PACIFIC GAS & ELECTRIC CO
Form 10-K/A
June 30, 2003

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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K/A

Amendment No. 3

(Mark One)

ý **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

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

For the transition period from _______ to _______

Commission File Number	Exact Name of Registrant as specified in its charter	State 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	PG&E Corporation One Market, Spear Tower Suite 2400 San Francisco, California
(Address of principal executive offices)	**(Address of principal executive offices)**
94177	94105
(Zip Code)	**(Zip Code)**
(415) 973-7000	(415) 267-7000
(Registrant's telephone number, including area code)	**(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	
Common Stock, no par value	New York Stock Exchange and Pacific Exchange
Preferred Stock Purchase Rights	
Pacific Gas and Electric Company	
First Preferred Stock, cumulative, par value $25 per share:	American Stock Exchange and Pacific Exchange
Redeemable: 7.04%, 5% Series A, 5%, 4.80%, 4.50%, 4.36%	

Title of Each Class	Name of Each Exchange on Which Registered
Mandatorily Redeemable: 6.57%, 6.30%	
Nonredeemable: 6%, 5.50%, 5%	
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 ý No o

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/A or any amendment to this Form 10-K/A. ý

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

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

Explanatory Note

Subsequent to the issuance of PG&E Corporation's 2002 Consolidated Financial Statements, management discovered a misclassification of certain offsetting revenues and expenses within the discontinued operations of PG&E NEG. As a result, PG&E Corporation's Note 6 of the Notes to the Consolidated Financial Statements has been revised to reflect the reclassification. The reclassification resulted in a decrease in 2002 Operating Revenues in the table in Note 6 from $1,289 million to $822 million and a similar decrease in Operating Expenses Cost of Commodity Sales and Fuel from $993 million to $526 million. The reclassification did not result in a change in the Consolidated Statement of Operations, the Consolidated Balance Sheets or the Consolidated Statements of Cash Flows.

This Amendment No. 3 to PG&E Corporation's and Pacific Gas and Electric Company's joint Annual Report on Form 10-K for the year ended December 31, 2002, as amended by Form 10-K/A Amendment No. 1 filed with the Securities and Exchange Commission on March 6, 2003, and Form 10-K/A Amendment No. 2 filed with the Securities and Exchange Commission on March 12, 2003, contains revised consolidated financial statements for PG&E Corporation for the year ended December 31, 2002. To reflect the revisions, this Amendment No. 3 hereby amends:

Part I, Item I. Business. Corrections have been made to the section entitled "Utility Operations".

Part II, Item 5. Market for Registrant's Common Equity and Related Stockholder Matters. References are made to the "Quarterly, Consolidated Financial Data (unaudited)" and the "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in this Form 10-K/A, Amendment No. 3.

Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations. Corrections have been made to the sections entitled "Cash Flows" and "Results of Operations".

Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk. Corrections have been made to "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the "Notes to the Consolidated Financial Statements" included in this Form 10-K/A, Amendment No. 3.

Part II, Item 8. Financial Statements and Supplementary Data. Corrections have been made to Note 1 and Note 6 of the "Notes to the Consolidated Financial Statements."

Part IV, Item 15. Exhibits, Financial Statement Schedules, and Reports on Form 8-K (amended to file herewith Exhibit 23, Independent Auditors' Consent (Deloitte & Touche LLP), Exhibit 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, and Exhibit 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.)

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 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 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 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 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);

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.

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, 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

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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.

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

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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, 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 IOUs and their parent holding companies had opposed this broader interpretation as being inconsistent with the prior 15 years' understanding of that condition as applying more narrowly to a priority on capital needed for investment purposes. The CPUC also interpreted the first priority condition as prohibiting a holding company from (1) acquiring assets of its utility subsidiary for inadequate consideration, and (2) acquiring assets of its utility subsidiary at any price, if such acquisition would impair the utility's ability to fulfill its obligation to serve or to operate in a prudent and efficient manner.

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.

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:

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.

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.

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 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

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 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 Comisión Reguladoro de

Energía, 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.

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 pur