or other non-economic concerns, and that those particular laws stand as an obstacle to the accomplishment and execution of the purposes and objectives of Congress and the Bankruptcy Code."

On March 18, 2002, the Bankruptcy Court entered an order and judgment disapproving the Utility's First Amended Disclosure Statement relating to the Utility Plan for the reasons set forth in its February 7, 2002 decision based upon the court's rejection of PG&E Corporation's and the Utility's express preemption theory. The Bankruptcy Court found that there was no just reason to delay appellate review of the court's ruling on express preemption, and directed the clerk to enter its order as a final judgment. The court stated that its order was not intended to address or finally adjudicate any issues or disputes other than express preemption, including but not limited to the implied preemption and sovereign immunity aspects of its February 7, 2002 decision, and reserved such issues for final rulings in connection with the plan confirmation process.

On March 22, 2002, PG&E Corporation and the Utility filed a notice of appeal from the Bankruptcy Court's March 18, 2002 order. PG&E Corporation and the Utility elected to have the appeal heard by the United States District Court for the Northern District of California, or the District Court. In addition, the CPUC, the City and



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County of San Francisco, and the California Attorney General, on behalf of a number of State entities, filed cross-appeals. Generally stated, the two issues that these parties identified for cross-appeal are: (1) whether the Bankruptcy Court erred in entering a final judgment concerning its ruling on express preemption, and (2) whether it was an abuse of discretion for the Bankruptcy Court to determine that there was no just reason to delay the entry of judgment on its express preemption ruling. On June 24, 2002, in ruling on a motion to dismiss the Utility's and PG&E Corporation's appeal, the District Court issued an order rejecting these contentions.

On August 30, 2002, the District Court issued an order reversing the Bankruptcy Court's March 18, 2002 order and remanding the case back to the Bankruptcy Court for further proceedings. The District Court ruled 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 CPUC, the California Attorney General, the City and County of San Francisco, and the California Hydropower Reform Coalition filed an appeal with the U.S. Court of Appeals for the Ninth Circuit, or the Ninth Circuit, and also filed a request with the District Court to stay its August 30, 2002 decision pending their appeal to the Ninth Circuit. On November 14, 2002, the District Court issued an order denying the request for a stay and certifiying its August 30, 2002 decision for discretionary review by the Ninth Circuit. The CPUC and the other appellants proceeded with an appeal to the Ninth Circuit, and briefing in the appeal is now closed. All appellants except the CPUC requested the Ninth Circuit to stay the District Court's August 30, 2002 decision pending the Ninth Circuit appeal. PG&E Corporation and the Utility filed their opposition to the motion for a stay on December 9, 2002. On January 17, 2003, the Ninth Circuit denied the motion for a stay pending appeal. On October 30, 2002, the Utility and PG&E Corporation filed a motion asking the Ninth Circuit to expedite the appeal, which was granted in part on November 18, 2002, along with a statement that the appeal would be calendared as soon as is practicable.

In addition, the United States Department of Justice has filed an amicus brief with the Ninth Circuit in which it supports the CPUC's construction of Bankruptcy Code Section 1123 but argues in favor of a remand to the District Court on the issue of implied preemption. Two additional sets of amici have filed briefs or have sought leave to file briefs in support of the CPUC's position in the appeal: (1) the National Association of Regulatory Commissioners, joining with a number of states (who do not require leave to file as amici); and (2) a number of California counties. On or about January 6, 2003, a number of public utility commissions from other states, as well as the State of Utah, filed a motion asking the Ninth Circuit for leave to join the amicus brief in support of the CPUC's position in the appeal. The Ninth Circuit has not yet set the appeal for oral argument.

Pursuant to the Bankruptcy Court's February 7, 2002 decision, the Utility Plan was amended to (1) eliminate express preemption provisions and (2) state with specificity the facts demonstrating that the State and the CPUC have waived their sovereign immunity, and, if the Bankruptcy Court finds that such immunity has been waived, to provide for declaratory and injunctive relief against the State and the CPUC.

After the Bankruptcy Court terminated the period during which only the Utility has the right to submit a proposed plan of reorganization, the CPUC filed a proposed alternative plan of reorganization with the Bankruptcy Court on April 15, 2002. After the Bankruptcy Court approved the disclosure statements relating to the Utility Plan and the CPUC's alternative plan, the disclosure statements relating to the competing plans were sent to creditors and equity holders entitled to vote on the plans in June 2002. Balloting was completed on August 12, 2002.

On June 7, 2002, PG&E Corporation and the Utility filed a motion with the Bankruptcy Court to extend, until December 31, 2002, the period during which no third parties, other than the CPUC, could submit an alternative proposed plan of reorganization. On June 24, 2002, the Official Committee of Unsecured Creditors, or the OCC, filed a response in the Bankruptcy Court requesting that the exclusivity period be modified to enable the OCC to submit an alternative plan. On July 9, 2002, the Bankruptcy Court issued an order granting the OCC's request and extending the exclusivity period until December 31, 2002, except as to the CPUC (which the court previously excepted) and the OCC.

In addition to other parties, the City of Palo Alto and the Northern California Power Agency, or NCPA, filed an objection to both proposed plans of reorganization. The objection asserts that, by virtue of the Utility's termination of a wholesale electric transmission contract between NCPA and the Utility, NCPA members, including Palo Alto, will now be subject to substantial charges from the California ISO. Palo Alto and NCPA assert that these charges, which are related primarily to congestion on the transmission system and a related ISO charge to entities that want to ensure delivery of power even in times when congestion is present, will increase dramatically if a proposed electric market redesign proposal is adopted for California. Palo Alto and NCPA further assert that the Utility's motivation for terminating the NCPA transmission contract was anticompetitive and violated the federal antitrust laws. They claim that damages associated with these increased ISO congestion charges could exceed $1 billion. In



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January 2003, the Bankruptcy Court held an estimation hearing to determine what value to put on a possible future damages award that NCPA and Palo Alto might receive, should they file, pursue, and establish liability on their antitrust claim.

On July 29, 2002, shortly before the voting period ended, the CPUC filed an application with the Bankruptcy Court alleging that the Utility, PG&E Corporation, and their third-party solicitor improperly solicited votes and seeking a temporary restraining order to prohibit the continuing solicitation of votes, an order to require the distribution of corrective materials, an order extending the deadline for creditors to vote on the competing plans of reorganization, and an order allowing creditors to recast their ballots. The Bankruptcy Court denied the application for such relief on August 5, 2002. The CPUC's underlying complaint, which also was filed with the Bankruptcy Court on July 29, 2002, against the Utility, PG&E Corporation, and their third-party solicitor, alleges that the defendants improperly solicited votes by allegedly making false and misleading statements to creditors and equity holders. On February 11, 2003, the Utility received notice that the CPUC had dismissed the complaint voluntarily. The dismissal is without prejudice, meaning that the CPUC could refile the complaint. On August 22, 2002, 10 days after the voting period ended, the CPUC and the OCC announced that the OCC had joined the CPUC to support a modified alternative plan. The CPUC and the OCC jointly filed an amended plan of reorganization on August 30, 2002, the CPUC/OCC Plan, and requested the Bankruptcy Court's permission to resolicit votes and preferences for the CPUC/OCC Plan.

On September 9, 2002, an independent voting agent stated that nine of the ten voting classes under the Utility Plan approved the Utility Plan. The original plan sponsored by the CPUC was rejected by all but one of the eight voting creditor classes. In order to proceed to the confirmation trial, each plan of reorganization needed to obtain the acceptance of at least one class of creditors holding impaired claims.

On September 20, 2002, the Bankruptcy Court denied the CPUC's and the OCC's request to reopen the voting. The Bankruptcy Court declined to rule on the CPUC's and the OCC's additional request for an order authorizing the resolicitation of creditor preferences. On November 6, 2002, the CPUC and the OCC filed a Second Amended CPUC/OCC Plan and also filed a motion asking the Bankruptcy Court to authorize the resolicitation of creditor preferences. The Bankruptcy Court heard oral arguments on the motion on November 27, 2002. On February 6, 2003, the Bankruptcy Court issued an order denying the CPUC's and the OCC's request.

The trial on confirmation of the CPUC/OCC Plan began on November 18, 2002 and the trial on confirmation of the Utility Plan began as scheduled on December 16, 2002. On January 24, 2003, the Bankruptcy Court issued an order modifying the original confirmation trial schedule and extending the hearing dates for the Utility Plan to the end of March 2003.

On December 20, 2002, the Utility filed a motion with the Bankruptcy Court requesting the Court to further extend the period during which only the Utility (with the exception of the CPUC and the OCC) can file a proposed plan of reorganization for the Utility from December 31, 2002 to April 30, 2003. On February 6, 2003, the Bankruptcy Court granted the Utility an indefinite extension of the exclusivity period.

With respect to the application filed with the Nuclear Regulatory Commission (NRC) for permission to transfer the NRC operating licenses held by the Utility for its Diablo Canyon nuclear power plant to Gen (which will become a subsidiary of PG&E Corporation after consummation of the Utility Plan) as contemplated by the Utility Plan, on June 25, 2002, the NRC issued an order denying various petitions to intervene and requests for hearing that had been filed by the CPUC, the County of San Luis Obispo, and the OCC, among others. In particular, the NRC found that the CPUC and OCC did not have standing to participate at the NRC with respect to public health and safety matters, as opposed to economic regulatory matters. In addition, the NRC found that the County's petition was untimely. Finally, the NRC found that neither the CPUC nor the County had raised any litigable issues within the NRC's jurisdiction and within the scope of its review of a license transfer application. The CPUC's and the County's issues were being properly addressed in other forums, such as the Bankruptcy Court and the FERC.

The CPUC and the County have filed a petition for review of this NRC decision in the United States Court of Appeals for the Ninth Circuit. The Utility has intervened in the case in support of the NRC's decision. The case is presently in the briefing process. No argument date has been set.

Several other parties filed petitions to intervene at the NRC expressing concerns solely with regard to how the antitrust conditions in the current Diablo Canyon licenses will be addressed in the proposed license transfers. These parties supported the Utility's proposal to retain the antitrust conditions and to make the reorganized Utility, Gen, and ETrans (the new limited liability company formed to operate the electric transmission business of the Utility as contemplated in the Utility Plan) jointly and severally responsible to comply with the antitrust conditions.



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The parties with an interest in the antitrust conditions sought intervention only if the NRC were to decide not to adopt the Utility's proposal. In its June 2002 decision, the NRC reserved its ruling as to these petitions. The NRC later sought additional briefs on legal issues presented by the Utility's antitrust proposal.

On February 14, 2003, the NRC issued a final order with respect to the pending antitrust issues. The NRC's order specifically decided that the NRC will not transfer the existing antitrust license conditions to any new licensee. In view of the age of the antitrust conditions and changes in the law since those conditions were adopted (in particular, those changes providing for nondiscriminatory open access to transmission), the NRC declined to reenact the conditions as part of the license transfer. Consistent with this decision, the NRC also rejected other issues related to the transfer application raised by the antitrust petitioners and rejected the requests for hearing on antitrust issues for lack of a viable issue for hearing.

With respect to the NRC license transfer application, the NRC has not yet issued its final order consenting to the transfer. No hearing issues remain to be decided. The NRC Staff must complete its safety evaluation and then would be authorized to issue the transfer order.

With respect to the application filed with the FERC for approval of the bilateral power sales agreement between the reorganized Utility and Gen as contemplated in the Utility Plan, the FERC must find that the power sales agreement is just and reasonable consistent with Section 205 of the Federal Power Act. Because the power sales agreement is viewed as an agreement between affiliates, in order to demonstrate that the pricing and non-price terms and conditions of the proposed power sales agreement are just and reasonable, Gen submitted benchmark evidence of contemporaneous sales made by non-affiliated parties for similar services in the California electric market. In June 2002, FERC accepted the power sales agreement for filing and ordered a hearing to determine whether Gen had submitted a valid benchmark, including whether specific comparability criteria have been appropriately addressed.

On October 10, 2002, the Administrative Law Judge, or ALJ, issued an initial decision finding that Gen successfully had "carried its burden" with respect to the benchmark analysis and had shown that the power sales agreement between the reorganized Utility and Gen was in fact comparable to the price and non-price terms and conditions of the selected benchmark contracts. The ALJ found no evidence in the record of any exercise of market power by Gen or any affiliate. In addition, the ALJ found that Gen's selection of contracts used as a comparison group in the benchmark analysis was appropriate and met all of the FERC's comparability criteria. The matter is now before the FERC for review of the hearing record and the ALJ's initial decision. The FERC will also consider the briefs on exceptions (addressing the ALJ's initial decision) that were filed by various parties. The ALJ's findings provide a basis for the FERC to find that the power sales agreement is just and reasonable. There is no specific time by which the FERC is required to take final action on the initial decision.

Neither PG&E Corporation nor the Utility can predict what the outcome of the Utility's bankruptcy proceeding will be.

Pacific Gas and Electric Company vs. California Public Utilities Commissioners

On November 8, 2000, Pacific Gas and Electric Company filed a lawsuit in the U.S. District Court for the Northern District of California against the CPUC Commissioners, asking the court to declare that the federally tariffed wholesale power costs that the Utility had incurred to serve its customers are recoverable in retail rates under the federal filed rate doctrine (the "Filed Rate Case"), and also asserting claims under the Takings, Commerce and Due Process Clauses of the United States Constitution. On January 29, 2001, the Utility's lawsuit was transferred to the U.S. District Court for the Central District of California where a similar lawsuit filed by Southern California Edison was pending.

On May 2, 2001, the District Court dismissed the Utility's amended complaint, without prejudice to refiling at a later date, on the ground that the lawsuit was premature since two CPUC decisions referenced in the complaint had not become final under California law. The court rejected all of the CPUC's other arguments for dismissal of the Utility's complaint.

On August 6, 2001, the Utility refiled its complaint in the U.S. District Court for the Northern District of California, based on the Utility's belief that the CPUC decisions referenced in the Court's May 2, 2001 order had become final under California law. On November 26, 2001, the case was transferred to United States District Court Judge Vaughn Walker in the Northern District of California as a related case to the Utility's appeal from the Bankruptcy Court's denial of the Utility's request for injunctive and declaratory relief against the retroactive accounting order adopted by the CPUC in March 2001, which is discussed above. At a joint case management



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conference held on March 7, 2002 in the two related actions, the court indicated that it would place priority on the Filed Rate Case and that it was necessary to clarify issues further in the Filed Rate Case before proceeding in the appeal of the Bankruptcy Court order regarding the CPUC's March 2001 accounting order. At the Utility's request, the court therefore set no dates for oral argument in the bankruptcy appeal, but indicated that the CPUC would be free at any time to attempt to establish that it was appropriate to reactivate the bankruptcy appeal in light of developments in the Filed Rate Case.

The Utility's complaint alleges that the wholesale power costs that the Utility has prudently incurred are paid pursuant to filed tariffs that the FERC has authorized and approved, and that under the U.S. Constitution and numerous court decisions, such costs cannot be disallowed by state regulators. The Utility's complaint also alleges that to the extent that the Utility is denied recovery of these wholesale power costs by order of the CPUC, such action constitutes an unlawful taking and confiscation of the Utility's property. The Utility argues that the CPUC's decisions are preempted by federal law under the filed rate doctrine, which requires the CPUC to allow the Utility to recover in full its reasonable procurement costs incurred under lawful rates and tariffs approved by the FERC, a federal governmental agency. The complaint also pleads claims under the Commerce Clause, Due Process Clause, and Equal Protection Clause of the U.S. Constitution.

On April 18, 2002, the Utility filed a motion for summary judgment requesting the court to enter judgment in the first and second claims for relief pleaded in the complaint on the basis that federal law requires the CPUC to permit the Utility to recover its wholesale procurement costs incurred in FERC-tariffed markets. Also, on April 18, 2002, the CPUC Commissioners and TURN, an intervenor in the Filed Rate Case, filed motions to dismiss the Utility's claim as well as motions for summary judgment asking the court to rule against the Utility on its federal preemption claims as a matter of law. The principal ground for the CPUC's and TURN's motions was that, by adopting the retroactive change in the accounting mechanisms for recovery of transition and power procurement costs in March 2001, the CPUC had already allowed the Utility to recover its wholesale procurement costs. (The retroactive accounting change, adopted by the CPUC on March 27, 2001, appeared to eliminate the Utility's true undercollected wholesale electricity costs by applying amounts that were previously applied first to transition cost recovery to undercollected procurement costs, effectively transforming undercollected procurement costs to under-collected transition costs. As discussed above, the Utility requested the Bankruptcy Court to enjoin the CPUC from enforcing the accounting order but the Bankruptcy Court denied the Utility's request.)

On July 25, 2002, the District Court issued an order denying the CPUC's and TURN's motions to dismiss the Filed Rate Case, as well as motions for summary judgment that had been filed by the CPUC, the Utility, and TURN. However, much of the District Court's order is a discussion of the merits of the Utility's federal preemption claims. The court rejected every argument advanced by the CPUC and TURN against the application of the filed rate doctrine, stating: "in most instances today a utility must purchase the power delivered to consumers pursuant to the rate filed with the appropriate federal agency."

After concluding that the Utility's federal preemption claims as pleaded are meritorious, the District Court denied the motions to dismiss without substantial discussion. The court stated that despite the unique features of the regulatory context underlying the Filed Rate Case, and the lack of precedent specifically on point, "the filed rate doctrine applies in this case in much the same way as it does under a cost-of-service regime." The court further stated that "Costs of wholesale energy, incurred pursuant to rate tariffs filed with FERC, whether these rates are market-based or cost-based, must be recognized as recoverable costs by state regulators and may not be trapped by excessively low retail rates or other limitations imposed at the state level." The court recognized that under the dual system of utility regulation, adherence to the filed rate requirement, in conjunction with the requirement that utilities provide electricity to end users, prohibits state regulators from trapping the costs prudently incurred pursuant to FERC-filed tariffs. The court also noted that "allowing a utility to pass through these costs to consumers--if that is what is required--would not provide a windfall to the utility, but would merely properly allocate the burden of responsibility for the expense of providing a mandated service to the public."

The court found, however, that the Utility's preemption claims could not be decided on summary judgment because two factual issues remained in dispute: (1) the appropriate time period for considering whether a net undercollection had occurred, and (2) the determination of which revenue sources, within Constitutional bounds, may be applied against the Utility's operating costs.

At an August 16, 2002 case management conference, the court adopted the pretrial and trial schedule stipulated to by the parties, including a trial date set for June 9, 2003. On August 23, 2002, the defendants filed a Notice of Appeal from those portions of the July 25, 2002 order denying defendants' motion to dismiss on Eleventh Amendment (sovereign immunity) and Johnson Act grounds. (The Johnson Act prohibits the district



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courts from enjoining, suspending, or restraining the operation of or compliance with any order affecting rates chargeable by a public utility and made by a state administrative agency as long as certain conditions are met.) On September 4, 2002, the Utility filed a motion with the District Court seeking written certification that the CPUC's appeal of the July 25, 2002 order on Eleventh Amendment and Johnson Act grounds was frivolous. On or about October 21, 2002, the District Court granted the Utility's motion and certified the CPUC's appeal as frivolous, which allowed the District Court to retain jurisdiction to proceed to trial while the CPUC's appeal to the Ninth Circuit was pending. On November 21, 2002, the Ninth Circuit without discussion granted the CPUC's motion to stay the District Court proceedings pending the CPUC's appeal of the District Court's July 25, 2002 order. As a consequence of the Ninth Circuit stay, the trial schedule previously set by the District Court, including the June 9, 2003, trial date, is inoperative.

On January 8, 2003, the Utility filed its Ninth Circuit brief in opposition to the CPUC's appeal, together with a motion asking the Ninth Circuit to expedite the hearing and the decision on the appeal. On January 13, 2003, the Ninth Circuit notified the Utility that a hearing date for the appeal has been set for March 10, 2003. Briefing on the appeal has been completed.

Neither PG&E Corporation nor the Utility can predict what the outcome of the Filed Rate Case litigation will be.

In connection with the Utility Plan, before the distribution of the outstanding common stock of Newco to PG&E Corporation, the Utility would assign to Newco or a subsidiary of Newco the rights to an amount equal to 95% of the net after-tax proceeds from any successful resolution of this case and resulting CPUC rate order requiring collection of wholesale costs in retail rates. The reorganized Utility would retain the rights to 5% of such proceeds.

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 entitled Jack Gillam; DOES 1 TO 5, Inclusive, and All Persons similarly situated vs. PG&E Corporation, Pacific Gas and Electric Company; and DOES 6 to 10, Inclusive. 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 entitled Jack Gillam, et al. vs. PG&E Corporation, Robert D. Glynn, Jr., and Peter A. Darbee, in the U.S. District Court for the Northern District of California. 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, claims that defendants caused PG&E Corporation's Condensed Consolidated Financial Statements for the second and third quarters of 2000 to be materially misleading in violation of federal securities laws by 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.

The defendants filed a motion to dismiss the first amended complaint, based largely on public disclosures by PG&E Corporation, the Utility, and others regarding the undercollections, 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 January 14, 2002, the District Court granted the defendants' motion to dismiss the plaintiffs' complaint with leave to amend the complaint. On February

4, 2002, the plaintiffs filed a second amended complaint in the District Court entitled Jack Gillam, et al. vs. PG&E Corporation, and Robert D. Glynn, Jr. In addition to containing many of the same allegations as were contained in the prior complaint, the complaint contains allegations similar to the allegations made in the California Attorney General's complaint against PG&E Corporation discussed below. On March 11, 2002, the defendants filed a motion to dismiss the second amended complaint. After a hearing on June 24, 2002, the District Court issued an order granting the defendants' motion to dismiss the second amended complaint. The dismissal is with prejudice, prohibiting the plaintiffs from filing a further amended complaint.

On November 15, 2002, plaintiffs filed an appeal of the District Court's order with the United States Court of Appeals for the Ninth Circuit, advancing substantially the same arguments that the District Court had rejected previously. The defendants filed an answering brief on January 2, 2003, and anticipate that oral argument may occur as early as the fall of 2003.



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

In re: Natural Gas Royalties Qui Tam Litigation

This litigation involves the consolidation of approximately 77 False Claims Act cases filed in various federal district courts by Jack J. Gyrnberg (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 U.S. District Court, for 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, or the 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 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 heating content of natural gas produced from federal or Indian leases. As a result, the relator alleges 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 of not less than $5,000 and not more than $10,000 against each defendant for each violation of the False Claims Act, an order requiring the defendants to discontinue certain measurement practices, and reimbursement for reasonable expenses, attorneys' fees, and costs incurred in connection with the litigation. The relator has filed a claim in the Utility's bankruptcy case for $2.48 billion, $2 billion of which is based upon the relator's calculation of penalties 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.

Moss Landing Power Plant

In December 1999, the Utility was notified by the purchaser of its former Moss Landing power plant that it had identified a cleaning procedure used at the plant that released heated water and organic debris from the intake, and that this procedure is not specified in the plant's National Pollutant Discharge Elimination System, or NPDES, permit issued by the Central Coast Regional Water Quality Control Board, or Central Coast Board. The purchaser notified the Central Coast Board of its findings and the Central Coast Board requested additional information from the purchaser. The Utility initiated an investigation of these activities during the time it owned the plant. The Utility notified the Central Coast Board that it had undertaken an investigation and that it would present the results to the Central Coast Board when the investigation was completed. In March 2000, the Central Coast Board requested the Utility to provide specific information regarding the "backflush" procedure used at Moss Landing. The Utility provided the requested information in April 2000. The Utility's investigation indicated that while the Utility owned Moss Landing, significant amounts of water were discharged from the cooling water intake. While the Utility's investigation did not clearly indicate that discharged waters had a temperature higher than ambient receiving water, the Utility believes that the temperature of the discharged water was higher than that of the receiving water.

In December 2000, the executive officer of the Central Coast Board made a settlement proposal to the Utility under which the Utility would pay $10 million, a portion of which would be used for environmental projects and the balance of which would constitute civil penalties. In March 2002, the Utility and the Central Coast Board reached a tentative settlement of this matter under which the Utility would pay a total of $5 million to be used for environmental projects. No civil penalties would be paid under the settlement. The parties are negotiating the documentation of the settlement. The final agreement will be subject to public comment and final approval by the Central Coast Board, and, once signed by the parties, will be incorporated into a consent decree to be entered in California Superior Court.



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The California Attorney General has filed a proof of claim in the Bankruptcy Court on behalf of the Central Coast Board seeking unspecified penalties for alleged discharges of heated cooling water at Moss Landing.

PG&E Corporation and the Utility believe that 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 results of operations.

Diablo Canyon Power Plant

On June 13, 2002, the Utility received a draft Enforcement Order from the California Department of Toxic Substances Control, or DTSC, alleging that the Diablo Canyon Power Plant, or Diablo Canyon, failed to maintain an adequate financial assurance mechanism to cover closure costs for its hazardous waste storage facility for several months during 2001. Under the California Health and Safety Code, operators of hazardous waste facilities must demonstrate to the DTSC (using a limited number of alternative methods specified by regulation) that the operator can close and clean up the facility at the end of its useful life. The Utility has used a "balance sheet" method in the past, but was unable to do so after the Utility's financial condition deteriorated in early 2001. Nevertheless, the Utility was able to secure an endorsement to its existing insurance policy that met the DTSC's requirements. The draft order seeks $340,000 in civil penalties for the period during which the Utility was unable to comply with the DTSC's requirements. The draft order also directs the Utility to maintain appropriate financial assurance on a going-forward basis. On September 4, 2002, the Utility received a draft Enforcement Order from DTSC alleging a variety of hazardous waste violations at Diablo Canyon. The violations were identified in an April 2001 inspection. The draft order seeks $24,330 in civil penalties. A tentative settlement has been reached with DTSC under which the Utility will pay approximately $165,000 in civil penalties and approximately $30,000 in costs. The final agreement, once signed by the parties, will be incorporated into a consent decree to be entered in California Superior Court.

PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material adverse impact on their financial condition or results of operations.

Compressor Station Chromium Litigation

There are 15 civil actions pending in California courts against the Utility relating to alleged chromium contamination, or the Chromium Litigation: (1) Aguayo v. Pacific Gas and Electric Company, filed March 15, 1995, in Los Angeles County Superior Court, (2) Aguilar v. Pacific Gas and Electric Company, filed October 4, 1996, in Los Angeles County Superior Court, (3) Acosta, et al. v. Betz Laboratories, Inc., et al., filed November 27, 1996, in Los Angeles County Superior Court, (4) Adams v. Pacific Gas and Electric Company and Betz Chemical Company, filed July 25, 2000, in Los Angeles County Superior Court, (5) Baldonado v. Pacific Gas and Electric Company, filed October 25, 2000, in Los Angeles County Superior Court, (6) Gale v. Pacific Gas and Electric Company, filed January 30, 2001, in Los Angeles County Superior Court, (7) Monice v. Pacific Gas and Electric Company, filed March 15, 2001, in San Bernardino County Superior Court, (8) Fordyce v. Pacific Gas and Electric Company, filed March 16, 2001, in San Bernardino Superior Court, (9) Puckett v. Pacific Gas and Electric Company, filed March 30, 2001, in Los Angeles County Superior Court, (10) Alderson, et al. v. PG&E Corporation, Pacific Gas and Electric Company, Betz Chemical Company, et al.,filed April 11, 2001, in Los Angeles County Superior Court, (11) Bowers, et al. v. Pacific Gas and Electric Company, et al., filed April 20, 2001, in Los Angeles County Superior Court, (12) Boyd, et al. v. Pacific Gas and Electric Company, et al., filed May 2, 2001, in Los Angeles County Superior Court, (13) Martinez, et al. v. Pacific Gas and Electric Company, filed June 29, 2001, in San Bernardino County Superior Court, (14) Kearney v. Pacific Gas and Electric Company, filed November 15, 2001, in Los Angeles County Superior Court, and (15) Miller v. Pacific Gas and Electric Company, filed November 21, 2001, in Los Angeles County Superior Court. All of these civil actions are now pending in the Los Angeles Superior Court, except the Monice case, still pending in San Bernardino County, and the Lytle case, still pending in Yolo County. One additional suit, Kearney v. Pacific Gas and Electric Company, filed November 15, 2001, in Los Angeles County Superior Court, was filed after the Petition Date and was dismissed without prejudice as to PG&E and PG&E Corporation on March 26, 2002, while plaintiffs' counsel sought and obtained permission from the Bankruptcy Court to pursue late claims. The Bankruptcy Court ruled that the six adult plaintiffs could not file untimely bankruptcy claims against PG&E. This ruling should prohibit these adult plaintiffs from proceeding in state court against PG&E. The court also ruled that the twenty-four minor plaintiffs in the case could file untimely bankruptcy claims against PG&E, which should permit these minor plaintiffs to reinstate their claims against PG&E in the pending civil suit.



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Two of these suits, Alderson and Kearney, also name PG&E Corporation as a defendant. The Utility has not yet been served with the complaints in the Gale or Lytle cases. There are now approximately 1,200 plaintiffs in the Chromium Litigation.

The complaints allege personal injuries, wrongful death, and loss of consortium and seek compensatory and punitive damages based on claims arising from alleged exposure to chromium contamination in the vicinity of the Utility's gas compressor stations located at Kettleman and Hinkley, California, and the area of California near Topock, Arizona. The plaintiffs include current and former employees of the Utility and their relatives, residents in the vicinity of the compressor stations, and persons who allegedly visited the gas compressor stations. The plaintiffs also include spouses or children of these plaintiffs who claim loss of consortium or wrongful death.

The Utility is responding to the suits in which it has been served and is asserting affirmative defenses. It will pursue appropriate legal defenses, including the 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.

The discovery referee has set the procedures for selecting trial test plaintiffs and alternates in the Aguayo, Acosta, and Aguilar cases. Ten of these trial test plaintiffs were selected by plaintiffs' counsel, seven plaintiffs were selected by defense counsel, and one plaintiff and two alternates were selected at random. Although a date for the first test trial in these cases was set for July 2, 2001, in Los Angeles County Superior Court, the Chapter 11 case automatically stayed all proceedings.

On March 27, 2002, the seven plaintiffs in the Fordyce case served their lawsuit on PG&E. The plaintiffs have all filed timely proofs of claim in the bankruptcy case.

In the Adams case, 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 plead 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 claim in the Utility's bankruptcy case (nearly all are plaintiffs in the Chromium Litigation) asserting that exposure to chromium at or near the compressor stations has caused personal injuries, wrongful death, or related damages. Approximately 1,035 claimants have filed proofs of claim requesting an approximate aggregate amount of $580 million and another approximately 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 U. S. District Court. On January 8, 2002, the Bankruptcy Court denied the Utility's request to transfer the chromium claims and granted the 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.

Before April 6, 2001, when the Utility filed its bankruptcy petition, the Utility was responding to the complaints in which it had been served and was asserting affirmative defenses. As of April 6, 2001, the Utility had filed 13 summary judgment motions challenging the claims of the trial test plaintiffs and had completed discovery of plaintiffs' experts. Plaintiffs' discovery of the Utility's experts was underway. Plaintiffs are completing discovery of the Utility's experts and of related issues, and four of the 13 summary judgment motions are scheduled for hearing in the first six months of 2003. At this stage of the proceedings and the claims objections, there is substantial uncertainty concerning the claims alleged, and the Utility is attempting to gather information concerning the alleged type and duration of exposure, the nature of injuries alleged by individual plaintiffs, and the additional facts necessary to support its legal defenses.

PG&E Corporation and the Utility believe that, in light of the reserves that have already been accrued with respect to this matter, 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 results of operations. See Note 16 of the "Notes to Consolidated Financial Statements" of the 2002 Annual Report to Shareholders, portions of which are filed as Exhibit 13 to this report. The Utility Plan provides that the aggregate after-tax amount of any liability resulting from the chromium litigation would be divided among ETrans, GTrans, Gen and the reorganized Utility approximately as follows: 12.5%, 12.5%, 25% and 50%, respectively.



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California Energy Trading Litigation

PG&E Energy Trading Holdings Corporation and various of its affiliates (collectively ET-Power) have been named as defendants, along with other generators and market participants in the California electricity market, in connection with a variety of claims arising out of the California energy crisis. ET-Power has been served with complaints in the following cases. It is possible that it will be served with additional complaints and that some of these cases will be consolidated with other cases in which similar allegations have been raised respecting other market participants. These proceedings are administrative and judicial in nature.

ET-Power has been named, along with multiple other defendants, in four class action lawsuits known as Pier 23 against marketers and other unnamed sellers of electricity in California markets. These cases are (1) Pier 23 Restaurant v. PG&E Energy Trading Corporation, et al., filed on January 24, 2001, in San Francisco Superior Court and subsequently removed to the United States District Court for the Northern District of California; (2) Hendricks v. Dynegy Power Marketing, Inc., PG&E Energy Trading Corporation, et al., filed on November 29, 2000, in San Diego Superior Court and subsequently removed to the United States District Court for the Southern District of California; (3) Sweetwater Authority v. Dynegy Inc., PG&E Energy Trading Corporation, et al., filed on January 16, 2001, in San Diego Superior Court and subsequently removed to the United States District Court for the Southern District of California; and (4) People of the State of California v. Dynegy Power Marketing, Inc., PG&E Energy Trading Corporation, et al., filed on January 18, 2001, in San Francisco Superior Court and subsequently removed to the United States District Court for the Northern District of California.

These cases are all currently pending in the U.S. District Court for the Southern District of California. Plaintiffs filed a motion to remand the proceedings to state court and in January 2003, the motion was granted. However, in view of various appeals of the remand order, the cases remain in federal court.

These suits allege violation by the defendants of state antitrust laws and state laws against unfair and unlawful business practices. Specifically, the named plaintiffs allege that the defendants, including the owners of in-state generation and various power marketers, conspired to manipulate the California wholesale power market to the detriment of California consumers. Included among the acts forming the basis of the plaintiffs' claims are the alleged improper sharing of generation outage data, improper withholding of generation capacity, and the manipulation of power market bid practices. The plaintiffs seek unspecified treble damages and, among other remedies, disgorgement of alleged unlawful profits for sales of electricity beginning in 1999 or 2000, restitution, injunctive relief, and attorneys' fees.

On May 13, 2002, ET-Power was named, along with multiple other defendants, in a complaint filed in San Francisco Superior Court by James A. Millar, individually and on behalf of the general public and as a representative taxpayer against energy suppliers and other unnamed sellers of electricity in the California market. In his complaint, plaintiff asserts the defendants violated state laws against unfair and fraudulent business practices by entering into certain long-term energy contracts with the DWR. The plaintiff claims that the contracts were made under circumstances that resulted in excessively high and unfair prices and, as a result, refunds should be made to the extent that the prices in the contracts were excessive. In addition, plaintiff seeks, among other remedies, an order enjoining enforcement of the allegedly unfair terms and conditions of the long-term contracts, declaratory relief, and attorneys' fees. The FERC is currently addressing the DWR contracts in the administrative actions before the FERC brought by the CPUC and California Electricity Oversight Board on February 25, 2002. On June 13, 2002, the defendants removed the case to the U.S. District Court for the Northern District of California based on federal preemption. The plaintiff filed a motion to remand the case to state court. On July 12, 2002 the Judicial Panel on Multidistrict Litigation entered a conditional order transferring this case to the U.S. District Court for the Southern District of California, where it is now before the same judge presiding over the Pier 23 cases. The panel determined that the Millar case, as well as seven other pending lawsuits, involved common questions of law and fact. ET-Power is currently not a defendant in any of these other lawsuits. The plaintiff has renewed his motion to remand these cases to state court.

On July 15, 2002, ET-Power was named among other sellers of power in an action filed by the Public Utility District No. 1 of Snohomish County, Public Utility District No. 1 of Snohomish County v. Dynegy Power Marketing, et al., in the U.S. District Court for the Central District of California. Plaintiff alleged various theories of manipulation of the deregulated California electricity market by the defendants in violation of state antitrust laws and state laws against unlawful and fraudulent business practices. Plaintiff claimed that the defendants manipulated the energy market, resulting in higher electricity prices and sought, among other remedies, disgorgement, restitution, injunctive relief, and treble damages. Plaintiff also claimed that the defendants failed to file their rates in advance with the FERC, which failure plaintiff asserts was a violation of the Federal Power Act. On October 11,



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2002, the Judicial Panel on Multidistrict Litigation entered a final order transferring the Snohomish case to the U.S. District Court for the Southern District of California and to the same judge presiding over the Pier 23 and Millar proceedings. The defendants filed a joint motion to dismiss and to strike various elements of the complaint. On January 8, 2003, the U.S. District Court for the Southern District of California dismissed the complaint, finding that the issue of whether and how market manipulation affected electricity rates was one that should be determined by the FERC. Plaintiff has filed a notice of appeal of the district court's decision with the U.S. Court of Appeals for the Ninth Circuit.

By letter dated May 7, 2002, ET-Power was advised by the California Attorney General, or AG, that it believes ET-Power (along with numerous other generators and market participants) violated state laws governing unfair and fraudulent business practices and that unless ET-Power settled the matter the AG would by June 1, 2002 file suit against ET-Power. The AG stated that he will claim that ET-Power failed to have its rates on file with FERC and that accordingly any sales made under such rates violated the Federal Power Act (a claim that the AG has made before FERC and which FERC has rejected) and that ET-Power exercised market-power in charging unjust and unreasonable prices. ET-Power has not yet been served with a complaint in this matter.

In addition to these judicial proceedings, on March 20, 2002 the AG filed a complaint at the FERC against ET-Power and other named and unnamed public utility sellers of energy and ancillary services. The California AG alleges that wholesale sellers of energy to the California Independent System Operator, or ISO, the California Power Exchange, or PX, and the California Department of Water Resources, or DWR, failed to file their rates in accordance with the requirements of Section 205 of the Federal Power Act. Specifically, the California AG claims that the FERC has not been able to determine whether the rates charged by such sellers are just and reasonable, that the FERC's reporting requirements are insufficient to provide the FERC the information necessary to make this determination, and that even if the FERC's policies and procedures did comply with Section 205 of the Federal Power Act, the wholesale sellers failed to comply with its quarterly reporting requirements. As a result, the California AG requests that (1) sellers should be directed to comply, on a prospective basis, with the requirements of Section 205 of the Federal Power Act; (2) sellers should be required to provide transaction-specific information to the FERC regarding their short-term sales to the ISO, the PX, and the DWR for the years 2000 and 2001; (3) if rates were charged that were not just and reasonable, refunds should be ordered; (4) the FERC should declare that market-based rates are not subject to the filed rate doctrine; and (5) the FERC should institute proceedings to determine whether any further relief would be appropriate. On May 31, 2002, the FERC issued a decision denying most of the relief requested and on July 1, 2002, the California AG filed a petition with the FERC seeking rehearing of its order. The FERC denied rehearing on September 23, 2002. The California AG has filed an appeal of the FERC's decision with the U.S. Court of Appeals for the Ninth Circuit.

PG&E Corporation believes that the outcome of these matters will not have a material adverse affect on PG&E Corporation's financial condition or results of operations.

California Attorney General Complaint

On January 10, 2002, the California AG filed a complaint in the San Francisco Superior Court against PG&E Corporation and its directors, as well as against directors of the Utility, based on allegations of unfair or fraudulent business acts or practices in violation of California Business and Professions, or B&P, Code Section 17200. Among other allegations, the AG alleged that past transfers of money from the Utility to PG&E Corporation, and allegedly from PG&E Corporation to other affiliates of PG&E Corporation, violated various conditions established by the CPUC in decisions approving the holding company formation. The AG 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. The AG alleged that these ringfencing transactions included conditions that restricted PG&E NEG's ability to provide any funds to PG&E Corporation, through dividends, capital distributions or similar payments, reducing PG&E Corporation's cash and thereby impairing PG&E Corporation's ability to comply with the capital requirements condition and subordinating the Utility's interests to the interests of PG&E Corporation and its other affiliates. (On January 9, 2002, the CPUC issued a decision interpreting the capital requirements condition (which it terms the "first priority condition") and concluded that the condition, at least under certain circumstances, includes the requirement that each of the holding companies "infuse the utility with all types of capital necessary for the utility to fulfill its 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 three major California investor-owned



utilities and their parent holding companies appealed the CPUC's interpretation of the capital requirements condition to various state appellate courts. The CPUC moved to consolidate all proceedings in the San Francisco state appellate court. The CPUC's request for consolidation was granted and all the petitions are now before the First Appellate District in San Francisco, California.)

The complaint seeks injunctive relief, the appointment of a receiver, restitution in an amount according to proof, civil penalties of $2,500 against each defendant for each violation of B&P Code section 17200, that the total penalty not be less than $500 million, and costs of suit.

In addition, the AG alleged that, through the Utility's bankruptcy proceedings, PG&E Corporation and the Utility engaged in unlawful, unfair, and fraudulent business practices by seeking to implement the transactions proposed in the proposed plan of reorganization filed in the Utility's bankruptcy proceeding. The AG's complaint also seeks restitution of assets allegedly wrongfully transferred to PG&E Corporation from the Utility. In PG&E Corporation's view, the Bankruptcy Court has original and exclusive jurisdiction of these claims. Therefore, on February 8, 2002, PG&E Corporation filed a notice of removal in the Bankruptcy Court to transfer the AG's complaint to the Bankruptcy Court.

After removing the California AG's complaint to the Bankruptcy Court, on February 15, 2002, PG&E Corporation filed a motion to dismiss, or in the alternative, to stay, the California AG's complaint with the Bankruptcy Court. Subsequently, the California AG filed a motion to remand the action to state court. The Bankruptcy Court held a hearing on April 24, 2002, to consider the remand motion. On June 20, 2002, the Bankruptcy Court issued an Amended Order on Motion to Remand. (An initial order was issued on June 2, 2002). The Bankruptcy Court held that federal law preempted the California AG's allegations concerning PG&E Corporation's participation in the Utility's bankruptcy proceedings. The Bankruptcy Court directed the California AG 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 June 20, 2002 order.

The appeal and cross-appeal are pending in the United States District

Court for the Northern District of California.

On August 9, 2002, the California AG 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 motions to strike certain allegations of the amended complaint. These motions are pending.

PG&E Corporation believes that the allegations of the complaint are without merit and will vigorously respond to and defend the litigation. PG&E Corporation is unable to predict whether the outcome of this litigation will have a material adverse effect on its financial condition or results of operations.

Complaint filed by the City and County of San Francisco, and the People of the State of California

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 AG's complaint including allegations of unfair competition in violation of B&P Code Section 17200. In addition, the complaint alleges causes of action for conversion, claiming that PG&E Corporation "took at least $5.2 billion from PG&E," and for unjust enrichment.

Among other allegations, plaintiffs allege that past transfers of money from the Utility to PG&E Corporation, allegedly used by PG&E Corporation to subsidize other affiliates of PG&E Corporation, violated various conditions established by the CPUC in decisions approving the holding company formation. The complaint also alleges that certain ring fencing transactions by which PG&E Corporation subsidiaries complied with credit rating agency criteria to establish independent credit ratings violated the holding company conditions. Plaintiffs also allege that by agreeing to certain restrictive covenants in certain financing agreements, PG&E Corporation also violated a holding company condition.

The complaint seeks injunctive relief, the appointment of a receiver, restitution, disgorgement, the imposition of a constructive trust, civil penalties of $2,500 against each defendant for each violation of B&P Code Section 17200 as authorized by B&P Code Section 17206, 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. On June 20, 2002, the Bankruptcy Court issued an Amended Order on Motion to Remand. (An initial order was issued



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on June 2, 2002.) In its remand order, the 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, but remanded the Section 17200 cause of action 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 United States 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.

PG&E Corporation believes that the allegations of the complaint are without merit and will vigorously respond to and defend the litigation. PG&E Corporation is unable to predict whether the outcome of this litigation will have a material adverse effect on its financial condition or results of operations.

Cynthia Behr v. PG&E Corporation, et al.

On February 14, 2002, this complaint was filed by a private plaintiff in Santa Clara Superior Court against PG&E Corporation and its directors, Pacific Gas and Electric Company's directors, and other parties, also alleging a violation of B&P Code Section 17200. 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 referred to above as to the Attorney General's case, 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 United States 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 believes that the allegations of the complaint are without merit and will vigorously respond to and defend the litigation. PG&E Corporation is unable to predict whether the outcome of this litigation will have a material adverse effect on its financial condition or results of operations.

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 3.5 cents per kWh in allegedly excessive electric rates and a refund of alleged recent overcollections in electric revenue since June 1, 2001. The complaint claims that electric rate surcharges adopted in the first quarter of 2001 due to the high cost of wholesale power, surcharges that increased the average electric rate by 4.0 cents per kWh, became excessive later in 2001. (In January 2001, the CPUC authorized a 1.0 cent per kWh rate increase to pay for energy procurement costs. In March 2001, the CPUC authorized an additional 3.0 cent per kWh 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 overcollection 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 impact on their financial condition or results of operations.

PG&E NEG's Brayton Point Generating Station

On March 27, 2002, the Attorney General of the State of Rhode Island notified USGenNE of his belief that Brayton Point is operating in violation of applicability statutory and regulatory provisions, including what he



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characterized as "protections afforded by common law." The Attorney General purported to provide notice under the Massachusetts General Laws of his intention to seek judicial relief within the following thirty days to abate the alleged violations and to recover damages and to obtain other unexplained statutory and equitable remedies. PG&E NEG believes that Brayton Point Station is in full compliance with all applicable permits, laws and regulations. The complaint has not yet been filed or served. In May 2002, the Attorney General stated that he did not plan to file the action until the EPA issues a draft NPDES permit for Brayton Point. On July 22, 2002, the EPA and the Massachusetts Department of Environment, or DEP, issued a draft NPDES permit for Brayton Point that, among other things, substantially limits the discharge of heat by Brayton Point into Mt. 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. For more information, see Note 16 of the "Notes to Consolidated Financial Statements" of the 2002 Annual Report to Shareholders, portions of which are filed as Exhibit 13 to this report. The Rhode Island Attorney General has since stated that he has no intention of pursuing this matter until he reviews USGenNE's response to the draft permit, which was submitted on October 4, 2002.

PG&E Corporation is unable to predict whether the Rhode Island Attorney General will pursue this matter and, if he does, the extent to which it will have a material adverse effect on PG&E Corporation's financial condition or results of operations.

ITEM 4. Submission of Matters to a Vote of Security Holders.

Not applicable.

## EXECUTIVE OFFICERS OF THE REGISTRANTS

"Executive officers," as defined by Rule 3b-7 of the General Rules and Regulations under the Securities and Exchange Act of 1934, of PG&E Corporation are as follows:

| Name | Age at December 31, 2002 | Position |
|---|---|---|
| R. D. Glynn, Jr | 60 | Chairman of the Board, Chief Executive Officer, and President |
| P. A Darbee | 49 | Senior Vice President and Chief Financial Officer |
| P. C. Iribe | 52 | Senior Vice President; Executive Vice President, PG&E National Energy Group, Inc |

| | | |
|---|---|---|
| C. P. Johns | 42 | Senior Vice President and Controller |
| T. B King | 41 | Senior Vice President; President, PG&E National Energy Group, Inc. |
| L. E Maddox | 47 | Senior Vice President; Executive Vice President, PG&E National Energy Group, Inc |
| D.D Richard, Jr | 52 | Senior Vice President, Public Affairs, Senior Vice President, Public Affairs, Pacific Gas and Electric Company |
| G. R Smith | 54 | Senior Vice President; President and Chief Executive Officer, Pacific Gas and Electric Company |
| G. B Stanley | 56 | Senior Vice President, Human Resources |
| B. R Worthington | 53 | Senior Vice President and General Counsel |

All officers of PG&E Corporation serve at the pleasure of the Board of Directors During the past five years, the executive officers of PG&E Corporation had the following business experience. Except as otherwise noted, all positions have been held at PG&E Corporation

| Name | Position | Period Held Office |
|---|---|---|
| R. D. Glynn, Jr. | Chairman of the Board, Chief Executive Officer, and President | January 1, 1998 to present |
| | Chairman of the Board, Pacific Gas and Electric Company | January 1, 1998 to present |



| | | |
|---|---|---|
| P. A. Darbee | Senior Vice President and Chief Financial Officer | July 9, 2001 to present |
| | Senior Vice President Chief Financial Officer, and Treasurer | September 20, 1999 to July 8, 2001 |
| | Vice President and Chief Financial Officer, Advance Fibre Communications, Inc. | June 30, 1997 to September 19, 1999 |
| P. C. Iribe | Senior Vice President | January 1, 1999 to present |
| | Executive Vice President, PG&E National Energy Group, Inc. | August 9, 2002 to present |
| | President and Chief Operating Officer, East Region, PG&E National Energy Group, Inc. | July 1, 2000 to present |
| | President and Chief Operating Officer, PG&E National Energy Group Company | November 1, 1998 to present |
| | Executive Vice President and Chief Operating Officer, PG&E National Energy Group Company (formerly known as PG&E Generating Company) | September 1, 1997 to October 31, 1998 |
| C. P. Johns | Senior Vice President and Controller | September 19, 2001 to present |
| | Vice President and Controller | July 1, 1997 to September 18, 2001 |
| | Vice President and Controller, Pacific Gas and Electric Company | June 1, 1996 to December 31, 1999 |
| T. B. King | Senior Vice President | January 1, 1999 to present |
| | President, PG&E National Energy Group, Inc. | November 15, 2002 to present |
| | President, PG&E Gas Transmission Corporation | November 15, 2002 to present |
| | President and Chief Operating Officer, Gas Transmission | August 9, 2002 to November 14, 2002 |
| | President and Chief Operating Officer, West Region, PG&E National Energy Group, Inc. | July 1, 2000 to August 8, 2002 |
| | President and Chief Operating Officer, PG&E Gas Transmission Corporation | November 23, 1998 to November 14, 2002 |
| | President and Chief Operating Officer, Kinder Morgan Energy Partners, L.P. | February 14, 1997 to November 22, 1998 |
| L. E. Maddox | Senior Vice President | June 1, 1997 to present |
| | Executive Vice President, PG&E National Energy Group, Inc. | November 15, 2002 to present |
| | President and Chief Operating Officer, Merchant Energy, PG&E National Energy Group, Inc. | August 9, 2002 to November 14, 2002 |
| | President and Chief Operating Officer, Trading, PG&E National Energy Group, Inc. | July 1, 2000 to August 8, 2002 |

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| President and Chief Executive Officer, PG&E Energy Trading-Gas Corporation | May 12, 1997 to present |



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|---|---|---|
| D. D. Richard, Jr. | Senior Vice President, Public Affairs | October 18, 2000 to present |
| | Vice President, Governmental Relations | July 1, 1997 to October 17, 2000 |
| | Senior Vice President, Public Affairs, Pacific Gas and Electric Company | May 1, 1998 to present |
| | Senior Vice President, Governmental and Regulatory Relations, Pacific Gas and Electric Company | July 1, 1997 to April 30, 1998 |
| G. B. Stanley | Senior Vice President, Human Resources | January 1, 1998 to present |
| | Senior Vice President, PG&E National Energy Group, Inc. | July 1, 2000 to present |
| | Vice President, Human Resources | June 1, 1997 to December 31, 1977 |
| B. R. Worthington | Senior Vice President and General Counsel | June 1, 1997 to present |
| | Vice President, PG&E National Energy Group, Inc. | January 20, 1999 to July 1, 2000 |

"Executive officers," as defined by Rule 3b-7 of the General Rules and Regulations under the Securities and Exchange Act of 1934, of Pacific Gas and Electric Company are as follows:

| Name | Age at December 31, 2002 | Position |
|---|---|---|
| G. R. Smith | 54 | President and Chief Executive Officer |
| K. M. Harvey | 44 | Senior Vice President, Chief Financial Officer, and Treasurer |
| R. J. Peters | 52 | Senior Vice President and General Counsel |
| J. K. Randolph | 58 | Senior Vice President and Chief of Utility Operations |
| D. D. Richard, Jr. | 52 | Senior Vice President, Public Affairs |
| G. M. Rueger | 52 | Senior Vice President, Generation and Chief Nuclear Officer |



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All officers of Pacific Gas and Electric Company serve at the pleasure of the Board of Directors. During the past five years, the executive officers of Pacific Gas and Electric Company had the following business experience. Except as otherwise noted, all positions have been held at Pacific Gas and Electric Company.

| Name | Position | Period Held Office |
|---|---|---|
| G. R. Smith | President and Chief Executive Officer | June 1, 1997 to present |
| | Senior Vice President, PG&E Corporation | January 1, 1999 to present |
| K. M. Harvey | Senior Vice President, Chief Financial Officer, and Treasurer | November 1, 2000 to present |
| | Senior Vice President, Chief Financial Officer, Controller, and Treasurer | January 1, 2000 to October 31, 2000 |
| | Senior Vice President, Chief Financial Officer, and Treasurer | July 1, 1997 to December 31, 1999 |
| R. J. Peters | Senior Vice President and General Counsel | January 1, 1999 to present |
| | Vice President and General Counsel | July 1, 1997 to December 31, 1998 |

| | | |
|---|---|---|
| J. K. Randolph | Senior Vice President and Chief of Utility Operations | May 5, 2000 to present |
| | Senior Vice President and General Manager, Transmission, Distribution and Customer Service Business Unit | January 24, 2000 to May 4, 2000 |
| | Senior Vice President and General Manager, Distribution and Customer Service Business Unit | July 1, 1997 to January 23, 2000 |
| D. D. Richard, Jr. | Senior Vice President, Public Affairs (Please refer to description of business experience for executive officers of PG&E Corporation above.) | May 1, 1998 to present |
| G. M. Rueger | Senior Vice President, Generation and Chief Nuclear Officer | April 2, 2000 to present |
| | Senior Vice President and General Manager, Nuclear Power Generation Business Unit | November 1, 1991 to April 1, 2000 |



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PART II

ITEM 5 Market for the Registrant's Common Equity and Related Stockholder Matters.

Information responding to part of Item 5, for each of PG&E Corporation and Pacific Gas and Electric Company, is set forth on page 177 under the heading "Quarterly Consolidated Financial Data (Unaudited)" in the 2002 Annual Report to Shareholders, which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report. As of February 1, 2003, there were 117,812 holders of record of PG&E Corporation common stock. PG&E Corporation common stock is listed on the New York, Pacific, and Swiss stock exchanges. The discussion of dividends with respect to PG&E Corporation's common stock is hereby incorporated by reference from "Management's Discussion and Analysis of Financial Condition and Results of Operations--Dividends" on page 36 of the 2002 Annual Report to Shareholders

On June 25, 2002, PG&E Corporation issued to certain lenders warrants to purchase approximately 2.4 million shares of PG&E Corporation common stock at an exercise price of $0.01 per share. On October 18, 2002, PG&E Corporation issued to certain lenders additional warrants to purchase approximately 2.7 million shares of PG&E Corporation common stock. The terms and provisions of the warrants, including a warrant exercise price of $0.01 per share, are substantially identical to the warrants issued on June 25, 2002. The issuance of the warrants by PG&E Corporation was not registered under the Securities Act of 1933 in reliance on the exemption afforded by Section 4(2).

Also, on June 25, 2002, PG&E Corporation issued $280 million aggregate principal amount of 7.50% Convertible Subordinated Notes due June 30, 2007. On October 18, 2002, the notes and the related indenture were amended to delete certain cross-default provisions, to increase the interest rate on the notes to 9.50% from 7.50%, to extend the maturity of the notes to June 30, 2010, from June 30, 2007, and to 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, if any). The notes are unsecured and are subordinate to other PG&E Corporation debt. PG&E Corporation has the right, subject to certain limitations, to pay interest by issuing additional notes in lieu of paying cash. In addition to interest, if PG&E Corporation pays cash dividends to holders of its common stock, note holders are entitled to receive cash equal to the dividends that would have been paid with respect to the number of shares that the holder would be entitled to receive if the notes had been converted on the dividend record date. The notes may be converted by the holders into shares of PG&E Corporation common stock at a conversion price of $15.0873 per share. The conversion price is subject to adjustment under certain circumstances, including upon consummation of any spin-off transaction of the Utility as proposed in its plan of reorganization or a spin-off of the shares of PG&E NEG. The issuance of the notes by PG&E Corporation was not registered under the Securities Act of 1933 in reliance on the exemption afforded by Section 4(2).

All obligations of PG&E Corporation with respect to certain loans are secured by a perfected first-priority security interest in the outstanding common stock of PG&E Corporation's subsidiary, the Utility, and all proceeds thereof. With respect to 35% of such common stock pledged for the benefit of the lenders, the lenders have customary rights of a pledgee of common stock, provided that certain regulatory approvals may be required in connection with any foreclosure on such stock. With respect to the remaining 65%, 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. PG&E Corporation may substitute common stock of Newco, a new corporation formed to hold the equity interests in the LLCs, for the common stock of the Utility in connection with the consummation of the Utility's plan of reorganization. The loans are also secured by substantially all assets of PG&E Corporation and continue to be secured by PG&E Corporation's ownership interest in PG&E National Energy Group, LLC, or PG&E NEG LLC, which is a Delaware limited liability company and the owner of the shares of PG&E NEG and PG&E NEG LLC's equity interest in PG&E NEG.

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 conversion of the notes and exercise of the warrants.

Finally, in connection with the original credit agreement, the lenders had received an option to purchase up to 3% of the shares of PG&E NEG. Under the original credit agreement, PG&E Corporation's exercise of each of its one-year extensions of the loan was conditioned upon PG&E NEG granting affiliates of the lenders an additional option to purchase 1% of the common stock of PG&E NEG, determined on a fully-diluted basis, at an exercise price of $1.00. In connection with a new credit agreement entered into on June 25, 2002, the 1% was reduced to



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approximately .87% of the common stock of PG&E NEG or up to 2.61%. On September 3, 2002, General Electric Capital Corporation, or GECC, gave PG&E Corporation notice that it would put its options to PG&E Corporation under the Option Agreement, and GECC and PG&E Corporation were engaged in a process of appraising the options as provided under the Option Agreement. On October 30, 2002, before the completion of the appraisal process, GECC gave 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. PG&E Corporation and PG&E NEG LLC have agreed with the other holders of options under the Option Agreement that they may exercise their put option any time before March 1, 2003. These options must in any event also be exercised before March 1, 2003. The issuance of the put option by PG&E Corporation was not registered under the Securities Act of 1933 in reliance on the exemption afforded by

Section 4(2).

Pacific Gas and Electric Company did not make any sales of unregistered equity securities during 2002, the period covered by this report.

ITEM 6. Selected Financial Data.

A summary of selected financial information, for each of PG&E Corporation and Pacific Gas and Electric Company for each of the last five fiscal years, is set forth on page 2 under the heading "Selected Financial Data" in the 2002 Annual Report to Shareholders, which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

Pacific Gas and Electric Company's ratio of earnings to fixed charges for the year ended December 31, 2002, was 3.91. Pacific Gas and Electric Company's ratio of earnings to combined fixed charges and preferred stock dividends for the year ended December 31, 2002, was 3.78. The statement of the foregoing ratios, together with the statements of the computation of the foregoing ratios filed as Exhibits 12.1 and 12.2 hereto, are included herein for the purpose of incorporating such information and exhibits into Registration Statement Nos. 33-62488, 33-64136, 33-50707, and 33-61959 relating to Pacific Gas and Electric Company's various classes of debt and first preferred stock outstanding.

ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

A discussion of PG&E Corporation's and Pacific Gas and Electric Company's consolidated results of operations and financial condition is set forth on pages 3 through 70 under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2002 Annual Report to Shareholders, which discussion is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

ITEM 7A. Quantitative and Qualitative Disclosures About Market Risk.

Information responding to Item 7A appears in the 2002 Annual Report to Shareholders on pages 59-67 under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations--Risk Management Activities," and on pages 97-98 and 141-143 under Notes 1 and 11 of the "Notes to the Consolidated Financial Statements" of the 2002 Annual Report to Shareholders, which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

ITEM 8. Financial Statements and Supplementary Data.

Information responding to Item 8 appears on pages 73 through 82 of the 2002 Annual Report to Shareholders under the following headings for PG&E Corporation: "Consolidated Statements of Operations," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Common Stockholders' Equity;" under the following headings for Pacific Gas and Electric Company: "Consolidated Statements of Operations," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Stockholders' Equity;" and under the following headings for PG&E Corporation and Pacific Gas and Electric Company jointly: "Notes to the Consolidated Financial Statements," "Quarterly Consolidated Financial Data (Unaudited)," "Independent Auditors' Report," and "Responsibility for the Consolidated Financial Statements," which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

ITEM 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

Not applicable.



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PART III

ITEM 10. Directors and Executive Officers of the Registrant.

Information regarding executive officers of PG&E Corporation and Pacific Gas and Electric Company is included in a separate item captioned "Executive Officers of the Registrants" contained on pages 72 through 75 in Part I of this report. Other information responding to Item 10 is included under the heading "Item No. 1: Election of Directors of PG&E Corporation and Pacific Gas and Electric Company" and under the heading "Section 16 Beneficial Ownership Reporting Compliance" in the Joint Proxy Statement relating to the 2003 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

ITEM 11. Executive Compensation.

Information responding to Item 11, for each of PG&E Corporation and Pacific Gas and Electric Company, is included under the heading "Compensation of Directors" and under the headings "Summary Compensation Table," "Option/SAR Grants in 2002," "Aggregated Option/SAR Exercises in 2002 and Year-End Option/SAR Values," "Long-Term Incentive Plan--Awards in 2002," "Retirement Benefits," "Employment Contracts/Arrangements," and "Termination of Employment and Change In Control Provisions" in the Joint Proxy Statement relating to the 2003 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

ITEM 12. Security Ownership of Certain Beneficial Owners and Management.

Information responding to Item 12, for each of PG&E Corporation and Pacific Gas and Electric Company, is included under the heading "Security Ownership of Management" and under the heading "Principal Shareholders" in the Joint Proxy Statement relating to the 2003 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

Equity Compensation Plan Information

The following table provides information as of December 31, 2002, concerning shares of PG&E Corporation common stock authorized for issuance under PG&E Corporation's existing equity compensation plans.

| | (a) | (b) | (c) |
|---|---|---|---|
| Plan Category | Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights | Weighted Average Exercise Price of Outstanding Options, Warrants and Rights | Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) |

| | | | |
|---|---|---|---|
| Equity compensation plans approved by shareholders | 31,019,981$ | 22 22 | 18,337,728(1) |
| Equity compensation plans not approved by shareholders | --$ | -- | -- |
| Total equity compensation plans | 31,019,981$ | 22.22 | 18,337,728 |

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(1)
Represents the total number of shares available for issuance under PG&E Corporation's Long-Term Incentive Program (LTIP) as of December 31, 2002, as stock options, stock appreciation rights, dividend equivalents, performance units, restricted stock, common stock equivalents, or other stock-based awards, including Special Incentive Stock Ownership Premiums Outstanding stock-based awards have been granted under various components of the LTIP as stock options, under the Non-Employee Director Stock Incentive Plan (as restricted stock), and under the Executive Stock Ownership Program (as stock equivalents paid out in stock upon retirement or termination). No more than 5,000,000 of the reserved shares may be awarded as restricted stock. For a description of the Corporation's Long-Term Incentive Program, see Note 14 to the Consolidated Financial Statements.

ITEM 13. Certain Relationships and Related Transactions

Information responding to Item 13, for each of PG&E Corporation and Pacific Gas and Electric Company, is included under the heading "Certain Relationships and Related Transactions" in the Joint Proxy Statement relating to the 2003 Annual Meetings of Shareholders, which information is hereby incorporated by reference



ITEM 14. Controls and Procedures.

Based on an evaluation of PG&E Corporation's and the Utility's disclosure controls and procedures conducted on February 7, 2003 and February 5, 2003, respectively, PG&E Corporation's and the Utility's principal executive officers and principal financial officers have concluded that such controls and procedures effectively ensure that information required to be disclosed by PG&E Corporation and the Utility in reports that the companies file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms

There were no significant changes in internal controls or in other factors that could significantly affect these controls subsequent to the date of their evaluation

ITEM 15. Exhibits, Financial Statement Schedules, and Reports on Form 8-K

(a)
The following documents are filed as a part of this report

1.
The following consolidated financial statements, supplemental information, and independent auditors' report are contained in the 2002 Annual Report to Shareholders, which have been incorporated by reference in this report

Consolidated Statements of Operations for the Years Ended December 31, 2002, 2001, and 2000, for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Balance Sheets at December 31, 2002, and 2001 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Common Stockholders' Equity for the Years Ended December 31, 2002, 2001, and 2000, for PG&E Corporation.

Consolidated Statements of Stockholders' Equity for the Years Ended December 31, 2002, 2001, and 2000 for Pacific Gas and Electric Company.

Notes to Consolidated Financial Statements.

Quarterly Consolidated Financial Data (Unaudited).

Independent Auditors' Report (Deloitte & Touche LLP).

Independent Auditors' Report (Deloitte & Touche LLP) included at page 94 of this Form 10-K/A.

2.
Financial statement schedules:

I--Condensed Financial Information of Parent for the Years Ended December 31, 2002, 2001, and 2000.

II--Consolidated Valuation and Qualifying Accounts for each of PG&E Corporation and Pacific Gas and Electric Company for the Years Ended December 31, 2002, 2001, and 2000.

Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements including the notes thereto.

3.
Exhibits required to be filed by Item 601 of Regulation S-K:

3.1Restated Articles of Incorporation of PG&E Corporation effective as of May 5, 2000 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2000 (File No. 1-12609), Exhibit 3.1)
3.2Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2)
3.3Bylaws of PG&E Corporation amended as of February 19, 2003 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 3.3)
3.4Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of May 6, 1998 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-2348), Exhibit 3.1)



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3.5Bylaws of Pacific Gas and Electric Company amended as of February 19, 2003 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 3.5)

4.1First and Refunding Mortgage of Pacific Gas and Electric Company dated December 1, 1920, and supplements thereto dated April 23, 1925, October 1, 1931, March 1, 1941, September 1, 1947, May 15, 1950, May 1, 1954, May 21, 1958, November 1, 1964, July 1, 1965, July 1, 1969, January 1, 1975, June 1, 1979, August 1, 1983, and December 1, 1988 (incorporated by reference to Registration No. 2-1324, Exhibits B-1, B-2, and B-3; Registration No. 2-4676, Exhibit B-22; Registration No. 2-7203, Exhibit B-23; Registration No. 2-8475, Exhibit B-24; Registration No. 2-10874, Exhibit 4B; Registration No. 2-14144, Exhibit 4B; Registration No. 2-22910, Exhibit 2B; Registration No. 2-23759, Exhibit 2B; Registration No. 2-35106, Exhibit 2B; Registration No. 2-54302, Exhibit 2C; Registration No. 2-64313, Exhibit 2C; Registration No. 2-86849, Exhibit 4.3; and Pacific Gas and Electric Company's Form 8-K dated January 18, 1989 (File No. 1-2348), Exhibit 4.2)

4.2Indenture related to PG&E Corporation's 7.5% Convertible Subordinated Notes due June 2007, dated as of June 25, 2002, between PG&E Corporation and U.S. Bank, N.A., as Trustee (incorporated by reference to PG&E Corporation's Form 8-K filed June 26, 2002 (File No. 1-12609), Exhibit 99.1).

4.3Supplemental Indenture related to PG&E Corporation's 9.50% Convertible Subordinated Notes due June 2010, dated as of October 18, 2002, between PG&E Corporation and U.S. Bank, N.A., as Trustee (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2002 (File No. 1-12609), Exhibit 4.1)

4.4Warrant Agreement, dated as of June 25, 2002, by and among PG&E Corporation, LB I Group Inc., and each other entity named on the signature pages thereto (incorporated by reference to PG&E Corporation's Form 8-K filed June 26, 2002 (File No. 1-12609), Exhibit 99.9).

4.5Warrant Agreement, dated as of October 18, 2002, by and among PG&E Corporation, LB I Group Inc., and each other entity named on the signature pages thereto (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2002 (File No. 1-12609), Exhibit 4.2)

4.6Form of Rights Agreement dated as of December 22, 2000, between PG&E Corporation and Mellon Investor Services LLC, including the Form of Rights Certificate as Exhibit A, the Summary of Rights to Purchase Preferred Stock as Exhibit B, and the Form of Certificate of Determination of Preferences for the Preferred Stock as Exhibit C (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 4.2)

10.1The Gas Accord Settlement Agreement, together with accompanying tables, adopted by the California Public Utilities Commission on August 1, 1997, in Decision 97-08-055 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 1997 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2), as amended by Operational Flow Order (OFO) Settlement Agreement, approved by the California Public Utilities Commission on February 17, 2000, in Decision 00-02-050, as amended by Comprehensive Gas OII Settlement Agreement, approved by the California Public Utilities Commission on May 18, 2000, in Decision 00-05-049 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2000 (File No. 1-12609 and File No. 1-2348), Exhibit 10); and the Gas Accord II Settlement Agreement, approved by the California Public Utilities Commission on August 22, 2002, in Decision 01-09-016 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.1)

10.2Second Amended and Restated Credit Agreement, dated as of October 18, 2002, among PG&E Corporation, as Borrower, the Lenders party thereto, Lehman Commercial Paper Inc., as Administrative Agent, and other parties (incorporated by reference to PG&E Corporation's Form 8-K filed October 22, 2002 (File No. 1-12609), Exhibit 99.1)

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10.3.1Utility Stock Pledge Agreement (35 percent)--Continued Tranche B Loan, dated as of October 18, 2002 (incorporated by reference to PG&E Corporation's Form 8-K filed October 22, 2002 (File No. 1-12609), Exhibit 99.2)

10.3.2Utility Stock Pledge Agreement (35 percent)--New Tranche B Loan, dated as of October 18, 2002 (incorporated by reference to PG&E Corporation's Form 8-K filed October 22, 2002 (File No. 1-12609), Exhibit 99.3)

10.3.3Utility Stock Pledge Agreement (65 percent)--Continued Tranche B Loan, dated as of October 18, 2002 (incorporated by reference to PG&E Corporation's Form 8-K filed October 22, 2002 (File No. 1-12609), Exhibit 99.4)

10.3.4Utility Stock Pledge Agreement (65 percent)--New Tranche B Loan, dated as of October 18, 2002 (incorporated by reference to PG&E Corporation's Form 8-K filed October 22, 2002 (File No. 1-12609), Exhibit 99.5)

10.4Amended and Restated Credit Agreement among PG&E National Energy Group, Inc. and Chase Manhattan Bank dated August 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2001 (File No. 1-12609), Exhibit 10.3

10.5Second Amendment, dated as of October 18, 2002, to the Amended and Restated Credit Agreement, dated as of August 22, 2001, among PG&E National Energy Group, Inc., JPMorgan Chase Bank (formerly known as The Chase Manhattan Bank), as Issuing Bank, the several lenders from time to time parties thereto, the Documentation Agents thereunder, the Syndication Agents thereunder, and JPMorgan Chase Bank, as Administrative Agent. (incorporated by reference to PG&E National Energy Group, Inc.'s Form 8-K filed October 28, 2002) (File No. 333-66032), Exhibit 10.1)

10.6Credit Agreement, dated as of May 29, 2001, among PG&E National Energy Group Construction Company, LLC, as Borrower, the lenders from time to time parties thereto, and Societe Generale, as Administrative Agent and Security Agent (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.6)

10.7First Amendment to Credit Agreement, dated as of June 5, 2002, among PG&E National Energy Group Construction Company, LLC, the lenders party thereto, and Societe Generale, as Administrative Agent and Security Agent (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.7)

10.8Guarantee and Agreement (Turbine Credit Agreement), dated as of May 29, 2001, made by PG&E National Energy Group, Inc. in favor of Societe Generale, as Security Agent (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.8)

10.9Amended and Restated Credit Agreement, dated as of March 15, 2002, among GenHoldings I, LLC, as Borrower, Societe Generale, as Administrative Agent and a Lead Arranger, Citibank, N.A., as Syndication Agent and a Lead Arranger, the other agents and arrangers thereunder, JP Morgan Chase Bank, as issuer of the Letters of Credit thereunder, the financial institutions party thereto from time to time, and various other parties (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.9)

10.10Amended and Restated Guarantee and Agreement dated as of March 15, 2002, by PG&E National Energy Group, Inc., in favor of Societe Generale, as Administrative Agent (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.10)

10.11Acknowledgement and Amendment Agreement, (GenHoldings I, LLC) dated as of April 5, 2002, by and among PG&E National Energy Group, Inc., GenHoldings

I, LLC, as Borrower, Societe Generale, as Administrative Agent, and the banks and lenders party thereto (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.11)



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10.12Waiver and Amendment Agreement, dated as of September 25, 2002, among GenHoldings I, LLC, as Borrower, Societe Generale, as Administrative Agent, Citibank N.A., as Depository Agent, and the banks and lender group agents party thereto (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.12)

10.13Third Waiver and Amendment, dated as of November 14, 2002, among GenHoldings I, LLC, as Borrower, various lenders identified as the GenHoldings Lenders, Societe Generale, as Administrative Agent, Citibank, N.A., as Security Agent, and acknowledged and agreed to by PG&E National Energy Group, Inc. (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.13)

10.14Fourth Waiver and Amendment dated as of December 23, 2002, among GenHoldings I, LLC, various lenders identified as the GenHoldings Lenders, the Administrative Agent, and acknowledged and agreed to by PG&E National Energy Group, Inc. (incorporated by reference to PG&E Corporation's and PG&E National Energy Group, Inc.'s Form 8-K filed January 16, 2003) (File Nos. 1-12609 and 333-66032), Exhibit 99.1)

10.15Second Omnibus Restructuring Agreement dated as of December 4, 2002 among La Paloma Generating Company, LLC, La Paloma Generating Trust, Ltd., and various other parties, including PG&E National Energy Group, Inc. (incorporated by reference to PG&E Corporation's and PG&E National Energy Group, Inc.'s Form 8-K filed January 16, 2003) (File Nos. 1-12609 and 333-66032), Exhibit 99.2)

10.16Priority Credit and Reimbursement Agreement among La Paloma Generating Company, LLC, La Paloma Generating Trust Ltd., Wilmington Trust Company, in its individual capacity and as Trustee, Citibank, N.A., as the Priority Working Capital L/C Issuer, the Several Priority Lenders from time to time parties hereto, Citibank, N.A., as administrative agent, and Citibank, N.A., as priority agent, dated as of December 4, 2002 (incorporated by reference to PG&E Corporation's and PG&E National Energy Group, Inc.'s Form 8-K filed January 16, 2003) (File Nos. 1-12609 and 333-66032), Exhibit 99.3)

10.17Guarantee and Agreement (La Paloma), dated as of April 6, 2001, by PG&E National Energy Group, Inc. in favor of Citibank, N.A., as Security Agent (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.17)

10.18Second Omnibus Restructuring Agreement dated as of December 4, 2002 among Lake Road Generating Company, LLC, Lake Road Generating Trust, Ltd., and various other parties, including PG&E National Energy Group, Inc. (incorporated by reference to PG&E Corporation's and PG&E National Energy Group, Inc.'s Form 8-K filed January 16, 2003) (File Nos. 1-12609 and 333-66032), Exhibit 99.4)

10.19Priority Credit and Reimbursement Agreement among Lake Road Generating Company, LLC, Lake Road Trust Ltd., Wilmington Trust Company, in its individual capacity and as Trustee, Citibank, N.A., as the Priority L/C Issuer, the Several Priority Lenders from time to time parties hereto, Citibank, N.A., as administrative agent, and Citibank, N.A., as priority agent, dated as of December 4, 2002 (incorporated by reference to PG&E Corporation's and PG&E National Energy Group, Inc.'s Form 8-K filed January 16, 2003) (File Nos. 1-12609 and 333-66032), Exhibit 99.5)

10.20Amendment, Waiver and Consent Agreement dated as of November 6, 2002, among

La Paloma Generating Company, LLC, La Paloma Generating Trust, Ltd., Wilmington Trust Company as Trustee, Citibank, N.A., as administrative agent and security agent, and various other parties (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.20)

10.21Guarantee and Agreement (Lake Road), dated as of April 6, 2001, made by PG&E National Energy Group, Inc. in favor of Citibank, N.A., as Security Agent (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.21)



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*10.22PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2001 (File No. 1-12609), Exhibit 10.4)

*10.23Agreement and Release between PG&E Corporation and Thomas G. Boren, dated December 18, 2002 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.23)

*10.24Description of Compensation Arrangement between PG&E Corporation and Peter Darbee (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1999 (File No. 1-12609), Exhibit 10.3)

*10.25Letter regarding Compensation Arrangement between PG&E Corporation and Thomas B. King dated November 4, 1998 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.6)

*10.26Letter regarding Compensation Arrangement between PG&E Corporation and Lyn E. Maddox dated April 25, 1997 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.7)

*10.27Letter Regarding Relocation Arrangement Between PG&E Corporation and Thomas B. King dated March 16, 2000 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2000 (File No. 1-12609), Exhibit 10)

*10.28Description of Relocation Arrangement Between PG&E Corporation and Lyn E. Maddox (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.9)

*10.29PG&E Corporation Senior Executive Officer Retention Program approved December 20, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10)

*10.30.1Letter regarding retention award to Robert D. Glynn, Jr. dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.1)

*10.30.2Letter regarding retention award to Gordon R. Smith dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.2)

*10.30.3Letter regarding retention award to Peter A. Darbee dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.3)

*10.30.4Letter regarding retention award to Bruce R. Worthington dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.4)

*10.30.5Letter regarding retention award to G. Brent Stanley dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.5)

*10.30.6Letter regarding retention award to Daniel D. Richard, Jr. dated January

22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.6)

*10.30.7Letter regarding retention award to James K. Randolph dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.7)

*10.30.8Letter regarding retention award to Gregory M. Rueger dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.8)

*10.30.9Letter regarding retention award to Kent M. Harvey dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.9)



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*10.30.10Letter regarding retention award to Roger J. Peters dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.10))

*10.30.11Letter regarding retention award to Lyn E. Maddox dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.12)

*10.30.12Letter regarding retention award to P. Chrisman Iribe dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.13)

*10.30.13Letter regarding retention award to Thomas B. King dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.14)

*10.31Pacific Gas and Electric Company Management Retention Program (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2001 (File No. 1-12609), Exhibit 10.1)

*10.32PG&E Corporation Management Retention Program (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2001 (File No. 1-12609), Exhibit 10.2)

*10.33PG&E Corporation Deferred Compensation Plan for Non-Employee Directors, as amended and restated effective as of July 22, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1998 (File No. 1-12609), Exhibit 10.2)

*10.34Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2002 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2001 (File No. 1-12609), Exhibit 10.25)

*10.35Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2003 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.35)

*10.36Supplemental Executive Retirement Plan of the Pacific Gas and Electric Company amended as of September 19, 2001 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2001 (File No. 1-2248), Exhibit 10.16)

*10.37.1Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Robert D. Glynn, Jr. dated December 20, 2002 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.37.1)

*10.37.2Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Bruce R. Worthington dated December 20, 2002 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.37.2)

*10.37.3Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Gregory M. Rueger dated December 20, 2002 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.37.3)

*10.37.4 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Gordon R. Smith dated December 20, 2002 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.37.4)

*10.37.5 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and James K. Randolph dated December 20, 2002 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.37.5)



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*10.37.6 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Thomas G. Boren dated December 20, 2002 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.37.6)

*10.38 Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for fiscal year 1989 (File No. 1-2348), Exhibit 10.16)

*10.39 Postretirement Life Insurance Plan of the Pacific Gas and Electric Company (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for fiscal year 1991 (File No. 1-2348), Exhibit 10.16)

*10.40 PG&E Corporation Retirement Plan for Non-Employee Directors, as amended and terminated January 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 1997 (File No. 1-12609), Exhibit 10.13)

*10.41 PG&E Corporation Long-Term Incentive Program, as amended May 16, 2001, including the PG&E Corporation Stock Option Plan, Performance Unit Plan, and Non-Employee Director Stock Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10)

*10.42 PG&E Corporation Executive Stock Ownership Program, amended as of September 19, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.20)

*10.43 PG&E Corporation Officer Severance Policy, amended as of December 19, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.43)

*10.44 PG&E Corporation Director Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.1)

*10.45 PG&E Corporation Officer Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.2)

*10.46 PG&E Corporation Form of Restricted Stock Award Agreement granted under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.46)

11 Computation of Earnings Per Common Share (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 11)

12.1 Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 12.1)

12.2 Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 12.2)

13The following portions of the 2002 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company are included: "Selected Financial Data," "Management's Discussion and Analysis of Financial Condition and Results of Operations," "Independent Auditors' Report," "Responsibility for Consolidated Financial Statements," financial statements of PG&E Corporation entitled "Consolidated Statements of Operations," "Consolidated Balance Sheets, " "Consolidated Statements of Cash Flows," and "Consolidated Statements of Common Stockholders' Equity," financial statements of Pacific Gas and Electric Company entitled "Consolidated Statements of Operations," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," "Consolidated Statements of Stockholders' Equity," "Notes to Consolidated Financial Statements," and "Quarterly Consolidated Financial Data (Unaudited)"

21Subsidiaries of the Registrant (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 21)



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23Independent Auditors' Consent (Deloitte & Touche LLP)

24.1Resolutions of the Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company authorizing the execution of the Form 10-K (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 24.1)

24.2Powers of Attorney (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 24.2)

99.1Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002

99.2Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002

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Management contract or compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 14(c) of Form 10-K.

The exhibits filed herewith are attached hereto (except as noted) and those indicated above which are not filed herewith were previously filed with the Commission and are hereby incorporated by reference. All exhibits filed herewith or incorporated by reference are filed with respect to both PG&E Corporation (File No. 1-12609) and Pacific Gas and Electric Company (File No. 1-2348), unless otherwise noted. Exhibits will be furnished to security holders of PG&E Corporation or Pacific Gas and Electric Company upon written request and payment of a fee of $0.30 per page, which fee covers only the registrants' reasonable expenses in furnishing such exhibits. The registrants agree to furnish to the Commission upon request a copy of any instrument defining the rights of long-term debt holders not otherwise required to be filed hereunder.

(b)
Reports on Form 8-K

Reports on Form 8-K(1) during the quarter ended December 31, 2002, and through the date hereof:

1.October 3, 2002Item 5. Other Events

A.PG&E Corporation-new waiver extension

B Pacific Gas and Electric Company bankruptcy Monthly Operating Report

Item 7. Financial Statements, Pro Forma, Financial Information, and Exhibits

Exhibit 99 1--Amendment to Second Amended and Restated Waiver and Amendment Agreement, dated October 1, 2002, by and among PG&E Corporation, PG&E National Energy Group, LLC, Lehman Commercial Paper Inc. as administrative agent, and certain of the lenders party to the Amended and Restated Credit Agreement dated as of June 25, 2002

Exhibit 99 2--Pacific Gas and Electric Company Income Statement for the month ended August 31, 2002, and Balance Sheet dated August 31, 2002

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2.October 10, 2002--Item 5. Other Events

PG&E Corporation only

A.PG&E National Energy Group, Inc. credit ratings downgrades

3.October 15, 2002 Item 5. Other Events

A.Pacific Gas and Electric Company's 2003 Cost of Capital Proceeding

B.Pacific Gas and Electric Company bankruptcy

4.October 21, 2002--Item 5. Other Events

PG&E Corporation only

A.PG&E National Energy Group credit ratings downgrades

5.October 22, 2002--Item 5. Other Events

PG&E Corporation only

Item 7. Financial Statements, Pro Forma Financial Information, and Exhibits

Exhibit 99.1--Second and Amended Restated Credit Agreement, dated as of October 18, 2002, among PG&E Corporation, the lenders party thereto, Lehman Commercial Paper Inc., as Administrative Agent, and other parties

Exhibit 99.2--Utility Stock Pledge Agreement (35 percent)--Continued Tranche B Loan, dated as of October 18, 2002

Exhibit 99.3--Utility Stock Pledge Agreement (35 percent)--New Tranche B Loan, dated as of October 18, 2002

Exhibit 99.4--Utility Stock Pledge Agreement (65 percent)--Continued Tranche B Loan, dated as of October 18, 2002

Exhibit 99.5--Utility Stock Pledge Agreement (65 percent)--New Tranche B Loan, dated as of October 18, 2002

6.November 18, 2002 Item 5. Other Events

PG&E Corporation only

A.PG&E National Energy Group, Inc. defaults

B.PG&E National Energy Group, Inc. credit ratings

7.December 4, 2002--Item 5. Other Events

A.Pacific Gas and Electric Company 2002 Attrition Revenue Adjustment

B.Pacific Gas and Electric Company bankruptcy: Monthly Operating Report

Item 7. Financial Statements, Pro Forma, Financial Information, and Exhibits

Exhibit 99.1--Pacific Gas and Electric Company Income Statement for the month ended October 31, 2002, and Balance Sheet dated October 31, 2002



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8.January 6, 2003 Item 5. Other Events

A.Resumption of Power Procurement

B.Pacific Gas and Electric Company bankruptcy: Monthly Operating Report

C.General Rate Case 2003

D.Pacific Gas and Electric Company bankruptcy: Monthly Operating Report

Item 7. Financial Statements, Pro Forma, Financial Information, and Exhibits

Exhibit 99.1--Pacific Gas and Electric Company Income Statement for the month ended November 30, 2002, and Balance Sheet dated November 30, 2002

9.January 16, 2003Item 5. Other Events

PG&E Corporation and PG&E National Energy Group, Inc.

Item 7. Financial Statements, Pro Forma, Financial Information, and Exhibits

Exhibit 99.1--Fourth Waiver and Amendment dated as of December 23, 2002, among GenHoldings I, LLC, various lenders identified as the GenHoldings Lenders, the Administrative Agent, and acknowledged and agreed to by PG&E National Energy Group, Inc.

Exhibit 99.2--Second Omnibus Restructuring Agreement dated as of December 4, 2002 among La Paloma Generating Company, LLC, La Paloma Generating Trust, Ltd., and various other parties, including PG&E National Energy Group, Inc.

Exhibit 99.3--Priority Credit and Reimbursement Agreement among La Paloma Generating Company, LLC, La Paloma Generating Trust Ltd., Wilmington Trust Company, in its individual capacity and as Trustee, Citibank, N.A., as the Priority Working Capital L/C Issuer, the Several Priority Lenders from time to time parties hereto, Citibank, N.A., as administrative agent, and Citibank, N.A., as priority agent, dated as of December 4, 2002

Exhibit 99.4--Second Omnibus Restructuring Agreement dated as of December 4, 2002 among Lake Road Generating Company, LLC, Lake Road Generating Trust, Ltd., and various other parties, including PG&E National Energy Group, Inc.

Exhibit 99.5--Priority Credit and Reimbursement Agreement among Lake Road Generating Company, LLC, Lake Road Trust Ltd., Wilmington Trust Company, in its individual capacity and as Trustee, Citibank, N.A., as the Priority L/C Issuer, the Several Priority Lenders from time to time parties hereto, Citibank, N.A., as administrative agent, and Citibank, N.A., as priority agent, dated as of December 4, 2002

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(1)
Unless otherwise noted, all reports were filed under Commission File Number 1-2348 (Pacific Gas and Electric Company) and Commission File Number 1-12609 (PG&E Corporation).



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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrants have duly caused this Amendment No. 1 on Form 10-K/A to their Annual Report on Form 10-K for the year ended December 31, 2002 to be signed on their behalf by the undersigned, thereunto duly authorized, in the City and County of San Francisco, on the 5th day of March, 2003.

| PG&E CORPORATION (Registrant) | PACIFIC GAS AND ELECTRIC COMPANY (Registrant) |
|---|---|
| By GARY P. ENCINAS | By GARY P. ENCINAS |
| (Gary P. Encinas, Attorney-in-Fact) | (Gary P. Encinas, Attorney-in-Fact) |



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I, Robert D. Glynn, Jr., certify that:

1. I have reviewed this annual report on Form 10-K/A of PG&E Corporation;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

*

designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

*

evaluated the effectiveness of the registrant's disclosure controls and procedures within 90 days prior to the filing date of this annual report (the Evaluation Date); and

*

presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

*

all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

*

any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 5, 2003

ROBERT D. GLYNN, JR.

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ROBERT D. GLYNN, JR.
Chairman, Chief Executive Officer and President
PG&E Corporation



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I, Peter A. Darbee, certify that:

1. I have reviewed this annual report on Form 10-K/A of PG&E Corporation;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

* designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

* evaluated the effectiveness of the registrant's disclosure controls and procedures within 90 days prior to the filing date of this annual report (the Evaluation Date); and

* presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

* all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

* any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 5, 2003

PETER A. DARBEE
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PETER A. DARBEE
Senior Vice President and Chief Financial Officer
PG&E Corporation



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I, Gordon R. Smith, certify that:

1. I have reviewed this annual report on Form 10-K/A of Pacific Gas and Electric Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

*
designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

*
evaluated the effectiveness of the registrant's disclosure controls and procedures within 90 days prior to the filing date of this annual report (the Evaluation Date); and

*
presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

*
all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

*
any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls;

and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 5, 2003

GORDON R. SMITH
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GORDON R. SMITH
President and Chief Executive Officer
Pacific Gas and Electric Company



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I, Kent M. Harvey, certify that:

1. I have reviewed this annual report on Form 10-K/A of Pacific Gas and Electric Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

*
designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

*
evaluated the effectiveness of the registrant's disclosure controls and procedures within 90 days prior to the filing date of this annual report (the Evaluation Date); and

*
presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

*
all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

*
any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 5, 2003

KENT M. HARVEY

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KENT M. HARVEY
Senior Vice President, Chief Financial Officer, and Treasurer
Pacific Gas and Electric Company



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INDEPENDENT AUDITORS' REPORT

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

We have audited the consolidated financial statements of PG&E Corporation and subsidiaries and of Pacific Gas and Electric Company (a Debtor-in-Possession) and subsidiaries as of December 31, 2002 and 2001, and for each of the three years in the period ended December 31, 2002 and have issued our report thereon dated February 24, 2003, which report includes explanatory paragraphs relating to (i) PG&E Corporation's adoption of new accounting standards in 2002 relating to accounting for goodwill and intangible assets, impairment of long-lived assets, discontinued operations, gains and losses on debt extinguishment, certain derivative contracts and PG&E Corporation's change in method of reporting gains and losses associated with energy trading contracts from the gross method to the net method and retroactive reclassification of the consolidated statements of operations for 2001 and 2000, (ii) PG&E Corporation's and Pacific Gas and Electric Company's adoption of new accounting standards in 2001 relating to derivative contracts, and (iii) the ability of PG&E Corporation and Pacific Gas and Electric Company to continue as going concerns. Such consolidated financial statements are included in the combined 2002 Annual Report to Shareholders (of PG&E Corporation and Pacific Gas and Electric Company) and are incorporated herein by reference. Our audits also included the respective consolidated financial statement schedules of PG&E Corporation and Pacific Gas and Electric Company, listed in Item 15(a)2. These consolidated financial statement schedules are the responsibility of the respective managements of PG&E Corporation and Pacific Gas and Electric Company. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statements schedules, when considered in relation to the respective basic financial statements of PG&E Corporation and Pacific Gas and Electric Company taken as a whole, present fairly in all material respects the information set forth therein.

DELOITTE & TOUCHE LLP
San Francisco, California
February 24, 2003



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SCHEDULE I--CONDENSED FINANCIAL INFORMATION OF PARENT
CONDENSED BALANCE SHEETS

| (in millions) | December 31, 2002 | December 31, 2001 |
|---|---|---|
| Assets: | | |
| Cash and cash equivalents | $ 182 | $ 348 |
| Restricted cash | 377 | -- |
| Advances to affiliates | 479 | 404 |
| Note receivable from subsidiary | 208 | 308 |
| Other current assets | 1 | 1 |
| Total current assets | 1,247 | 1,061 |
| Equipment | 20 | 19 |
| Accumulated depreciation | (12) | (9) |
| Net equipment | 8 | 10 |
| Investments in subsidiaries | 2,963 | 4,595 |
| Other investments | 33 | 61 |
| Deferred income taxes | 702 | 42 |
| Other | 34 | 57 |
| Total Assets | $ 4,987 | $ 5,826 |
| Liabilities and Stockholders' Equity: | | |
| Current Liabilities: | | |
| Accounts payable--related parties | $ 31 | $ 22 |
| Accounts payable--other | 38 | 17 |
| Note payable to subsidiary | -- | 75 |
| Accrued taxes | 133 | 309 |
| Other | 57 | 25 |
| Total current liabilities | 259 | 448 |
| Noncurrent Liabilities: | | |
| Long-term debt | 976 | 904 |
| Other | 46 | 182 |
| Total noncurrent liabilities | 1,022 | 1,086 |
| Stockholders' Equity: | | |
| Common stock | 6,274 | 5,986 |
| Common stock held by subsidiary | (690) | (690) |
| Reinvested earnings | (1,878) | (1,004) |
| Total stockholders' equity | 3,706 | 4,292 |
| Total Liabilities and Stockholders' Equity | $ 4,987 | $ 5,826 |

SCHEDULE I--CONDENSED FINANCIAL INFORMATION OF PARENT--(Continued)
CONDENSED STATEMENTS OF INCOME
For the Years Ended December 31, 2002, 2001, and 2000

| (in millions except per share amounts) | 2002 | 2001 | 2000 |
|---|---|---|---|
| Administrative service revenue | $ 96 | $ 95 | $ 111 |
| Equity in earnings (losses) of subsidiaries | (434) | 1,037 | (3,415) |
| Operating expenses | (141) | (108) | (111) |
| Interest income | 30 | 35 | 20 |
| Interest expense | (253) | (132) | (27) |
| Other income | 81 | 4 | 2 |
| Income (Loss) Before Income Taxes | (621) | 931 | (3,420) |
| Less: Income Taxes | (564) | (52) | (4) |
| Income (Loss) from continuing operations | (57) | 983 | (3,416) |
| Discontinued operations | (756) | 107 | 59 |
| Cumulative effect of a change in an accounting principle | (61) | 9 | -- |
| Net income (loss) before intercompany elimination | (874) | 1,099 | (3,357) |
| Eliminations of intercompany (profit) loss | -- | -- | (7) |
| Net income (loss) | $ (874) | $1,099 | $(3,364) |
| Weighted Average Common Shares Outstanding | 371 | 363 | 362 |
| Earnings (Loss) Per Common Share, Basic | $(2.36) | $ 3.03 | $ (9.29) |
| Earnings (Loss) Per Common Share, Diluted | $(2.36) | $ 3.02 | $ (9.29) |

CONDENSED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2002, 2001, and 2000

| (in millions) | 2002 | 2001 | 2000 |
|---|---|---|---|
| Cash Flows from Operating Activities: | | | |
| Net income (loss) | $ (874) | $ 1,099 | $(3,364) |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | | |
| Equity in earnings of subsidiaries | 1,623 | (1,143) | 3,316 |
| Deferred taxes | (525) | (51) | 20 |
| Distributions from consolidated subsidiaries | -- | -- | 475 |
| Other-net | (608) | 218 | 232 |
| Net cash provided by operating activities | $ (382) | $ 123 | $ 679 |
| Cash Flows From Investing Activities | | | |
| Capital expenditures | (1) | (4) | 1 |
| Investment in subsidiaries | -- | -- | (555) |
| Loans to subsidiaries | -- | -- | (308) |
| Return of capital by Utility (share repurchases) | -- | -- | 275 |
| Other-net | -- | -- | (9) |
| Net cash provided (used) by investing activities | $ (1) | $ (4) | $ (596) |

| | | | |
|---|---|---|---|
| Cash Flows From Financing Activities. | | | |
| Common stock issued | 217 | 15 | 65 |
| Common stock repurchased | -- | (1) | (2) |
| Loans from subsidiary | -- | -- | 75 |
| Long-term debt issued | 908 | 904 | -- |
| Long-term debt matured, redeemed, or repurchased | (908) | -- | -- |
| Short-term debt issued (redeemed) | -- | (931) | 405 |
| Dividends paid | -- | (109) | (436) |
| Other-net | -- | -- | 6 |
| Net cash provided (used) by financing activities | $ 217 | $ (122) | $ 113 |
| Net Change in Cash and Cash Equivalents | (166) | (3) | 196 |
| Cash and Cash Equivalents at January 1 | 348 | 351 | 155 |
| Cash and Cash Equivalents at December 31 | $ 182 | $ 348 | $ 351 |



PG&E CORPORATION
SCHEDULE II--CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2002, 2001, and 2000

| Column A | | Column B | Column C | | Column D | Column E |
|---|---|---|---|---|---|---|
| | | | Additions | | | |
| (in millions) | Description | Balance at Beginning of Period | Charged to Costs and Expenses | Charged to Other Accounts | Deductions | Balance at End of Period |
| Valuation and qualifying accounts deducted from assets | | | | | | |
| 2002: | | | | | | |
| Allowance for uncollectible accounts (2) | | $ 89 | 58 | (2) | 32(1) | 113 |
| 2001: | | | | | | |
| Allowance for uncollectible accounts (2) | | $ 71 | $ 82 | $ -- | $ 64(1) | $ 89 |
| Provision for loss on generation-related regulatory assets and undercollected purchased power costs (3) | | $ 6,939 | $ -- | $ -- | $ 6,939 | $ -- |
| 2000: | | | | | | |
| Allowance for uncollectible accounts (2) | | $ 65 | $ 48 | $ 2 | $ 44(1) | $ 71 |
| Provision for loss on generation-related regulatory assets and undercollected purchased power costs (3) | | $ -- | $ 6,939 | $ -- | $ -- | $ 6,939 |

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(1)
Deductions consist principally of write-offs, net of collections of receivables previously written off.

(2)
Allowance for uncollectible accounts is deducted from "Accounts Receivable Customers, net" and "Accounts Receivable Energy Marketing."

(3)
Provision was deducted from "Regulatory Assets."



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PACIFIC GAS AND ELECTRIC COMPANY
A DEBTOR-IN-POSSESSION
SCHEDULE II--CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2002, 2001, and 2000

| Column A | | Column B | Column C | | Column D | Column E |
| --- | --- | --- | --- | --- | --- | --- |
| | | | Additions | | | |
| (in millions) | Description | Balance at Beginning of Period | Charged to Costs and Expenses | Charged to Other Accounts | Deductions | Balance at End of Period |
| Valuation and qualifying accounts deducted from assets: | | | | | | |
| 2002· | | | | | | |
| Allowance for uncollectible accounts (2) | | $ 48 | $ 35 | $ (2) | $ 23(1) | $ 58 |
| 2001 | | | | | | |
| Allowance for uncollectible accounts (2) | | $ 52 | $ 24 | -- | $ 28(1) | $ 48 |
| Provision for loss on generation-related regulatory assets and undercollected purchased power costs (3) | | $ 6,939 | $ -- | $ -- | $ 6,939 | $ -- |
| 2000 | | | | | | |
| Allowance for uncollectible accounts (2) | | $ 46 | $ 19 | 2 | $ 15(1) | $ 52 |
| Provision for loss on generation-related regulatory assets and undercollected purchased power costs (3) | | $ -- | $ 6,939 | $ -- | $ -- | $ 6,939 |

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(1)
Deductions consist principally of write-offs, net of collections of receivables previously written off.

(2)
Allowance for uncollectible accounts is deducted from "Accounts Receivable Customers, net."

(3)
Provision was deducted from "Regulatory Assets."

EXHIBIT INDEX

| Exhibit Number | Exhibit Description |
|---|---|
| 3.1 | Restated Articles of Incorporation of PG&E Corporation effective as of May 5, 2000 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2000 (File No. 1-12609), Exhibit 3.1) |
| 3.2 | Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2) |
| 3.3 | Bylaws of PG&E Corporation amended as of February 19, 2003 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 3.3) |
| 3.4 | Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of May 6, 1998 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-2348), Exhibit 3.1) |
| 3.5 | Bylaws of Pacific Gas and Electric Company amended as of February 19, 2003 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 3.5) |
| 4.1 | First and Refunding Mortgage of Pacific Gas and Electric Company dated December 1, 1920, and supplements thereto dated April 23, 1925, October 1, 1931, March 1, 1941, September 1, 1947, May 15, 1950, May 1, 1954, May 21, 1958, November 1, 1964, July 1, 1965, July 1, 1969, January 1, 1975, June 1, 1979, August 1, 1983, and December 1, 1988 (incorporated by reference to Registration No. 2-1324, Exhibits B-1, B-2, and B-3; Registration No. 2-4676, Exhibit B-22; Registration No. 2-7203, Exhibit B-23; Registration No. 2-8475, Exhibit B-24; Registration No. 2-10874, Exhibit 4B; Registration No. 2-14144, Exhibit 4B; Registration No. 2-22910, Exhibit 2B; Registration No. 2-23759, Exhibit 2B; Registration No. 2-35106, Exhibit 2B; Registration No. 2-54302, Exhibit 2C; Registration No. 2-64313, Exhibit 2C; Registration No. 2-86849, Exhibit 4.3; and Pacific Gas and Electric Company's Form 8-K dated January 18, 1989 (File No. 1-2348), Exhibit 4.2) |
| 4.2 | Indenture related to PG&E Corporation's 7.5% Convertible Subordinated Notes due June 2007, dated as of June 25, 2002, between PG&E Corporation and U.S. Bank, N.A., as Trustee (incorporated by reference to PG&E Corporation's Form 8-K filed June 26, 2002 (File No. 1-12609), Exhibit 99.1). |
| 4.3 | Supplemental Indenture related to PG&E Corporation's 9.50% Convertible Subordinated Notes due June 2010, dated as of October 18, 2002, between PG&E Corporation and U.S. Bank, N.A., as Trustee (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2002 (File No. 1-12609), Exhibit 4.1) |
| 4.4 | Warrant Agreement, dated as of June 25, 2002, by and among PG&E Corporation, LB I Group Inc., and each other entity named on the signature pages thereto (incorporated by reference to PG&E Corporation's Form 8-K filed June 26, 2002 (File No. 1-12609), Exhibit 99.9). |
| 4.5 | Warrant Agreement, dated as of October 18, 2002, by and among PG&E Corporation, LB I Group Inc., and each other entity named on the signature pages thereto (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2002 (File No. 1-12609), Exhibit 4.2) |
| 4.6 | Form of Rights Agreement dated as of December 22, 2000, between PG&E |

Corporation and Mellon Investor Services LLC, including the Form of Rights Certificate as Exhibit A, the Summary of Rights to Purchase Preferred Stock as Exhibit B, and the Form of Certificate of Determination of Preferences for the Preferred Stock as Exhibit C (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 4.2)

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10.1The Gas Accord Settlement Agreement, together with accompanying tables, adopted by the California Public Utilities Commission on August 1, 1997, in Decision 97-08-055 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 1997 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2), as amended by Operational Flow Order (OFO) Settlement Agreement, approved by the California Public Utilities Commission on February 17, 2000, in Decision 00-02-050, as amended by Comprehensive Gas OII Settlement Agreement, approved by the California Public Utilities Commission on May 18, 2000, in Decision 00-05-049 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2000 (File No. 1-12609 and File No. 1-2348), Exhibit 10); and the Gas Accord II Settlement Agreement, approved by the California Public Utilities Commission on August 22, 2002, in Decision 01-09-016 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.1)

10.2Second Amended and Restated Credit Agreement, dated as of October 18, 2002, among PG&E Corporation, as Borrower, the Lenders party thereto, Lehman Commercial Paper Inc., as Administrative Agent, and other parties (incorporated by reference to PG&E Corporation's Form 8-K filed October 22, 2002 (File No. 1-12609), Exhibit 99.1)

10.3.1Utility Stock Pledge Agreement (35 percent)--Continued Tranche B Loan, dated as of October 18, 2002 (incorporated by reference to PG&E Corporation's Form 8-K filed October 22, 2002 (File No. 1-12609), Exhibit 99.2)

10.3.2Utility Stock Pledge Agreement (35 percent)--New Tranche B Loan, dated as of October 18, 2002 (incorporated by reference to PG&E Corporation's Form 8-K filed October 22, 2002 (File No. 1-12609), Exhibit 99.3)

10.3.3Utility Stock Pledge Agreement (65 percent)--Continued Tranche B Loan, dated as of October 18, 2002 (incorporated by reference to PG&E Corporation's Form 8-K filed October 22, 2002 (File No. 1-12609), Exhibit 99.4)

10.3.4Utility Stock Pledge Agreement (65 percent)--New Tranche B Loan, dated as of October 18, 2002 (incorporated by reference to PG&E Corporation's Form 8-K filed October 22, 2002 (File No. 1-12609), Exhibit 99.5)

10.4Amended and Restated Credit Agreement among PG&E National Energy Group, Inc. and Chase Manhattan Bank dated August 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2001 (File No. 1-12609), Exhibit 10.3

10.5Second Amendment, dated as of October 18, 2002, to the Amended and Restated Credit Agreement, dated as of August 22, 2001, among PG&E National Energy Group, Inc., JPMorgan Chase Bank (formerly known as The Chase Manhattan Bank), as Issuing Bank, the several lenders from time to time parties thereto, the Documentation Agents thereunder, the Syndication Agents thereunder, and JPMorgan Chase Bank, as Administrative Agent. (incorporated by reference to PG&E National Energy Group, Inc.'s Form 8-K filed October 28, 2002) (File No. 333-66032), Exhibit 10.1)

10.6Credit Agreement, dated as of May 29, 2001, among PG&E National Energy Group Construction Company, LLC, as Borrower, the lenders from time to time parties thereto, and Societe Generale, as Administrative Agent and Security Agent (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.6)

10.7 First Amendment to Credit Agreement, dated as of June 5, 2002, among PG&E National Energy Group Construction Company, LLC, the lenders party thereto, and Societe Generale, as Administrative Agent and Security Agent (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.7)

10.8 Guarantee and Agreement (Turbine Credit Agreement), dated as of May 29, 2001, made by PG&E National Energy Group, Inc. in favor of Societe Generale, as Security Agent (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.8)

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10.9 Amended and Restated Credit Agreement, dated as of March 15, 2002, among GenHoldings I, LLC, as Borrower, Societe Generale, as Administrative Agent and a Lead Arranger, Citibank, N.A., as Syndication Agent and a Lead Arranger, the other agents and arrangers thereunder, JP Morgan Chase Bank, as issuer of the Letters of Credit thereunder, the financial institutions party thereto from time to time, and various other parties (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.9)

10.10 Amended and Restated Guarantee and Agreement dated as of March 15, 2002, by PG&E National Energy Group, Inc., in favor of Societe Generale, as Administrative Agent (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.10)

10.11 Acknowledgement and Amendment Agreement, (GenHoldings I, LLC) dated as of April 5, 2002, by and among PG&E National Energy Group, Inc., GenHoldings I, LLC, as Borrower, Societe Generale, as Administrative Agent, and the banks and lenders party thereto (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.11)

10.12 Waiver and Amendment Agreement, dated as of September 25, 2002, among GenHoldings I, LLC, as Borrower, Societe Generale, as Administrative Agent, Citibank N.A., as Depository Agent, and the banks and lender group agents party thereto (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.12)

10.13 Third Waiver and Amendment, dated as of November 14, 2002, among GenHoldings I, LLC, as Borrower, various lenders identified as the GenHoldings Lenders, Societe Generale, as Administrative Agent, Citibank, N.A., as Security Agent, and acknowledged and agreed to by PG&E National Energy Group, Inc. (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.13)

10.14 Fourth Waiver and Amendment dated as of December 23, 2002, among GenHoldings I, LLC, various lenders identified as the GenHoldings Lenders, the Administrative Agent, and acknowledged and agreed to by PG&E National Energy Group, Inc. (incorporated by reference to PG&E Corporation's and PG&E National Energy Group, Inc.'s Form 8-K filed January 16, 2003) (File Nos. 1-12609 and 333-66032), Exhibit 99.1)

10.15 Second Omnibus Restructuring Agreement dated as of December 4, 2002 among La Paloma Generating Company, LLC, La Paloma Generating Trust, Ltd., and various other parties, including PG&E National Energy Group, Inc. (incorporated by reference to PG&E Corporation's and PG&E National Energy Group, Inc.'s Form 8-K filed January 16, 2003) (File Nos. 1-12609 and 333-66032), Exhibit 99.2)

10.16 Priority Credit and Reimbursement Agreement among La Paloma Generating Company, LLC, La Paloma Generating Trust Ltd., Wilmington Trust Company, in its individual capacity and as Trustee, Citibank, N.A., as the Priority

Working Capital L/C Issuer, the Several Priority Lenders from time to time parties hereto, Citibank, N.A., as administrative agent, and Citibank, N.A., as priority agent, dated as of December 4, 2002 (incorporated by reference to PG&E Corporation's and PG&E National Energy Group, Inc.'s Form 8-K filed January 16, 2003) (File Nos. 1-12609 and 333-66032), Exhibit 99.3)

10.17 Guarantee and Agreement (La Paloma), dated as of April 6, 2001, by PG&E National Energy Group, Inc. in favor of Citibank, N.A., as Security Agent (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.17)

10.18 Second Omnibus Restructuring Agreement dated as of December 4, 2002 among Lake Road Generating Company, LLC, Lake Road Generating Trust, Ltd., and various other parties, including PG&E National Energy Group, Inc. (incorporated by reference to PG&E Corporation's and PG&E National Energy Group, Inc.'s Form 8-K filed January 16, 2003) (File Nos. 1-12609 and 333-66032), Exhibit 99.4)

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10.19 Priority Credit and Reimbursement Agreement among Lake Road Generating Company, LLC, Lake Road Trust Ltd., Wilmington Trust Company, in its individual capacity and as Trustee, Citibank, N.A., as the Priority L/C Issuer, the Several Priority Lenders from time to time parties hereto, Citibank, N.A., as administrative agent, and Citibank, N.A., as priority agent, dated as of December 4, 2002 (incorporated by reference to PG&E Corporation's and PG&E National Energy Group, Inc.'s Form 8-K filed January 16, 2003) (File Nos. 1-12609 and 333-66032), Exhibit 99.5)

10.20 Amendment, Waiver and Consent Agreement dated as of November 6, 2002, among La Paloma Generating Company, LLC, La Paloma Generating Trust, Ltd., Wilmington Trust Company as Trustee, Citibank, N.A., as administrative agent and security agent, and various other parties (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.20)

10.21 Guarantee and Agreement (Lake Road), dated as of April 6, 2001, made by PG&E National Energy Group, Inc. in favor of Citibank, N.A., as Security Agent (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.21)

*10.22 PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2001 (File No. 1-12609), Exhibit 10.4)

*10.23 Agreement and Release between PG&E Corporation and Thomas G. Boren, dated December 18, 2002 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.23)

*10.24 Description of Compensation Arrangement between PG&E Corporation and Peter Darbee (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1999 (File No. 1-12609), Exhibit 10.3)

*10.25 Letter regarding Compensation Arrangement between PG&E Corporation and Thomas B. King dated November 4, 1998 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.6)

*10.26 Letter regarding Compensation Arrangement between PG&E Corporation and Lyn E. Maddox dated April 25, 1997 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.7)

*10.27 Letter Regarding Relocation Arrangement Between PG&E Corporation and Thomas B. King dated March 16, 2000 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2000 (File No.

1-12609), Exhibit 10)

*10.28Description of Relocation Arrangement Between PG&E Corporation and Lyn E. Maddox (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.9)

*10.29PG&E Corporation Senior Executive Officer Retention Program approved December 20, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10)

*10.30.1Letter regarding retention award to Robert D. Glynn, Jr. dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.1)

*10.30.2Letter regarding retention award to Gordon R. Smith dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.2)

*10.30.3Letter regarding retention award to Peter A. Darbee dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.3)

*10.30.4Letter regarding retention award to Bruce R. Worthington dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.4)

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*10.30.5Letter regarding retention award to G. Brent Stanley dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.5)

*10.30.6Letter regarding retention award to Daniel D. Richard, Jr. dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.6)

*10.30.7Letter regarding retention award to James K. Randolph dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.7)

*10.30.8Letter regarding retention award to Gregory M. Rueger dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.8)

*10.30.9Letter regarding retention award to Kent M. Harvey dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.9)

*10.30.10Letter regarding retention award to Roger J. Peters dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.10))

*10.30.11Letter regarding retention award to Lyn E. Maddox dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.12)

*10.30.12Letter regarding retention award to P. Chrisman Iribe dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.13)

*10.30.13Letter regarding retention award to Thomas B. King dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.14)

*10.31Pacific Gas and Electric Company Management Retention Program (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2001 (File No. 1-12609), Exhibit 10.1)

*10.32PG&E Corporation Management Retention Program (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2001 (File No. 1-12609), Exhibit 10.2)

*10.33PG&E Corporation Deferred Compensation Plan for Non-Employee Directors, as amended and restated effective as of July 22, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended

September 30, 1998 (File No. 1-12609), Exhibit 10.2)

*10.34 Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2002 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2001 (File No. 1-12609), Exhibit 10.25)

*10.35 Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2003 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.35)

*10.36 Supplemental Executive Retirement Plan of the Pacific Gas and Electric Company amended as of September 19, 2001 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2001 (File No. 1-2248), Exhibit 10.16)

*10.37.1 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Robert D. Glynn, Jr. dated December 20, 2002 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.37.1)

*10.37.2 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Bruce R. Worthington dated December 20, 2002 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.37.2)

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*10.37.3 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Gregory M. Rueger dated December 20, 2002 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.37.3)

*10.37.4 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Gordon R. Smith dated December 20, 2002 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.37.4)

*10.37.5 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and James K. Randolph dated December 20, 2002 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.37.5)

*10.37.6 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Thomas G. Boren dated December 20, 2002 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.37.6)

*10.38 Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for fiscal year 1989 (File No. 1-2348), Exhibit 10.16)

*10.39 Postretirement Life Insurance Plan of the Pacific Gas and Electric Company (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for fiscal year 1991 (File No. 1-2348), Exhibit 10.16)

*10.40 PG&E Corporation Retirement Plan for Non-Employee Directors, as amended and terminated January 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 1997 (File No. 1-12609), Exhibit 10.13)

*10.41 PG&E Corporation Long-Term Incentive Program, as amended May 16, 2001, including the PG&E Corporation Stock Option Plan, Performance Unit Plan, and Non-Employee Director Stock Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10)

*10.42 PG&E Corporation Executive Stock Ownership Program, amended as of September 19, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.20)

*10.43 PG&E Corporation Officer Severance Policy, amended as of December 19, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.43)

*10.44 PG&E Corporation Director Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.1)

*10.45 PG&E Corporation Officer Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.2)

*10.46 PG&E Corporation Form of Restricted Stock Award Agreement granted under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.46)

11 Computation of Earnings Per Common Share (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 11)

12.1 Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 12.1)

12.2 Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 12.2)

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13 The following portions of the 2002 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company are included: "Selected Financial Data," "Management's Discussion and Analysis of Financial Condition and Results of Operations," "Independent Auditors' Report," "Responsibility for Consolidated Financial Statements," financial statements of PG&E Corporation entitled "Consolidated Statements of Operations," "Consolidated Balance Sheets, " "Consolidated Statements of Cash Flows," and "Consolidated Statements of Common Stockholders' Equity," financial statements of Pacific Gas and Electric Company entitled "Consolidated Statements of Operations," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," "Consolidated Statements of Stockholders' Equity," "Notes to Consolidated Financial Statements," and "Quarterly Consolidated Financial Data (Unaudited)"

21 Subsidiaries of the Registrant (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 21)

23 Independent Auditors' Consent (Deloitte & Touche LLP)

24.1 Resolutions of the Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company authorizing the execution of the Form 10-K (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 24.1)

24.2 Powers of Attorney (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 24.2)

99.1 Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002

99.2 Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002

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Management contract or compensatory plan or arrangement required to be filed as

an exhibit to this report pursuant to Item 14(c) of Form 10-K.

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QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 13

## 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.



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## 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



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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



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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,



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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



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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;



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* 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;



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* 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.



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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



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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 it 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



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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



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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.



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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.



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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



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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.

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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.



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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 plant's do not achieve agreed-upon levels of performance. The face amount of PG&E NEG's and its subsidiaries' guarantees relating to PG&E



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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.



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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



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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 Commitment | Bank 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



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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



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*
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:

| | Year Ended December 31, | | |
|---|---|---|---|
| (in millions) | 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 in $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.



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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.



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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.

| (in millions) | Utility | PG&E National Energy Group: Total PG&E NEG | PG&E National Energy Group: Integrated Energy & Marketing Activities | PG&E National Energy Group: Interstate Pipeline Operations | PG&E National Energy Group: 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



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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



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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



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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



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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



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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



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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.



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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



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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.



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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



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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



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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



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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, the CPUC issued a proposed decision 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, the CPUC issued an alternate proposed decision granting 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



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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



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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



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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



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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



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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



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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.