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.

The information in this preliminary prospectus is not complete and may be changed. We may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This preliminary prospectus is not an offer to sell these securities and it is not soliciting an offer to buy these securities in any jurisdiction where the offer or sale is not permitted.

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.

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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)

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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,		Increase	
	2001	**2000**	**(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,			
	2001	2000	Increase (Decrease)	% Change
	(revenues, except averages, in millions)			
Bundled gas revenue	$3,107	$2,229	$ 878	39.4%
Transportation service only revenue	375	338	37	10.9%
Other	(346)	216	(562)	260%
Total natural gas revenues	$3,136	$2,783	$ 353	12.7%
Average price of natural gas sold per Mcf	$11.48	$ 7.93	$3.55	44.8%
Total bundled gas sales (in Bcf)	271	281	(10)	(3.6)%

In 2001, natural gas revenues increased $353 million, or 13%, due to a higher average cost of natural gas, which was passed on to customers through higher rates. The average bundled price of natural gas sold during 2001 increased $3.55 per Mcf, or 45%, compared to 2000. The increase was offset by an approximate 4% decrease in usage in 2001 primarily as a result of conservation efforts.

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

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

Cost of 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, 2001	2000	Increase (Decrease)	% Change
	(costs, except averages, in millions)			
Cost of purchased power	$ 3,224	$ 6,642	$ (3,418)	(51.5)%
Fuel used in our generation	102	99	3	3.0%
Other adjustments to cost of electricity	(552)		(552)	
Deferred electric procurement cost		(6,465)	6,465	100%
Provision for loss on generation-related regulatory assets and under-collected purchased power costs		6,939	(6,939)	(100)%
Total cost of electricity	$ 2,774	$ 7,215	$ (4,441)	(61.6)%
Average cost of purchased power per kWh	$ 0.143	$ 0.152	$ (0.009)	(5.9)%
Total purchased power (in GWh)	22,592	43,762	(21,170)	(48.4)%

The cost of electricity for 2001 decreased $4.4 billion, or 62%, compared to 2000. This decrease was primarily affected by the following factors:

We were no longer purchasing electricity through the PX market. Instead, the DWR purchased 28,640 GWh of electricity on behalf of our customers to cover our customers electricity demands not met by our generation facilities and electricity purchase contracts in 2001.

A statewide energy conservation campaign and mild weather caused our customers to use approximately 3% less electricity in 2001 compared to 2000.

At the end of 2000, we determined that we could no longer conclude that our under-collected wholesale electricity costs and remaining transition costs were probable of recovery in future rates. Accordingly, we charged $6.9 billion to expense at December 31, 2000 as a provision for loss on generation-related regulatory assets and under-collected purchased electricity costs.

Cost of Natural Gas

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

	Year Ended December 31, 2001	2000	Increase (Decrease)	% Change
	(costs, except averages, in millions)			
Cost of natural gas purchased	$1,593	$1,331	$ 262	19.7%
Cost of gas transportation	239	94	145	154.3%
Total cost of natural gas	$1,832	$1,425	$ 407	28.6%

Average price of natural gas purchased per Mcf	$ 6.77	$ 5.07	$1.70	33.5%
Total natural gas purchased (in Bcf)	235	262	(27)	(10.3)%

Our cost of natural gas increased $407 million, or 29%, for 2001 compared to 2000 primarily due to an increase in the average cost of natural gas of $1.70 per Mcf, or 34%. Furthermore, as mentioned above, in 2001 our cost to transport natural gas to our service area increased significantly due to $111 million in costs related to the involuntary termination of natural gas transportation hedges.

Operating and Maintenance

In 2001, our operating and maintenance expenses decreased by $302 million, or 11%, from 2000 primarily due to reduced expenses related to the liability for chromium litigation, with respect to which $140 million was recorded in 2000 and nothing in 2001, and lower regulatory and other generation-related costs.

Depreciation, Amortization and Decommissioning

Depreciation, amortization and decommissioning decreased $2.6 billion, or 74%, in 2001 from 2000 due to the accelerated depreciation of generation-related assets in 2000, and as a result of less depreciation being recorded in 2001 as the majority of our generation-related assets were fully depreciated after the acceleration.

Reorganization Fees and Expenses

In accordance with SOP 90-7, beginning with the filing of our Chapter 11 petition in April 2001, we have reported 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 $97 million for 2001.

Interest Income

In 2001, our interest income decreased $63 million, or 34%, compared to 2000 due primarily to the write-off of generation-related regulatory balancing account interest. The decrease was partially offset by increases in interest on short-term investments and other balancing accounts.

Interest Expense

In 2001, our interest expense increased by $355 million, or 57%, compared to 2000 due to increased debt levels and higher interest rates as a result of our credit rating downgrade.

Income Taxes

Income tax expense was $596 million for 2001. In 2000, we recorded an income tax credit of $2.2 billion. This income tax benefit reflects full utilization of the income tax benefits generated by our pre-tax loss in 2000. We were able to carry back our benefit for federal income taxes and receive a refund of federal income taxes paid in prior years. California provides only for the carryforward of losses. Finally, 2001 includes the amortization of deferred tax credits based on the sale and write off of our generation-related assets to which they related.

Financial Impact of the CPUC Settlement Agreement on Our Results of Operations

As to our past results, in the CPUC settlement agreement, the CPUC agreed that headroom, surcharges and base revenues accrued or collected by us through December 31, 2003 would not be subject to refund. However, if headroom revenues accrued by us during 2003 are greater than $875 million (pre-tax), we must refund the excess to ratepayers and, if headroom revenues are less than $775 million (pre-tax), the CPUC will allow us to collect the shortfall in rates.

The more significant financial impact, however, is on our future operations. As a result of the CPUC settlement agreement, we will record two new regulatory assets. The first regulatory asset is a $2.21 billion after-tax regulatory asset (which is equivalent to an approximately $3.7 billion pre-tax regulatory asset) that the CPUC agreed to establish as a separate and additional part of our rate base. The second regulatory asset, in the amount of approximately $800 million after-tax (which is equivalent to approximately $1.3 billion pre-tax), results from the CPUC s reaffirmation in the CPUC settlement agreement of our adopted 2003 electricity generation rate base as just and reasonable. Recognition of these regulatory assets will result in net income of approximately $3.0 billion and have the effect of increasing our total assets by approximately $5.0 billion.

The recognition of these regulatory assets also will increase our shareholders equity by approximately $3.0 billion. On a pro forma basis after giving effect to the recognition of these regulatory assets, our shareholders equity would have been $7.4 billion at June 30, 2003. This will represent a level comparable to our shareholders equity at December 31, 1997, before California implemented electricity industry restructuring. Recognition of the regulatory assets also will require us to record approximately $2.0 billion of additional deferred tax liabilities. These deferred taxes will be paid as the regulatory assets are amortized and collected in rates.

The implementation of the CPUC settlement agreement also will result in a decrease in our net income in 2004 compared to 2003. The CPUC will reduce our rates by % effective January 1, 2004, causing a decrease in revenues of approximately $. The rates give effect to the amortization of the new regulatory assets. Amortization of the $2.21 billion after-tax regulatory asset in 2004 will be approximately $144 million after-tax, subject to certain reductions, with the amortization each year thereafter increasing, as a result of the nine-year mortgage-style amortization, to $382 million after-tax, subject to certain reductions, in 2012. The generation-related regulatory asset will be amortized on a straight-line basis over the remaining life of our generation assets, an average of approximately 16 years. The amortization of the regulatory assets will have no impact on cash flow as both represent non-cash expenses, similar to depreciation. However, cash flows will be affected by the January 2004 rate change.

Under the CPUC settlement agreement, the unamortized balance of the $2.21 billion after-tax regulatory asset will earn a return on equity of no less than 11.22% annually for its term and, after the equity component of our capital structure reaches 52%, the authorized equity component of this regulatory asset will be no less than 52% for its remaining term regardless of the actual equity component of our capital structure or future authorized return on equity.

Further, under the CPUC settlement agreement, from January 1, 2004 until Moody s Investors Service, Inc., or Moody s, has issued an issuer rating for us of not less than A3 or Standard & Poor s Ratings Services, or Standard & Poor s, has issued a long-term issuer credit rating for us of not less than A-, our authorized return on equity for our CPUC-regulated utility functions will be no less than 11.22% per year and the authorized equity ratio for ratemaking purposes will be no less than 52%, except that for 2004 and 2005, the authorized equity ratio will equal the greater of the proportion of equity in the forecast of our average capital structure for calendar years 2004 and 2005 filed in our cost of capital proceedings and 48.6%.

For a further discussion of the impact of the CPUC settlement agreement on ratemaking see Ratemaking below.

Liquidity and Capital Resources

Overview

At June 30, 2003, we had approximately $4.0 billion of cash and cash equivalents. Of this amount, $234 million is restricted as to its use. We invest our cash in investments of short duration including:

certificates of deposit and time deposits;

bankers acceptances and other short-term securities issued by banks;

asset-backed securities;

repurchase agreements;

commercial paper; and

discounted notes issued or guaranteed by the United States government or its agencies.

The majority of this cash and cash equivalents has been generated since we filed our Chapter 11 petition. Our principal source of cash is payments from our customers. In addition, we have not declared or paid any common or preferred dividends since our credit rating fell below investment grade in January 2001, eliminating one of our significant cash requirements, and the terms of the CPUC settlement agreement prohibit us from

paying dividends on our common stock before July 1, 2004. Since the electricity surcharges were implemented in June 2001 and wholesale electric prices stabilized in mid-2001, the cash generated by our operations has exceeded our cash requirements.

During our Chapter 11 case, we have been meeting all our cash requirements, including the requirements of our capital expenditure program, with internally generated funds. During this period, we have not had access to the capital markets. Other than obligations stayed by the bankruptcy court, we are paying all our obligations as they come due. In addition, we have accrued and paid interest on certain pre-petition liabilities and principal of maturing mortgage bonds with bankruptcy court approval. For more information, see the section of this prospectus titled Description of Our Plan of Reorganization.

The following section discusses the significant changes in our historical cash flows from operating, investing and financing activities.

Operating Activities

Our cash flows from operating activities were as follows:

	Six Months Ended June 30,		Year Ended December 31,		
	2003	2002	2002	2001	2000
			(in millions)		
Net income (loss)	$ 272	$ 1,065	$ 1,819	$ 1,015	$ (3,483)
Non-cash (income) expenses:					
Depreciation, amortization and decommissioning	605	565	1,193	896	3,511
Net reversal of ISO accrual		(970)	(970)		
Change in accounts payable	252	97	198	1,312	3,063
Change in income taxes payable/receivable	51	493	(50)	1,120	(1,120)
Payments authorized by the bankruptcy court on amounts classified as liabilities subject to compromise	(62)	(947)	(1,442)	(16)	
Other changes in operating assets and liabilities	86	327	386	438	(1,416)
Net cash provided by operating activities	$ 1,204	$ 630	$ 1,134	$ 4,765	$ 555

Net cash provided by operating activities increased by $574 million during the six months ended June 30, 2003 compared to the same period in 2002. This increase was primarily due to the following factors:

Payments on amounts classified as liabilities subject to compromise decreased by $885 million in the six months ended June 30, 2003 compared to the same period in 2002, due to significant pre-petition amounts paid to qualifying facilities in the six months ended June 30, 2002, based on bankruptcy court-approved settlements;

Net income in the six months ended June 30, 2002, included a net $970 million reduction to cost of electricity related to the reversal of accrued ISO charges; and

The increase in net cash provided by operating activities was the result of decreased cash outlays partially offset by a decrease in net income of $793 million.

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

We filed our Chapter 11 petition in April 2001, which automatically stayed all payments on liabilities incurred before our filing. After the filing, we resumed paying our ongoing expenses in the ordinary course of business. As a result, the growth in accounts payable is $1.1 billion lower in 2002 compared to 2001;

We received a $1.1 billion income tax refund in 2001; no comparable refund was received in 2002;

In 2002, we repaid approximately $901 million in principal owed to qualifying facilities before filing our Chapter 11 petition under bankruptcy court-approved agreements. Among other things, the agreements provided for repayments of amounts owed to qualifying facilities before the filing either in full or in six to 12 monthly installments; and

In 2002, the bankruptcy court issued an order authorizing us to pay pre-petition and post-petition interest to:

- Holders of certain undisputed claims, including commercial paper, senior notes, floating rate notes, medium-term notes, deferrable interest subordinated debentures, prior bond claims, revolving line of credit claims and secured debt claims;

- Trade creditors, including qualifying facilities; and

- Certain other general unsecured creditors.

We paid approximately $1.0 billion in pre-petition and post-petition interest related to these claims during 2002. The interest payments included accrued interest on financial debt previously classified as liabilities subject to compromise totaling $433 million.

Operating activities provided net cash of $4.8 billion in 2001 and $555 million in 2000. The increase in 2001 was primarily due to an increase in net income and the receipt of a $1.1 billion income tax refund in 2001. Of the $4.5 billion increase in net income, $2.6 billion was attributable to a decrease in depreciation, a non-cash expense.

Investing Activities

Our cash flows from investing activities were as follows:

	Six Months Ended June 30,		Year Ended December 31,		
	2003	**2002**	**2002**	**2001**	**2000**
			(in millions)		
Capital expenditures	$(730)	$(743)	$(1,546)	$(1,343)	$(1,245)
Net proceeds from sale of assets	11	5	11		6
Other investing activities	13	13	26	5	32
Net cash used by investing activities	$(706)	$(725)	$(1,509)	$(1,338)	$(1,207)

During our Chapter 11 case, capital expenditures have been funded with cash provided by operating activities.

Net cash used by investing activities decreased by $19 million during the six months ended June 30, 2003 compared to the same period in 2002. The decrease was attributable to a decrease in capital expenditures and an increase in net proceeds from the sale of assets during the six months ended June 30, 2003.

Net cash used in investing activities increased by $171 million during 2002, compared to 2001. The increase relates principally to an increase of $203 million in capital expenditures, partially offset by proceeds from asset sales. The capital expenditure increase related primarily to electric transmission substation and line improvements intended to improve system reliability.

Net cash used in investing activities increased by $131 million during 2001 compared to 2000, all of which was attributable to increased capital expenditures. The capital expenditure increase related primarily to electric transmission substation reliability projects.

Financing Activities

Our cash flows from financing activities were as follows:

	Six Months Ended June 30,		Year Ended December 31,		
	2003	2002	2002	2001	2000
			(in millions)		
Common stock repurchased	$	$	$	$	$ (275)
Dividends paid					(475)
Net long-term debt issued, matured, redeemed or repurchased		(333)	(333)	(111)	373
Rate reduction bonds matured	(141)	(141)	(290)	(290)	(290)
Net (repayments) borrowings under credit facilities and short-term borrowings				(28)	2,630
Other financing activities		(1)		(1)	(26)
Net cash provided (used) by financing activities	$(141)	$(475)	$(623)	$(430)	$1,937

Net cash used by financing activities decreased by $334 million during the six months ended June 30, 2003 compared to the same period in 2002. The decrease is mainly due to $333 million in principal repayments on mortgage bonds in the six months ended June 30, 2002, with no such repayment in the six months ended June 30, 2003.

Financing activities used $623 million of net cash in 2002, primarily reflecting the repayments of long-term debt and rate reduction bonds. Pursuant to bankruptcy court approval, we repaid $333 million in principal on our mortgage bonds that matured in March 2002. PG&E Funding LLC, our wholly owned subsidiary, also repaid $290 million in principal on its rate reduction bonds during each of 2001 and 2002. The rate reduction bonds are not included in our Chapter 11 case. PG&E Funding LLC receives funds from which it pays the principal and interest on the rate reduction bonds from a specific rate element in our customer bills. We remit the collection of these billings to PG&E Funding LLC on a daily basis.

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

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

The payments on the medium-term notes and the mortgage bonds were made before our April 2001 Chapter 11 filing.

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

(in millions)

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

During November 2000, we issued $680 million of senior notes due 2005. The proceeds of these notes were used to finance electricity purchases from the PX. During 2000, $307 million of long-term debt matured or was redeemed.

Cash Requirements of Our Plan of Reorganization

We will use the net proceeds from the initial offering of the debt securities offered by the registration statement of which this prospectus is a part, other financings effected on or about the effective date of our plan of reorganization and cash on hand to pay in full the allowed claims of our creditors (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.

We will establish one or more escrow accounts for disputed claims and deposit cash into these accounts. Until paid, the cash portion of disputed claims will earn interest at the same rate as if the cash had been invested in either money market funds consisting primarily of short-term U.S. treasury securities or obligations of or guaranteed by the United States or any agency of the United States, at our option. If the amount of cash deposited into the escrow accounts is insufficient to make the required payments on disputed claims that are later allowed, we will pay the creditor the amount of the cash shortfall. If the amount of cash deposited into the escrow accounts is greater than that needed to make the required payments on disputed claims that are later allowed, we will retain the excess cash.

Timely asserted environmental, fire suppression, pending litigation and tort and workers compensation claims will pass through our Chapter 11 case unimpaired and will be satisfied by us in the ordinary course of business.

Future Liquidity

On or about the effective date of our plan of reorganization, we expect to establish one or more credit facilities in the amount of approximately $ billion. These facilities are intended to be used for the purposes of funding our operating expenses and seasonal fluctuations in working capital, providing letters of credit and, if we deem appropriate, paying allowed claims. We currently anticipate approximately $ of these credit facilities will be available for revolving borrowings and the remaining approximately $ will be allocated to letters of credit. While we expect to enter into these new credit facilities on or about the effective date of our plan of reorganization, there can be no assurance that we will be successful and, if so, on what terms.

We expect that the cash we will retain after the effective date of our plan of reorganization, together with cash generated by our operations and available from the credit facilities which we expect to establish, as described above, will be sufficient to fund our operations and our capital expenditures for the foreseeable future.

Capital Expenditures and Commitments

Capital Expenditures

The safe operation of a utility system requires substantial capital investment. Our investment in plant and equipment totaled approximately $1.5 billion in 2002, $1.3 billion in 2001 and $1.2 billion in 2000. For the first six months of 2003, our capital expenditures totaled $730 million. Over the next five years, our capital expenditures are expected to average approximately $1.7 billion annually.

The following table reflects our estimated capital expenditures over the next five years:

	(in millions)
2004	$ 1,695
2005	$ 1,806
2006	$ 1,569
2007	$ 1,659
2008	$ 1,716

The significant capital expenditure projects include:

- New customer connections and expansion of the existing electricity and natural gas distribution systems anticipated to average $400 million annually over the next five years;

- Replacements and upgrades to portions of our electricity distribution system anticipated to average approximately $300 million annually over the next five years;

- Replacement of natural gas distribution pipelines expected to total approximately $375 million over the next five years;

- Substation upgrades and expansion of line capacity of the electric transmission system expected to average approximately $260 million annually over the next five years. Significant individual projects include construction of a 500 kV transmission facility in the Bay Area, a 230 kV transmission facility upgrade in San Francisco, and the upgrade to a section of the transmission system known as Path 15, discussed further below;

- Replacements and upgrades to our natural gas transportation facilities expected to total approximately $600 million over the next five years;

- Replacement of turbines and steam generators and other equipment at our Diablo Canyon power plant, replacements and upgrades to our hydroelectric generation facilities and costs associated with relicensing our hydroelectric generation facilities expected to average approximately $180 million annually over the next five years; and

- Investment in common plant, which includes computers, vehicles, facilities, and communications equipment, expected to average approximately $150 million annually over the next five years.

We anticipate that our capital expenditures in the next five years will be somewhat higher than our capital expenditures in recent years. These additional expenditures are necessary to replace aging and obsolete equipment and to accommodate anticipated electricity and natural gas load growth. We retain some ability to delay or defer substantial amounts of these planned expenditures in light of changing economic conditions and changing technology. It is also possible that these projects may be replaced by other projects. Consistent with past practice, we expect that any capital expenditures will be included in our rate base.

The discussion above does not include any capital expenditures for new generation facilities. While the residual net open position is currently small, it is expected to increase over time. To meet this need, we will need to either enter into contracts with third-party generators for additional supplies of electricity or develop or otherwise acquire additional generation facilities, or satisfy our residual net open position through a combination of the two.

Commitments

Overview. We have substantial financial obligations and commitments related to our financing and operating activities, including the obligations representing allowed claims that we expect to satisfy on, or as soon as practicable after, the effective date of our plan of reorganization.

Financial Commitments. Our current commitments under financing arrangements include obligations to repay mortgage bonds, senior notes, medium-term notes, pollution control bond-related agreements, deferrable interest subordinated debentures, lines of credit, reimbursement agreements associated with letters of credit, floating rate notes and commercial paper. On the effective date of our plan of reorganization, we expect to reinstate certain pollution control bond-related obligations (and in certain events related mortgage bonds), the amount of which will not be determined until shortly before the effective date of our plan of reorganization. The balance of these obligations will be paid in full in cash on or as soon as practicable after the effective date of our plan of reorganization. Following the effective date of our plan of reorganization, our obligations also will include the debt securities issued pursuant to this prospectus in connection with our plan of reorganization and any other financings effected on or about the effective date.

In addition, PG&E Funding LLC must make scheduled payments on its rate reduction bonds. The balance owed on these bonds at December 31, 2002 was $1.45 billion. Annual principal payments on the rate reduction bonds total approximately $290 million. The rate reduction bonds will be fully retired by the end of 2007.

Contractual Commitments. Our contractual commitments include power purchase agreements (including agreements with qualifying facilities, irrigation districts and water agencies, bilateral power purchase contracts, and renewable energy contracts), natural gas supply and transportation agreements, nuclear fuel agreements, and other commitments, including operating leases.

The following table reflects our commitments as of December 31, 2002:

	2003	2004	2005	2006	2007	Thereafter	Total
				(in millions)			
Power purchase agreements:							
Qualifying facilities	$1,680	$1,600	$1,450	$1,350	$1,280	$7,800	$15,160
Irrigation district and water agencies	66	59	52	54	55	692	978
Bilateral contracts	196						196
Renewable energy contracts	42	42	42	42	42		210
Natural gas supply and transportation agreements	595	138	83	26	10		852
Nuclear fuel agreements	59	50	12	13	14	65	213
Other commitments	60	45	39	24	11	11	190(1)
Total(2)	$2,698	$1,934	$1,678	$1,509	$1,412	$8,568	$17,799

(1) Includes commitments for operating lease agreements for office space in the aggregate amount of $55 million, capital infusion agreements for limited partnership interests in the aggregate amount of $26 million, contracts to retrofit generating equipment at our facilities in the aggregate amount of $73 million, load-control and self-generation CPUC initiatives in the aggregate amount of $16 million, and contracts for local and long-distance telecommunications and other software in the aggregate amount of $20 million.

(2) Excludes letters of credit in the amounts of $10 million expiring in 2003 and $620 million expiring in 2004.

Power Purchase Agreements

+ *Qualifying Facilities.* Our power purchase agreements with qualifying facilities require us to pay for energy and capacity. Energy payments are based on the qualifying facility s actual electricity output and capacity payments are based on the qualifying facility s contractual capacity commitment. Capacity payments may be adjusted if the facility fails to meet or exceeds performance requirements specified in the applicable power purchase agreements. 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 dates and will terminate only when the owner of the qualifying facility exercises its termination option. Qualifying facility power purchase agreements accounted for approximately 25% of our 2002 electricity sources and approximately 21% of our 2001 electricity sources. No single qualifying facility accounted for more than 5% of our electricity sources in 2002 or 2001.

their contracts to fix their energy payments at $0.054 per kWh through July 2006. Beginning in August 2006, the energy payments will revert back to the short-run avoided cost rates.

+ *Irrigation Districts and Water Agencies.* We have contracts with various irrigation districts and water agencies to purchase hydroelectric power. Under these contracts, we must make specified semi-annual minimum payments based on the irrigation districts and water agencies debt service requirements, whether or not any hydroelectric power is supplied (so long as the supplier retains its FERC authorization) and variable payments for operation, maintenance and debt service costs incurred by the suppliers. These contracts expire on various dates from 2004 to 2031. Our irrigation district and water agency contracts in the aggregate accounted for approximately 4% of our 2002 electricity sources and for approximately 3% of our 2001 electricity sources.

+ *Bilateral Contracts.* At December 31, 2002, we had outstanding two bilateral forward electricity contracts that expire in 2003.

+ *Renewable Energy Requirement.* In June 2003, the CPUC issued a decision pursuant to Senate Bill 1078, or SB 1078, that adopts the framework for a renewable energy portfolio standard requiring each California investor-owned utility to increase purchases of renewable energy by at least 1% of its retail sales per year. By the end of 2017, we must purchase at least 20% of our total electricity from renewable resources. Under SB 1078, we were not obligated to purchase additional renewable energy until we received an investment grade credit rating. However, under subsequently enacted Senate Bill 67, or SB 67, we may be required to purchase additional renewable energy once we are able to do so on reasonable terms and the renewable energy contracts will not impair the restoration of our creditworthiness. Until that time, we will accumulate an annual procurement target, or APT, based on 1% of annual retail sales. When we receive an investment grade credit rating or the CPUC determines that the SB 67 requirements are satisfied, we expect to enter into purchase contracts for renewable energy to meet our accumulated APT.

We currently estimate the annual 1% increase in renewable resource electricity in our portfolio will initially require between 80 and 100 MW of additional renewable capacity to be added per year. The CPUC approved offers we submitted that were sufficient to meet our 2003 renewable energy requirement in December 2002. Pursuant to this approval, we have entered into three contracts with renewable energy suppliers that include both capacity and energy payments. During 2003, electricity under the contracts is sold by the suppliers to the DWR, which resells the electricity to our customers. We expect to reimburse the DWR for the contract costs. After 2003 and once certain conditions are met, we will become obligated under the contracts for the remainder of their five-year terms. We have submitted to the CPUC for approval several contracts intended to meet our 2004 renewable energy requirement. *Natural Gas Supply and Transportation Agreements* We purchase natural gas directly from producers and marketers in both Canada and the United States to serve our core customers. The contract lengths and natural gas sources of our portfolio of natural gas purchase contracts have fluctuated, generally based on market conditions. Currently, we have a $10 million standby letter of credit and a pledge of our natural gas customer accounts receivable for the purpose of securing the purchase of natural gas. The core natural gas inventory also may be pledged, but only if the amount of our natural gas customer accounts receivable is less than the amount that we owe to natural gas suppliers. To date, the amount of our accounts receivable pledge has been sufficient because it has not been less than the amount we owe to natural gas suppliers. The pledged amounts of customer accounts receivable were $220 million at June 30, 2003 and $513 million at December 31, 2002. These arrangements will terminate following the effective date of our plan of reorganization. We also have long-term natural gas transportation service agreements with various Canadian and interstate pipeline companies. These agreements include provisions for payment of fixed demand charges for reserving firm pipeline capacity, as well as volumetric transportation charges. The total

Additional Commitments

Electricity Purchases to Meet Demand. On January 1, 2003, we resumed buying electricity to meet our residual net open position. We had 14 contracts to supply 2003 capacity during peak demand periods, all of which expired after the peak summer months. The contractual commitments table above does not include these contracts, nor does it include contracts we expect to enter into to supply capacity during peak demand periods in the future. In order to enter into these contracts, we have posted, and expect to post, collateral with the ISO and other counterparties. We also buy electricity in short-term market transactions (*i.e.*, forward contracts ranging from one hour ahead to one month ahead).

DWR Allocated Contracts. In January 2003, we became responsible for scheduling and dispatching the electricity subject to the 19 DWR allocated contracts on a least-cost basis. Of these contracts, a total average capacity for 2003 of approximately 2,600 MW is subject to must take contracts, which require the DWR to take and pay for the electricity regardless of need. A total average capacity for 2003 of approximately 1,800 MW is subject to contracts which require the DWR to pay a capacity charge but do not require the purchase of a firm amount of electricity. Energy payments are due only for the power actually delivered. The DWR is currently legally and financially responsible for these contracts and the contractual commitments table above does not include these contracts.

The DWR has stated publicly that it intends to transfer full legal title to, and responsibility for, the DWR allocated contracts to the California investor-owned utilities as soon as possible. However, the DWR allocated contracts cannot be transferred to us without the consent of the CPUC. The CPUC settlement agreement provides that the CPUC will not require us to accept an assignment of, or to assume legal or financial responsibility for, the DWR allocated contracts unless each of the following conditions has been met:

- after assumption, our issuer rating by Moody s will be no less than A2 and our long-term issuer credit rating by Standard & Poor s will be no less than A;

- the CPUC first makes a finding that the DWR allocated contracts being assumed are just and reasonable; and

- the CPUC has acted to ensure that we will receive full and timely recovery in our retail electricity rates of all costs associated with the DWR allocated contracts without further review.

The CPUC settlement agreement does not limit the CPUC s discretion to review the prudence of our administration and dispatch of the DWR allocated contracts consistent with applicable law.

WAPA Sales Contracts Commitments. In 1967, we and the Western Area Power Administration, or WAPA, entered into several long-term power contracts. These contracts give us access to WAPA s excess hydroelectric power and obligate us to provide WAPA with electricity when its resources are not sufficient to meet its requirements. The contracts terminate on December 31, 2004.

The costs to fulfill our obligations to WAPA under the contracts cannot be accurately estimated at this time because both the purchase price and the amount of electricity WAPA will need from us through the balance of

2003 and 2004, when the WAPA contracts terminate, are uncertain. However, we expect that the cost of meeting our contractual obligations to WAPA will be greater than the amount that we receive from WAPA under the contracts. Although it is not indicative of future sales commitments or sales-related costs, our estimated net costs, based upon our portfolio and after subtracting revenues received from WAPA, for electricity delivered under the contracts were approximately $127 million in 2002, approximately $350 million in 2001 and approximately $405 million in 2000. The contractual commitments table above does not include our WAPA commitment.

Advanced Metering Improvements. The contractual commitments table above also does not include any amounts related to the possible implementation of an advanced metering infrastructure to enable the California investor-owned utilities to measure residential and small commercial customers usage of electricity on a time-of-use basis and to apply varying tariffs, or demand responsive tariffs, during peak and non-peak demand periods with the goal of encouraging customers to reduce energy consumption during peak demand periods. Advanced meters are capable of recording usage in time intervals and can be read remotely. While demand responsive tariffs are being implemented for large industrial customers, who already have advanced metering systems in place, a statewide pilot program is in progress to test whether and how much residential and small customers will respond to dynamic, or time varying, rates. If the CPUC determines that it would be cost-effective to install advanced metering on a large scale and orders us to proceed with large scale development of advanced metering for residential and small commercial customers, we expect that we would incur substantial costs to convert our meters, build the meter reading network, and build the data storage and processing facilities to bill a substantial portion of our customers based on dynamic rates.

Path 15 Upgrade. In December 2002, we agreed to participate in a project sponsored by WAPA to upgrade the transfer capability of the section of transmission system known as Path 15, located in central California. The project entails construction of a new 84-mile, 500 kV transmission line by WAPA between two of our existing substations in northern and central California. All the participants have agreed to turn over operational control of the transmission system upgrade to the ISO upon completion of the project. Our share of the costs of this project is approximately $75 million. Our commitments are contingent upon WAPA meeting certain construction milestones. Our commitment for this project is included in the table of estimated capital expenditures.

Contingencies

We have significant gain and loss contingencies that are discussed below.

Nuclear Insurance

We have several types of nuclear insurance for our nuclear power plants. We have insurance coverage for property damages and business interruption losses as a member of Nuclear Electric Insurance Limited, or NEIL. NEIL is a mutual insurer owned by utilities with nuclear facilities. NEIL provides property damage and business interruption coverage of up to $3.24 billion per incident. Under this insurance, if any nuclear generation facility insured by NEIL suffers a catastrophic loss causing a prolonged accidental outage, we may be required to pay additional annual premiums of up to $36.7 million.

NEIL also provides coverage for damages caused by acts of terrorism at nuclear power plants. If one or more acts of domestic terrorism cause property damage covered under any of the nuclear insurance policies issued by NEIL to any NEIL member within a 12-month period, the maximum recovery under all those nuclear insurance policies may not exceed $3.24 billion plus the additional amounts recovered by NEIL for these losses from reinsurance. Under the Terrorism Risk Insurance Act of 2002, NEIL would be entitled to receive substantial proceeds from reinsurance coverage for an act caused by foreign terrorism. The Terrorism Risk Insurance Act of 2002 expires on December 31, 2005.

Under the Price-Anderson Act, public liability claims from a nuclear incident are limited to $10.9 billion. As required by the Price-Anderson Act, we have purchased the maximum available public liability insurance of $300 million for our Diablo Canyon power plant. The balance of the $10.9 billion of liability protection is covered by a loss-sharing program among utilities owning nuclear reactors. Under the Price-Anderson Act, owner participation in this loss-sharing program is required for all owners of reactors of 100 MW or higher. If a nuclear incident results in costs in excess of $300 million, then we may be responsible for up to $100.6 million per reactor, with payments in each year limited to a maximum of $10 million per incident until we have fully paid our share of the liability. Since our Diablo Canyon power plant has two nuclear reactors of over 100 MW, we may be assessed up to $201.2 million per incident, with payments in each year limited to a maximum of $20 million per incident.

In addition, we have $53.3 million of liability insurance coverage for our retired nuclear generating unit at Humboldt Bay, or Humboldt Bay Unit 3, and have a $500 million indemnification from the NRC for liability arising from nuclear incidents covering liabilities in excess of the $53.3 million of liability insurance.

Workers Compensation Security

We are self-insured for workers compensation. We must deposit collateral with the California Department of Industrial Relations to maintain our status as a self-insurer for workers compensation claims. Acceptable forms of collateral include surety bonds, letters of credit, cash and securities. At June 30, 2003, we provided collateral in the form of approximately $365 million in surety bonds.

In February 2001, several surety companies provided cancellation notices because of our financial situation. The cancellation of these bonds has not impacted our self-insured status under California law. The California Department of Industrial Relations has not agreed to release the canceling sureties from their obligations for claims occurring before the cancellation and has continued to apply the canceled bond amounts, totaling $185 million, towards the $365 million collateral requirement. At June 30, 2003, three additional surety bonds totaling $180 million made up the balance of our collateral. We replaced a $60 million surety bond with a cash deposit of $43 million in October 2003. Corp has guaranteed our reimbursement obligation associated with these surety bonds and our underlying obligation to pay workers compensation claims.

Balancing Account Reserves

In 2002, the CPUC ordered us to create certain electric balancing accounts to track specific electric-related amounts, including revenue shortfalls from baseline allowance increases and costs related to the self-generation incentive program, for which the CPUC has not yet determined specific recovery methods. In the decisions ordering the creation of these balancing accounts, the CPUC indicated that the recovery methods for these amounts would be determined in the future. Because we cannot conclude that the amounts in these balancing accounts are probable of recovery in future rates, we have reserved these balances by recording a charge against earnings. At June 30, 2003, the reserve associated with these balancing accounts was approximately $220 million.

DWR Electricity Revenue Requirement

Because we act as a billing and collection agent for the DWR, amounts collected on behalf of the DWR (related to its revenue requirement) are not included in our revenues.

The DWR filed its proposed 2004 revenue requirement with the CPUC on September 19, 2003. The DWR has proposed a $4.5 billion revenue requirement for power charge-related costs and $873 million in bond charge-related costs in 2004 that would be collected from the customers of the California investor-owned utilities. The CPUC is responsible for allocating the proposed 2004 revenue requirement among the customers of the California investor-owned utilities.

The CPUC s allocation of the DWR revenue requirement for the 2001-2002 period among the three California investor-owned utilities is (and the DWR revenue requirements for 2003 and 2004 may be) subject to adjustments based on the actual amount of electricity purchased by the DWR for the utilities customers during the 2001-2002 period. The CPUC allocated approximately 48.3% of the adopted DWR power charge-related revenue requirement for the 2001-2002 period, or about $4.4 billion, to us.

In testimony we submitted to the CPUC in October 2003, we estimated that we over-remitted $107 million in power charges to the DWR for the 2001-2002 period based on the allocation methodology applied by the CPUC in determining the allocation of the 2001-2002 DWR power charge-related revenue requirement. We also proposed that the CPUC use a different allocation methodology under which we estimate we over-remitted $211 million. Testimony submitted by Southern California Edison and other parties includes varying estimates of our adjustment depending on the allocation method proposed. Southern California Edison calculated that we over-remitted approximately $101 million in power charges to the DWR based on the allocation methodology applied by the CPUC in determining the allocation of the DWR power charge-related revenue requirement. However, Southern California Edison also has proposed that the CPUC apply the allocation methodology used to allocate the DWR bond charge-related revenue requirement to allocate the bond proceeds among the customers of the California investor-owned utilities and, under this methodology, has estimated that we have under-remitted $453 million in DWR revenue requirements. Our testimony noted that the CPUC had already rejected this proposal in its decision allocating the 2003 DWR bond charge-related revenue requirement.

We have proposed to include any adjustments to the 2001-2002 DWR revenue requirement in each California investor-owned utility s allocation of the 2004 DWR revenue requirement to be collected through the DWR remittance rate. Southern California Edison supports this proposal, but San Diego Gas & Electric Company has proposed that any under-remittance be paid by the California investor-owned utility immediately. CPUC hearings are scheduled to begin on October 27, 2003 and the CPUC is expected to issue a decision on the 2001-2002 adjustments (as well as the 2004 DWR revenue requirement) in January 2004.

We expect that any amounts the CPUC determines that we have under-remitted or over-remitted to the DWR for the 2001-2002 period will be included in the DWR revenue requirements in 2004 and subsequent periods, and collected or refunded on a going forward basis from our customers. However, we are unable to predict the outcome of this matter. If the CPUC retroactively determines that we have under-remitted a material amount to the DWR and orders us to make a one-time payment from cash on hand rather than collect the under-remitted amount from customers on a going forward basis, our financial condition and results of operations would be materially adversely affected.

Environmental Matters

We may be required to pay for environmental remediation at sites where we have been, or may be, a potentially responsible party under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended, or CERCLA, and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites, and sites used by us to store, recycle, or dispose of potentially hazardous materials. Under federal and California laws, we may be responsible for remediation of hazardous substances even if we did not deposit those substances on the site.

We record an environmental remediation liability when site assessments indicate remediation is probable and we can estimate a range of reasonably likely cleanup costs. We review our remediation liability on a quarterly basis for each site where we may be exposed to remediation responsibilities. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring and site closure using current technology, enacted laws and regulations, experience gained at similar sites and the probable level of involvement and financial condition of other potentially responsible parties. Unless there is a better estimate within this range of possible costs, we record the costs at the lower end of this range.

We had an undiscounted environmental remediation liability of $302 million at June 30, 2003 and $331 million at December 31, 2002. During the six months ended June 30, 2003, the liability was reduced by $29 million primarily due to a reassessment of the estimated cost of remediation. The $302 million accrued at June 30, 2003, includes $105 million related to the pre-closing remediation liability associated with divested generation facilities, and $197 million related to remediation costs for those generation facilities, that we still own, natural gas gathering sites, compressor stations, and manufactured gas plant sites that are either owned by us or are the subject of remediation orders by environmental agencies or claims by the current owners of the former gas plant sites. Of the $302 million environmental remediation liability, we have recovered $155 million through rates charged to our customers, and expect to recover approximately $93 million of the balance in future rates. Any amounts collected in excess of our ultimate obligations may be subject to refunds to ratepayers. We also are recovering our costs from insurance carriers and from other third parties whenever it is possible.

The cost of the hazardous substance remediation is difficult to estimate. The estimate depends on a number of uncertainties, including our responsibility, the complexity of environmental laws and regulations and the selection of compliance alternatives. We estimate the upper limit of the range using assumptions least favorable to us, which is based upon a range of reasonably possible outcomes. Our future undiscounted environmental remediation liability could increase to as much as $418 million if the 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 clean-up costs at additional sites.

The California Attorney General filed claims in our Chapter 11 case on behalf of various California state environmental agencies for environmental remediation at numerous sites totaling approximately $770 million. For most of these sites, remediation is ongoing in the ordinary course of business or we are in the process of remediation in cooperation with the relevant agencies and other parties responsible for contributing to the clean-up. Other sites identified in the California Attorney General s claims may not, in fact, require remedial or cleanup actions. Since our plan of reorganization provides that these types of claims will be determined in the applicable administrative or judicial forum and not discharged in our Chapter 11 case, and since we have not argued that our Chapter 11 case relieves us of our obligations to respond to valid environmental remediation orders, we believe the claims seeking specific cash recoveries are unenforceable.

Diablo Canyon Nuclear Power Plant. Our Diablo Canyon power plant employs a once-through cooling water system, which is regulated under a National Pollutant Discharge Elimination System, or NPDES, permit issued by the Central Coast Regional Water Quality Control Board, or the Central Coast Board. This permit allows our Diablo Canyon power plant to discharge the cooling water at a temperature no more than 22 degrees above the temperature of the ambient receiving water and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, marine and wildlife habitat, shellfish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft cease and desist order alleging that, although the temperature limit has never been exceeded, our Diablo Canyon power plant s discharge was not protective of beneficial uses.

In October 2000, we reached a tentative settlement of this matter with the Central Coast Board, or the Central Coast settlement agreement, pursuant to which the Central Coast Board agreed to find that the discharge of cooling water from our Diablo Canyon power plant protects beneficial uses and that the intake technology reflects the best technology available as defined in the Federal Clean Water Act. As part of the Central Coast settlement agreement, we agreed to take measures to preserve certain acreage north of the plant and will fund approximately $6 million in environmental projects and future environmental monitoring related to coastal resources. On June 17, 2003, the Central Coast settlement agreement was fully executed by us, the Central Coast Board and the California Attorney General s Office. In order for the Central Coast settlement agreement to become effective, among other things, the Central Coast Board must renew our Diablo Canyon power plant s NPDES permit. However, at its July 10, 2003 meeting, the Central Coast Board did not renew the permit and continued the permit renewal hearing indefinitely. Several Central Coast Board members indicated that they no longer supported the Central Coast settlement agreement and the Central Coast Board requested its staff to develop additional information on possible mitigation measures.

The California Attorney General has filed a claim in our Chapter 11 case on behalf of the Central Coast Board seeking unspecified penalties and other relief in connection with our Diablo Canyon power plant s operation of its cooling water system. We are seeking withdrawal of this claim.

We believe that the ultimate outcome of this matter will not have a material impact on our financial condition or results of operations.

Additional Security Measures. Various federal regulatory agencies have issued guidance and the NRC recently has issued orders regarding additional security measures to be taken at various facilities we own. Our facilities affected by the guidance and the orders include generation facilities, transmission substations and natural gas transportation facilities. The guidance and the orders may require additional capital investment and an increased level of operating costs. However, we do not believe these costs will have a material impact on our consolidated financial condition or results of operations.

Legal Matters

In the normal course of business, we are named as a party in a number of claims and lawsuits. The most significant of these are discussed below. The filing of our Chapter 11 petition automatically stayed the litigation described below, except as otherwise noted.

Chromium Litigation. There are 14 civil suits pending against us in several California state courts relating to alleged chromium contamination. Currently, there are approximately 1,200 plaintiffs in the chromium litigation cases. Approximately 1,260 individuals have filed proofs of claim in our Chapter 11 case, most of whom are plaintiffs in the chromium litigation cases. Approximately 1,035 claimants have filed proofs of claim requesting approximately $580 million in damages and another approximately 225 claimants have filed claims for an unknown amount.

In general, plaintiffs and claimants allege that exposure to chromium at or near our gas compressor stations located at Kettleman and Hinkley, California, and the area of California near Topock, Arizona, caused personal injuries, wrongful death, or other injury and seek related damages. The bankruptcy court has granted certain claimants motion for relief from stay so that the state court lawsuits pending before the Chapter 11 filing can proceed.

We are responding to the suits in which we have been served and are asserting affirmative defenses. We will pursue appropriate legal defenses, including statute of limitations, exclusivity of workers compensation laws, and factual defenses, including lack of exposure to chromium and the inability of chromium to cause certain of the illnesses alleged.

To assist in managing and resolving litigation with this many plaintiffs, the parties agreed to select plaintiffs from three of the cases for a test trial. Ten of these initial trial plaintiffs were selected by plaintiffs counsel, seven plaintiffs were selected by defense counsel, and one plaintiff and two alternates were selected at random. We have filed 13 summary judgment motions challenging the claims of the test trial plaintiffs. Two of these motions are scheduled to be heard in December 2003 and two of these motions are scheduled to be heard in January 2004. We also have filed a motion to dismiss the complaint in one of the cases that is scheduled for hearing on November 14, 2003. The trial of the 18 test cases is scheduled to begin in March 2004.

We have recorded a reserve in our financial statements in the amount of $160 million for these matters. We believe that, after taking into account the reserves recorded at June 30, 2003 with respect to this matter, the ultimate outcome of this matter will not have a material adverse impact on our financial condition or future results of operations.

Natural Gas Royalties Litigation. This litigation involves the consolidation of approximately 77 False Claims Act cases filed in various federal district courts by Jack J. Grynberg (called a relator in the parlance of the False Claims Act) on behalf of the United States of America, against more than 330 defendants, including us. The cases were consolidated for pretrial purposes in the U.S. District Court for the District of Wyoming. The current case grows out of prior litigation brought by the same relator in 1995 that was dismissed in 1998.

Under procedures established by the False Claims Act, the United States, acting through the U.S. Department of Justice, or the DOJ, is given an opportunity to investigate the allegations and to intervene in the case and take over its prosecution if it chooses to do so. In April 1999, the DOJ declined to intervene in any of the cases.

The complaints allege that the various defendants, most of whom are pipeline companies or their affiliates, incorrectly measured the volume and heating content of natural gas produced from federal or Indian leases. As a result, the relator alleges that the defendants underpaid, or caused others to underpay, the royalties that were due to the United States for the production of natural gas from those leases.

The complaints do not seek a specific dollar amount or quantify the royalties claim. The complaints seek unspecified treble damages, civil penalties and reasonable expenses associated with the litigation. The relator has filed a claim in our Chapter 11 case for $2.5 billion, $2.0 billion of which is based upon the relator s calculation of penalties sought against us.

We believe the allegations to be without merit and intend to present a vigorous defense. We believe that the ultimate outcome of the litigation will not have a material adverse effect on our financial condition or results of operations.

William Ahern, et al. v. Pacific Gas and Electric Company. On February 27, 2002, a group of 25 ratepayers filed a complaint against us at the CPUC demanding an immediate reduction of approximately $0.035 per kWh in allegedly excessive electricity rates and a refund of alleged over-collections in electricity revenue since June 1, 2001. The complaint claims that electricity rate surcharges adopted in the first quarter of 2001, which increased the average electricity rate by $0.04 per kWh, became excessive later in 2001. The only alleged over-collection amount calculated in the complaint is approximately $400 million during the last quarter of 2001. On April 2, 2002, we filed an answer, arguing that the complaint should be denied and dismissed immediately as an impermissible collateral action and on the basis that the alleged facts, even if assumed to be true, do not establish that currently authorized electricity rates are not reasonable.

On May 10, 2002, we filed a motion to dismiss the complaint. The CPUC has not yet issued a decision. However under the CPUC settlement agreement, the CPUC acknowledges and agrees that the surcharge revenues accrued or collected by us through and including December 31, 2003, are the property of our Chapter 11 estate, have been or will be used for utility purposes, including to pay creditors in our Chapter 11 case, have been included in our retail electricity rates consistent with state and federal law and are not subject to refund.

Our Regulatory Environment

Various aspects of our business are subject to a complex set of energy, environmental and other governmental laws, regulations and regulatory proceedings at the federal, state and local levels.

The FERC, an independent agency within the U.S. Department of Energy, or the DOE, regulates 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, tariffs and conditions of service of the ISO and the terms and rates of wholesale electricity sales. The FERC also has jurisdiction over our electric transmission revenue requirements and rates, the licensing of our hydroelectric generation facilities and the interstate sale and transportation of natural gas.

The CPUC has jurisdiction to set the rates, terms and conditions of service for our electricity distribution, natural gas distribution and natural gas transportation and storage services in California. The CPUC also has jurisdiction over our issuances of securities, dispositions of utility assets and facilities, energy purchases on behalf of our electricity and natural gas retail customers, rates of return, rates of depreciation, aspects of the siting and operation of natural gas transportation assets, oversight of nuclear decommissioning utility performance, investigation of many aspects of our business, and certain aspects of our siting and operation of our electric transmission system. Ratemaking for retail sales from our generation facilities is under the jurisdiction of the CPUC.

Ratemaking

2003 General Rate Case Settlements

We have recently entered into two settlement agreements with various intervenors in our 2003 general rate case, both of which have been submitted to the CPUC for approval.

Distribution. In September 2003, we reached an agreement, or the rate case settlement, with various intervenors on all disputed economic issues related to the electricity and natural gas distribution revenue requirements of the 2003 general rate case, with the exception of our request that the CPUC include the costs of a pension contribution in our revenue requirements. The CPUC will resolve the pension contribution issue, as well as other issues raised by non-settling intervenors, in its final decision and our revenue requirement will be adjusted accordingly.

The rate case settlement proposes that we would receive a total 2003 revenue requirement of $2.5 billion for electricity distribution operations, representing a $236 million increase in our total electricity distribution revenue requirement over the currently authorized amount. The rate case settlement provides that the amount of electricity distribution rate base on which we would be entitled to earn an authorized rate of return would be $7.7 billion, based on recorded 2002 plant and including weighted average capital additions for 2003 of $292 million. The rate case settlement also provides for a new balancing account, effective January 1, 2004, to ensure that we recover our authorized total electricity distribution revenue requirement regardless of our level of sales.

The rate case settlement also would result in a total 2003 revenue requirement of $927 million for our natural gas distribution operations, representing a $52 million increase in our total natural gas distribution revenue requirement over the currently authorized amount. The rate case settlement also provides that the amount of natural gas distribution rate base on which we would be entitled to earn an authorized rate of return would be $2.1 billion, based on recorded 2002 plant and including weighted average capital additions for 2003 of $89.2 million.

Generation. In April 2002, the CPUC issued a decision authorizing us to recover reasonable costs incurred in 2002 for our own electricity generation operations, subject to reasonableness review in our 2003 general rate case and other proceedings. In May 2003, the CPUC issued a resolution approving our tariff revisions and our request to establish various balancing and memorandum accounts with modifications in compliance with its April 2002 decision.

In July 2003, we reached an agreement, or the generation settlement, with various intervenors that would set a total 2003 generation revenue requirement of $955 million. This revenue requirements excludes fuel expense, the cost of electricity purchases, the DWR revenue requirement and the nuclear decommissioning revenue requirement. If approved by the CPUC, the generation settlement would resolve all generation-specific issues raised in our 2003 general rate case, but would not resolve various tax methodology issues or the amount of administrative and general expenses and common plant to allocate to generation.

The rate case settlement discussed above would resolve these remaining issues. If the generation settlement and the rate case settlement are approved by the CPUC, our revenue requirement for our electricity generation operations would be set at $912 million for 2003, representing a $38 million increase over the currently authorized amount. In addition, the rate case settlement provides for a new balancing account, effective January 1, 2004, to ensure that we recover our authorized electricity generation revenue requirements regardless of the level of sales.

Under the CPUC settlement agreement, our adopted 2003 electricity generation rate base of $1.6 billion was deemed just and reasonable by the CPUC and not subject to modification, adjustment or reduction, except as necessary to reflect capital expenditures and changes in authorized depreciation. This reaffirmation of our electricity generation rate base allows recognition of an after-tax regulatory asset of approximately $800 million (which is equivalent to approximately $1.3 billion pre-tax).

We cannot predict when or whether the rate case settlement or generation settlement will be approved by the CPUC, or if approved, the outcome of any rehearing petitions or appeals that may be filed.

Attrition Rate Adjustments for 2004-2006

We may receive annual increases in the base revenues established during the test year of a general rate case, known as attrition rate adjustments, for the years between general rate cases to avoid a reduction in earnings in those years due to, among other things, inflation and increases in invested capital. Under the generation settlement and rate case settlement, attrition revenue increases for 2004, 2005 and 2006 would be authorized in the 2003 general rate case. The attrition increase for 2004 and 2005 would be calculated as the prior year s revenue requirement multiplied by the change in the consumer price index. For 2006, the 2005 revenue requirement would be multiplied by the sum of the change in the consumer price index plus 1% to calculate the attrition increase. The generation attrition revenue requirement would also include additional revenues to cover the costs of refueling activities at our Diablo Canyon power plant. For electricity and natural gas distribution operations, the attrition increases would be subject to a minimum increase of 2% and a maximum increase of 3% for 2004, a minimum increase of 2.25% and a maximum increase of 3.25% for 2005, and a minimum increase of

3% and a maximum increase of 4% for 2006. For electricity generation operations, the attrition increases would be subject to a minimum increase of 1.5% and a maximum increase of 3% for 2004 and 2005, and a minimum increase of 2.5% and a maximum increase of 4% for 2006. The rate case settlement notes that outcomes in future cost of capital proceedings could affect our revenue requirements, including the attrition adjustments.

2003 Cost of Capital Proceeding

Our currently authorized return on common equity, or return on equity, is 11.22% and our currently authorized cost of debt is 7.57%. We also have a currently authorized capital structure of 48.00% common equity, 46.20% long-term debt and 5.80% preferred equity. The November 2002 decision in our 2003 cost of capital proceeding adopted these authorized figures, but held the case open to address the effect that implementing and financing a confirmed plan of reorganization would have on our return on equity, costs of debt and preferred equity and ratemaking capital structure. Subsequently, in February 2003, we filed a petition to modify the November 2002 decision to waive the normal requirement that we file a test year 2004 cost of capital application. In May 2003, the CPUC granted our request, exempting us from filing a test year 2004 cost of capital application.

Under the CPUC settlement agreement, the CPUC will set our capital structure and authorized return on equity in our annual cost of capital proceedings in its usual manner; provided that, from January 1, 2004 until Moody s has issued an issuer rating for us of not less than A3 or Standard & Poor s has issued a long-term issuer credit rating for us of not less than A-, our authorized return on equity will be no less than 11.22% per year and our authorized equity ratio for ratemaking purposes will be no less than 52%, except that, for 2004 and 2005, our authorized equity ratio will equal the greater of the proportion of equity in the forecast of our average capital structure for calendar years 2004 and 2005 filed in our cost of capital proceedings and 48.6%.

Procurement Activities

The CPUC has no authority to review the reasonableness of procurement costs in the DWR s contracts, although our administration of the DWR allocated contracts and our least-cost dispatch of the electricity associated with the DWR allocated contracts are subject to a maximum annual procurement disallowance of $36 million. Activities excluded from the disallowance cap include gas procurement activities in support of our new contracts, electricity generation resources, qualifying facilities contracts and certain electricity generation expenses. We can provide no assurance that the CPUC will not increase or eliminate this maximum annual procurement disallowance in the future.

Effective January 1, 2003, we established the energy resource recovery account, or ERRA, to record and recover electricity costs associated with our authorized procurement plan, excluding the costs associated with the DWR allocated contracts. In February 2003, we filed our 2003 ERRA forecast application requesting that the CPUC reset our 2003 ERRA revenue requirement to $1.4 billion. We are authorized to file an application to change retail electricity rates when we reach the trigger threshold (*i.e.*, when our forecasts indicate we will face an under-collection of electricity procurement costs in excess of 5% of our prior year s generation revenues, excluding amounts collected for the DWR). In our February 2003 application, we requested that the CPUC set the trigger threshold at $224 million. The CPUC will finalize our starting ERRA revenue requirement and ERRA trigger threshold after it reviews our ERRA application. We cannot predict when or whether we will reach the trigger threshold. On August 15, 2003, we and the CPUC s Office of Ratepayer Advocates, or the ORA, proposed a stipulation to an administrative law judge and the CPUC that would reduce our 2003 ERRA revenue requirement by $40 million to $1.37 billion. The CPUC issued a decision adopting the stipulation in October 2003.

In August 2003, we filed an application requesting that the CPUC approve the 2004 ERRA forecast revenue requirement of $1.5 billion associated with our 2004 short-term procurement plan and approve as reasonable our ERRA recorded costs for the period from January 2003 through May 2003. We have also asked the CPUC to approve our proposed revenue requirement of $840 million to recover the 2004 costs related to the above-market generation and procurement costs and certain other generation-related costs.

DWR Electricity Revenue Requirement

Although AB IX prohibited the DWR from purchasing electricity on the spot market and from entering into new agreements to purchase electricity after December 31, 2002, the DWR is currently legally and financially responsible for the long-term contracts it entered into before December 31, 2002. The DWR pays for its costs of purchasing electricity from a revenue requirement collected from electricity customers of the three California investor-owned utilities through a charge, called a power charge. Because we act as a billing and collection agent for the DWR, amounts collected on behalf of the DWR (related to its revenue requirement) are not included in our revenues.

In December 2002, the CPUC issued a decision allocating approximately $2.0 billion of the DWR s 2003 $4.5 billion total statewide power charge-related revenue requirement to our customers. This revenue requirement includes the forecasted costs associated with the DWR allocated contracts during 2003.

In July 2003, the DWR submitted a supplemental 2003 revenue requirement to the CPUC that reduced the amount of the total 2003 statewide power charge-related revenue the DWR was requesting by approximately $1.0 billion. On September 4, 2003, the CPUC issued a decision that allocated this $1.0 billion reduction among the customers of the three California investor-owned utilities. The decision allocated approximately $444 million of the reduction to our retail electricity customers and required us to provide a one-time bill credit to our customers to pass through the revenue requirement reduction within 45 days. Prior ambiguities in the formula that determines the calculation of our collections payable to the DWR resulted in our underpayment of amounts to the DWR through June 2003. These ambiguities were resolved by the CPUC in a decision issued on September 4, 2003. At June 30, 2003, we had accrued a $516 million reserve based on our own estimate of underpayments. We subsequently paid the DWR $77 million (which equals the $521 million shortfall ultimately determined to be due to the DWR, less our customers approximately $444 million share of the $1.0 billion statewide reduction in the DWR s 2003 revenue requirement). This approximately $444 million share of the statewide revenue reduction has been returned to our customers in the form of bill credits issued to our customers in September and October 2003. The September 4, 2003 decision also reduces our DWR power charge remittance rate from $0.105 per kWh to $0.095 per kWh effective September 2003. This reduction in the remittance rate is in addition to the approximately $444 million reduction described above.

Our customers also must pay a share of the costs associated with the DWR s $11.3 billion bond offering completed in November 2002. The proceeds of this bond offering were used to repay the State of California and lenders to the DWR for electricity purchases made before the DWR electricity revenue requirement was in place and to provide the DWR with funds needed to make its electricity purchases. The debt service costs are collected from our electricity customers as part of the DWR revenue requirement. We collected and passed through to the DWR from our rates approximately $172 million in bond charges during the six months ended June 30, 2003. We expect to collect and pass through DWR bond charges of approximately $352 million during 2003. In its proposed revenue requirement for 2004, the DWR states that it expects to collect $873 million for bond charges in 2004 that would be collected from the customers of the California investor-owned utilities. The CPUC is responsible for allocating the proposed 2004 bond charge-related revenue requirement among the customers of the California investor-owned utilities. Under the CPUC settlement agreement, the CPUC has agreed that DWR bond charges allocated to our customers will be included in our rates in a manner that will not affect our collection of other authorized costs or return on capital.

The DWR filed its proposed 2004 revenue requirement with the CPUC on September 19, 2003. The DWR has proposed a $4.5 billion revenue requirement for power charge-related costs and $873 million in bond charge-related costs in 2004 that would be collected from the customers of the California investor-owned utilities. The CPUC is responsible for allocating the proposed 2004 revenue requirement among the customers of the California investor-owned utilities.

The CPUC s allocation of the DWR revenue requirement for the 2001-2002 period among the three California investor-owned utilities is (and the DWR revenue requirements for 2003 and 2004 may be) subject to adjustments based on the actual amount of electricity purchased by the DWR for the utilities customers during the 2001-2002 period. The CPUC allocated approximately 48.3% of the adopted DWR power charge-related revenue requirement for the 2001-2002 period, or about $4.4 billion, to us.

In testimony we submitted to the CPUC in October 2003, we estimated that we over-remitted $107 million in power charges to the DWR for the 2001-2002 period based on the allocation methodology applied by the CPUC in determining the allocation of the 2001-2002 DWR power charge-related revenue requirement. We also proposed that the CPUC use a different allocation methodology under which we estimate we over-remitted $211 million. Testimony submitted by Southern California Edison and other parties includes varying estimates of our adjustment depending on the allocation method proposed. Southern California Edison calculated that we over-remitted approximately $101 million in power charges to the DWR based on the allocation methodology applied by the CPUC in determining the allocation of the DWR power charge-related revenue requirement. However, Southern California Edison also has proposed that the CPUC apply the allocation methodology used to allocate the DWR bond charge-related revenue requirement to allocate the bond proceeds among the customers of the California investor-owned utilities and, under this methodology, has estimated that we have under-remitted $453 million in DWR revenue requirements. Our testimony noted that the CPUC had already rejected this proposal in its decision allocating the 2003 DWR bond charge-related revenue requirement.

We have proposed to include any adjustments to the 2001-2002 DWR revenue requirement in each California investor-owned utility s allocation of the 2004 DWR revenue requirement to be collected through the DWR remittance rate. Southern California Edison supports this proposal, but San Diego Gas & Electric Company has proposed that any under-remittance be paid by the California investor-owned utility immediately. CPUC hearings are scheduled to begin on October 27, 2003 and the CPUC is expected to issue a decision on the 2001-2002 adjustments (as well as the 2004 DWR revenue requirement) in January 2004.

We expect that any amounts the CPUC determines that we have under-remitted or over-remitted to the DWR for the 2001-2002 period will be included in the DWR revenue requirements in 2004 and subsequent periods, and collected or refunded on a going forward basis from our customers. However, we are unable to predict the outcome of this matter. If the CPUC retroactively determines that we have under-remitted a material amount to the DWR and orders us to make a one-time payment from cash on hand rather than collect the under-remitted amount from customers on a going forward basis, our financial condition and results of operations would be materially adversely affected.

Qualifying Facilities and Other Existing Bilateral Agreements

Based on a CPUC decision dated April 4, 2002 that established our revenue requirements for our electricity generation operations, the costs of our existing contracts with qualifying facilities and other electricity providers are passed through to ratepayers in full. For 2002, a forecast of approximately $1.8 billion for these costs was adopted. Since the beginning of 2003, we have been recovering the actual costs of qualifying facilities and other power purchase agreements through ratemaking mechanisms, including the ERRA.

Direct Access

In a November 2002 decision, the CPUC established a cost responsibility surcharge, or CRS, mechanism to implement utility-specific non-bypassable charges on direct access customers for their shares of the bond costs and electricity costs incurred by the DWR and the above-market cost related to our own generation resources and electricity purchase contracts. The November 2002 decision imposed a cap on the CRS of $0.027 per kWh. We implemented this capped surcharge on January 1, 2003. A July 2003 decision ordered that the CRS funds be applied to recover (in the following order) the DWR bond charges, our ongoing above-market costs related to our own generation resources and electricity purchase contracts and the DWR power charges. The July 2003 decision found that, subject to prospective adjustment in the annual DWR revenue requirement proceeding, the CRS cap of $0.027 per kWh, plus interest on the direct access CRS under-collection, will be sufficient to repay any shortfall to customers who receive bundled service by the time the DWR allocated contracts terminate. The CPUC has also held in April and July 2003 decisions that certain customers reducing or terminating our electricity service after February 2001 should be responsible for payment of the CRS, subject to specific exemptions.

We do not expect the CPUC s implementation of this decision or the level of the CRS cap to have a material adverse effect on our results of operations or financial condition.

Energy Crisis Refunds

Various parties, including us and the State of California, are seeking up to $8.9 billion in refunds for electricity overcharges during the California energy crisis on behalf of electricity purchasers. On December 12, 2002, a FERC administrative law judge issued an initial decision finding that power suppliers overcharged the California investor-owned utilities, the State of California, and other buyers by $1.8 billion from October 2000 to June 2001 (the only time period for which the FERC permitted refund claims), but that California buyers still owe the power suppliers $3.0 billion, leaving $1.2 billion in net unpaid bills.

In March 2003, the FERC confirmed most of the administrative law judge s findings, but partially modified the refund methodology established by the administrative law judge. In October 2003, the FERC issued a decision confirming the modified refund methodology contained in the March 2003 order. The modified refund methodology included use of a new natural gas price methodology as the basis for mitigated prices and directed the ISO and PX to make compliance filings establishing refund amounts by March 2004. Under the CPUC settlement agreement, we and Corp agreed to continue to cooperate with the CPUC and the State of California in seeking refunds from generators and other energy suppliers. The net after-tax amount of any refunds, claim offsets or other credits from generators or other energy suppliers relating to our PX, ISO, qualifying facilities or energy service provider costs that we actually realize in cash or by offset of creditor claims in the Chapter 11 case, is to be applied by us to reduce the outstanding balance of the regulatory asset created by the CPUC settlement agreement, dollar for dollar. See the section of this prospectus titled Description of Our Plan of Reorganization The CPUC Settlement Agreement Principal Terms Regulatory Asset.

We have recorded $1.8 billion of claims filed by various electricity generators in our Chapter 11 case as liabilities subject to compromise. We currently estimate that these claims would have been reduced to approximately $1.2 billion based on refund methodology recommended in the administrative law judge s initial decision. The recent recalculation of market prices according to the modified methodology adopted by the FERC could result in a reduction of several hundred million dollars in the amount of the suppliers claims. This reduction could be offset by the amount of any additional fuel cost allowance for suppliers if they provide evidence that natural gas prices were higher than the natural gas prices assumed in the refund methodology and accepted by the FERC.

On June 25, 2003, the FERC issued a series of orders directing more than 40 companies to show cause why they should not disgorge profits for a variety of violations of the ISO and PX tariffs related to market manipulation during the summer of 2000. We were one of the companies named in these orders. As to those allegations relating to us, we have submitted information to the FERC showing that some transactions were misidentified and do not relate to us, and that other identified transactions did not constitute improper behavior, but rather were justifiable under then-existing operational circumstances. The FERC staff is expected to determine before November 3, 2003 whether it will continue to investigate us in light of our explanations. Due to the limited dollar amount of our transactions identified as possibly in violation of the tariffs, we do not expect the outcome to have a material adverse impact on our financial condition or results of operations.

The FERC, also in June 2003, began an investigation of why companies should not disgorge profits related to bids for electricity in violation of ISO and PX tariffs during the period from May 1 through October 1, 2000. We submitted information explaining our bidding, which was designed to ensure optimal dispatch of our resources, including when and at what level we operated our hydroelectric generation facilities. We expect that the amount we would be required to pay, if any, would be immaterial and substantially less than the refunds we would receive from other companies. Therefore, we do not expect the outcome to have a material adverse impact on our financial condition or results of operations. This proceeding is being conducted as a FERC staff investigation and results are not expected until the first quarter of 2004.

In addition, the CPUC has opened a proceeding to examine whether the amounts paid to qualifying facilities during the California energy crisis reflect dysfunctional market conditions that warrant a refund of a portion of those payments.

Electric Transmission

On January 13, 2003, we filed an application with the FERC requesting authority to recover $545 million in electric transmission retail rates annually, a 44% increase over the revenue requirement then in effect. The requested increase is mainly attributable to significant capital additions and replacements made to our transmission system to accommodate load growth, maintain the infrastructure and 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 proposed rates went into effect, subject to refund, on August 13, 2003.

On March 28, 2003, we filed an application requesting an update to the rates contained in several of our existing wholesale transmission contracts. The FERC issued an order on May 27, 2003 that will allow the proposed rates for existing transmission contract customers to go into effect, subject to refund, on October 28, 2003. Our proposed rates to these existing transmission contract customers are designed to recover an additional $17 million of revenues on an annual basis.

Under a transmission control agreement, or TCA, entered into as a result of AB 1890, we and the other transmission owners are responsible under the ISO tariff for the costs of the reliability must run agreements between the ISO and owners of the generation facilities subject to reliability must run agreements, or reliability must run plants. Under the reliability must run agreements, reliability must run plants must remain available to generate electricity when needed for local transmission system reliability upon the ISO s demand. At June 30, 2003, the ISO had reliability must run agreements for which we could be obligated to pay an estimated $911 million in net costs during the period from July 1, 2003 to June 30, 2005. The amount will be reduced by amounts we expect to receive under the reliability must run contracts related to our generation facilities. These costs are recoverable under applicable ratemaking mechanisms.

It is possible that we may receive a refund of reliability must run costs that we previously paid to the ISO. In June 2000, a FERC administrative law judge issued an initial decision approving rates that, if affirmed by the FERC, would require the subsidiaries of the Mirant Corporation, or Mirant, that are parties to three reliability must run agreements with the ISO to refund to the ISO, and the ISO to refund to us, excess payments of approximately $300 million, including interest, for availability of Mirant s generation facilities under these agreements. However, on July 14, 2003, the Mirant subsidiaries that are parties to these agreements filed petitions for reorganization under Chapter 11. We are unable to predict at this time when the FERC will issue a final decision on this issue, what the FERC s decision will be and the amount of any refunds, which may be impacted by these Chapter 11 filings, we will ultimately receive. Any cash refunds received would be used to lower future reliability service rates depending on the time period covered by the refunds. If the resolution involves other than a cash refund, it is uncertain how the resolution would be reflected in rates.

We serve as the scheduling coordinator with the ISO for transmission service on the ISO-controlled grid for some of our existing transmission contract customers. The ISO bills us for providing services associated with these customers loads and resources. These ISO charges are referred to as scheduling coordinator costs. In March 2003, we requested that the FERC permit us to recover $83.1 million in scheduling coordinator costs from our existing transmission contract customers for the period from April 1, 1998 to August 31, 2002. Some of our existing transmission contract customers have challenged our request to recover the scheduling coordinator costs from them. Due to these challenges, we are uncertain whether we will be able to fully recover these costs.

Natural Gas Ratemaking

Natural Gas Distribution

The treatment of our natural gas distribution operations in our 2003 general rate case is discussed above under 2003 General Rate Case Settlements Distribution above.

Natural Gas Transportation and Storage

In 1998, we implemented a ratemaking pact called the Gas Accord under which the natural gas transportation and storage services we provide were separated for ratemaking purposes from our distribution services. The Gas Accord established natural gas transportation rates through 2002 and natural gas storage rates through March 2003. Under the Gas Accord, we were at risk of not recovering our natural gas transportation and storage costs and did not have regulatory balancing account protection for over-collections or under-collections of natural gas transportation revenues.

In August 2002, the CPUC approved a settlement agreement, or the Gas Accord settlement, that provided for a one-year extension of our existing natural gas transportation and storage rates and terms and conditions of service, as well as rules governing contract extensions and a contract solicitation period. In January 2003, we filed an amended Gas Accord II application proposing to permanently retain the Gas Accord market structure, extend the incentive mechanism for recovery of core procurement costs, and increase our rates for natural gas transportation service for 2004 and for storage service for the period from April 1, 2004 to March 31, 2005 by $30 million, after removal of the cost of capital issues from this proceeding.

We proposed a 2004 rate increase to be calculated on a demand or throughput forecast basis. In addition, for the 12-month period ending December 31, 2004 for transportation service, and for the 12-month period ending March 31, 2005 for storage service, we propose to provide an option for current holders of contract capacity to extend their rights and for a structured contract solicitation period to be held for any capacity not currently under contract. We may experience a material reduction in natural gas transportation operating revenues if we are unable to renew or replace existing transportation contracts at the beginning or throughout the Gas Accord II period, if we are forced to renew or replace those contracts on less favorable terms than adopted by the CPUC or if overall demand for transportation and storage services is less than anticipated and reflected by the CPUC in rates. A proposed decision in this proceeding is expected in the fourth quarter of 2003. Until the CPUC issues a decision, the natural gas transportation and storage rates set forth in the Gas Accord settlement will continue to be in effect. We cannot predict what the outcome of this proceeding will be, or whether the outcome will materially adversely affect our financial condition or results of operations.

Under the Gas Accord settlement, as with the Gas Accord, we are at risk for any natural gas transportation revenue volatility. Capacity is sold at competitive market-based rates within a cost-of-service tariff framework. Because we sell most of our capacity based on the volumes of natural gas our customers actually ship rather than through long-term firm capacity contracts, our natural gas transportation revenues similarly fluctuate.

Natural Gas Procurement

We set the natural gas procurement rate for our core customers monthly based on the forecasted costs of natural gas, core pipeline capacity and storage costs. We reflect the difference between actual natural gas purchase costs and forecasted natural gas purchase costs in several natural gas procurement balancing accounts, with under-collections and over-collections taken into account in subsequent monthly rates.

The Gas Accord also established the core procurement incentive mechanism, or CPIM, which is used to determine the reasonableness of our costs of purchasing natural gas for our customers. CPIM purchase costs include reasonable natural gas transportation charges, including demand charges, and natural gas commodity costs. The Gas Accord settlement agreement extended the CPIM for one year through December 2003. Under the CPIM, our purchase costs are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas price at indices at the points where we typically purchase natural gas. Costs that fall within a tolerance band, which is currently 99% to 102% around the benchmark, are considered reasonable and are fully recoverable in customers rates. Currently, one-half of the costs outside the tolerance band are recoverable in our customers rates, and our customers receive one-half of the benefit of any savings outside the tolerance band in their rates. However, in June 2003, we reached a settlement with the ORA that, if approved by the CPUC, would increase the amount of savings passed through to ratepayers from one-half to three-fourths, retroactive to November 1, 2002. Under the settlement, ratepayers would continue to bear one-half of the costs incurred above the tolerance band.

Any awards associated with the CPIM normally are reflected annually in the purchased natural gas balancing account after the close of the annual period used to measure the CPIM, which is each 12-month period ending October 31. These awards are not included in earnings until approved by the CPUC.

We filed our annual CPIM report on May 30, 2003, recommending that we receive an award of $2.4 million. The report addresses natural gas procurement costs, interstate and intrastate transportation costs, and ratepayer savings and awards issued to us during the period from November 2001 through October 2002. On September 3, 2003, the ORA issued a report concurring with our recommended award. We anticipate CPUC approval before December 31, 2003.

Capacity Purchases on El Paso and Transwestern Pipelines

In July 2002, the CPUC ordered the California investor-owned utilities to contract for additional amounts of El Paso pipeline capacity to gain firm access to the southwest natural gas producing basins. Since the July 2002 decision, we have signed contracts for capacity on the El Paso pipeline totaling approximately $50.8 million for the period from November 2002 to December 2007. The CPUC pre-approved the costs of these contracts as just and reasonable. The July 2002 decision also ordered the utilities to retain their then-current interstate pipeline capacity levels and sell any excess capacity to third parties only under short-term capacity release arrangements. It also ordered that, to the extent the utilities comply with the decision, they will be able to fully recover their costs associated with existing capacity contracts.

Under a previous CPUC decision, we could not recover in rates any costs paid to Transwestern Pipeline Company, or Transwestern, for natural gas pipeline capacity through 1997. We pay approximately $22 million in annual reservation charges under the Transwestern contract. The Gas Accord provided for partial recovery of Transwestern costs from 1998 forward. See Natural Gas Transportation and Storage above. In June 2003, we reached a settlement with The Utility Reform Network, or TURN, that would allow us to fully recover Transwestern costs beginning in July 2003. The CPUC has not yet approved this settlement.

In December 2002, the CPUC granted our request to recover in rates El Paso pipeline capacity costs and prepayments made to El Paso from all natural gas customers. We began recovering these costs from all natural gas customers in March 2003. We have requested that the CPUC re-allocate all the costs, including Transwestern costs, assuming the CPUC approves our settlement with TURN, to our core customers because the pipeline capacity is used to serve core customers.

El Paso Settlement

In June 2003, we, along with a number of other entities, entered into the El Paso settlement, which resolves all potential and alleged causes of action against El Paso for its part in alleged manipulation of natural gas and electricity commodity and transportation markets during the period from September 1996 to March 2003. Under the El Paso settlement s terms, El Paso will pay approximately $1.5 billion in cash and non-cash consideration. Of that total, approximately $352 million will be paid up front, another approximately $227 million (depending on the proceeds) will be paid from the sale of El Paso stock and approximately $875 million will be paid over 15 to 20 years. El Paso also agreed to a $125 million reduction in El Paso s long-term electricity supply contracts with the DWR and to provide pipeline capacity to California and to ensure specific reserve capacity for us, if needed. The exact amounts allocated to each entity are detailed in a master settlement agreement and delineated in an allocation agreement. The CPUC has issued a draft decision determining the precise means of allocation, under which our natural gas ratepayers would receive approximately $80 million and our electricity ratepayers would receive approximately $216 million. The CPUC expects to complete the final allocation of these refunds during the fourth quarter of 2003. The agreement is now pending approval by the FERC and the San Diego County Superior Court.

It is uncertain when or whether these required approvals will be obtained. The CPUC settlement agreement provides that the net after-tax amount of any consideration that we actually realize in cash related to electricity refunds (but not the natural gas refunds) will reduce the outstanding balance of the new $2.21 billion after-tax regulatory asset if consistent with CPUC rules or orders.

Accounting Pronouncements Issued But Not Yet Adopted

Changes to Accounting for Certain Derivative Contracts

In June 2003, the Financial Accounting Standards Board, or FASB, issued a new Derivatives Implementation Group, or DIG, interpretation of SFAS No. 133, Issue No. C20, *Scope Exceptions: Interpretation of the Meaning of Not Clearly and Closely Related in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature*, or DIG C20. The implementation guidance in DIG C20 is effective prospectively for all existing and all future derivative contracts in the fourth quarter of 2003. We currently are evaluating the impacts, if any, of DIG C20 on our consolidated financial statements.

Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity*, or SFAS No. 150. The requirements of SFAS No. 150 are applicable to us in the third quarter of 2003. SFAS 150 will be implemented by reclassifying and remeasuring our preferred stock with mandatory redemption provisions. The remeasurement and reclassification will not have a significant impact on our earnings. Our preferred stock with mandatory redemption provisions will be reflected on the balance sheet as a liability using present value techniques. Any differences between the current carrying value and the remeasured amount will be accounted for as a cumulative effect of a change in accounting principle. Beginning July 2003, we will record dividends on our preferred stock with mandatory redemption provisions and any payments in excess of its carrying amount as interest expense. We will not reclassify dividends paid or accrued in prior periods.

Determining Whether an Arrangement Contains a Lease

In May 2003, the Emerging Issues Task Force, or EITF, reached consensus on EITF 01-8, *Determining whether an Arrangement Contains a Lease*, or EITF 01-8. EITF 01-8 establishes criteria to be applied to any new or modified agreement in order to ascertain if such agreement is in effect a lease, and subject to lease accounting treatment and disclosure requirements principally found in SFAS No. 13, *Accounting for Leases.* EITF 01-8 is effective for all new or modified arrangements entered into as of July 1, 2003. We currently are assessing the impact of EITF 01-8.

Amendment of Statement 133 on Derivative Instruments and Hedging Activities

In April 2003, the FASB issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*, or SFAS No. 149. SFAS No. 149 amends and clarifies the accounting and reporting for derivative instruments, including certain derivatives embedded in other contracts, and for hedging activities under SFAS No. 133. SFAS No. 149 clarifies under what circumstances a contract with an initial net investment meets the characteristics of a derivative according to SFAS No. 133 and when a derivative contains a financing component that warrants special reporting in the statement of cash flows.

The requirements of SFAS No. 149 are effective for contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. We currently are evaluating the impacts, if any, of SFAS No. 149 on our consolidated financial statements.

Consolidation of Variable Interest Entities

In January 2003, the FASB issued Financial Interpretation No. 46, *Consolidation of Variable Interest Entities*, or FIN 46, which expands upon existing accounting guidance addressing when a company should include in its financial statements the assets, liabilities and activities of another entity or arrangement with which it is involved. A variable interest entity is an entity that does not have sufficient equity investment at risk to permit the entity to finance its activities without additional subordinated financial support from other parties or an entity where equity investors lack the essential characteristics of a controlling financial interest.

Until the issuance of FIN 46, a company generally included another entity in its consolidated financial statements only if it controlled the entity through voting interests. FIN 46 changes that by requiring a variable interest entity to be consolidated by a company if that company is subject to a majority of the risk of loss from the variable interest entity s activities or entitled to receive a majority of the entity s residual returns, or both. A company that consolidates a variable interest entity is now referred to as the primary beneficiary of that entity. FIN 46 requires disclosure of variable interest entities that the company is not required to consolidate but in which it has a significant variable interest.

The consolidation requirements of FIN 46 apply immediately to variable interest entities created after January 31, 2003. There were no new variable interest entities created by us between February 1, 2003 and June 30, 2003. The consolidation requirements are applicable to us in the fourth quarter of 2003. We are evaluating the impacts of FIN 46 s initial recognition, measurement and disclosure provisions on our consolidated financial statements, and currently are unable to estimate variable interest entities that will be consolidated or disclosed when FIN 46 becomes effective.

We have investments in unconsolidated affiliates, which are mainly engaged in the purchase of residential real estate. It is possible that we will be required to consolidate our interests in two of these entities as a result of the adoption of FIN 46. As of June 30, 2003, our recorded investment in these entities is approximately $16 million. As a limited partner, our exposure to potential loss is limited to our investment in each partnership.

Customer Information System

We implemented a new customer information system at the end of 2002 and continue to work through various billing and collection issues associated with the change over to the new system. The implementation has, among other things, required us to put into place new processes for recording and estimating revenues and electricity-related costs. We do not expect the system changes to have a significant impact on our financial condition and results of operations.

Employee Benefit Plans

On May 28, 2003, we remeasured the assets and liabilities of our defined benefit pension plan. In connection with the remeasurement, which reflected a reduction in the current discount rate from the defined benefit pension plan s previous actuarial valuation, we recorded a minimum pension obligation of $478 million, the amount by which the accumulated benefit obligation exceeded the fair market value of plan assets, and reduced our pension asset from $887 million to $353 million. We previously recognized a regulatory liability for timing differences between recognition of pension costs in accordance with GAAP and ratemaking purposes. As a result of the remeasurement, we reduced this regulatory liability by $911 million. The remaining amount of $60 million, net of income tax benefit of $41 million, has been recorded as a component of shareholders equity in our consolidated balance sheets. The charge to other comprehensive income does not affect earnings or cash flow, and could be reversed in future periods if the fair value of plan assets exceeds the accumulated benefit obligation. Our defined benefit pension plan currently exceeds the minimum funding requirements of the Employee Retirement Income Security Act of 1974.

Related Party Transactions

In accordance with various agreements, we and other subsidiaries of Corp provide to Corp and receive from Corp various services. We and Corp exchange administrative and professional support services in support of operations. These services are priced either at the fully loaded cost (*i.e.*, direct costs and allocation of overhead costs) or at the higher of fully loaded cost or fair market value, depending on the nature of the services. Corp also allocates certain other corporate administrative and general costs to us and other subsidiaries using a variety of factors, including the number of employees, operating expenses excluding fuel purchases, total assets, and other cost-causal methods. We purchase natural gas transportation services from Gas Transmission Northwest Corporation, or GTN. Effective April 1, 2003, we no longer purchase natural gas from National Energy and Gas Transmission Energy Trading Holdings Corporation, or NEG ET. Both GTN and NEG ET are subsidiaries of National Energy and Gas Transmission, Inc., or NEGT, a subsidiary of Corp. Our significant related party transactions and related receivable (payable) balances were as follows:

	Six Months Ended June 30,		Year Ended December 31,			Receivable (Payable) Balance Outstanding at	
	2003	2002	2002	2001	2000	June 30, 2003	December 31, 2002
			(in millions)				
Revenues from:							
Administrative services provided to Corp	$ 4	$ 3	$7	$6	$ 12		