PACIFIC GAS & ELECTRIC CO
Form 10-K/A
March 06, 2003

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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K/A

Amendment No. 1

(Mark One)

/X/ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 2002

or

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

For the transition period from ________ to ________

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	PG&E Corporation
77 Beale Street	One Market, Spear Tower
P.O. Box 770000	Suite 2400
San Francisco, California	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%	
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 /X/ No / /

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

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

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

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

DOCUMENTS INCORPORATED BY REFERENCE

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

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

Explanatory Note

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

Part I, Item 1. Business

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

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

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

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

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

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

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GLOSSARY OF TERMS

AB 1890	Assembly Bill 1890, the California electric industry restructuring legislation
BACT	Best available control technology
BCAP	Biennial Cost Allocation Proceeding
bcf	billion cubic feet
BFM	block forward market
BTA	best technology available
Btu	British thermal unit
CCAA	California Clean Air Act
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
core customers	residential and smaller commercial gas customers
core subscription customers	noncore customers who choose bundled service
CPIM	core procurement incentive mechanism
CPUC	California Public Utilities Commission
Diablo Canyon	Diablo Canyon Nuclear Power Plant
DOE	United States Department of Energy
DWR	California Department of Water Resources
EMF	electric and magnetic fields
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GRC	General Rate Case
Humboldt Unit 3	Humboldt Bay Power Plant (Unit 3)
HWRC	hazardous waste remediation costs
IPP	independent power producer
IOU or IOUs	investor owned utility or utilities
ISO	Independent System Operator
KV	Kilovolts
KVa	kilovolt-amperes
KW	Kilowatts
Mcf	thousand cubic feet
MDt	thousand decatherms
MMcf	million cubic feet
MW	Megawatts
MWh	megawatt-hour
noncore customers	industrial and larger commercial gas customers
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
ORA	Office of Ratepayer Advocates, a division of the California Public Utilities Commission
PG&E Energy	PG&E NEG's integrated energy and marketing segment
PG&E ET	PG&E Energy Trading Holdings Corporation and its subsidiaries
PG&E Gen LLC	PG&E Generating Company, LLC and its affiliates
PG&E GTC	PG&E Gas Transmission Corporation and its subsidiaries
PG&E GTN	PG&E Gas Transmission, Northwest Corporation

PG&E NBP	PG&E North Baja Pipeline, LLC
PG&E NEG	PG&E National Energy Group, Inc.
PG&E Pipeline	PG&E NEG's interstate pipeline operations
PURPA	Public Utility Regulatory Policies Act of 1978
PX	California Power Exchange
QF	qualifying facility
RCRA	Resource Conservation and Recovery Act
RTO	regional transmission organization
TCBA	Transition Cost Balancing Account
throughput	the amount of natural gas transported through a pipeline system
TRA	Transition Revenue Account
TURN	The Utility Reform Network
USGenNE	USGen New England, Inc.

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 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 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

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

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

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

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

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

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

State and Other Regulations

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

In addition, the National Energy Board of Canada and the Canadian gas-exporting provinces issue licenses and permits for removal of natural gas from Canada. The Mexican 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 purchase transportation-only and distribution-only services from the Utility. The Utility's industrial and larger commercial customers, or noncore customers, now purchase their gas from producers, marketers and brokers. Substantially all residential and smaller commercial customers, or core customers, buy gas as well as transmission and distribution services from the Utility as a bundled service.

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

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

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

Electric Generation and Natural Gas Transmission

During 2002, adverse changes in the national energy markets affected PG&E NEG's business including:

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

Resulting significant financial distress and liquidity problems among market participants leading to numerous financial restructurings and less market participation.

PG&E NEG has been significantly impacted by these adverse changes. New generation came online while the demand for power was dropping. This oversupply and reduced demand resulted in low spark spreads (the net of power prices less fuel costs) and depressed operating margins. These changes in the energy industry have had a significant negative impact on the financial results and liquidity of PG&E NEG as discussed in Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations."

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

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

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

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

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

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

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

UTILITY OPERATIONS

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

Ratemaking Mechanisms

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

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

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

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

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

Electric Ratemaking

As required by AB 1890, electric rates for all customers were frozen at the level in effect on June 10, 1996, and, beginning January 1, 1998, rates for residential and small commercial customers were further reduced by 10%. In the first quarter of 2001, the CPUC authorized the Utility to begin collecting energy surcharges totaling $0.04 per kWh (composed of a $0.01 per kWh surcharge approved in January and a $0.03 per kWh surcharge approved in March). Although the CPUC authorized the $0.03 per kWh surcharge in March 2001, the Utility did not begin collecting the revenues until June 2001. As a result, in May 2001, the CPUC authorized the Utility to collect an additional $0.005 per kWh surcharge revenue for 12 months to make up for the time lag in collection of the $0.03 surcharge revenues. Although the collection of this "half-cent surcharge" was originally scheduled to end on May 31, 2002, the CPUC issued a resolution ordering the Utility to continue collecting the half-cent surcharge until further consideration by the CPUC. The CPUC initially restricted the use of these surcharge revenues to pay for the Utility's "ongoing procurement costs" and "future power purchases."

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

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

the Utility's approved utility cost components,

the cost of energy sold to customers, and

the DWR's revenue requirement allocated to the Utility's customers.

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

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

Electric Distribution.

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

2002 Attrition Rate Adjustment Request. In the 2003 GRC, the CPUC asked parties to comment on the Utility's need for a 2002 attrition rate adjustment. The Utility informed the CPUC in November 2001 that the Utility would need a 2002 attrition rate adjustment to recover escalating electric and gas distribution service costs. In April 2002, the CPUC issued a ruling authorizing any attrition rate adjustment that ultimately may be granted to become effective as of April 22, 2002. In June 2002, the Utility filed its application, requesting a $76.7 million increase to its annual electric distribution revenue requirement, and a $19.5 million increase to its annual gas distribution revenue requirement. In December 2002 a proposed decision was issued that would deny this request. The Utility filed comments in late December 2002 arguing that the proposed decision was based on a fundamental misunderstanding of the facts. In February 2003 an alternate proposed decision was issued that would grant a $63.5 million increase to the Utility's annual electric distribution revenue requirement, and a $10.3 million increase to the Utility's annual gas distribution revenue requirement. A final decision is expected to be issued in the first quarter of 2003.

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

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

Electric Transmission

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

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

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

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

Transmission Owner Rate Cases. On January 29, 2003, the FERC approved a settlement filed by the Utility that allows the Utility to recover $292 million on an annual basis from March 31, 1998 until October 29, 1998 and $316 million on an annual basis from October 30, 1998 until May 30, 1999 in TO Tariff electric transmission rates. During that period, somewhat higher rates were collected, subject to refund. As a result of the approval, the Utility will refund $30 million it had accrued for potential refunds related to the 14-month period ended May 30, 1999. In April 2000, the FERC approved a settlement that permitted the Utility to recover $329 million on an annual basis in TO Tariff electric transmission rates retroactively for the 10-month period from May 31, 1999 to March 31, 2000. In September 2000, the FERC approved another settlement that permitted the Utility to recover $352 million annually in TO Tariff electric transmission rates and made this retroactive to April 1, 2000. Further, in July 2001, the FERC approved another settlement that permits the Utility to collect $379 million annually in TO Tariff electric transmission rates retroactive to May 6, 2001. The transmission rates charged to TO Tariff customers are adjusted for other transmission revenue credits related to ISO congestion management charges and other transmission related services billed by the ISO and remitted to the Utility as a transmission owner.

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

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

Reliability Services Costs The ISO bills the Utility for reliability services based on payments that the ISO makes to generators under reliability must-run contracts and for locational out-of-market calls required to support reliability of the transmission system. The Utility charges its customers rates designed to recover these reliability service charges, without mark-up or service fees. The Utility records these customer charges as operating revenue, and records a corresponding expense under its cost of power line item to reflect the fact that the Utility must pass this revenue on to the ISO. Costs and revenues related to reliability services are tracked in the reliability services balancing account.

Transition Charges Beginning on January 1, 2001, the Utility pays the ISO's high-voltage blended transmission rate which is higher than the Utility-specific high-voltage transmission rate. The difference between the ISO's rate and the Utility's rate is tracked in the Utility's transmission access charge balancing account and will be collected once frozen retail rates are changed by the CPUC.

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

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

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

In January 2000, the FERC accepted a filing by the Utility to establish a separate tariff to allow the Utility to recover both the shortfall and future scheduling coordinator costs from its ETC customers. The FERC has authorized the separate tariff, subject to refund, which has been challenged by ETC customers. For the period beginning April 1998 through December 31, 2002, the Utility transferred $107 million of scheduling coordinator costs from the TRBA to accounts receivable net of a $66 million reserve for potential uncollectible costs. The Utility also has disputed approximately $27 million of these costs as incorrectly billed by the ISO.

Electric Generation

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

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

Electric Procurement

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

Energy Resource Recovery Account, or ERRA. As of January 1, 2003, the California IOUs have resumed procuring electricity to meet the amount of their customers' electricity needs that cannot be met with utility-owned generation, electricity supplied under QF and other contracts, and electricity allocated to their customers under the DWR contracts. Effective January 1, 2003, the Utility established the Energy Resource Recovery Account, or ERRA, to record and recover electricity costs, excluding the DWR's power contract costs, associated with the Utility's authorized procurement plan. Electricity costs recorded in ERRA include, but are not limited to, fuel costs for retained generation, QF contracts, inter-utility contracts, ISO charges, irrigation district contracts and other power purchase agreements, bilateral contracts, forward hedges, pre-payments and collateral requirements associated with procurement (including disposition of surplus electricity), and ancillary services. The Utility offsets these costs by reliability-must-run revenues, the Utility's allocation of surplus sales revenues and the ERRA revenue requirement. The CPUC has authorized the Utility to file an expedited trigger application at any time that its forecast indicates the undercollection in the

ERRA will be in excess of 5% of the Utility's recorded generation revenues for the prior year excluding amounts collected for the DWR. The Utility currently estimates that its 5% threshold amount will be

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

On February 3, 2003, the Utility filed its 2003 ERRA forecast application requesting that the CPUC reset the Utility's 2003 ERRA revenue requirement to $1.413 billion and that the ERRA trigger threshold of $224 million be adopted. The CPUC will examine the Utility's forecast of costs for 2003 and will finalize the Utility's starting ERRA revenue requirement and ERRA trigger threshold when it reviews the Utility's ERRA application.

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

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

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

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

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

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

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

Funds remitted under the CRS will be applied first to the DWR bond charges, second to the DWR electricity charges, and third to the Utility's ongoing procurement and generation costs. Direct access customers who have returned to bundled service will be responsible for their share of the unrecovered costs resulting from the CRS. To the extent the cap results in an undercollection of DWR charges, the shortfall would have to be remitted to DWR from bundled customers' funds. Interest on undercollections will be assessed at the DWR's bond interest rate on an interim basis while the CPUC examines a long-term plan for financing the CRS. The Utility does not expect that the CPUC's implementation of this decision or the level of the CRS cap will have a material adverse effect on its results of operations or financial condition.

DWR Revenue Requirements, Servicing Order and Operating Order. The CPUC has adopted rates for the DWR that allow the DWR to collect electricity and bond-related charges from ratepayers to recover what it spent to procure electricity for the customers of the California IOUs during 2001 and 2002. The recovery is being financed partially through a statewide revenue requirement allocated among the three California IOUs and partially through the DWR's November 2002 issuance of $11.3 billion in revenue bonds, which will be repaid by the customers of the three California IOUs through the bond charge discussed below. In February 2002, the CPUC approved a decision that set the statewide DWR revenue requirement for 2001 and 2002. In March 2002, the CPUC reallocated the amounts contained in the February 2002 decision among the customers of the three California IOUs. The March 2002 decision allocated $4.4 billion of a total statewide power charge revenue requirement of approximately $9.0 billion to the Utility's customers. Of the $4.4 billion allocated to the customers of the Utility, approximately $2.6 billion related to 2001 power charges and approximately $1.8 billion related to 2002 power charges. In December 2002, the CPUC issued a decision allocating approximately $2 billion of the DWR's 2003 power charge-related revenue requirements to the Utility's customers. This revenue requirement includes the variable costs of the DWR contracts allocated to the Utility's customers by an earlier decision in September 2002. The DWR plans to submit a revised 2003 power charge-related revenue requirement to the CPUC in late March 2003. A separate proceeding will consider a revision or true-up for the revenue requirements remitted to the DWR for 2001 and 2002 costs, once final 2002 cost data is available. This true-up proceeding is scheduled for April 2003.

Before the DWR's 2003 statewide revenue requirement filing with the CPUC in August 2002, the Utility filed comments with the DWR alleging that major portions of the DWR's revenue requirements were not "just and reasonable" as required by AB 1X and that the DWR was not complying with the procedural requirements of AB 1X in making its determination. On August 26, 2002, the Utility filed with the DWR a motion for reconsideration of the DWR's determination that its revenue requirements were "just and reasonable." The DWR denied the Utility's motion on October 8, 2002. On October 17, 2002, the Utility filed a lawsuit in a California court asking the court to find that the DWR's revenue requirements had not been demonstrated to be "just and reasonable" and lawful, and that the DWR had violated the procedural requirements of AB 1X in making its determination. In part, the Utility based its allegations on the State of California's petition pending before the FERC seeking to set aside many of the DWR contracts on the basis that they are not "just and reasonable." The Utility asked that the court order that the DWR's revenue requirement determination be withdrawn as invalid, and that the DWR be precluded from imposing its revenue requirements on the Utility and its customers until it has complied with the law. No schedule has yet been set for consideration of the lawsuit.

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

In December 2002, the CPUC adopted an operating order requiring the Utility to perform the operational, dispatch, and administrative functions for the DWR's allocated contracts beginning on January 1, 2003. (Similar operating orders were also adopted for the other two California IOUs.) The operating order sets forth the terms

and conditions under which the Utility will administer the DWR allocated contracts and requires the Utility to dispatch all the generating assets within its portfolio on a least-cost basis for the benefit of the Utility's customers. The order specifies that the DWR will retain legal and financial responsibility for the DWR allocated contracts and that the order does not result in an assignment of the allocated DWR contracts to the Utility.

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

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

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

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

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

DWR Bond Charges. On October 24, 2002, the CPUC approved a decision that, in part, imposes bond charges to recover the DWR's bond costs from most bundled customers effective November 15, 2002, although the decision found that the Utility would not need to increase customers' overall rates to incorporate the bond charge. The DWR bond charge also will be imposed on all direct access customers, as described above. On December 30, 2002, the CPUC adopted a 2003 bond charge of $0.005 per kWh to start January 6, 2003. The Utility expects to accrue DWR bond-related charges of approximately $336 million during the 12 months ended November 14, 2003. Until the CPUC implements bottoms-up billing (billing for specific rate components) for the Utility, any bond charges will reduce the amount of revenue available to recover previously written-off undercollected purchase power costs and transition costs.

Gas Ratemaking

Natural Gas Distribution

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

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

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

Natural Gas Transportation and Storage

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

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

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

Under the Gas Accord, the Utility is at risk for recovery of its gas transportation and storage costs, and does not have regulatory balancing account protection for over- or undercollections of revenues. Under the Gas Accord, the Utility sells a portion of the transportation and storage capacity at competitive market-based rates. Revenues are sensitive to changes in the weather, natural gas fired generation and price spreads between two delivery or pricing points.

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

Natural Gas Procurement

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

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

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

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

Public Purpose Programs

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

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

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

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

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

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

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

ELECTRIC UTILITY OPERATIONS

Electric Distribution

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

Electric Distribution Operating Statistics

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

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

	2002	2001	2000	1999	1998
Customers (average for the year):					
Residential	4,171,365	4,165,073	4,071,794	4,017,428	3,962,318
Commercial	483,946	484,430	471,080	474,710	469,136
Industrial	1,249	1,368	1,300	1,151	1,093
Agricultural	78,738	81,375	78,439	85,131	85,429
Public street and highway lighting	24,119	23,913	23,339	20,806	18,351
Other electric utilities	5	5	8		14
Total	4,759,422	4,756,164	4,645,960	4,599,226	4,536,341
Deliveries (in GWh):					
Residential	27,435	26,840	28,753	27,739	26,846
Commercial	31,328	30,780	31,761	30,426	28,839
Industrial(1)	14,729	16,001	16,899	16,722	16,327
Agricultural(1)	4,000	4,093	3,818	3,739	3,069
Public street and highway lighting	674	418	426	437	445
Other electric utilities	64	241	266	167	2,358
California Department of Water Resources Allocation (2001 and 2002 only)	(21,031)	(28,640)			
Total energy delivered(2)	57,199	49,733	81,923	79,230	77,884
Revenues (in thousands):					
Residential(3)	$ 3,641,582	$ 3,364,466	$ 3,007,675	$ 2,961,788	$ 2,891,424
Commercial(3)	4,468,465	3,925,218	2,693,316	2,837,111	2,793,336
Industrial(3)	1,275,033	1,312,280	509,486	863,951	933,316

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

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

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

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

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

Electric Resources

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

Retained Generation

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

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

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

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

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

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

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

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

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

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

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

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

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

The Price-Anderson Act, as amended by Congress in 1988, limits public liability claims that could arise from a nuclear incident to a maximum of $9.5 billion per incident. The Utility has purchased primary insurance of $300 million for the Diablo Canyon Power Plant for public liability claims resulting from a nuclear incident. The Utility has secondary financial protection that provides an additional $9.2 billion of coverage, as required by the Price-Anderson Act. Under the Price-Anderson Act, secondary financial protection is required for all nuclear electrical generation reactors having a rated operating capacity of at least 100 MW. There are 105 currently licensed reactors having a rated capacity in excess of 100 MW, including Diablo Canyon's Units 1 and 2. The Price-Anderson Act provides for loss sharing among utilities owning nuclear generating facilities if a costly incident occurs. If a nuclear incident results in claims in excess of $300 million, the Utility may be assessed up to $176 million per incident, with payments in each year limited to a maximum of $20 million per incident. The Utility also has $53.3 million of private liability insurance for Humboldt Bay Power Plant, where the Utility has a shutdown nuclear unit. In addition, the Utility has a $500 million indemnification from the NRC for public liability arising from nuclear incidents covering liabilities in excess of the $53.3 million of private liability insurance for Humboldt Bay Power Plant. The Price-Anderson Act expired on August 1, 2002. By the terms of the act itself, the provisions of the act will remain in effect until Congress renews the act. The current draft of the bill to renew this act would increase the maximum assessment per nuclear incident per unit to $99 million from $88 million, with payments in each year limited to a maximum of $15 million per nuclear incident per unit, increased from $10 million.

Allocation of DWR Electricity to the California Investor-Owned Utilities

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

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

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

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

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

Although the IOUs will be held to a reasonableness standard in their scheduling and dispatch decision-making and their administration of the DWR contracts, the CPUC has determined that the maximum risk of potential disallowance each IOU should face for all of its procurement activities, including the operation and dispatch of DWR's contracts, should be limited to twice the IOU's annual administrative costs of managing procurement activities. The Utility anticipates that its annual administrative costs of managing procurement activities will be approximately $18 million in 2003. The DWR has stated publicly that it intends to transfer full legal title of, and responsibility for, the DWR electricity contracts to the IOUs as soon as possible. However, SB 1976 does not contemplate a transfer of title of the DWR contracts to the IOUs. In addition, the operating order issued by the CPUC on December 19, 2002, implementing the Utility's operational and scheduling responsibility with respect to the DWR allocated contracts specifies that the DWR will retain legal and financial responsibility for the contracts and that the December 19, 2002, order does not result in an assignment of the DWR allocated contracts. The Utility's proposed plan of reorganization prohibits the Utility from accepting, directly or indirectly, assignment of legal or financial responsibility for the DWR contracts. There can be no assurance that either the State of California or the CPUC will not seek to provide the DWR with authority to effect such a transfer of legal title in the future. The Utility has informed the CPUC, the DWR and the State that the Utility would vigorously oppose any attempt to transfer the DWR allocated contracts to the Utility without the Utility's consent.

Qualifying Facility Agreements

The Utility is required by CPUC decisions to purchase electric energy and capacity from independent power producers that are qualifying facilities, or QFs, under the Public Utility Regulatory Policies Act of 1978 or PURPA. Pursuant to PURPA, the CPUC required California utilities to enter into a series of QF long-term power purchase agreements and approved the applicable terms, conditions, price options, and eligibility requirements. The agreements require the Utility to pay for energy and capacity. Energy payments are based on the QF project's actual electrical output and capacity payments are based on the QF project's total available capacity and contractual capacity commitment. Capacity payments may be reduced or increased if the facility fails to meet or, alternatively, exceeds performance requirements specified in the applicable power purchase agreements.

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

In August 2002, the CPUC ordered the IOUs to offer transitional standard offer no. 1 contracts, or TSO1 contracts, to certain QFs whose power purchase agreements with the IOU had expired or were about to expire. The term of these transitional contracts will end when the IOU fully implements its CPUC-approved long-term procurement plan or on December 31, 2003, whichever occurs first. The Utility signed TSO1 contracts with nine QFs. These new contracts have been approved by the Bankruptcy Court and the CPUC and became effective on January 1, 2003.

Since December 2001, the Bankruptcy Court has approved supplemental agreements between the Utility and most QFs to resolve the applicable interest rate to be applied to pre-petition amounts owed to QFs. The supplemental agreements

- set the interest rate for pre-petition payables at 5%,
- provide for a "catch-up payment" of all accrued and unpaid interest through the initial payment date, and
- depending on the amount owed, either (a) provide for the immediate payment of the principal and interest amount of the pre-petition payables or (b) payment in 12 or 6 equal monthly payments beginning on the last business day of the month during which Bankruptcy Court approval was granted.

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

Renewable Resource Energy Contracts

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

Other Third-Party Power Agreements

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

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

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

	2002	2001	2000	1999	1998
Gigawatt-hours received	28,088	23,732	26,027	25,910	25,994
Energy payments (in millions)	$ 1,051	$ 1,454	$ 1,549	$ 837	$ 943
Capacity payments (in millions)	$ 506	$ 473	$ 519	$ 539	$ 529

	2002	2001	2000	1999	1998
Irrigation district and water agency payments (in millions)	$ 57	$ 54	$ 56	$ 60	$ 53
Bilateral contract payments	$ 196	$ 155	$ 53	0	0

Western Area Power Administration. In 1967, the Utility and the Western Area Power Administration, or WAPA, entered into a long-term power contract governing (1) the interconnection of the Utility's and WAPA's transmission systems, (2) WAPA's use of the Utility's transmission and distribution system, and (3) the integration of the Utility's and WAPA's loads and resources. The contract gave the Utility access to surplus hydroelectric generation and obligates the Utility to provide WAPA with electricity when its own resources are not sufficient to meet its requirements. The contract terminates on December 31, 2004.

As a result of California's electric industry restructuring in 1998, the Utility was required to procure the electric power that it needed to meet its own and WAPA's requirements from the PX. This caused the Utility to be exposed to market-based energy pricing rather than the cost of service-based energy pricing that had been presumed when the contract was executed. As a result, the Utility paid substantially more for the energy it purchased on behalf of WAPA than it received for the sales of energy to WAPA. The cost to fulfill the Utility's obligations to WAPA under the contract is uncertain. However, the Utility expects that the cost of meeting its obligation to WAPA will be greater than the price that the Utility receives from WAPA under the contract. In part, the amount of electricity the Utility will be required to deliver to WAPA depends on the amount of electricity available from WAPA's hydroelectric resources. Under AB 1890, the Utility's retail ratepayers pay for this difference as a stranded power purchase cost. The amount of the difference between the Utility's cost to meet its obligations to WAPA and the revenues it receives from WAPA cannot be accurately estimated at this time since both the purchase price and the amount of energy WAPA will need from the Utility through the end of the contract are uncertain. Though it is not indicative of future sales commitments or sales-related costs, WAPA's net amount purchased from the Utility was 3,619 GWh in 2002, 4,823 GWh in 2001, and 5,120 GWh in 2000.

Electric Transmission

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

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

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

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

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

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

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

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

GAS UTILITY OPERATIONS

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

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

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

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

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

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

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

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

Gas Operating Statistics

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

	2002	2001	2000	1999	1998
Customers (average for the year):					
Residential	3,738,524	3,705,141	3,642,266	3,593,355	3,536,089
Commercial	206,953	205,681	203,355	203,342	200,620
Industrial	1,819	1,764	1,719	1,625	1,610
Other gas utilities	5	6	6	4	5
Total	3,947,301	3,912,592	3,847,346	3,798,326	3,738,324
Gas supply thousand cubic feet (Mcf) (in thousands):					
Purchased from suppliers in:					
Canada	210,716	209,630	216,684	230,808	298,125
California	19,533	10,425	32,167	18,956	17,724
Other states	67,878	76,589	75,834	107,226	122,342
Total purchased	298,127	296,644	324,685	356,990	438,191
Net (to storage) from storage	(218)	(27,027)	19,420	(980)	(14,468)

	2002	2001	2000	1999	1998
Total	297,909	269,617	344,105	356,010	423,723
Pacific Gas and Electric Company use, losses, etc.[1]	16,394	(939)	62,960	47,152	129,305
Net gas for sales	281,515	270,556	281,145	308,858	294,418
Bundled gas sales Mcf (in thousands):					
Residential	202,141	197,184	210,515	233,482	223,706
Commercial	78,812	72,528	66,443	70,093	66,082
Industrial	563	831	4,146	5,255	4,616
Other gas utilities	0	13	41	28	14
Total	281,516	270,556	281,145	308,858	294,418
Transportation only Mcf (in thousands):					
Vintage system (Substantially all Industrial)[2]	508,090	646,079	606,152	484,218	396,872
Revenues (in thousands):					
Bundled gas sales:					
Residential	$ 1,379,036	$ 2,307,677	$ 1,680,745	$ 1,542,705	$ 1,414,313
Commercial	499,214	783,080	513,080	448,655	426,299
Industrial	2,447	15,904	35,347	24,638	24,634
Other gas utilities	829	2	0	77	1,072
Bundled gas revenues	1,881,526	3,106,663	2,229,172	2,016,075	1,866,318
Transportation only revenue:					
Vintage system (Substantially all Industrial)	$ 308,212	$ 365,550	$ 324,319	$ 267,544	$ 232,038
PG&E Expansion (Line 401)	8,275	9,380	13,392	19,091	42,194
Transportation service only revenue	316,487	374,930	337,711	286,635	274,232
Miscellaneous	126,415	(92,531)	84,526	(47,311)	41,364
Regulatory balancing accounts	11,431	(253,476)	131,762	(259,648)	(448,351)
Operating revenues	$ 2,335,859	$ 3,135,586	$ 2,783,171	$ 1,995,751	$ 1,733,563