PACIFIC GAS & ELECTRIC CO
Form S-3
October 27, 2003

As filed with the Securities and Exchange Commission on October 27, 2003
Registration No. 333-

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form S-3

REGISTRATION STATEMENT UNDER THE SECURITIES ACT OF 1933

Pacific Gas and Electric Company

(Exact Name of Registrant as Specified in Its Charter)

California	**77 Beale Street** **P.O. Box 770000** **San Francisco, CA 94177** **(415) 973-7000**	**94-0742640**
(State or Other Jurisdiction of Incorporation or Organization)	*(Address, Including Zip Code, and Telephone Number, Including Area Code, of Registrant s Principal Executive Offices)*	*(I.R.S. Employer Identification Number)*

Bruce R. Worthington
Senior Vice President and General Counsel
PG&E Corporation
One Market Spear Tower, Suite 2400
San Francisco, CA 94105
(415) 267-7000
(Name, Address, Including Zip Code, and Telephone Number, Including Area Code, of Agent for Service)

Approximate date of commencement of proposed sale to the public: From time to time after the effective date of this Registration Statement.

If the only securities being registered on this form are being offered pursuant to dividend or interest reinvestment plans, please check the following box. o

If any of the securities being registered on this form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, other than securities offered only in connection with dividend or interest reinvestment plans, check the following box. þ

If this form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, please check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o ____________

If this form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o ____________

If delivery of the prospectus is expected to be made pursuant to Rule 434, please check the following box. o

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to Be Registered	Amount to Be Registered	Proposed Maximum Offering Price Per Debt Security	Proposed Maximum Aggregate Offering Price	Amount of Registration Fee
Debt Securities	$9,400,000,000(1)	100%(1)(2)(3)	$9,400,000,000(1)(2)(3)	$760,460

(1) Includes an indeterminate principal amount of debt securities as may from time to time be issued at indeterminate prices; provided that in no event will the aggregate initial price of all debt securities sold under this registration statement exceed $9,400,000,000. If any such debt securities are issued at an original issue discount, then the aggregate initial offering price as so discounted shall not exceed $9,400,000,000, notwithstanding that the stated aggregate principal amount of such debt securities may exceed such amount.

(2) Estimated solely for the purpose of calculating the registration fee pursuant to Rule 457(o) under the Securities Act of 1933, as amended. The proposed maximum initial offering price per security will be determined from time to time by the registrant in connection with the issuance of the debt securities.

(3) Exclusive of accrued interest, if any.

The registrant hereby amends this Registration Statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this Registration Statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933 or until this Registration Statement shall become effective on such date as the Commission, acting pursuant to said Section 8(a), may determine.

PROSPECTUS

Subject to Completion, dated October 27, 2003

$9,400,000,000

Pacific Gas and Electric Company

Debt Securities

Under this prospectus, we may offer and sell from time to time debt securities with an aggregate initial offering price of up to $9,400,000,000 in one or more offerings. This prospectus provides you with a general description of the debt securities that may be offered.

Each time we sell debt securities, we will provide a prospectus supplement that contains specific information about the offering and the terms of the offered debt securities. The prospectus supplement also may add, delete, update or change information contained in this prospectus. You should carefully read this prospectus and any applicable prospectus supplement for the specific offering before you invest in any of the debt securities. This prospectus may not be used to sell debt securities unless accompanied by a prospectus supplement.

The debt securities may be sold to or through underwriters, dealers or agents or directly to other purchasers. A prospectus supplement will set forth the names of any underwriters, dealers or agents involved in the sale of the debt securities, the aggregate principal amount of debt securities to be purchased by them and the compensation they will receive.

We were incorporated in California in 1905. Our principal executive offices are located at 77 Beale Street, San Francisco, California 94177, and our telephone number at that location is (415) 973-7000.

Please see Risk Factors beginning on page 1 for a discussion of factors you should

consider in connection with a purchase of the debt securities offered by this prospectus.

None of the Securities and Exchange Commission, any state securities commission or any other regulatory body has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

, 2003.

TABLE OF CONTENTS

Unless otherwise indicated, when used in this prospectus, the terms we, our and us refer to Pacific Gas and Electric Company and its subsidiaries, and the term Corp refers to our parent, PG&E Corporation.

In addition, unless otherwise indicated, the disclosure throughout this prospectus assumes that:

the California Public Utilities Commission, or the CPUC, has approved the settlement agreement which was executed by us, Corp and the CPUC on , 2003, and is referred to in this prospectus as the CPUC settlement agreement, as well as the financings and rates contemplated by the CPUC settlement agreement, and that no appeals have been or will be made of these approvals;

our plan of reorganization, which was confirmed by the United States Bankruptcy Court for the Northern District of California, or the bankruptcy court, on , 2003 and is referred to in this prospectus as our plan of reorganization, has not been modified in any material way since the date of confirmation, and the confirmation order is final and nonappealable; and

all the other conditions to the effectiveness of our plan of reorganization have been satisfied or are reasonably anticipated to be satisfied within 90 days of the closing date of the initial offering of debt securities under this prospectus.

UNITS OF MEASUREMENT

1 Kilowatt (kW)	=	One thousand watts
1 Kilowatt-Hour (kWh)	=	One kilowatt continuously for one hour
1 Megawatt (MW)	=	One thousand kilowatts
1 Megawatt-Hour (MWh)	=	One megawatt continuously for one hour
1 Gigawatt (GW)	=	One million kilowatts
1 Gigawatt-Hour (GWh)	=	One gigawatt continuously for one hour
1 Kilovolt (kV)	=	One thousand volts
1 MVA	=	One megavolt ampere
1 Mcf	=	One thousand cubic feet
1 MMcf	=	One million cubic feet
1 Bcf	=	One billion cubic feet
1 Decatherm (Dth)	=	Ten therms, also equivalent to one million British thermal units
1 MDth	=	One thousand decatherms

ABOUT THIS PROSPECTUS

This prospectus is part of a registration statement that we filed with the Securities and Exchange Commission, or the SEC, using a shelf registration process. Under this shelf registration process, we may from time to time sell debt securities with an aggregate initial offering price of up to $9,400,000,000 in one or more offerings.

This prospectus provides you with only a general description of the debt securities that we may offer. This prospectus does not contain all of the information set forth in the registration statement of which this prospectus is a part, as permitted by the rules and regulations of the SEC. For additional information regarding us and the offered debt securities, please refer to the registration statement of which this prospectus is a part. Each time we sell debt securities, we will provide a prospectus supplement that contains specific information about the offering and the terms of the offered securities. The prospectus supplement also may add, delete, update or change information contained in this prospectus. You should rely only on the information in the applicable prospectus supplement if this prospectus and the applicable prospectus supplement are inconsistent. Before purchasing any debt securities, you should carefully read both this prospectus and the applicable prospectus supplement, together with the additional information described under the section of this prospectus titled Where You Can Find More Information.

You should rely only on the information contained or incorporated by reference in this prospectus and in any applicable prospectus supplement. We have not authorized any other person to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. Neither we nor any underwriter, dealer or agent will make an offer to sell the debt securities in any jurisdiction where the offer or sale is not permitted. You should assume that the information in this prospectus and any applicable prospectus supplement is accurate only as of the dates on their covers. Our business, financial condition, results of operations and prospects may have changed since those dates.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This prospectus, the documents incorporated by reference in this prospectus and any applicable prospectus supplement contain various forward-looking statements. These forward-looking statements can be identified by the use of words such as assume, expect, intend, plan, project, believe, estimate, predict, anticipate, may, might, will, should, could, goal, potential and similar expressions. W forward-looking statements on our current expectations and projections about future events, our assumptions regarding these events and our knowledge of facts at the time the statements are made. These forward-looking statements are subject to various risks and uncertainties that may be outside our control, and our actual results could differ materially from our projected results. These risks and uncertainties include, among other things:

- governmental and regulatory policies and legislative, regulatory or ratemaking actions generally, including those of the California legislature, the U.S. Congress, the CPUC and the Federal Energy Regulatory Commission, or the FERC, as to allowed rates of return, industry and rate structure, price mitigation or bid caps on wholesale electricity prices, timely recovery of our investments and costs, the disposition of utility assets and facilities, treatment of affiliate contracts and relationships, operation and construction of facilities, and enforcement of or compliance with applicable rules, tariffs, licenses and orders;

- our ability to manage over time our residual net open position, which is the portion of our electricity customers demand not satisfied by electricity from our generation facilities, our electricity purchase contracts or California Department of Water Resources, or DWR, electricity contracts allocated to our customers;

- the inability of various counterparties to perform their supply obligations under their electricity purchase contracts with us or with the DWR, thereby increasing the risk that we will need to buy additional electricity;

- weather, storms, earthquakes, fires, other natural disasters, explosions, accidents, mechanical breakdowns and other events or perils that affect demand, result in power outages, reduce generating output or damage our assets or operations or those of third parties on which we rely;

- unanticipated changes in our operating expenses and capital expenditures;

- the level and volatility of wholesale electricity and natural gas prices and our ability to manage and respond to this volatility successfully;

- the effect of compliance with existing and future environmental laws, regulations and policies;

- increased competition as a result of the takeover by condemnation, or municipalization, of our distribution assets, self-generation by our customers and other forms of competition that may result in stranded investment capital, decreased customer growth, loss of customer load and additional barriers to cost recovery;

- unanticipated population growth or decline, changes in market demand and demographic patterns, and general economic and financial market conditions, including unanticipated changes in interest or inflation rates;

- the extent to which the cities and counties in our service territory become community choice aggregators and the extent to which our distribution customers can switch between purchasing electricity from us or from alternate energy service providers and the attendant risks from any material loss or gain of customers;

- the operation and decommissioning of our Diablo Canyon nuclear power plant, which expose us to potentially significant environmental and capital expenditure risks, and, to the extent we are unable to increase our spent fuel storage capacity by 2007 or find an alternative depository, the risk that we may be required to close our Diablo Canyon power plant and purchase electricity from more expensive sources;

- acts of terrorism;

- the outcome of pending litigation, rate cases and other regulatory proceedings;
- significant changes in our relationship with our employees, the availability of qualified personnel and potential adverse effects if labor disputes were to occur;
- actions of rating agencies; and
- new accounting pronouncements, including significant changes in accounting policies material to us.

For additional factors that could affect the validity of our forward-looking statements, you should read the section of this prospectus titled Risk Factors.

You should read this prospectus and any applicable prospectus supplements, the documents that we have filed as exhibits to the registration statement of which this prospectus is a part and the documents that we refer to under the section of this prospectus titled Where You Can Find More Information completely and with the understanding that our actual future results could be materially different from what we currently expect. We qualify all our forward-looking statements by these cautionary statements. These forward-looking statements speak only as of the date of this prospectus. Except as required by applicable laws or regulations, we do not undertake any obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

RISK FACTORS

You should carefully consider the risks and uncertainties described below and the other information contained in this prospectus or any applicable prospectus supplement or incorporated by reference in this prospectus before you decide whether to purchase the debt securities. The risks and uncertainties described below are not the only ones we may face. The following risks, together with additional risks and uncertainties not currently known to us or that we may currently deem immaterial, could impair our business operations and ultimately affect our ability to make payments on the debt securities.

Risks Related to Us

Our financial viability depends upon our ability to recover our costs in a timely manner from our customers through regulated rates and otherwise execute our business strategy.

We are a regulated entity subject to CPUC jurisdiction in almost all aspects of our business, including the rates, terms and conditions of our services, procurement of electricity and natural gas for our customers, issuance of securities, dispositions of utility assets and facilities and aspects of the siting and operation of our electricity and natural gas distribution systems. Executing our business strategy depends on periodic CPUC approvals of these and related matters. Our ongoing financial viability depends on our ability to recover from our customers in a timely manner all our costs, including the costs of electricity and natural gas purchased by us for our customers, in our CPUC-approved rates and our ability to pass through to our customers in rates our FERC-authorized revenue requirements. During the California energy crisis, the high price we had to pay for electricity on the wholesale market, coupled with our inability to fully recover our costs in retail rates, caused our costs to significantly exceed our revenues and ultimately caused us to file a petition under Chapter 11 of the United States Bankruptcy Code, or Chapter 11. Even though the CPUC settlement agreement contemplates that the CPUC will give us the opportunity to recover our reasonable and prudent future costs in our rates, there can be no assurance that the CPUC will find that all of our costs are reasonable and prudent or will not otherwise take or fail to take actions to our detriment. In addition, there can be no assurance that the bankruptcy court or other courts will implement and enforce the terms of the CPUC settlement agreement and our plan of reorganization in a manner that would produce the economic results that we intend or anticipate. Further, there can be no assurance that FERC-authorized tariffs will be adequate to cover the related costs. If we are unable to recover any material amount of our costs through our rates in a timely manner, our financial condition and results of operations would be materially adversely affected.

We may be unable to purchase electricity in the wholesale market or to increase our generating capacity in a manner that the CPUC will find reasonable or in amounts sufficient to satisfy our residual net open position.

The electricity we generate and have under contract, combined with the electricity furnished under the DWR electricity contracts allocated to our customers, or the DWR allocated contracts, may not be sufficient to satisfy our customer s electricity demand in the future. Our residual net open position will increase over time for a number of reasons, including:

- periodic expirations of our existing electricity purchase contracts;
- periodic expirations or other terminations of the DWR allocated contracts; and
- increases in our customers electricity demands due to customer and economic growth or other factors.

In addition, unexpected outages at our Diablo Canyon power plant or any of our other significant generation facilities, or a failure to perform by any of the counterparties to our electricity purchase contracts or the DWR allocated contracts, would immediately increase our residual net open position.

As existing electricity purchase contracts expire, sources of electricity otherwise become unavailable or demand increases, we will purchase electricity in the wholesale market. These purchases will be made under contracts priced at the time of execution or, if made in the spot market, at the then-current market price of wholesale electricity. There can be no assurance that sufficient replacement electricity will be available at prices and on terms that the CPUC finds reasonable, or at all. Our financial condition and results of operations would be materially adversely affected if we were unable to purchase electricity in the wholesale market on terms the CPUC finds reasonable or in quantities sufficient to satisfy our residual net open position.

Alternatively, the CPUC may require us or we may elect to satisfy all or a part of our residual net open position by developing or acquiring additional generation facilities. This could result in significant additional capital expenditures or other costs and may require us to issue additional debt, which we may not be able to issue on reasonable terms, or at all. In addition, if we are not able to recover a material part of the cost of developing or acquiring additional generation facilities in our rates in a timely manner, our financial condition and results of operations would be materially adversely affected.

Our financial condition and results of operations could be materially adversely affected if we are unable to successfully manage the risks inherent in operating our facilities.

We own and operate extensive electricity and natural gas facilities that are interconnected to the U.S. western electricity grid and numerous interstate and continental pipelines. The operation of our facilities and the facilities of third parties on which we rely involves numerous risks, including:

- operating limitations that may be imposed by environmental or other regulatory requirements;
- imposition of stringent operational performance standards by agencies with regulatory oversight of our facilities;
- environmental and personal injury liabilities;
- fuel interruptions;
- blackouts;
- labor disputes;
- weather, storms, earthquakes, fires, floods or other natural disasters; and
- explosions, accidents, mechanical breakdowns and other events or perils that affect demand, result in power outages, reduce generating output or cause damage to our assets or operations or those of third parties on which we rely.

The occurrence of any of these events could result in lost revenues or increased expenses, or both, that may not be fully recovered through insurance, rates or other means in a timely manner, or at all.

Electricity and natural gas markets are highly volatile and insufficient regulatory responsiveness to that volatility could cause events similar to those that led to the filing of our Chapter 11 petition to occur.

In the recent past, the commodity markets for electricity and natural gas have been highly volatile and subject to substantial price fluctuations. A variety of factors may contribute to commodity market volatility, including:

- weather;
- supply and demand;
- the availability of competitively priced alternative energy sources;
- the level of production of natural gas;
- the price of other fuels that are used to produce electricity, including crude oil and coal;

the transparency, efficiency, integrity and liquidity of regional energy markets affecting California;

electric transmission or natural gas transportation capacity constraints;

federal, state and local energy and environmental regulation and legislation; and

natural disasters, war, terrorism and other catastrophic events.

These factors are largely outside our control. If wholesale electricity or natural gas prices increase significantly, public pressure or other regulatory or governmental influences could constrain the willingness of the CPUC to authorize timely recovery of our costs. Moreover, the volatility of commodity markets could cause us to apply more frequently to the CPUC for authority to timely recover our costs in rates. If we are unable to recover any material amount of our costs in our rates in a timely manner, our financial condition and results of operations would be materially adversely affected.

Our operations are subject to extensive environmental laws, and changes in, or liabilities under, these laws could adversely affect our financial condition and results of operations.

Our operations are subject to extensive federal, state and local environmental laws. Complying with these environmental laws has in the past required significant expenditures for hazardous substance removal, environmental remediation, environmental monitoring and pollution control equipment at our facilities and the surrounding areas, as well as for related fees and permits. Moreover, compliance in the future may require significant expenditures relating to electric and magnetic fields, or EMFs. Due to the potential for imposition of stricter standards and greater regulation in the future and the possibility that other potentially responsible parties may not be financially able to contribute to these costs, our environmental compliance and remediation costs could increase and the timing of our capital expenditures in the future may accelerate. If we are unable to recover the costs of complying with environmental laws in our rates in a timely manner, our financial condition and results of operations could be materially adversely affected. In addition, in the event we must pay materially more than the amount that we currently have reserved on our balance sheet to satisfy our environmental remediation obligations and we are unable to recover these costs from insurance or through rates in a timely manner, our financial condition and results of operations would be materially adversely affected.

We face the risk of unrecoverable costs if our customers obtain distribution and transportation services from other providers as a result of municipalization or other forms of competition.

Our customers could bypass our distribution and transportation system by obtaining service from other sources. Forms of bypass of our electricity distribution system include the construction of duplicate distribution facilities to serve specific existing or new customers, the municipalization of our distribution facilities by local governments or districts, self-generation by our customers and other forms of competition. Bypass of our system may result in stranded investment capital, loss of customer growth or additional barriers to cost recovery. Our natural gas transportation facilities also are at risk of being bypassed by customers who build pipeline connections that bypass our natural gas transportation system. As customers and local public officials explore their energy options in light of the recent California energy crisis, these bypass risks may be increasing and may increase further if our rates exceed the cost of other available alternatives. In addition, technological changes could result in the development of economically attractive alternatives to purchasing electricity through our distribution facilities. We cannot currently predict the impact of these actions and developments on our business, although one possible outcome is a decline in the demand for the services that we provide, which would result in a corresponding decline in our revenues.

If the number of our customers declines due to bypass, technological changes or other forms of competition, and our rates are not adjusted in a timely manner to allow us to fully recover our investment and electricity procurement costs, our financial condition and results of operations would be materially adversely affected.

We face the risk of unrecoverable costs resulting from changes in the number of customers in our service territory for whom we purchase electricity.

As part of California s electricity industry restructuring, our customers were given the choice of either continuing to receive electricity procurement, transmission and distribution services, or bundled service, from us, or electing to purchase electricity from alternate energy service providers, and to thus become direct access customers. The CPUC suspended the right of end-user customers to become direct access customers on September 20, 2001, although customers that were then direct access customers have been allowed to remain on direct access. Separately, the CPUC has instituted a rulemaking implementing California s Assembly Bill 117, or AB 117, permitting California cities and counties to purchase and sell electricity for their residents once they have registered as community choice aggregators. We would continue to provide distribution, metering and billing services to the community choice aggregators customers and would be those customers electricity provider of last resort. However, once registration has occurred, each community choice aggregator would procure electricity for all of its residents who do not affirmatively elect to continue to receive electricity from us.

If we lose a material number of customers as a result of cities and counties electing to become community choice aggregators or the CPUC allowing resumption of direct access, our electricity purchase contracts could obligate us to purchase more electricity than our remaining customers require, the excess of which we would have to sell in the wholesale spot market, possibly at a loss. Further, if we must provide electricity to customers discontinuing direct access or who elect to leave a community choice aggregator, we may be required to make unanticipated purchases of additional electricity at higher prices.

If we have excess electricity or we must make unplanned purchases of electricity as a result of the actions of community choice aggregators customers or direct access customers, and the CPUC fails to adjust our rates to reflect the impact of these actions, our financial condition and results of operations could be materially adversely affected.

The operation and decommissioning of our nuclear power plants expose us to potentially significant liabilities and capital expenditures.

The operation and decommissioning of our nuclear power plants expose us to potentially significant liabilities and capital expenditures, including those arising from the storage, handling and disposal of radioactive materials and uncertainties related to the regulatory, technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives. We maintain decommissioning trusts and external insurance coverage to reduce our financial exposure to these risks. However, the costs or damages we may incur in connection with the operation and decommissioning of nuclear power plants could exceed the amount of our insurance coverage and other amounts set aside for these potential liabilities. In addition, as an operator of two operating nuclear reactor units, we may be required under federal law to pay up to $201.2 million of liabilities arising out of each nuclear incident occurring not only at our Diablo Canyon power plant but at any other nuclear power plant in the United States. If we cannot recover any material amount of these excess costs or damages in our rates in a timely manner, our financial condition and results of operations would be materially adversely affected.

In addition, the Nuclear Regulatory Commission, or the NRC, has broad authority under federal law to impose licensing and safety-related requirements upon owners and operators of nuclear power plants. In the event of non-compliance, the NRC has the authority to impose fines or to force a shutdown of the nuclear plant, or both, depending upon the NRC s assessment of the severity of the situation. Safety requirements promulgated by the NRC have, in the past, necessitated substantial capital expenditures at our Diablo Canyon power plant and additional significant capital expenditures could be required in the future.

If we fail to increase the spent fuel storage capacity at our Diablo Canyon nuclear power plant by the spring of 2007 and there are no other available alternatives, we would be forced to close it and would therefore be required to purchase electricity from more expensive sources.

Under the terms of the NRC operating licenses for our Diablo Canyon power plant, there must be sufficient storage capacity for the radioactive spent fuel produced by this plant. Under current operating procedures, we believe that our Diablo Canyon power plant s existing spent fuel pools have sufficient capacity to enable it to operate until the spring of 2007. Although we are taking actions to increase our Diablo Canyon power plant s spent fuel storage capacity and exploring other alternatives, there can be no assurance that we can obtain the necessary regulatory approvals to expand spent fuel capacity or that other alternatives will be available or implemented in time to avoid a disruption in production or shutdown of one or both units at this plant. As the proposed permanent spent fuel depository at Yucca Mountain, Nevada will not be available by 2007, there will not be any available third party spent fuel storage facilities. If there is a disruption in production or shutdown of one or both units at this plant, we will need to purchase electricity from more expensive sources.

Acts of terrorism could materially adversely affect our financial condition and results of operations.

Our facilities, including our operating and retired nuclear facilities and the facilities of third parties on which we rely, could be targets of terrorist activities. A terrorist attack on these facilities could result in a full or partial disruption of our ability to generate, transmit, transport or distribute electricity or natural gas or cause environmental repercussions. Any operational disruption or environmental repercussions could result in a significant decrease in our revenues or significant reconstruction or remediation costs, which could materially adversely affect our financial condition and results of operations.

Adverse judgments or settlements in the chromium litigation cases could materially adversely affect our financial condition and results of operations.

We are a named defendant in 14 civil actions currently pending in California courts relating to alleged chromium contamination. The chromium litigation complaints allege personal injuries, wrongful death and loss of consortium and seek unspecified compensatory and punitive damages based on claims arising from alleged exposure to chromium contamination in the vicinity of three of our natural gas compressor stations. If we pay a material amount in excess of the amount that we currently have reserved on our balance sheet to satisfy chromium-related liabilities and costs, our financial condition and results of operations could be materially adversely affected.

Changes in, or liabilities under, our permits, authorizations or licenses could adversely affect our financial condition and results of operations.

Our operations are subject to a number of governmental permits, authorizations and licenses. These permits, authorizations and licenses may be revoked or modified by the agency that granted them if facts develop that differ significantly from the facts assumed when they were issued. Furthermore, discharge permits and other approvals and licenses are granted for a term that is 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. For example, we currently have eight hydroelectric generation facilities undergoing FERC license renewal. In connection with a license renewal, the FERC may impose new license conditions that could, among other things, require increased expenditures or result in reduced electricity output and/or capacity at the licensed hydroelectric generation facility. If we are unable to obtain, renew or comply with these governmental permits, authorizations or licenses, or we are unable to recover any increased costs of complying with additional license requirements or any other associated costs in a timely manner, our financial condition and results of operations could be materially adversely affected.

Risks Related to the Debt Securities

After giving effect to our plan of reorganization, we will have a significant amount of debt, and the agreements governing that indebtedness will allow us to incur additional debt in the future, which could adversely affect our ability to make payments on the debt securities.

After giving effect to our plan of reorganization (including the expected issuance of debt securities offered by this prospectus in connection with our plan of reorganization, borrowings under our contemplated credit facilities and payments to holders of allowed claims and equity interests), we currently expect to have approximately $9.4 billion in total debt outstanding on the effective date of our plan of reorganization (excluding rate reduction bonds). In addition, the indentures governing the debt securities offered by this prospectus and the terms of the contemplated credit facilities will allow us to incur additional indebtedness. Our level of debt could have important consequences to holders of the debt securities. For example, additional debt could require us to dedicate a greater portion of our cash flow to paying interest expense and debt amortization, which would reduce the funds available to us for our operations and capital expenditures, limit our ability to obtain additional financing for capital expenditures, working capital or for other purposes and increase our vulnerability to adverse economic and industry conditions.

Our ability to make scheduled payments of principal and interest on the debt securities and to satisfy other debt obligations will depend on the cash flow from our operations and other available sources of liquidity, such as equity offerings or additional debt financings. We can provide no assurance that these sources of liquidity will be available to us if and when needed or on terms acceptable to us. The level of indebtedness we expect to have outstanding after giving effect to our plan of reorganization and the establishment of the credit facilities, as well as future indebtedness levels, could adversely affect our ability to make payments of principal and interest on the debt securities.

There is no existing market for the debt securities, and we cannot assure you that an active trading market will develop.

There is no existing market for the debt securities and we do not intend to apply for listing of the debt securities on any securities exchange or any automated quotation system. There can be no assurance as to the liquidity of any market that may develop for the debt securities, the ability of the holders of the debt securities to sell their debt securities or the price at which holders of the debt securities will be able to sell their debt securities. Future trading prices of the debt securities will depend on many factors, including prevailing interest rates, our financial condition and results of operations, the then-current ratings assigned to the debt securities and the market for similar securities.

If a particular offering of debt securities is sold to or through underwriters, the underwriters may attempt to make a market in the debt securities. However, the underwriters would not be obligated to do so and they could terminate any market-making activity at any time without notice. If a market for any of the debt securities does not develop, holders of those debt securities may be unable to resell them for an extended period of time and those debt securities may not be readily accepted as collateral for loans.

The terms of our debt instruments could restrict our flexibility and limit our ability to make payments on the debt securities.

Some of the pollution control bond-related agreements that we may reinstate as part of our plan of reorganization and both forms of indenture governing the debt securities offered by this prospectus contain restrictions on the amount and type of secured indebtedness that we may incur. In addition, if we issue unsecured debt securities under this prospectus in connection with our plan of reorganization, the existing mortgage indenture that we will amend and restate contains, and will continue to contain, an interest coverage ratio that we must satisfy before we can issue future mortgage bonds. We expect that the contemplated credit facilities will contain financial and operational covenants. In addition, the instruments governing future indebtedness that we may incur could also contain financial covenants and other restrictions on us. These covenants and restrictions could limit our flexibility and limit our ability to borrow additional funds to finance operations and to make principal and interest payments on the debt securities. In addition, failure to comply with these covenants could result in an event of default under the terms of the agreements that, if not cured or waived, could result in the indebtedness becoming due and payable. The effect of these covenants, or our failure to comply with them, could materially adversely affect our business, financial condition, results of operations and our ability to satisfy our obligations under the debt securities.

USE OF PROCEEDS

Each prospectus supplement will describe the uses of the proceeds from the issuance of the debt securities offered by that prospectus supplement.

SELECTED CONSOLIDATED FINANCIAL DATA

The following table presents our selected consolidated financial data for the years ended December 31, 2002, 2001, 2000, 1999 and 1998 and the six months ended June 30, 2003 and 2002. We derived the selected consolidated financial data for the years ended December 31, 2002, 2001 and 2000 from our audited consolidated financial statements included in this prospectus and the selected consolidated financial data for the years ended December 31, 1999 and 1998 from our audited consolidated financial statements not included in this prospectus. We derived the selected consolidated financial data for the six months ended June 30, 2003 and 2002 from our unaudited interim consolidated financial statements included in this prospectus. In the opinion of our management, the interim financial statements include all normal recurring adjustments necessary to present fairly the information required to be set forth in those financial statements. However, our operating results for interim periods are not necessarily indicative of a full year s operations. In addition, our historical operating results are not necessarily indicative of future operations. The data below should be read in conjunction with, and is qualified in its entirety by reference to, our consolidated financial statements, the notes to those financial statements and the section of this prospectus titled Management s Discussion and Analysis of Financial Condition and Results of Operations.

	Six Months Ended June 30,		Year Ended December 31,				
	2003	**2002**	**2002**	**2001**	**2000**	**1999**	**1998**
				(dollars in millions)			
Consolidated Statements of Operations Data:							
Operating revenues:							
Electric	$3,299	$3,971	$ 8,178	$ 7,326	$ 6,854	$7,232	$7,191
Natural gas	1,498	1,196	2,336	3,136	2,783	1,996	1,733
Total operating revenues	4,797	5,167	10,514	10,462	9,637	9,228	8,924
Operating expenses:							
Depreciation, amortization and decommissioning	605	565	1,193	896	3,511	1,564	1,438
Other operating expenses	3,388	2,295	5,408	7,088	11,327	5,671	5,610
Total operating expenses	3,993	2,860	6,601	7,984	14,838	7,235	7,048
Operating income (loss)(1)	804	2,307	3,913	2,478	(5,201)	1,993	1,876
Interest expense(2)	(444)	(546)	(988)	(974)	(619)	(593)	(621)
Other income	38	35	72	107	183	36	103
Income tax (provision) benefit	(125)	(731)	(1,178)	(596)	2,154	(648)	(629)
Net income (loss) from continuing operations(1)	$ 273	$1,065	$ 1,819	$ 1,015	$ (3,483)	$ 788	$ 729
Other Data (unaudited):							
Ratio of earnings to fixed charges(3)	1.87x	4.16x	3.91x	2.58x	x(4)	3.25x	3.02x
EBITDA(5)	$1,447	$2,907	$ 5,178	$ 3,481	$ (1,507)	$3,593	$3,417

	June 30,	December 31,				
	2003	**2002**	**2001**	**2000**	**1999**	**1998**
			(in millions)			
Consolidated Balance Sheet Data:						
Cash and cash equivalents	$ 3,700	$ 3,343	$ 4,341	$ 1,344	$ 101	$ 90
Restricted cash	234	150	53	50		
Working capital	3,395	3,382	4,291	(6,192)	(1,603)	(999)
Net property, plant and equipment	15,913	13,957	13,357	13,001	12,718	12,872
Total assets	26,013	24,551	25,269	21,988	21,470	22,950

Debt, classified as current	881	571	623	5,743	1,204	1,218
Long-term debt	2,429	2,739	3,019	3,342	4,877	5,444
Rate reduction bonds (excluding current portion)	1,019	1,160	1,450	1,740	2,031	2,321
Liabilities subject to compromise	9,456	9,391	11,384			
Preferred securities with mandatory redemption provisions	137	137	437	437	437	437
Shareholders equity	4,394	4,194	2,398	1,410	5,771	6,348

(1) Operating income (loss) and net income (loss) from continuing operations reflect the write-off of generation-related regulatory assets and under-collected electricity purchase costs in 2000. For more information, see the section of this prospectus titled Management s Discussion and Analysis of Financial Condition and Results of Operations and the notes to our consolidated financial statements.

(2) Interest expense includes non-contractual interest expense of $67 million and $103 million for the six months ended June 30, 2003 and 2002, respectively, and $149 million and $164 million for the years ended December 31, 2002 and 2001, respectively.

(3) For the purpose of computing ratios of earnings to fixed charges, earnings represent net income adjusted for income taxes and fixed charges. Fixed charges include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases and the amount of earnings required to cover the preferred security distribution requirements of our wholly owned trust.

(4) The ratio of earnings to fixed charges indicates a deficiency of less than one-to-one coverage of $5.6 billion.

(5) EBITDA is defined as income before provision for income taxes, interest expense and depreciation, amortization and decommissioning. We believe that EBITDA provides one of the best comparative measures for operating performance and is a standard measure commonly reported and widely used by analysts, investors and other parties as an indication of our ability to service our debt. EBITDA is not intended to represent net cash provided by operating activities and should not be considered as an alternative to net income as an indicator of operating performance or to cash flows as a measure of liquidity. EBITDA is not a measurement of operating performance computed in accordance with accounting principles generally accepted in the United States of America, or GAAP, and it should not be considered a substitute for operating income or cash flows from operations prepared in conformity with GAAP. Our method of computation may or may not be comparable to other similarly titled measures used by other companies.

EBITDA is calculated from net income (loss) from continuing operations (which we believe to be the most directly comparable financial measures calculated in accordance with GAAP). Set forth below is a reconciliation of EBITDA to both net income (loss) from continuing operations and net cash provided by operating activities.

	Six Months Ended June 30,		Year Ended December 31,				
	2003	2002	2002	2001	2000	1999	1998
			(in millions)				
Net income (loss) from continuing operations	$ 273	$ 1,065	$ 1,819	$ 1,015	$ (3,483)	$ 788	$ 729
Adjustments to reconcile EBITDA to net income (loss) from continuing operations:							
Depreciation, amortization and decommissioning	605	565	1,193	896	3,511	1,564	1,438
Interest expense	444	546	988	974	619	593	621
Income tax provision (benefit)	125	731	1,178	596	(2,154)	648	629
EBITDA	$ 1,447	$ 2,907	$ 5,178	$ 3,481	$ (1,507)	$ 3,593	$ 3,417
Adjustments to reconcile EBITDA to net cash provided by operating activities:							
Cash paid for interest	(341)	(683)	(1,105)	(361)	(587)	(531)	(600)
Cash paid for taxes	32	(353)	(1,186)	556		(1,001)	(1,115)
Deferral of electric procurement costs					(6,465)		
Provision for loss on generation-related regulatory assets and undercollected purchased power costs					6,939		
Reversal of ISO accrual		(970)	(970)				
Change in deferred charges and other non-current liabilities	284	363	102	(954)	480	101	31
Change in working capital (other than income taxes payable)	(59)	161	363	2,379	2,263	464	2,061
Payments authorized by bankruptcy court	(62)	(947)	(1,442)	(16)			
Other, net	(97)	152	194	(320)	(568)	(430)	(58)
Net cash provided by operating activities	$ 1,204	$ 630	$ 1,134	$ 4,765	$ 555	$ 2,196	$ 3,736

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION

AND RESULTS OF OPERATIONS

You should read the following discussion in conjunction with the sections of this prospectus titled Special Note Regarding Forward-Looking Statements, Risk Factors, Selected Consolidated Financial Data and the financial statements and related notes included elsewhere in this prospectus.

Overview

We are a leading vertically integrated electricity and natural gas utility. We operate in northern and central California and are engaged in the businesses of electricity generation, electric transmission, natural gas transportation and storage, and electricity and natural gas distribution.

We own and operate an extensive hydroelectric system, the Diablo Canyon nuclear power plant and two fossil fuel-fired plants. The electricity generated from these facilities, along with electricity furnished under electricity purchase contracts, or as needed from the spot market, is used to satisfy our customers electricity demands. The DWR also provides electricity to us for distribution to our customers under the DWR allocated contracts. We purchase natural gas for our core customers, comprised of small commercial and residential customers, and transport this natural gas along with natural gas purchased principally by our large commercial and industrial customers directly from suppliers through our natural gas transportation and distribution system. We have arrangements with interstate natural gas transportation companies to ship the natural gas purchased for our core customers from producing areas (principally in western Canada and the southwest United States) to our pipeline facilities in California.

The electricity and natural gas industries have undergone various stages of deregulation since the mid-1990s. Natural gas deregulation preceded electricity deregulation and the regulatory framework for natural gas has been relatively stable in recent years. In 1996, the State of California adopted legislation restructuring the electricity markets in California and, in 1998, the CPUC implemented electricity industry restructuring.

Beginning in May 2000, wholesale electricity prices began to increase. Since our retail electricity rates remained frozen, we financed the higher costs of wholesale electricity by issuing debt and drawing on our credit facilities. Our inability to recover our electricity purchase costs from customers ultimately resulted in billions of dollars in defaulted debt and unpaid bills and caused us to file a voluntary petition for relief under Chapter 11 on April 6, 2001. Pursuant to Chapter 11, we have retained control of our assets and are authorized to operate as a debtor-in-possession while we are subject to the jurisdiction of the bankruptcy court.

Our plan of reorganization was confirmed by the bankruptcy court on . We expect to emerge from bankruptcy before the end of the first quarter of 2004. Our plan of reorganization generally provides for payment in full of all allowed creditor claims (except for the claims of holders of pollution control bond-related obligations that will be reinstated) plus applicable interest on claims in certain classes and all cumulative dividends in arrears and mandatory sinking fund payments associated with our preferred stock. After giving effect to our plan of reorganization (including the expected issuance of debt securities offered by this prospectus in connection with our plan of reorganization, borrowings under our contemplated credit facilities and payments to holders of allowed claims and equity interests), we currently expect to have approximately $9.4 billion in total debt outstanding on the effective date of our plan of reorganization (excluding rate reduction bonds). Under our plan of reorganization, we would remain a vertically integrated electricity and natural gas utility primarily regulated by the CPUC. For more information regarding our plan of reorganization, see the section of this prospectus titled Description of Our Plan of Reorganization.

Our consolidated financial statements have been prepared on a going concern basis, which contemplates continuity of operations, realization of assets and repayment of liabilities in the ordinary course of business. In addition, these financial statements apply principles used by rate regulated companies.

In this Management s Discussion and Analysis of Financial Condition and Results of Operations, we first discuss our historical results of operations. Under Liquidity and Capital Resources below, we discuss our current cash position and our historical cash flows. We also discuss our commitments and contingencies and other matters that are relevant to understanding our financial condition and results of operations.

Critical Accounting Policies

The preparation of consolidated financial statements in accordance with GAAP involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The accounting policies described below are considered to be critical accounting policies due, in part, to their complexity and because their application is relevant and material to our financial position and results of operations, and because these policies require the use of material judgments and estimates. These policies and their key characteristics are outlined below.

Unbilled and Surcharge Revenues

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

Since the CPUC authorized the collection of surcharge revenues in January, March and May 2001, we have collected generation-related revenues in excess of generation-related costs of approximately $2.0 billion (after-tax). We have not provided reserves for potential refunds of these surcharges, nor would the surcharges be subject to refund under the CPUC settlement agreement.

DWR Revenues

We act as a pass-through entity for electricity purchased by the DWR on behalf of our customers. Although charges for electricity provided by the DWR are included in the amounts we bill our customers, we deduct from our electric revenues the amounts passed through to the DWR. The pass-through amounts are based on the quantities of electricity provided by the DWR that are consumed by customers at the CPUC-approved remittance rate. These pass-through amounts are excluded from our electric revenues in our consolidated statements of operations.

Regulatory Assets and Liabilities

We apply Statement of Financial Accounting Standards, or SFAS, No. 71, *Accounting for the Effects of Certain Types of Regulation*, or SFAS No. 71, to our regulated operations. Under SFAS No. 71, regulatory assets represent costs that otherwise would be charged to expense under GAAP. These costs are later recovered through regulated rates. Regulatory liabilities are created by rate actions of a regulator and later will be credited to customers through the ratemaking process. Regulatory assets and liabilities are recorded when it is probable that these items will be recovered or reflected in future rates. If it is determined that these items are no longer likely to be recovered under SFAS No. 71, they will be written off at that time. At June 30, 2003, we reported regulatory assets of $2.1 billion, including current regulatory balancing accounts receivable, and regulatory liabilities of $1.2 billion, including current regulatory balancing accounts payable.

Environmental Remediation Liabilities

We record an environmental remediation liability when site assessments indicate remediation is probable and we can estimate a range of reasonably likely cleanup costs. This liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring and site closure. This liability is reviewed on a quarterly basis and is recorded at the lower range of estimated costs, unless there is a better estimate available. At June 30, 2003, our undiscounted environmental remediation liability was $302 million. Our future environmental remediation liability could increase to as much as $418 million if other potentially responsible parties are not financially able to contribute to these costs, the extent of contamination or necessary remediation is greater than anticipated, or we are found to be responsible for cleanup costs at additional sites.

The process of estimating remediation liabilities is difficult and changes in the estimate could occur given the uncertainty concerning our ultimate liability, the complexity of environmental laws and regulations, the selection of compliance alternatives and the financial resources of other responsible parties.

Our Chapter 11 Filing

Our financial statements are prepared in accordance with the American Institute of Certified Public Accountants Statement of Position, or SOP, 90-7, *Financial Reporting by Entities in Reorganization Under the Bankruptcy Code*, which is used by reorganizing entities operating under the United States Bankruptcy Code, or the Bankruptcy Code. Under SOP 90-7, certain claims against us before our Chapter 11 filing are classified as liabilities subject to compromise. We reported a total of $9.5 billion of liabilities subject to compromise at June 30, 2003. While we operate under the protection of the bankruptcy court, the realization of assets and the liquidation of liabilities are subject to uncertainty, as additional claims to liabilities subject to compromise can change due to such actions as the resolution of disputed claims or certain bankruptcy court actions.

Results of Operations

The following table sets forth certain operating data for the years ended December 31, 2002, 2001 and 2000 and for the six months ended June 30, 2003 and 2002:

	Six Months Ended June 30,		Year Ended December 31,		
	2003	**2002**	**2002**	**2001**	**2000**
			(in millions)		
Operating revenues					
Electric	$3,299	$3,971	$ 8,178	$ 7,326	$ 6,854
Natural gas	1,498	1,196	2,336	3,136	2,783
Total operating revenues	4,797	5,167	10,514	10,462	9,637
Operating expenses					
Cost of electric energy	1,056	339	1,482	2,774	6,741
Deferred electric procurement cost					(6,465)
Cost of natural gas	806	513	954	1,832	1,425
Operating and maintenance	1,426	1,409	2,817	2,385	2,687
Depreciation, amortization and decommissioning	605	565	1,193	896	3,511
Provision for loss on generation-related regulatory assets and under-collected purchased electricity costs					6,939
Reorganization professional fees and expenses	100	34	155	97	
Total operating expenses	3,993	2,860	6,601	7,984	14,838
Operating income (loss)	804	2,307	3,913	2,478	(5,201)
Reorganization interest income	27	41	71	91	
Interest income	4		3	32	186
Interest expense:					
Contractual interest expense	(377)	(443)	(839)	(810)	(619)
Noncontractual interest expense	(67)	(103)	(149)	(164)	
Other income (expense), net	7	(6)	(2)	(16)	(3)
Income (loss) before income taxes	398	1,796	2,997	1,611	(5,637)
Income tax provision (benefit)	125	731	1,178	596	(2,154)
Income before cumulative effect of a change in accounting principle	273	1,065	1,819	1,015	(3,483)
Cumulative effect of a change in accounting principle (net of income tax benefit of $1 million for the six months ended June 30, 2003)	(1)				

Net income (loss)	272	1,065	1,819	1,015	(3,483)
Preferred dividend requirement	12	12	25	25	25
Income (loss) available for (allocated to) common stock	$ 260	$ 1,053	$ 1,794	$ 990	$ (3,508)

Overall Results and Income Volatility

Due to the California energy crisis, we have experienced volatility in our results. In 2000, we experienced a significant loss due to the high wholesale energy prices and the write-off of under-collected purchased power and generation-related costs. In 2001, we produced income as one, three and half cent surcharges, made necessary by the California energy crisis, were implemented and wholesale electricity prices moderated during the latter half of the year. Our results for 2002 reflected a full year of the surcharges implemented in 2001 and adjustments associated with the allocated DWR contracts. Results for the first six months of 2003 reflected a decline in operating revenues compared to the same period in 2002. As discussed further below, the results for the first six months of 2002 also included some favorable adjustments to our cost of energy.

Comparison of Six-Month Periods Ended June 30, 2003 and June 30, 2002

Electric Revenues

The following table shows a breakdown of our electric revenues by customer class:

	Six Months Ended June 30,			
	2003	**2002**	**Increase (Decrease)**	**% Change**
		(in millions)		
Residential	$ 1,744	$ 1,759	$ (15)	(0.9)%
Commercial	1,916	1,996	(80)	(4.0)%
Industrial	656	705	(49)	(7.0)%
Agricultural	198	221	(23)	(10.4)%
Subtotal	4,514	4,681	(167)	(3.6)%
Direct access credits	(150)	(190)	40	21.1%
DWR pass-through revenue	(1,351)	(743)	(608)	81.8%
Miscellaneous	286	223	63	28.3%
Total electric operating revenues	$ 3,299	$ 3,971	$ (672)	(16.9)%

Electric operating revenues decreased $672 million, or 17%, for the six months ended June 30, 2003 compared to the same period in 2002 primarily due to the following:

Amounts recorded as pass-through revenue to the DWR increased by $608 million, or 82%, for the six months ended June 30, 2003 compared to the same period in 2002. We pass revenue through to the DWR for electricity provided by the DWR to our customers. The increase in DWR pass-through revenue was primarily due to changes to the methodology used to calculate DWR pass-through revenues beginning in the third quarter of 2002, an additional bond charge passed through to the DWR, which began in November 2002, and an increase in the amount of electricity supplied by the DWR.

From January 2001 through December 2002, the DWR was responsible for procuring electricity required to satisfy the electricity demand of customers not satisfied by electricity from our generation facilities and existing electricity contracts, which we refer to as our net open position. We resumed purchasing electricity on the open market in January 2003, but still relied on electricity provided by the DWR allocated contracts to service a significant portion of our total load. Revenues collected on behalf of the DWR and the DWR s related costs were not included in our consolidated statements of operations, reflecting our role as a billing and collection agent, for which we collected no fees, for the DWR s sales to our customers.

Lower average sales revenue due to a May 2002 CPUC decision that increased baseline quantity allowances. An increase to a customer s baseline quantity allowance increases the amount of the customer s monthly usage that is covered under the lowest possible rate and is exempt from the three cent surcharge.

These effects were partially offset by:

A decrease in direct access credits for the six months ended June 30, 2003 of $40 million, or 21%, compared to the same period in 2002. This decrease was primarily due to a $78 million adjustment that increased direct access credits and industrial customer revenues in the first quarter of 2002. This decrease was partly offset by increases in direct access credits due to increases in revenues recorded in the second quarter of 2003 to include an estimate of $64 million for electricity delivered to customers whose bills have been delayed. In accordance with CPUC regulations, we provide an energy credit to direct access customers who buy their electricity from an alternate energy service provider. We bill direct access customers based on fully bundled rates, which include generation, distribution, transmission and other components. However, each direct access customer receives an energy credit equal to the procurement component of the fully bundled rates, which includes our estimated procurement and generation cost, and our generation component of the frozen rate for electricity provided by the DWR.

An increase in electricity sales volume due to warmer weather in June 2003 and an increase in the amount recorded in the second quarter of 2003 to include an estimate of $64 million for electricity delivered to customers whose bills were delayed.

Natural Gas Revenues

The following table shows a breakdown of our natural gas revenues:

	Six Months Ended June 30,			
	2003	**2002**	**Increase (Decrease)**	**% Change**
	(revenues, except averages, in millions)			
Bundled gas revenue	$1,485	$1,145	$ 340	29.7%
Transportation service only revenue	133	160	(27)	(16.9)%
Other	(120)	(109)	(11)	10.1%
Total natural gas revenues	$1,498	$1,196	$ 302	25.3%
Average bundled price of natural gas sold per Mcf	$ 8.89	$ 6.54	$2.35	35.9%
Total bundled gas sales (in Bcf)	167	175	(8)	(4.6)%

Bundled natural gas revenue increased $340 million, or 30%, for the six months ended June 30, 2003 compared to the same period in 2002. The increase was primarily a result of a higher average cost of natural gas we purchased from suppliers, which was passed along to customers through higher rates. The average bundled price of natural gas sold increased $2.35 per Mcf, or 36%, for the six months ended June 30, 2003 compared to the same period in 2002.

Transportation service only revenues decreased $27 million, or 17%, for the six months ended June 30, 2003 compared to the same period in 2002. The decrease was primarily due to a decrease in demand for gas transportation services by natural gas-fired electricity generators in California.

Other natural gas revenue primarily includes amounts tracked in natural gas balancing accounts. Over-collections and under-collections are deferred until they are refunded to or received from our customers through rate adjustments.

Cost of Electricity

The following table shows a breakdown of our cost of electricity (which includes the cost of fuel used by our owned generation facilities and electricity purchase costs) and the total amount and average cost of purchased power, excluding in each case the cost and volume of electricity provided by the DWR to our customers:

	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002	Increase (Decrease)	% Change
	(costs, except averages, in millions)			
Cost of purchased power	$ 1,145	$ 886	$ 259	29.2%
Proceeds from surplus sales allocated to us	(133)		(133)	(100)%
Fuel used in our generation	44	48	(4)	(8.3)%
Adjustment to purchased power accruals		(595)	595	100%
Total cost of electricity	$ 1,056	$ 339	$ 717	211.5%
Average cost of purchased power per kWh	$ 0.083	$ 0.073	$0.010	13.7%
Total purchased power (in GWh)	13,863	12,138	1,725	14.2%

Our cost of electricity increased $717 million, or 212%, for the six months ended June 30, 2003 compared to the same period in 2002. The increase in the cost of electricity for the six months ended June 30, 2003 was mainly due to a net $595 million reduction to the cost of electricity recorded in March 2002 as a result of FERC and CPUC decisions that allowed us to reverse previously accrued California Independent System Operator, or ISO, charges and to adjust for the amount previously accrued as payable to the DWR for its 2001 revenue requirement. The increase in the cost of electricity also was due to an increase in the total volume of electricity purchased. In the first quarter of 2003, we began buying and selling electricity on the open market in accordance with our CPUC-approved electricity procurement plan. For further information, see the section of this prospectus titled Business Ratemaking Mechanisms Electricity Ratemaking Electricity Procurement Procurement Resumption and the ERRA. Based on the CPUC requirement to perform least-cost dispatch, we are required to dispatch all of the electricity resources within our portfolio, including the DWR allocated contracts, in the most cost-effective way to our ratepayers. This requirement in certain cases requires us to schedule more electricity than is required to meet our retail load and to sell this additional electricity on the open market. This typically occurs when the expected sales proceeds exceed the variable costs to operate a resource or call on a contract.

The increase in total costs was partially offset by proceeds from surplus electricity sales. Proceeds from the sale of surplus electricity are allocated between us and the DWR based on the percentage of volume supplied by each entity to our total load. Our net proceeds from the sale of surplus electricity after deducting the portion allocated to the DWR are recorded as a reduction to the cost of electricity.

Cost of Natural Gas

The following table shows a breakdown of our cost of natural gas:

	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002	Increases (Decreases)	% Change
	(costs, except averages, in millions)			
Cost of natural gas sold	$ 738	$ 462	$ 276	59.7%
Cost of gas transportation	68	51	17	33.3%
Total cost of natural gas	$ 806	$ 513	$ 293	57.1%

Average price of natural gas purchased per Mcf	$4.42	$2.64	$1.78	67.4%
Total natural gas purchased (in Bcf)	167	175	(8)	(4.6)%

Our cost of natural gas increased $276 million, or 60%, for the six months ended June 30, 2003 compared to the same period in 2002. The increase was primarily due to an increase in the average market price of natural gas purchased of $1.78 per Mcf, or 67%, for the six months ended June 30, 2003 compared to the same period in 2002.

Our cost to transport natural gas to our service area increased by $17 million, or 33%, for the six months ended June 30, 2003 compared to the same period in 2002. The increase was primarily due to new pipeline transportation charges paid to the El Paso Natural Gas Company, or El Paso. We, along with the other California investor-owned utilities, were ordered by the CPUC in July 2002 to enter into long-term contracts to purchase additional firm transportation services on the El Paso pipeline. Firm transportation service is the dedication of pipeline capacity to the purchaser s natural gas in priority over the natural gas of other capacity purchasers.

Operating and Maintenance

Our operating and maintenance expenses increased $17 million, or 1%, for the six months ended June 30, 2003 compared to the same period in 2002. This increase was primarily due to increases in employee benefit plan-related expenses, public purpose programs spending, customer-related costs and maintenance expenses due to maintenance performed during the scheduled refueling outage at our Diablo Canyon power plant in the first quarter of 2003. These increases were partially offset by lower recorded costs for environmental matters, and a decrease in the recorded liabilities for regulatory matters due to FERC and CPUC decisions on previous transmission owner rate cases and other matters.

Depreciation, Amortization and Decommissioning

Depreciation, amortization and decommissioning expenses increased $40 million, or 7%, for the six months ended June 30, 2003 compared to the same period in 2002. This increase was due mainly to an increase in amortization of the rate reduction bond regulatory asset, which began at the end of January 2002, and an overall increase in our plant assets. Amortization of the rate reduction bond regulatory asset for the six months ended June 30, 2003 increased $20 million from the same period in 2002. The increase reflected the amortization of the regulatory asset for the full six-month period in 2003 compared to the amortization of the regulatory asset for only five months in 2002.

Reorganization Fees and Expenses

In accordance with SOP 90-7, we report reorganization fees and expenses separately on our consolidated statements of operations. These costs primarily include professional fees for services in connection with our Chapter 11 case and totaled $100 million for the six months ended June 30, 2003. This was an increase of $66 million, or 194%, from the same period in 2002. The increase reflected costs associated with preparing for our emergence from bankruptcy.

Interest Income

In accordance with SOP 90-7, we report reorganization interest income separately on our consolidated statements of operations. Interest income primarily includes interest earned on cash accumulated during our Chapter 11 case. Interest income decreased $10 million, or 24%, for the six months ended June 30, 2003 compared to the same period in 2002. The decrease was due primarily to lower average interest rates earned on our short-term investments.

Interest Expense

Our interest expense decreased $102 million, or 19%, for the six months ended June 30, 2003 compared to the same period in 2002. The decrease was due to a reduction of interest on rate reduction bonds and a lower level of unpaid debts accruing interest.

Income Taxes

Income tax expense decreased $606 million, or 83%, for the six months ended June 30, 2003 compared to the same period in 2002. The primary reason for the decline was the 78% decrease in pre-tax income. The effective income tax rate for the six months ended June 30, 2003 was 31% compared to 41% for the same period in 2002. The decrease in the effective income tax rate was primarily due to the effect of regulatory treatment of depreciation differences in the six months ended June 30, 2003 compared to the six months ended June 30, 2002.

Comparison of Years Ended December 31, 2002 and December 31, 2001

Electric Revenues

The following table shows a breakdown of our electric revenues by customer class:

	Year Ended December 31,			
	2002	2001	Increase (Decrease)	% Change
	(in millions)			
Residential	$ 3,646	$ 3,396	$ 250	7.4%
Commercial	4,588	4,105	483	11.8%
Industrial	1,449	1,554	(105)	(6.8)%
Agricultural	520	525	(5)	(1.0)%
Subtotal	10,203	9,580	623	6.5%
Direct access credits	(285)	(461)	176	38.2%
DWR pass-through revenue	(2,056)	(2,173)	117	5.4%
Miscellaneous	316	380	(64)	(16.8)%
Total electric operating revenues	$ 8,178	$ 7,326	$ 852	11.6%

Electric operating revenues for 2002 increased $852 million, or 12%, compared to 2001. This increase in electric operating revenues was primarily due to the following three factors:

The amount of CPUC-authorized surcharges increased $751 million in 2002 from 2001. This increase reflects the collection of $0.035 per kWh in surcharges, effective June 2001, for all of 2002 compared to the collection of these surcharges for only seven months during 2001.

Direct access credits in 2002 decreased $176 million, or 38%, from 2001. The decrease in direct access credits was due to a decrease in the average direct access credit per kWh, which was partially offset by an increase in the total electricity provided to direct access customers by alternate energy service providers. The average direct access credit per kWh was higher in 2001 than in 2002 because in the beginning of 2001 we used the California Power Exchange, or PX, price for wholesale electricity to calculate direct access credits. Since the PX closed in January 2001, direct access credits have been calculated based on the procurement component of the fully bundled rate, which has been significantly lower than the PX price. The average direct access credit decreased from $0.116 per kWh in 2001 to $0.038 per kWh in 2002. In 2002, alternate energy service providers supplied approximately 7,433 GWh of electricity to direct access customers, compared to 3,982 GWh in 2001.

Revenue passed through to the DWR decreased by $117 million, or 5%, in 2002 from 2001. The decrease in DWR pass-through revenues in 2002 was primarily due to a decrease in our net open position, which was caused by an increase in the number of direct access customers and an increase in the amount of electricity we were able to purchase from qualifying facilities due to renegotiated payment terms through our Chapter 11 case. The decrease in our net open position in 2002 was partially offset by the accrual of an additional $369 million in pass-through revenues in 2002 due to changes proposed by the DWR to the methodology used to calculate DWR remittances.

Natural Gas Revenues

The following table shows a breakdown of our natural gas revenues:

	Year Ended December 31, 2002	Year Ended December 31, 2001	Increase (Decrease)	% Change
	(revenues, except averages, in millions)			
Bundled gas revenue	$1,882	$3,107	$(1,225)	(39.4)%
Transportation service only revenue	316	375	(59)	(15.7)%
Other	138	(346)	484	139.9%
Total natural gas revenues	$2,336	$3,136	$ (800)	(25.5)%
Average bundled price of natural gas sold per Mcf	$ 6.68	$11.48	$ (4.80)	(41.8)%
Total bundled gas sales (in Bcf)	282	271	11	4.1%

In 2002, our natural gas revenues decreased $800 million, or 26%, from 2001 primarily as a result of a lower average cost of natural gas, which was passed along to customers through lower rates. The average bundled price of natural gas sold during 2002 decreased $4.80 per Mcf, or 42%, compared to 2001.

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

The increase in other natural gas revenue was mainly due to a decrease in the deferral of natural gas revenue in 2002, which was attributed to the abnormally high price for natural gas in the beginning of 2001.

Cost of Electricity

The following table shows a breakdown of our cost of electricity (which includes the cost of fuel used by our owned generation facilities and electricity purchase costs) and the total amount and average cost of purchased power, excluding in each case the cost and volume of electricity provided by the DWR to our customers:

	Year Ended December 31, 2002	Year Ended December 31, 2001	Increase (Decrease)	% Change
	(costs, except averages, in millions)			
Cost of purchased power	$ 1,980	$ 3,224	$(1,244)	(38.6)%
Fuel used in our generation	97	102	(5)	(4.9)%
Other adjustments to cost of electricity	(595)	(552)	(43)	(7.8)%
Total cost of electricity	$ 1,482	$ 2,774	$(1,292)	(46.6)%
Average cost of purchased power per kWh	$ 0.081	$ 0.143	$(0.062)	(43.4)%
Total purchased power (in GWh)	24,552	22,592	1,960	8.7%

The cost of electricity for 2002 decreased $1.3 billion, or 47%, compared to 2001. The decrease was attributable to the following factors:

Our average cost of purchased power decreased in 2002 compared to 2001 primarily as a result of the significantly lower prices for electricity subsequent to the stabilization of the energy market in the second half of 2001. In addition, the average cost of electricity decreased because we purchased more electricity from qualifying facilities, other generators and irrigation districts, which provided electricity at a lower cost than the electricity we purchased in the market in the beginning of 2001. In 2002, the DWR purchased all of the electricity needed to meet our customers electricity demands not met by our generation facilities and electricity purchase contracts, whereas in 2001 we purchased the electricity ourselves through the PX market through the first half of January. As previously discussed, we serve as a billing and collection agent for the DWR and therefore do not reflect the DWR s cost of electricity in our consolidated statement of operations; and

A net $595 million reduction to the cost of electricity recorded in March 2002 as a result of FERC and CPUC decisions that allowed us to reverse previously accrued ISO charges and to adjust the amount of previously accrued pass-through revenues payable to the DWR.

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

Cost of Natural Gas

The following table shows a breakdown of our cost of natural gas:

	Year Ended December 31,			
	2002	2001	Increase (Decrease)	% Change
	(costs, except averages, in millions)			
Cost of natural gas purchased	$ 853	$1,593	$ (740)	(46.5)%
Cost of gas transportation	101	239	(138)	(57.7)%
Total cost of natural gas	$ 954	$1,832	$ (878)	(47.9)%
Average price of natural gas per Mcf	$3.38	$ 6.77	$(3.39)	(50.1)%
Total price of gas purchased (in Bcf)	252	235	17	7.2%

In 2002, our cost of natural gas decreased $878 million, or 48%, from 2001 primarily due to a decrease of $3.39 per Mcf, or 50%, in the average market price of natural gas purchased.

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

Operating and Maintenance

In 2002, our operating and maintenance expenses increased $432 million, or 18%, from 2001. This increase was mainly due to the following factors:

Increases in employee benefit plan-related expense primarily due to unfavorable returns on plan investments and lower interest rates, which caused a decrease in discount rates on our present-valued benefit obligations;

Increases in environmental liability estimates;

Increases in customer accounts and service expenses related to our new customer billing system;

The amortization of previously deferred electric transmission-related costs, which are collected in rates; and

The deferral of over-collected electric revenue associated with rate reduction bonds. Before 2000, these revenues were used to finance the rate reduction implemented in 1998.

Depreciation, Amortization and Decommissioning

Our depreciation, amortization and decommissioning expenses increased $297 million, or 33%, in 2002 from 2001. This increase was due mainly to amortization of the rate reduction bond regulatory asset that began in January 2002, and totaled $290 million in 2002.

Reorganization Fees and Expenses

In accordance with SOP 90-7, we report reorganization fees and expenses separately on our consolidated statements of operations. Such costs primarily include professional fees for services in connection with our Chapter 11 case and totaled $155 million in 2002 and $97 million in 2001.

Interest Income

In accordance with SOP 90-7, we report reorganization interest income separately on our consolidated statements of operations. Such income primarily includes interest earned on cash accumulated during our Chapter 11 case. Interest income decreased $49 million, or 40%, in 2002 from 2001. The decrease in interest income in 2002 was due in most part to lower average interest rates on our short-term investments.

Interest Expense

In 2002, our interest expense increased $14 million, or 1%, from 2001 due to our Chapter 11 case, which has resulted in higher negotiated interest rates and an increased level of unpaid debts accruing interest.

Income Taxes

Income tax expense increased $582 million, or 98%, in 2002 compared to 2001, primarily due to the 86% increase in pre-tax income. The effective income tax rate for 2002 was 39.3% compared to 37.0% in 2001. The increase was mainly caused by the amortization of deferred tax credits in 2001 associated with generation assets written off. The tax credits were being amortized over the lives of the assets to which they related. When these assets were sold or written off, the tax credits remaining on these assets were amortized into income.

Comparison of Years Ended December 31, 2001 and December 31, 2000

Electric Revenues

The following table shows a breakdown of our electric revenues by customer class:

	Year Ended December 31,			
	2001	2000	Increase (Decrease)	% Change
		(in millions)		
Residential	$ 3,396	$ 3,062	$ 334	10.9%
Commercial	4,105	3,110	995	32.0%
Industrial	1,554	1,053	501	47.6%
Agricultural	525	420	105	25.0%
Subtotal	9,580	7,645	1,935	25.3%
Direct access credits	(461)	(1,055)	594	56.3%
DWR pass-through revenue	(2,173)		(2,173)	
Miscellaneous	380	264	116	43.9%
Total electric operating revenues	$ 7,326	$ 6,854	$ 472	6.9%

Our electric revenues for 2001 increased by $472 million, or 7%, from 2000 and were significantly affected by the following factors:

There was a $594 million decrease in direct access credits in 2001 compared to 2000. This decrease was due to the reduction in total electricity provided to direct access customers by alternate energy service providers and a reduction in the number of direct access customers as the wholesale price of electric power in California increased during 2001.

Electricity surcharges increased revenues in 2001, but were offset by pass-through revenue collected on behalf of the DWR. Electricity surcharges authorized by the CPUC increased revenue in 2001 by

$2.2 billion. The increase provided by electricity surcharges was offset by the pass-through revenue of $2.2 billion for electricity that the DWR provided to our customers. As discussed above, revenues collected on behalf of the DWR and the related costs are not reflected in our consolidated statements of operations.

Conservation efforts by our customers in response to the California energy crisis, mild weather and higher prices from the electricity surcharge implemented in June 2001 reduced electricity sales volumes by 3% in 2001 compared to 2000, lowering electric revenues.

Natural Gas Revenues

The following table shows a breakdown of our natural gas revenues:

	Year Ended December 31,		Increase
	2001		