PACIFIC GAS & ELECTRIC CO
Form 10-Q/A
March 05, 2002

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C., 20549

FORM 10-Q/A
Amendment No. 1 to

(Mark One)
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15 (D) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2001

OR

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

For the transition period from ___________ to __________

Commission File Number	Exact Name of Registrant as specified in its charter	State or other Jurisdiction of Incorporation	IRS Employer Identification Number
1-12609	PG&E Corporation	California	94-3234914
1-2348	Pacific Gas and Electric Company	California	94-0742640

Pacific Gas and Electric Company 77 Beale Street P.O. Box 770000 San Francisco, California 94177	PG&E Corporation One Market, Spear Tower Suite 2400 San Francisco, California 94105

(Address of principal executive offices) (Zip Code)

Pacific Gas and Electric Company (415) 973-7000	PG&E Corporation (415) 267-7000

Registrant's telephone number, including area code

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding twelve months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

Yes X No

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of latest practicable date.

Common Stock Outstanding, July 31, 2001:

PG&E Corporation	387,130,925 shares
Pacific Gas and Electric Company	Wholly-owned by PG&E Corporation

INTRODUCTORY NOTE

PG&E Corporation has previously disclosed that its subsidiary, PG&E National Energy Group, Inc (PG&E NEG), has used "synthetic leases" in connection with some of its power plant projects and turbine acquisition commitments. Subsequent to the issuance of PG&E Corporation's 1999 and 2000 consolidated financial statements, management determined that the assets and liabilities associated with these leases should have been consolidated. This Amendment No. 1 to PG&E Corporation's and Pacific Gas and Electric Company's joint Quarterly Report on Form 10-Q/A for the quarter ended June 30, 2001, contains revised Consolidated Financial Statements for PG&E Corporation for the quarters ended June 30, 2001 and 2000. To reflect the revisions, this Amendment No. 1 hereby amends Part I. Financial Information of the original filing. Although the full text of the amended Form 10-Q is contained herein, this Amendment No. 1 does not update Part II nor does this Amendment No. 1 update any other disclosures to reflect developments since the original date of filing. The exhibits that were filed with the original filing have not been re-filed with this amendment but instead have been incorporated by reference to the original filing.

PG&E CORPORATION AND
PACIFIC GAS AND ELECTRIC COMPANY

Form 10-Q/A
FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2001

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PART I. FINANCIAL INFORMATION

ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions, except per share amounts)

	Three months e June 30,	
	2001	2
	(As revised, see	
Operating Revenues		
Utility	$2,309	$2
Energy commodities and services	2,701	3
Total operating revenues	5,010	5
Operating Expenses		
Cost of energy for utility	67	1
Cost of energy commodities and services	2,335	3
Operating and maintenance	894	

Depreciation, amortization, and decommissioning	259	
Reorganization professional fees and expenses	8	
Total operating expenses	3,563	5
Operating income	1,447	
Reorganization interest income	32	
Interest income	42	
Interest expense	(312)	
Other income (expense), net	4	
Income Before Income Taxes	1,213	
Income tax provision (benefit)	463	
Net Income (Loss)	$ 750	$
Weighted average common shares outstanding	363	
Earnings (Loss) Per Common Share, Basic		
Net Earnings (Loss)	$ 2.07	$0
Earnings (Loss) Per Common Share, Diluted		
Net Earnings (Loss)	$ 2.07	$0
Dividends Declared Per Common Share	$ -	$0

The accompanying Notes to the Condensed Consolidated Financial Statements are an integral part of this statement.

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PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

	Balance a
	June 30, 2001 (As revised,
ASSETS	
Current Assets	
Cash and cash equivalents	$ 726
Short-term investments	3,757
Accounts receivable:	
Customers (net of allowance for doubtful accounts of $103 million and $71 million, respectively)	2,895

Regulatory balancing accounts	46
Price risk management	2,656
Inventories	501
Income taxes receivable	-
Prepaid expenses and other	447
Total current assets	11,028
Property, Plant, and Equipment	
Utility	24,341
Non-utility:	
Electric generation	2,671
Gas transmission	1,559
Construction work in progress	1,606
Other	123
Total property, plant, and equipment (at original cost)	30,300
Accumulated depreciation and decommissioning	(12,350)
Net property, plant, and equipment	17,950
Other Noncurrent Assets	
Regulatory assets	1,872
Nuclear decommissioning funds	1,332
Price risk management	1,045
Other	3,202
Total noncurrent assets	7,451
TOTAL ASSETS	$ 36,429

The accompanying Notes to the Condensed Consolidated Financial Statements are an integral part of this statement.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

	Balance at	
	June 30, 2001	December 31, 2000
	(As revised, see Note 9)	
LIABILITIES AND EQUITY		
Liabilities Not Subject to Compromise		
Current Liabilities		
Short-term borrowings	$ 445	$ 4,530

Long-term debt, classified as current	10	2,391
Current portion of rate reduction bonds	290	290
Accounts payable:		
Trade creditors	1,273	5,896
Regulatory balancing accounts	352	196
Other	535	459
Price risk management	2,548	1,999
Other	820	1,570
Total current liabilities	6,273	17,331
Noncurrent Liabilities		
Long-term debt	7,349	5,550
Rate reduction bonds	1,600	1,740
Deferred income taxes	1,795	1,656
Deferred tax credits	173	192
Price risk management	1,029	1,867
Other	3,903	3,864
Total noncurrent liabilities	15,849	14,869
Liabilities Subject to Compromise		
Financing debt	5,792	-
Trade creditors	5,168	-
Total liabilities subject to compromise	10,960	-
Preferred Stock of Subsidiaries	480	480
Utility Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures	-	300
Common Stockholders' Equity		
Common stock, no par value, authorized 800,000,000 shares, issued 387,177,497 and 387,193,727 shares, respectively	5,971	5,971
Common stock held by subsidiary, at cost, 23,815,500 shares	(690)	(690)
Accumulated deficit	(2,305)	(2,105)
Accumulated other comprehensive loss	(109)	(4)
Total common stockholders' equity	2,867	3,172
Commitments and Contingencies (Notes 1, 2, 3, and 6)	-	-
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$36,429	$36,152

The accompanying Notes to the Condensed Consolidated Financial Statements are an integral part of this statement.

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PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

Six months ended June 3

	2001	2000
	(As revised, see Note 9	
Cash Flows From Operating Activities		
net income (loss)	$ (201)	$ 52
Adjustments to reconcile net income (loss) to		
net cash provided (used) by operating activities:		
Depreciation, amortization, and decommissioning	514	41
Deferred income taxes and tax credits-net	120	11
Price risk management assets and liabilities, net	(30)	(2
Other deferred charges and noncurrent liabilities	(174)	(36
Net effect of changes in operating assets and liabilities:		
Short-term investments	(2,123)	13
Accounts receivable-trade	1,445	(50
Inventories	(109)	15
Accounts payable	621	64
Accrued taxes	1,241	12
Regulatory balancing accounts payable	332	19
Other working capital	(791)	31
Other-net	(116)	(
Net cash provided by operating activities	729	1,73
Cash Flows From Investing Activities		
Capital expenditures	(1,102)	(97
Other-net	(115)	(1
Net cash used by investing activities	(1,217)	(98
Cash Flows From Financing Activities		
Net repayments under credit facilities	(1,033)	(48
Long-term debt issued	2,275	31
Long-term debt matured, redeemed, or repurchased	(844)	(34
Common stock issued	-	2
Dividends paid	(109)	(21
Net cash provided (used) by financing activities	289	(70
Net Change in Cash and Cash Equivalents	(199)	4
Cash and Cash Equivalents at January 1	925	28
Cash and Cash Equivalents at June 30	$ 726	$ 32
Supplemental disclosures of cash flow information		
Cash paid for:		
Interest (net of amounts capitalized)	$ 302	$ 35
Income taxes paid (refunded) - net	(1,241)	2
Transfer of liabilities and other payables subject to compromise from operating payables and liabilities	10,960	

The accompanying Notes to the Condensed Consolidated Financial Statements are an integral part of this statement.

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PACIFIC GAS AND ELECTRIC COMPANY, A DEBTOR-IN-POSSESSION
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions)

	Three months ended June 30,		Six m ended
	2001	2000	2001
Operating Revenues			
Electric	$1,497	$1,801	$2,756
Gas	812	495	2,115
Total operating revenues	2,309	2,296	4,871
Operating Expenses			
Cost of electric energy	(362)	975	1,955
Cost of gas	429	182	1,345
Operating and maintenance	676	543	1,208
Depreciation, amortization, and decommissioning	222	44	439
Reorganization professional fees and expenses	8	-	8
Total operating expenses	973	1,744	4,955
Operating Income (Loss)	1,336	552	(84)
Reorganization interest income	32	-	32
Interest income	17	12	24
Interest expense (contractual interest of $195 million and $396 million for the three- and six-months ended June 30, 2001, respectively)	(257)	(144)	(458)
Other income (expense), net	(2)	-	(6)
Income (Loss) Before Income Taxes	1,126	420	(492)
Income tax provision (benefit)	424	198	(200)
Net Income (Loss)	702	222	(292)
Preferred dividend requirement	6	6	12
Income (Loss) Available for (Allocated to) Common Stock	$ 696	$ 216	$ (304)

The accompanying Notes to the Condensed Consolidated Financial Statements are an integral part of this statement.

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PACIFIC GAS AND ELECTRIC COMPANY, A DEBTOR-IN-POSSESSION
CONDENSED CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

	Balance at	
	June 30, 2001	Decem 2
ASSETS		
Current Assets		
Cash and cash equivalents	$ 132	$
Short-term investments	3,125	1
Accounts receivable:		
Customer (net of allowance for doubtful accounts of $54 million and $52 million, respectively)	1,547	1
Related parties	20	
Regulatory balancing account	46	
Inventories:		
Gas stored underground and fuel oil	262	
Materials and supplies	126	
Income taxes receivable	-	1
Prepaid expenses and other	210	
Total current assets	5,468	4
Property, Plant, and Equipment		
Electric	16,787	16
Gas	7,554	7
Construction work in progress	266	
Total property, plant, and equipment (at original cost)	24,607	24
Accumulated depreciation and decommissioning	(11,521)	(11
Net property, plant, and equipment	13,086	13
Other Noncurrent Assets		
Regulatory assets	1,843	1
Nuclear decommissioning funds	1,332	1
Other	1,487	1
Total noncurrent assets	4,662	4
TOTAL ASSETS	$ 23,216	$ 21

The accompanying Notes to the Condensed Consolidated Financial Statements are an integral part of this statement.

PACIFIC GAS AND ELECTRIC COMPANY, A DEBTOR-IN-POSSESSION
CONDENSED CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

LIABILITIES AND EQUITY
Liabilities Not Subject to Compromise
Current Liabilities

Short-term borrowings
Long-term debt, classified as current
Current portion of rate reduction bonds
Accounts payable:
    Trade creditors
    Related parties
    Regulatory balancing accounts
    Other
Deferred income taxes
Other

Total current liabilities

Noncurrent Liabilities

Long-term debt
Rate reduction bonds
Deferred income taxes
Deferred tax credits
Other

Total noncurrent liabilities
Liabilities Subject to Compromise
Financing debt
Trade creditors

Total liabilities subject to compromise

Preferred Stock With Mandatory Redemption Provisions
    6.30% and 6.57%, outstanding 5,500,000 shares,
    due 2002-2009
Company Obligated Mandatorily Redeemable Preferred Securities
    of Trust Holding Solely Utility Subordinated Debentures
    7.90%, 12,000,000 shares due 2025
Stockholders' Equity

Preferred Stock Without Mandatory Redemption Provisions
    Nonredeemable-5% to 6%, outstanding 5,784,825 shares
    Redeemable-4.36% to 7.04%, outstanding 5,973,456 shares
Common stock, $5 par value, authorized
    800,000,000 shares, issued 321,314,760 shares

Common stock held by subsidiary, at cost, 19,481,213 shares
Additional paid-in capital
Accumulated deficit
Accumulated other comprehensive loss

Total stockholders' equity

Commitments and Contingencies (Notes 1, 2, 3, and 6)

TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY

The accompanying Notes to the Condensed Consolidated Financial Statements are an integral part of this statement.

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PACIFIC GAS AND ELECTRIC COMPANY, A DEBTOR-IN-POSSESSION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Six months ended June 30,	
	2001	2000
Cash Flows From Operating Activities		
Net income (loss)	$ (292)	$ 456
Adjustments to reconcile net income to net cash provided (used) by operating activities:		
Depreciation, amortization, and decommissioning	439	345
Deferred income taxes and tax credit-net	12	170
Price risk management assets and liabilities, net	(38)	-
Other deferred charges and noncurrent liabilities	(272)	(303)
Net effect of changes in operating assets and liabilities:		
Short-term investments	(1,842)	(6)
Accounts receivable	619	(46)
Income tax receivable	1,120	-
Inventories	(108)	15
Accounts payable	606	399
Accrued taxes	-	99
Regulatory balancing accounts, net	332	190
Other working capital	(99)	(16)
Other-net	366	(5)
Net cash provided by operating activities	843	1,298
Cash Flows From Investing Activities		
Capital expenditures	(575)	(572)
Other-net	34	(16)

Net cash used by investing activities	(541)	(588)
Cash Flows From Financing Activities		
Net borrowings (repayments) under credit facilities	(28)	31
Long-term debt matured, redeemed, or repurchased	(252)	(216)
Common stock repurchased	-	(275)
Dividends paid	-	(250)
Other-net	(1)	4
Net cash used by financing activities	(281)	(706)
Net Change in Cash and Cash Equivalents	21	4
Cash and Cash Equivalents at January 1	111	80
Cash and Cash Equivalents at June 30	$ 132	$ 84
Supplemental disclosures of cash flow information		
Cash paid for:		
Interest (net of amounts capitalized)	$ 265	$ 261
Income taxes paid (refunded) - net	(1,120)	-
Transfer of liabilities and other payables subject to compromise from operating payables and liabilities	11,148	-

The accompanying Notes to the Condensed Consolidated Financial Statements are an integral part of this statement.

PG&E CORPORATION AND PACIFIC GAS AND ELECTRIC COMPANY, A DEBTOR-IN-POSSESSION

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Note 1: GENERAL

Basis of Presentation

PG&E Corporation was incorporated in California in 1995 and became the holding company of Pacific Gas and Electric Company, a debtor-in-possession, (the Utility) on January 1, 1997. The Utility, incorporated in California in 1905, is the predecessor of PG&E Corporation. Effective with PG&E Corporation's formation, the Utility's interests in its unregulated subsidiaries were transferred to PG&E Corporation. As discussed further in Note 3, on April 6, 2001, the Utility filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code (Bankruptcy Code) in the United States Bankruptcy Court for the Northern District of California (Bankruptcy Court). Under Chapter 11, the Utility retains control of its assets and is authorized to operate its business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court.

This Quarterly Report on Form 10-Q/A is a combined report of PG&E Corporation and the Utility. Therefore, the Notes to the Condensed Consolidated Financial

Statements apply to both PG&E Corporation and the Utility. PG&E Corporation's condensed consolidated financial statements include the accounts of PG&E Corporation, the Utility, and PG&E Corporation's wholly owned and controlled subsidiaries. The Utility's condensed consolidated financial statements include its accounts as well as those of its wholly owned and controlled subsidiaries.

PG&E Corporation and the Utility believe that the accompanying condensed consolidated financial statements reflect all adjustments that are necessary to present a fair statement of the condensed consolidated financial position and results of operations for the interim periods. All material adjustments are of a normal recurring nature unless otherwise disclosed in this Form 10-Q/A. All significant intercompany transactions have been eliminated from the condensed consolidated financial statements.

Certain amounts in the prior year's condensed consolidated financial statements have been reclassified to conform to the 2001 presentation. Results of operations for interim periods are not necessarily indicative of results to be expected for a full year.

This quarterly report should be read in conjunction with PG&E Corporation's and the Utility's Consolidated Financial Statements and Notes to Consolidated Financial Statements incorporated by reference in their combined 2000 Annual Report on Form 10-K/A, and PG&E Corporation's and the Utility's other reports filed with the Securities and Exchange Commission since their 2000 Form 10-K/A was filed.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions. These estimates and assumptions affect the reported amounts of revenues, expenses, assets and liabilities and the disclosure of contingencies. Actual results could differ from these estimates.

Accounting for Price Risk Management Activities

Effective January 1, 2001, PG&E Corporation and the Utility adopted Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities". The Statement, as amended, required PG&E Corporation and the Utility to recognize all derivatives, as defined in the Statement, on the balance sheet at fair value. PG&E Corporation's transition adjustment to implement this new Statement on January 1, 2001 resulted in a non-material decrease to earnings and a decrease of $243 million to accumulated other comprehensive income. The Utility's transition adjustment to implement this new Statement resulted in a non-material decrease to earnings and an increase of $90 million to accumulated other comprehensive income.

Derivatives are classified as price risk management assets or price risk management liabilities on the balance sheet. Derivatives, or any portion thereof, that are not effective hedges are adjusted to fair value through income. For derivatives that are effective hedges, depending on the nature of the hedge, changes in the fair value are either offset by changes in the fair value of the hedged assets or liabilities through earnings or recognized in accumulated other comprehensive income until the hedged item is recognized in earnings. Net gains or losses recognized for the three- and six-month periods ended June 30, 2001, were included in various places on the income statement including energy commodities service revenue, cost of energy commodities and services, other income (expense), net, or interest income or interest expense.

Contracts for the physical delivery of purchase and sale quantities under the normal course of business are exempt from the requirements of SFAS No. 133 under the normal purchases and sales exception, and thus are not reflected on the balance sheet at fair value. The Financial Accounting Standards Board(FASB) is considering an interpretation by the Derivatives Implementation Group (DIG) that indicates that certain forward contracts with embedded optionality cannot qualify for the normal purchases and sales exception. Any gains or losses from the changes in fair value of these contracts in PG&E Corporation's non-regulated businesses will impact the income statement unless those contracts qualify for hedge accounting treatment. PG&E Corporation is currently reviewing its contracts to evaluate the impact of these interpretations on its financial statements, and will implement this guidance, as applicable, on a prospective basis.

As of June 30, 2001, the maximum length of time over which PG&E Corporation has hedged its exposure to the variability in future cash flows associated with commodity price risk is through December 2005 and for interest rate risk it is through March 2014.

The Utility had Power Exchange (PX) block-forward contracts valued at $243 million, which were derecognized in February 2001 when they were seized by California Governor Gray Davis for the benefit of the State, acting under California's Emergency Services Act (the Act). The block-forward contracts had an unrealized gain at the time they were seized. Under the Act, the State must pay the Utility for the reasonable value of the contracts, although the PX may seek to recover the monies that the Utility owes to the PX from any proceeds realized from the contracts. The Utility has filed a complaint against the State to recover the value of the seized contracts.

The Utility is party to various electric and gas bilateral contracts, some of which were terminated in the first six months of 2001. See Note 2. The value of certain gas contracts terminated during the first six months of the year was $60 million, net of taxes and regulatory impact. This balance is being amortized out of accumulated other comprehensive income at the same rate that hedged items are recognized in earnings.

Earnings (Loss) Per Share

Basic earnings (loss) per share is computed by dividing net income (loss) by the weighted average number of common shares outstanding during the period. Diluted earnings per share is computed by dividing net income by the weighted average number of common shares outstanding plus the assumed issuance of common shares for all potentially dilutive securities.

The following is a reconciliation of PG&E Corporation's net income (loss) and weighted average common shares outstanding for calculating basic and diluted net income (loss) per share.

	Three months ended June 30,	
	2001	2000
(in millions)		
Net Income (Loss)	$ 750	$ 248

Weighted average common shares outstanding	363	361
Add: Outstanding options reduced by the number of shares that could be repurchased with the proceeds from such purchase	-	1
Shares outstanding for diluted calculation	363	362
Earnings (Loss) per common share, basic	$2.07	$0.69
Earnings (Loss) per common share, dilutive	$2.07	$0.68

The diluted share base for 2001 excludes incremental shares of 285 million related to employee stock options. These shares are excluded due to the anti-dilutive effect as a result of the net loss. PG&E Corporation reflects the preferred dividends of subsidiaries as other expense for computation of both basic and diluted earnings per share.

Accumulated Other Comprehensive Income (Loss)

The objective of PG&E Corporation's and the Utility's accumulated other comprehensive income (loss) is to report a measure for all changes in equity of an enterprise that result from transactions and other economic events of the period other than transactions with shareholders. PG&E Corporation's and the Utility's other comprehensive income (loss) consists principally of changes in the market value of certain financial hedges with the implementation of SFAS No. 133 on January 1, 2001, as well as foreign currency translation adjustments.

New Accounting Pronouncements

In June 2001, the FASB issued SFAS No. 141, "Business Combinations." This Standard, which applies to all business combinations accounted for under the purchase method completed after June 30, 2001, prohibits the use of pooling-of-interests method of accounting for business combinations and provides a new definition of intangible assets. PG&E Corporation and Pacific Gas and Electric Company do not expect that implementation of this Standard will have a significant impact on its financial statements.

Also, in June 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets." This Standard eliminates the amortization of goodwill, and requires that goodwill be reviewed annually for impairment. This Standard also requires that the useful lives of previously recognized intangible assets be reassessed and the remaining amortization periods be adjusted accordingly. This Standard is effective for fiscal years beginning after December 15, 2001, and affects all goodwill and other intangible assets recognized on the Company's statement of financial position at that date, regardless of when the assets were initially recognized. PG&E Corporation and Pacific Gas and Electric Company have not yet determined the effects of this Standard on its financial statements.

In July 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." This Standard is effective for fiscal years beginning after June 15, 2002, and provides accounting requirements for asset retirement obligations associated with tangible long-lived assets. PG&E Corporation and Pacific Gas and Electric Company have not yet determined the effects of this Standard on its financial statements.

NOTE 2: THE CALIFORNIA ENERGY CRISIS

In 1998, California became one of the first states in the country to implement electric industry restructuring and establish a competitive market framework for electric generation. Electric industry restructuring was mandated by the California Legislature in Assembly Bill 1890 (AB 1890). The electric industry restructuring established a transition period, mandated a rate freeze, and included a plan for recovery of generation-related costs that were expected to be uneconomic under a competitive market (transition costs). The California Public Utilities Commission (CPUC) required the California investor-owned utilities to file a plan to voluntarily divest at least 50% of their fossil-fueled generation facilities and discouraged utility operation of their remaining facilities by reducing the return on such assets. The competitive market framework called for the creation of the PX and the Independent System Operator (ISO). Before it ceased operating, the PX established market-clearing prices for electricity. The ISO's role was to schedule delivery of electricity for all market participants and operate certain markets for electricity. Until December 15, 2000, the Utility was required to sell all of its owned and contracted for generation to, and purchase all electricity for its customers from, the PX. Customers were given the choice of continuing to buy electricity from the Utility or buying electricity from independent power generators or retail electricity suppliers. Most of the Utility's customers continued to buy electricity through the Utility.

Beginning in June 2000, wholesale prices for electricity sold through the PX and ISO experienced unanticipated and massive increases. The average price of electricity purchased by the Utility for the benefit of its customers was 18.2 cents per kilowatt-hour (kWh) for the period of June 1 through December 31, 2000, compared to 4.2 cents per kWh during the same period in 1999. The Utility was only permitted to collect approximately 5.4 cents per kWh in rates from its customers during that period. The increased cost of the purchased electricity strained the financial resources of the Utility. Because of the rate freeze, the Utility has been unable to pass on the increases in power costs to its customers. In order to finance the higher costs of energy, during the third and fourth quarter of 2000, the Utility increased its lines of credit to $1,850 million (net increase of $850 million), issued $1,240 million of debt under a 364-day facility, and issued $680 million of five-year notes.

The Utility continued to finance the higher costs of wholesale power while interested parties evaluated various solutions to the energy crisis. In November 2000, the Utility filed its Rate Stabilization Plan (RSP), which sought to end the rate freeze and pass along the increased wholesale electric costs to customers through increased rates. The CPUC evaluated the Utility's proposal and deferred its decision until March 2001, although the CPUC did increase rates one cent per kWh for 90 days effective January 4, 2001. This increase resulted in approximately $70 million of additional revenue per month, which was not nearly enough to cover the higher wholesale costs of electricity, nor did it help with the costs already incurred.

By January 16, 2001, the Utility had borrowed more than $3.0 billion under its various credit facilities to pay its energy costs. As a result of the California energy crisis and its impact on the Utility's financial resources, PG&E Corporation's and the Utility's credit rating deteriorated to below investment grade in January 2001. This credit downgrade precluded PG&E Corporation and the Utility from access to capital markets. Commencing in January 2001, PG&E Corporation and the Utility began to default on maturing commercial paper. In addition, the Utility became unable to pay the full amount of invoices received for wholesale power purchases and made only partial payments. The Utility had no credit under which it could purchase wholesale electricity on behalf of its customers on a continuing basis and generators were only selling to the Utility under emergency action taken by the U.S. Secretary of Energy.

In January 2001, the California Legislature and the Governor authorized the California Department of Water Resources (DWR) to purchase wholesale electric energy on behalf of the Utility's retail customers.

On March 27, 2001, the CPUC authorized an average increase in retail rates of 3.0 cents per kWh, which was in addition to the emergency 1.0 cent per kWh surcharge adopted on January 4, 2001 by the CPUC. The revenue generated by this rate increase was to be used only for power procurement costs that are incurred after March 27, 2001 and could not be used to pay amounts owed to creditors. Although the rate increase was authorized immediately, the Utility did not begin collecting in rates the 3.0 cent per Kwh surcharge until June 1, 2001, when the rate design was adopted by the CPUC. As a result of the delay in implementation, the additional surcharge that went into effect on June 1, 2001 was 3.5 cents per kWh, of which 0.5 cents per kWh amortizes the under-collection that accrued between March 27 and the June 1, 2001 implementation date over the twelve month period ending June 2002.

In light of the magnitude of the under-collected purchased power costs and the lack of solutions to the energy crisis, on April 6, 2001, the Utility sought protection from its creditors through a Chapter 11 bankruptcy filing. The filing for bankruptcy and the related uncertainty around the terms and conditions of any reorganization plan that is ultimately adopted will have a significant impact on the Utility's future liquidity and results of operations.

PG&E Corporation, itself, had cash and short-term investments of $272 million at June 30, 2001, and believes that the funds will be adequate to maintain its operations through and beyond 2001. In addition, PG&E Corporation believes that itself and its other subsidiaries not subject to CPUC regulation are substantially protected from the continuing liquidity and financial difficulties of the Utility. A discussion of the events leading up to the bankruptcy filing, PG&E Corporation's and the Utility's actions, and the ongoing uncertainty follows.

Transition Period and Rate Freeze

California's deregulation legislation passed by the California Legislature in 1996 established a transition period, which was to begin in 1998. During this period, electric rates for all customers were frozen at 1996 levels, with rates for residential and small commercial customers being reduced in 1998 by 10% and frozen at that level. During the transition period, investor-owned utilities were given the opportunity to recover their transition costs. Transition costs were generation-related costs that were expected to be uneconomic under the new industry structure.

To pay for the 10% rate reduction, the Utility refinanced $2.9 billion (the expected revenue reduction from the rate decrease) of its transition costs with the proceeds from the sale of rate reduction bonds. The bonds allow for the rate reduction by lowering the carrying cost on a portion of the transition costs and by deferring recovery of a portion of the transition costs until after the transition period. During the rate freeze, the rate reduction bond debt service did not increase the Utility customers' electric rates. If the transition period ends before March 31, 2002, the Utility may be obligated to return a portion of the economic benefits of the transaction to customers. The timing of any such return and the exact amount of such portion, if any, have not yet been determined.

The rate freeze was scheduled to end on the earlier of March 31, 2002, or the date the Utility had recovered all of its transition costs. The Utility believes it recovered its eligible transition costs possibly as early as the end of May 2000. At August 31, 2000, the Utility's remaining transition costs were less than a then-recently negotiated $2.8 billion hydroelectric generation asset valuation. If the final valuation for the hydroelectric assets is greater than $2.8 billion, as the Utility expects, the Utility will have recovered its transition costs earlier. The under-collected wholesale electricity costs as of the end of the earlier determined transition period will be less than the August 31, 2000 balance of $2.2 billion, and could be zero depending on the ultimate valuation of the hydroelectric generating facilities and when the transition period actually ends. However, the CPUC has not yet accepted the Utility's estimated market valuation of its hydroelectric assets nor has the CPUC determined that the rate freeze has ended.

Wholesale Prices of Electricity

As previously stated, beginning in June 2000, the Utility experienced unanticipated and massive increases in the wholesale costs of the electricity purchased from the PX and ISO on behalf of its retail customers. The Utility believes that since it has not met the creditworthiness standards under the ISO's tariff since early January 2001, the Utility should not be responsible for the ISO's purchases made to meet the Utility's net open position. (The net open position is the amount of power needed by retail electric customers that cannot be met by utility-owned generation or power under contract to the utilities.) On February 14, 2001, the

Federal Energy Regulatory Commission (FERC) ordered that the ISO could only buy power on behalf of creditworthy entities. The FERC order also stated that the ISO could continue to schedule power for the Utility as long as it comes from its own generation units and is routed over its own transmission lines. Despite the FERC orders, the ISO continued to bill the Utility for the ISO's wholesale power purchases. On April 6, 2001, the FERC issued a further order directing the ISO to implement its prior order, which the FERC clarified, applying to all third-party transactions whether scheduled or not. In light of the FERC's April 6, 2001 order, the Utility has not recorded any such estimated ISO charges after April 6, 2001, except for the ISO's grid management charge, although the Utility has accrued the full amount of the ISO charges up to April 6, 2001 in the accompanying financial statements. On June 13, 2001, the FERC denied the ISO's request for rehearing of its April 6, 2001 order.

On June 26, 2001, the Bankruptcy Court issued a preliminary injunction prohibiting the ISO from charging the Utility for the ISO's wholesale power purchases made in violation of bankruptcy law, the ISO's tariff, and the FERC's February 14 and April 6, 2001 orders. In issuing the injunction, the Bankruptcy Court noted that the FERC orders permit the ISO to schedule transactions that involve either a creditworthy buyer or a creditworthy counterparty, and noted the existence of unresolved issues regarding how to ensure these creditworthiness requirements for real-time transactions and emergency dispatch orders issued by the ISO to power sellers. The Utility believes that its only responsibility for third party power delivered to its customers is to pay the DWR the amount collected from customers, whether the third party power is purchased by a creditworthy buyer or whether the purchase is facilitated by a creditworthy counterparty.

The generation-related cost component of frozen retail rates, which provides for recovery of generation costs, including wholesale electricity purchased by the Utility and, if available, for recovery of transition costs, was 5.4 cents per kWh, during the six months ended June 30, 2000. In 2001, the CPUC approved two rate increases, which increased the generation-related cost component. On January 4, 2001, the generation-related cost component increased 1.0 cent per kWh. On June 1, 2001, the generation-related cost component increased by 3.5 cents per kWh. As discussed below, the CPUC approved an average 3.0 cents per kWh surcharge for power costs incurred after March 27, 2001, but the Utility did not begin collecting in rates the 3.0 cents per kWh surcharge until June 1, 2001. At the time of implementation, the actual surcharge was 3.5 cents per kWh to reflect the under-collection that accrued due to the delay in implementation.

Through April 6, 2001, the excess of wholesale electricity costs billed to the Utility by the ISO above the generation-related cost component available in frozen rates has been expensed as incurred and is included in the cost of electric energy on the Utility's Condensed Consolidated Statement of Operations. The amount of under-collected purchased power costs incurred for the six-month period ended June 30, 2001 was approximately $.9 billion. The under-collected purchased power costs accrued as of March 31, 2001, included an estimated cost of $579 million for the month of March based upon usage and historical market price estimates. In May 2001, the ISO provided the invoice for its March purchases, which totaled $257 million. An adjustment for the difference between the estimated amount at March 31, 2001, and the actual amount was recorded in the second quarter as a reduction to the Cost of Electric Energy in the Consolidated Statement of Operations.

Under current CPUC decisions, if the under-collected purchased power costs are not recovered through frozen rates by the end of the transition period, they cannot be recovered. However, in the CPUC decision adopting the 3.0 cent per kWh rate increase, the CPUC indicated that in light of recent legislative action and regulatory developments, it would be premature and unwise to opine as to the ultimate disposition of this under-collection. Once the transition period has ended and the rate freeze is over, the Utility's customers will be responsible for wholesale electricity costs. However, actual changes in customer rates will not occur until new retail rates are authorized by the CPUC or, to the extent allowed, by the Bankruptcy Court.

The under-collected purchased power costs would generally be deferred for future recovery as a regulatory asset subject to future collection from customers in rates. However, due to the lack of regulatory, legislative, or judicial relief, the Utility has determined that it can no longer conclude that its uncollected wholesale electricity costs and remaining transition costs are probable of recovery in future rates. Therefore, such costs are expensed as incurred.

Mitigation Efforts

The Utility is actively exploring ways to reduce its exposure to wholesale electricity price volatility and to recover its written-off under-collected wholesale electricity costs and Transition Cost Balancing Account (TCBA) balances. As previously indicated, the Utility believes the transition period has ended and filed an application with the CPUC asking it to so rule. The Utility has also filed an application with the FERC to address the current market crisis, filed a lawsuit against the CPUC in federal district court, worked with interested parties to address power market dysfunction before appropriate regulatory bodies, hedged a portion of its open procurement position against higher purchased power costs through forward purchases, and filed an application with the CPUC seeking approval of a five-year rate stabilization plan. The Utility's actions and related activities are discussed below.

Application with the FERC

On October 16, 2000, the Utility joined with Southern California Edison (SCE) and The Utility Reform Network (TURN) in filing a petition with the FERC requesting that the FERC; (1) immediately find the California wholesale electricity market to be not workably competitive and the resulting prices to be unjust and unreasonable; (2) immediately impose a cap on the price for energy and ancillary services; and (3) institute further expedited proceedings regarding the market failure, mitigation of market power, structural solutions, and responsibility for refunds.

On December 15, 2000, the FERC issued an order in response to the above filing. The remedies proposed by the FERC included, among other things; (1) eliminating the requirement that the California investor-owned utilities must sell all of their power into, and buy all of their power needs from, the PX; (2) modifying the single price auction so that bids above $150 per megawatt hour (MWh) (15.0 cents per kWh) cannot set the market clearing prices paid to all bidders, effective January 1, 2001 through April 30, 2001; (3) establishing an independent governing board for the ISO; and (4) establishing penalties for under-scheduling power loads. The FERC did not order any refunds based on its findings, but announced its intent to retain the discretion to order refunds for wholesale electricity costs incurred from October 2000 through December 31, 2002. In March 2001, the FERC ordered refunds of $69 million for January 2001 and indicated it would continue to review December 2000 wholesale prices. In April 2001, the FERC ordered refunds of $588 thousand for February and March 2001. The generators have appealed the decisions. Any refunds will be offset against amounts owed the generators.

During June and July 2001, a FERC administrative law judge conducted settlement negotiations between power sellers, representatives of the State of California, California investor-owned utilities and other interested parties, to try to reach an agreement about calculation of potential refunds. The settlement negotiations were unsuccessful and on July 25, 2001, the FERC issued an order that limits potential refunds to the ISO and PX spot markets during the period of October 2, 2000 through June 20, 2001, and adopted a refund calculation methodology that uses daily spot gas prices and includes a 10% premium on prices after January 5, 2001, to reflect the added risk to the sellers resulting from the lack of creditworthiness of the California investor owned utilities. The ISO has 15 days to submit a re-creation of the mitigated prices that result from using the methodology to the administrative law judge (ALJ) overseeing the proceedings. The FERC directed the ALJ to make findings of fact with respect to: (1) the mitigated price in each hour of the refund period; (2) the amount of refunds owed by each supplier according to the methodology established; and (3) the amount currently owed to each supplier (with separate quantities due from each entity) by the ISO, the investor owned utilities, and the State of California. The ALJ is to then certify his findings of fact to the FERC within 45 days after the receipt of the material from the ISO. A prehearing conference is scheduled to be held on August 13, 2001 to address procedural issues related to the evidentiary hearings developing a record on the scope and methodology for calculating refunds announced in the July 25, 2001 order.

Federal Lawsuit

On November 8, 2000, the Utility filed a lawsuit in federal district court in San Francisco against the CPUC Commissioners. The Utility asked the court to declare that the federally approved wholesale electricity costs the Utility has incurred to serve its customers are recoverable in retail rates both before and after the end of the transition period. The lawsuit stated that the wholesale power costs the Utility has incurred are paid pursuant to filed rates, which the FERC has authorized and approved and that under the United States Constitution and numerous federal court decisions, state regulators cannot disallow such costs. The Utility's lawsuit also alleged that to the extent that the Utility is denied recovery of these mandated wholesale electricity costs by order of the

CPUC, such action constitutes an unlawful taking and confiscation of the Utility's property.

On May 2, 2001, the court dismissed the Utility's complaint without prejudice to refile the lawsuit at a later time. Although ruling in the Utility's favor on five of the six grounds for dismissal, the court found that the Utility's complaint was not ripe because some of the CPUC's decisions that the Utility was challenging were interim orders that will only become final upon a grant or denial of rehearing. The Utility filed a request for rehearing of the CPUC's decisions. Under applicable rules, if the CPUC has not acted on the request within 60 days of filing, the request is deemed denied. While the CPUC has not yet acted on the Utility's request, the 60-day period has expired and the Utility believes the decisions have become final. Therefore, the Utility intends to refile its case in federal district court shortly.

Legislative Action

On February 1, 2001, the governor of California signed into law AB 1X. AB 1X extended a preliminary authority of the DWR to purchase power. Public Utilities Code Section 360.5, adopted in AB 1X, requires the CPUC to determine the portion of each electric utility's existing electric retail rate that represents the difference between the generation related component of the utility's retail rate in effect on January 5, 2001, and the sum of the costs of the utility's own generation, qualifying facilities (QFs) contracts, existing bilateral contracts, and ancillary services (the California Procurement Adjustment or CPA). Currently, the CPA

is just a calculation and is not paid to the DWR. Initially, the DWR indicated that it intended to buy power only at "reasonable prices" to meet the utilities' net open position, leaving the ISO to buy the remainder. AB 1X does not address whether or how the Utility will be able to pay for the ISO's wholesale power costs billed to the Utility that exceed the generation-related costs components of electric rates. The ISO billed the Utility for its costs to purchase power to cover the amount of the Utility's net open position not covered by the DWR. As discussed above, the Utility has expensed these costs from January through April 6, 2001 in the accompanying financial statements. Although the Utility continues to receive bills from ISO for its power purchases made after April 6, 2001, the Utility has recorded only the ISO's grid management charge as an expense after April 6, 2001. It is not clear whether and to what extent the Utility will ultimately be responsible for the ISO costs billed to the Utility.

In light of the FERC's April 6, 2001 order the Utility has not recorded any such estimated ISO charges after April 6, 2001, except for the ISO's grid management charge.

Further, it is unclear how much of the ISO's power purchases have been made by the DWR on behalf of the Utility's customers. On June 21, 2001, the Utility received a request from the DWR that the Utility pay the DWR the amounts required by current CPUC orders for the DWR's out-of-market purchases made on behalf of the Utility's customers between January 17, 2001 and June 2, 2001, pursuant to AB 1X. The Utility has previously received invoices from the ISO for what the Utility believes may be the same energy.

The amounts requested by the DWR in its June 21, 2001 invoices are based on the amounts that the Utility is authorized to collect from customers pursuant to AB 1X and current CPUC orders, which are significantly less than the ISO invoices, which are based on market prices. However, the CPUC orders establishing the amount the Utility is required to collect and pay the DWR are interim and subject to revision when the CPUC allocates the DWR's overall revenue requirements under AB 1X. Since the Utility believes that it is merely a pass through entity for such costs and related revenues, the Utility does not reflect these amounts in its Consolidated Statements of Operations.

A determination that the DWR is the creditworthy buyer or counterparty for the ISO's third-party purchases in accordance with the FERC tariffs could result in a reversal of the prior recorded ISO expenses and could result in a material increase to earnings depending on the amount ultimately authorized by the CPUC to be collected by the Utility from ratepayers on the DWR's behalf.

Rate Stabilization Plan

On November 22, 2000, the Utility filed an application with the CPUC seeking approval of a five-year RSP beginning on January 1, 2001. The Utility requested an initial average rate increase of 22.4%. The Utility also proposed that it receive actual costs, including a regulated return, for electricity generation provided by it with the idea that profits that would have been generated at market rates be recovered from customers later in the five-year rate stabilization period. With respect to Diablo Canyon Nuclear Power Plant (Diablo Canyon) the Utility has proposed to defer all profits (discussed below in "Diablo Canyon Benefits Sharing"), until 2003, when the allocation of revenues between ratepayers and shareholders will be readjusted. The readjustment is intended to allow, by the end of 2005, the total net revenues earned by Diablo Canyon, over the five-year plan, to be allocated equally between shareholders and ratepayers according to existing CPUC decisions.

On January 4, 2001, the CPUC issued an emergency interim decision denying the Utility's request for a rate increase. Instead, the decision permitted the Utility to establish an interim surcharge applied to electric rates on an equal-cents-per-kWh basis of 1.0 cent per kWh, subject to refund and adjustment. The surcharge was to remain in effect for 90 days from the effective date of the decision. The Utility was required to establish a balancing account to track the revenue provided by the surcharge and to apply these revenues to ongoing wholesale electricity costs. The surcharge was made permanent in the CPUC's March 27, 2001 decision, referred to below.

On January 26, 2001, an assigned CPUC commissioner's ruling was issued in the Utility's RSP proceeding. The ruling stated that in phase one of the case, the scope of the proceeding would include (1) reviewing the independent audit of the Utility's accounts to determine whether there is a financial necessity for additional relief for the utilities, (2) reviewing TURN's accounting proposal to transfer the under-collected balances in the utilities Transition Revenue Accounts (TRAs) to their respective TCBAs and reviewing the generation memorandum accounts, and (3) considering whether the rate freeze has ended only on a prospective basis.

On January 30, 2001, the independent consultants engaged by the CPUC issued their review report on the Utility's financial position as of December 3, 2000, as well as that of PG&E Corporation and the Utility's affiliates. The review found that the Utility made an accurate representation of its financial situation noting accurate representations of its borrowing capabilities, credit condition, and events of default. The review also found that the Utility accurately represented recorded entries to its TRA and TCBA. The review alleged certain deficiencies with respect to bidding strategies, cash conservation matters, and cash flow forecast assumptions. The Utility filed rebuttal testimony on February 14, 2001. Hearings to consider the issues and reports of the independent consultants began on February 20, 2001.

On March 27, 2001, the CPUC ruled on parts of the Utility's RSP and granted an increase in rates by adopting an average 3.0 cents per kWh surcharge. Although the increase was authorized immediately, the 3.0 cents per kWh surcharge would not be collected in rates until the CPUC established an appropriate rate design for the surcharge, which was adopted on May 15, and implemented on June 1, 2001. The actual surcharge that went into effect on June 1, 2001 was 3.5 cents per kWh, of which 0.5 cents per kWh amortizes the under-collection accrued between March 27, 2001, and the June 1, 2001 implementation date. The revenue generated by the rate increase is to be used only for power procurement costs that are incurred after March 27, 2001. The CPUC declared that the revenues generated by this surcharge are subject to refund (1) if not used to pay for such power purchases, (2) to the extent that generators and sellers of power make refunds for over-collections, or (3) to the extent any administrative body or court denies the refunds of over-collections in a proceeding where recovery has been hampered by a lack of cooperation from the Utility. The 3.0 cents per kWh surcharge is in addition to the emergency interim surcharge approved on January 4, 2001, which the CPUC made permanent in this decision. The CPUC also modified accounting rules in response to a proposal made by TURN as described below.

Also, on March 27, 2001, the CPUC issued a decision ordering the Utility and the other California investor-owned utilities to pay the DWR a per-kWh price equal to the applicable generation-related retail rate per kWh established for each utility, for each kWh that the DWR sells to the customers of each utility. The CPUC determined that the generation-related component of retail rates should be equal to the total bundled electric rate (including the 1.0 cent per kWh interim surcharge adopted by the CPUC on January 4, 2001) less the following non-generation-related rates or charges: transmission, distribution, public purpose programs, nuclear decommissioning, and the fixed transition amount. The CPUC determined that the Utility's company-wide average generation-related rate component is 6.471 cents per kWh before June 1, 2001. On June 1, 2001, the CPUC adopted an additional rate surcharge of 3.516 cents per kWh. The CPUC ordered the utilities to pay the DWR within 45 days after the DWR supplies power to their retail customers, subject to penalties for each day that payment is late. For power supplied through May 31, 2001, the amount of power scheduled to retail end-use customers after March 27, 2001, for which the DWR is entitled to be paid, would be based on the product of the number of kWh that the DWR scheduled to the Utility 45 days earlier and the Utility's company-wide average generation-related rate of 6.471 cents per kWh, as ordered by the CPUC. For power scheduled to the Utility after June 1, 2001, the Utility began remitting to the DWR in the more precise manner as outlined in the CPUC decision discussed above.

In addition, on April 3, 2001, the CPUC adopted a method to calculate the CPA, as described in Public Utilities Code Section 360.5 (added by AB 1X effective February 1, 2001). Section 360.5 requires the CPUC to determine (1) the portion of each electric utility's electric retail rate effective on January 5, 2001, that is equal to the difference between the generation-related component of the utility's retail rate in effect on January 5, 2001, and the sum of the costs of the utility's own generation, QF contracts, existing bilateral contracts (i.e., entered into before February 1, 2001), and ancillary services, and (2) the amount of the CPA that is allocable to the power sold by the DWR. The CPUC decided that the CPA should be a set rate calculated by determining each utility's generation-related revenues (for the Utility the CPUC has proposed that this be equal to 6.471 cents per kWh multiplied by total kWh sales by the Utility to the Utility's retail customers), then subtracting the result by each utility's total kWh sales. Each utility's CPA rate will be used to determine the amount of bonds the DWR may issue.

Using the CPUC's methodology, but substituting the CPUC's cost assumptions with actual expected costs and including costs the CPUC has refused to recognize, the

Utility's calculations show that the CPA for the 11-month period February through December 2001 would be negative by $2.2 billion, (i.e., there would be no CPA available to the DWR) assuming the DWR purchases 84% of the Utility's net open position. If AB 1X were amended to also include in the CPA all the incremental revenue from the 3.0 cent per kWh increase discussed above (approximately $2.3 billion for 11 months), then the amount available to the DWR for the CPA for the comparable 11-month period, assuming the Utility were allowed to recover its costs first, would be approximately $100 million. The Utility believes the method adopted by the CPUC is unlawful and inconsistent with Section 360.5 because, among other reasons, it establishes a set rate that does not reflect actual residual revenues, overstates the CPA by excluding and/or understating authorized costs, and to the extent it is dedicated to the DWR does not allow the Utility to recover its own revenue requirements and costs of service. The Utility's application for rehearing of this decision has been denied.

Initially, the DWR advised the CPUC that its revenue requirement for the DWR's power purchases was $4.715 billion and has asked the CPUC to establish specific rates payable to the DWR to collect that revenue requirement as authorized by AB 1X. The DWR's stated revenue requirement is greater than the revenues that would be provided by the 3.0 cent surcharge. Unless the CPUC increases rates to provide sufficient revenues for the DWR to recover its revenue requirement, none of the revenues from the 3.0 cent surcharge will be available to the Utility to recover its procurement costs incurred after March 27, 2001 (including any ISO charges for which the DWR disclaims responsibility).

On July 23, 2001, the DWR filed information concerning its revenue requirements with the CPUC. The DWR stated that it seeks to collect $13.072 billion from electric customers for the period January 17, 2001 through December 2002. Of this amount, the

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DWR seeks to collect approximately $5.2 billion from the Utility's customers. The Utility is required currently to pay the DWR approximately $0.10 per kWh for each kWh provided by the DWR, including all of the 3.0cent surcharge approved by the CPUC in March 2001. The DWR's filing indicated that the average cost it is seeking from California utility customers is 10.8 cents per kWh for 2001 and 13.7 cents per kWh in 2002. On July 24, 2001, the Utility requested that the DWR hold a public hearing on its revised revenue requirement because the DWR's filing lacked sufficient detail to determine the impact its revenue requirements may have on ratepayers and the Utility.

In March 2001, the CPUC also adopted TURN's proposal to transfer on a monthly basis the balance in each utility's TRA to the utilities' TCBA. The TRA is a regulatory balancing account that is credited with total revenue collected from ratepayers through frozen rates and which tracks under-collected power purchase costs. The TCBA is a regulatory balancing account that tracks the recovery of generation-related transition costs. The accounting changes are retroactive to January 1, 1998. The Utility believes the CPUC is retroactively transforming the power purchase costs in the TRA into transition costs in the TCBA. However, the CPUC characterized the accounting changes as merely reducing the prior revenues recorded in the TCBA, thereby affecting only the amount of transition cost recovery achieved to date. The CPUC also ordered that the utilities restate and record their generation memorandum account balances to the TRA on a monthly basis before any transfer of generation revenues to the TCBA. The CPUC found that based on the accounting changes, the conditions for meeting the end of the rate freeze have not been met.

The Utility believes the adoption of TURN's proposed accounting changes results in illegal retroactive ratemaking, constitutes an unconstitutional taking of the Utility's property, and violates the federal filed rate doctrine. The Utility also believes the other CPUC decisions are similarly illegal to the extent they would compel the Utility to make payments to the DWR and QFs without providing adequate revenues for such payments. The Utility filed an application for rehearing of this decision. The Utility also requested the Bankruptcy Court to enjoin the CPUC from requiring the Utility to implement the regulatory accounting changes.

On June 1, 2001, the Bankruptcy Court issued a decision denying the Utility's request and granting the CPUC's motion to dismiss the complaint. The Utility has filed an appeal of the Bankruptcy Court's order. The Utility will continue to pursue all legal challenges to this unlawful CPUC decision.

Qualifying Facilities Contracts

In early 2001, the Utility had been paying only 15% of amounts due QFs. A number of QFs requested the Bankruptcy Court to either terminate their contracts requiring them to sell power to the Utility or have the contracts suspended for the summer of 2001 so the QFs can sell power at market-based rates. On March 27, 2001, the CPUC issued a decision requiring the Utility and the other California investor-owned utilities to pay QFs fully for energy deliveries made on and after the date of the decision, within 15 days of the end of the QFs' billing period. The decision permits QFs to establish a 15-day billing period as compared to the current monthly period. The CPUC noted that its change to the payment provision was required to maintain energy reliability in California and thus provided that failure to make a required payment would result in a fine in the amount owed to the QFs. The decision also adopts a revised pricing formula relating to the California border price of gas applicable to energy payments to all QFs, including those that do not use natural gas as a fuel. Based on the Utility's preliminary review of the decision, the revised pricing formula would reduce the Utility's 2001 average QF energy and capacity payments from approximately 12.7 cents per kWh to 12.3 cents per kWh. Since May 2001, the QFs under contract to the Utility are being paid in full for power purchased since early April 2001.

In July 2001, the Utility signed five-year agreements with 131 of its QFs, ensuring the Utility and its customers receive a reliable supply of electricity at an average energy price of 5.37 cents per kilowatt-hour. Under the terms of the agreements, the Utility will assume the QF contracts and pay the pre-petition debt on these 131 QF contracts, totaling $740 million, on the effective date of the plan of reorganization. The total amount the company owed to QFs when it filed for Chapter 11 was approximately $1 billion. The agreements represent 75% of debt owed to QFs. For certain of these QFs, if the effective date has not occurred by July 15, 2003, the Utility will pay 2% of the principal amount of the pre-petition debt per month until the effective date of the plan of reorganization or until July 15, 2005, when it will pay the remaining pre-petition debt. By locking into the average fixed cost, the Utility will help protect its customers from the price fluctuations in the wholesale market. Each of the agreements requires formal approval from the U.S Bankruptcy Court. Most of the agreements have already been approved, and the Utility will be making filings for the remainder in the near future.

Bilateral Contracts

Under the terms of AB 1890, the Utility was required to purchase all of its power from the PX and ISO to meet the needs of its customers. On August 3, 2000, after the California energy crisis had begun, the CPUC approved the Utility's use of bilateral contracts, subject to the Utility reaching agreement with the CPUC on reasonableness standards. After two months of unsuccessful discussions with the CPUC, on October 16, 2000, the Utility filed an advice letter seeking CPUC approval of specific reasonableness standards in order to expedite implementation of the August 3, 2000 decision. In spite of the Utility's efforts, the CPUC has not adopted reasonableness standards implementing the August 3, 2000 decision.

In October 2000, the Utility entered into multiple bilateral contracts with suppliers for long-term electricity deliveries. Some of these contracts were terminated by the counterparties who were entitled to do so in the event of a the decline in the Utility's credit quality to below investment grade, certain of these contracts were terminated by the counterparties. The terms of the contracts require that at termination, the contracts be settled at the then market-value of the contract. One contract has been settled with the counter-party for $405 million. Two others are in negotiations and have combined estimated market values at termination date that ranges from $126 million to $217 million. The settled contract and lower end of the range of market values for the contracts under negotiation total $552 million and have been recognized as a reduction to the Cost of Electric Energy in the Consolidated Statement of Operations. As of June 30, 2001, remaining individual contracts range in size from approximately 61,200 MWhs to 3,504,000 MWhs of supply annually. The contracts extend to 2003.

PX Energy Credits

In accordance with CPUC regulations, the Utility provides a PX energy credit to those customers (known as direct access customers) who have chosen to buy their electric energy from an energy service provider (ESP) other than the Utility. As wholesale power prices began to increase beginning in June 2000, the level of PX credits issued to direct access customers increased correspondingly to the point where the credits exceeded the Utility's distribution and transmission charges to direct access customers. For the six months ended June 30, 2001, the PX credits reduced electric revenue by $80 million. The Utility ceased paying most of these credits in December 2000, and as of June 30, 2001, the total of accumulated credits for direct access customers that have not been paid by the Utility is approximately $513 million. The actual amount that will be refunded to ESPs will be dependent upon when the rate freeze ends and whether there are any adjustments made to wholesale energy prices by the FERC.

Generation Valuation

Under the California electric industry restructuring legislation, the valuation of the Utility's remaining generation assets (primarily its hydroelectric facilities) must be completed by December 31, 2001. Any excess of market value over the assets' book value would be used to offset the Utility's transition costs.

In August 2000, the Utility and a number of interested parties filed an application with the CPUC requesting that the CPUC approve a settlement agreement reached by these parties. The agreement was filed in the Utility's proceeding to determine the market value of the hydroelectric generation assets. In this settlement agreement, the Utility indicated that it would transfer its hydroelectric generation assets, at a negotiated value of $2.8 billion, to an affiliate. Due to the high wholesale prices and the corresponding increase in the value of its hydroelectric generation assets, in November 2000, as part of an application with the CPUC seeking approval of a five-year RSP, the Utility withdrew its support from the settlement agreement, eliminating it from consideration in the proceeding.

In December 2000, the Utility submitted updated testimony in the hydroelectric valuation proceeding indicating the market value of the hydroelectric assets ranges from $3.9 billion to $4.2 billion assuming a competitive auction or other arms-length sale.

In the December 15, 2000 FERC order, the FERC ordered that ratemaking for the Utilty's remaining generation be returned to the jurisdiction of the CPUC. In January 2001, California Assembly Bill 6 was passed which prohibits disposal of any of the Utility's generation facilities, including the hydroelectric facilities, before January 1, 2006. At June 30, 2001, the book value of the Utility's net investment in hydroelectric generation assets was approximately $585 million.

On June 15, 2001, the Utility filed testimony in its RSP proceeding to present its revenue requirement for cost-based rates for its retained generation, including its hydroelectric and nuclear facilities, qualifying facilities, bilateral contracts, and ancillary services. The Utility argued that the revenue requirements for its hydroelectric facilities should be based on a market valuation of its hydroelectric assets, as required by current law, at a minimum value of $4.1 billion. Based on this valuation, the Utility argued that its rate freeze ended as early as April 2000, notwithstanding the implementation of the retroactive changes to the transition period ratemaking mechanisms discussed above. Combined with the revenue requirements for other retained generation and purchase power costs, the Utility proposed a 2001 revenue requirement of $6.7 billion. The Utility was directed by the CPUC to present other revenue requirement scenarios. These alternate scenarios produce 2001 revenue requirements between $3.9 billion based on the amount of unrecovered capital costs at April 30, 2001 and assuming the rate freeze ended before January 1, 2001, to $9.9 billion which amount assumes the rate freeze has not ended. It is likely that the CPUC will not act on the Utility's 2001 revenue requirement filing until after the CPUC acts on the DWR's revenue requirement. In such event, it is uncertain whether current rates as they may be apportioned between the Utility and the DWR will be sufficient for the Utility to recover the revenue

requirements that may eventually be adopted by the CPUC.

Diablo Canyon Benefits Sharing

As required by a prior CPUC decision, on June 30, 2000, the Utility filed an application with the CPUC requesting approval of its proposal for sharing with ratepayers 50% of the post-rate freeze net benefits of operating Diablo Canyon. The net benefit sharing methodology proposed in the Utility's application would be effective at the end of the current electric rate freeze for the Utility's customers and would continue for as long as the Utility owned Diablo Canyon. Under the proposal, the Utility would share the net benefits of operating Diablo Canyon based on the auditedprofits from operations, determined consistent with the prior CPUC decisions. If Diablo Canyon experiences losses, such losses would be deferred and netted against profits in the calculation of the net benefits in subsequent periods (or against profits in prior periods if subsequent profits are insufficient to offset such losses). Any changes to the net sharing methodology must be approved by the CPUC. The CPUC has suspended the proceedings to consider the net benefit-sharing proposal. In the Utility's RSP, parties have proposed that the requirement to establish a sharing methodology be rescinded and the Diablo Canyon be placed on cost-of-service ratemaking. In the Utility's June 15, 2001 revenue requirement testimony in its rate stabilization proceedings, the Utilty proposed that the revenue requirements for Diablo Canyon should reflect the 50/50 sharing of net benefits between shareholders and ratepayers using a market revenue benchmark and actual ongoing costs. It is uncertain what future ratemaking will be applicable to Diablo Canyon.

NOTE 3: VOLUNTARY PETITION FOR RELIEF UNDER CHAPTER 11

On April 6, 2001, the Utility filed a voluntary petition for relief under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court. Under Chapter 11, the Utility retains control of its assets and is authorized to operate its business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court. Subsidiaries of the Utility, including PG&E Funding LLC (which holds Rate Reduction Bonds, discussed further in Note 2) and PG&E Holdings LLC (which holds stock of the Utility), are not included in the Utility's petition. The Utility's Consolidated Financial Statements have been prepared in accordance with the American Institute of Certified Public Accountants' Statement of Position 90-7 (SOP 90-7), "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code," and on a going concern basis, which contemplates continuity of operation, realization of assets and liquidation of liabilities in the ordinary course of business. However, as a result of the filing, such realization of assets, and liquidation of liabilities are subject to uncertainty.

Certain claims against the Utility in existence prior to the filing of the petition for relief are stayed while the Utility continues business operations as a debtor-in-possession. These claims are reflected in the June 30, 2001, balance sheets as "liabilities subject to compromise." Additional claims (liabilities subject to compromise) may arise subsequent to the filing date resulting from (1) negotiations; (2) rejection of executory contracts, including leases; (3) actions by the Bankruptcy Court; (4) further developments with respect to disputed claims; (5) proofs of claim; or (6) other events. Payment terms for these amounts will be established through the bankruptcy proceedings. Claims secured against the Utility's assets ("secured claims") also are stayed, although the holders of such claims have the right to move the court for relief from the stay. Secured claims are secured primarily by liens on substantially all of the Utility's assets and by pledged accounts receivable from gas customers. The Bankruptcy Court has approved making the regular interest payments on the Utility's secured debt.

A creditors' committee has been appointed as an official committee and, in accordance with the provisions of the Bankruptcy Code, will have the right to be heard on all matters that come before the Bankruptcy Court. The Utility expects that the creditors' committee will play an important role in the negotiation of the terms of any plan of reorganization.

Since the filing, the Bankruptcy Court has approved various requests by the Utility to permit the Utility to carry on its normal business operations, and pay certain pre-petition obligations. Additionally, the Utility has secured approval for approximately $1.5 billion in capital expenditures for on-going business needs such as upgrading and improving transmission lines and substations. The Utility's current actions are intended to allow the Utility to continue to operate while the bankruptcy proceedings continue.

On January 10, 2001, the Utility suspended the payment of its fourth quarter 2000 common stock dividend of $109 million, declared in October 2000, to PG&E Corporation and its wholly owned subsidiary PG&E Holdings, LLC Until its financial condition is restored, the Utility is precluded from paying common stock dividends to PG&E Corporation and PG&E Holdings, LLC In addition, the Utility's Board of Directors did not declare the regular preferred stock dividends for the three-month period ended January 31, 2001, or for the three-month period ended April 30, 2001. Dividends on all Utility preferred stock are cumulative. Until cumulative dividends on preferred stock are paid, the Utility may not pay any dividends on its common stock, nor may the Utility repurchase any of its common stock.

In July 2001, the Bankruptcy Court granted a motion that the Utility had filed requesting that the court extend until December 6, 2001, the period during which the Utility has the exclusive right to file a plan of reorganization in its Chapter 11 case. Under the

normal timeline, the exclusivity period would have ended on August 6, 2001, 120 days after the Utility's April 6, 2001, Chapter 11 filing. The Utility filed for an extension of the exclusivity period in the event that additional time is needed to continue discussions with creditors and to develop and file a comprehensive and feasible plan of reorganization. The Bankruptcy Court may confirm a plan of reorganization only upon making certain findings required by the Bankruptcy Code, and a plan may be confirmed over the dissent of non-accepting creditors and equity security holders if certain requirements of the Bankruptcy Code are met. The payment rights and other entitlements of pre-petition creditors and the Utility's shareholders may be substantially altered by any plan of reorganization confirmed by the Bankruptcy Court. Although it is the Utility's intent to pay all valid claims, pre- petition creditors may receive, under a plan, less than 100% of the face value of their claims, and the interests of the Utility's equity security holders may be affected. A plan of reorganization could materially change the amounts and classification reported in the consolidated financial statements.

The Utility is not able at this time to predict the outcome of its bankruptcy case, the terms and provisions of any plan of reorganization, or the effect of the Chapter 11 reorganization process on the claims of the creditors of the Utility or the interests of the Utility's equity security holders. However, the Utility believes, based on information presently available to it, that cash available from operations will provide sufficient liquidity to allow it to continue as a going concern for the foreseeable future.

NOTE 4: PRICE RISK MANAGEMENT

PG&E Corporation's net gain (loss) on trading contracts for the three- and six-month periods ended June 30, 2001 are $93 million and $121 million, respectively.

PG&E Corporation's and the Utility's ineffective portion of changes in fair values of cash flow hedges are immaterial for the three- and six-month periods ended June 30, 2001. PG&E Corporation's and the Utility's estimated net derivative gains or losses included in accumulated other comprehensive income (loss) at June 30, 2001 that are expected to be reclassified into earnings within the next twelve months are net losses of $59 million and $38 million, respectively. The actual amounts reclassified from accumulated other comprehensive income (loss) to earnings can differ as a result of market price changes. PG&E Corporation expects approximately $20 million of these net derivative losses to be offset when the items being hedged are recognized in earnings.

The schedule below summarizes the activities affecting accumulated other comprehensive loss from derivative instruments for the three- and six-month periods ended June 30, 2001.

	Three months ended June 30, 2001	Six months end June 30, 200
	PG&E	PG&E

(in millions)	Corporation	Utility	Corporation	Uti
Beginning derivative gains (losses) included in accumulated other comprehensive income (loss)	$(315)	$(52)	$(243)	$
Net gain (loss) of current period hedging transactions	178	(8)	149	
Net gain (loss) reclassified to earnings	31	19	(12)	(1
Ending derivative gains (losses) included in accumulated other comprehensive income (loss)	(106)	(41)	(106)	(
Foreign currency translation adjustment	(3)	(1)	(3)	
Ending accumulated other comprehensive income (loss) at June 30, 2001	$(109)	$(42)	$(109)	$(

Credit Risk

The use of financial instruments to manage the risks associated with changes in energy commodity prices creates exposure resulting from the possibility of nonperformance by counterparties pursuant to the terms of their contractual obligations. The counterparties associated with the instruments in PG&E Corporation's and the Utility's portfolio consist primarily of investor-owned and municipal utilities, energy trading companies, financial institutions, and oil and gas production companies. PG&E Corporation and the Utility minimize credit risk by dealing primarily with creditworthy counterparties in accordance with established credit approval practices and limits. PG&E Corporation assesses the financial strength of its counterparties at least quarterly and requires that counterparties post security in the forms of cash, letters of credit, corporate guarantees of acceptable credit quality, or eligible securities if current net receivables and replacement cost exposure exceed contractually specified limits.

PG&E Corporation experienced a loss of approximately $9 million and $34 million due to the nonperformance of counterparties during the three- and six-month periods ended June 30, 2001, respectively. Counterparties considered to be investment grade or higher comprise 84% of the total credit exposure. At June 30, 2001, PG&E Corporation's and the Utility's gross credit risk exposure amounted to $1.1 billion and $142 million, respectively.

NOTE 5: UTILITY OBLIGATED MANDATORILY REDEEMABLE PREFERRED SECURITIES OF TRUST HOLDING SOLELY UTILITY SUBORDINATED DEBENTURES

The Utility, through its wholly owned subsidiary, PG&E Capital I (Trust), has outstanding 12 million shares of 7.90% Cumulative Quarterly Income Preferred Securities (QUIPS), with an aggregate liquidation value of $300 million. Concurrent with the issuance of the QUIPS, the Trust issued to the Utility 371,135 shares of common securities with an aggregate liquidation value of $9 million. The Trust in turn used the net proceeds from the QUIPS offering and issuance of the common stock securities to purchase subordinated debentures issued by the Utility with a face value of $309 million, due 2025. These subordinated debentures are the only assets of the Trust. Proceeds from the sale of the subordinated debentures were used to redeem and repurchase higher- cost preferred stock.

The Utility's guarantee of the QUIPS, considered together with the other obligations of the Utility with respect to the QUIPS, constitutes a full and unconditional guarantee by the Utility of the Trust's contractual obligations under the QUIPS issued by the Trust. The subordinated debentures may be redeemed at the Utility's option beginning in 2000 at par value plus accrued interest through the redemption date. The proceeds of any redemption will be used by the Trust to redeem QUIPS in accordance with their terms.

Upon liquidation or dissolution of the Utility, holders of these QUIPS would be entitled to the liquidation preference of $25 per share plus all accrued and unpaid dividends thereon to the date of payment.

On March 16, 2001, the Utility deferred quarterly interest payments on the Utility's 7.90% Deferrable Interest Subordinated Debentures, Series A, due 2025, until further notice in accordance with the indenture. The corresponding quarterly payments on the 7.90% QUIPS, issued by the Trust due on April 2, 2001, have been similarly deferred. Distributions can be deferred up to a period of five years under the terms of the indenture. Per the indenture, investors will accumulate interest on the unpaid distributions at the rate of 7.90%.

On April 12, 2001, Bank One, N.A., as successor-in-interest to The First National Bank of Chicago, gave notice that an Event of Default exists under the Trust Agreement in that the Utility on April 6, 2001 filed a voluntary petition for relief under Chapter 11 of the Bankruptcy Code. Pursuant to the Trust Agreement, the bankruptcy filing by the Utility constitutes an Early Termination Event. The Trust Agreement directs that upon the occurrence of an Early Termination Event, the Trust shall be liquidated by the Trustees as expeditiously as the Trustees determine to be possible by distributing, after satisfaction of liabilities to creditors of the Trust, to each Security holder a like amount of the Utility's 7.90% Deferrable Interest Subordinated Debentures, Series A, due 2025.

NOTE 6: COMMITMENTS AND CONTINGENCIES

Nuclear Insurance

The Utility has insurance coverage for property damage and business interruption losses as a member of Nuclear Electric Insurance Limited (NEIL). Under this insurance, if a nuclear generating facility suffers a loss due to a prolonged accidental outage, the Utility may be subject to maximum retrospective assessments of $12 million (property damage) and $4 million (business interruption), in each case per policy period, in the event losses exceed the resources of NEIL.

The Utility has purchased primary insurance of $200 million for public liability claims resulting from a nuclear incident. The Utility has secondary financial protection, which provides an additional $9.3 billion in coverage, which is mandated by federal legislation. It provides for loss sharing among utilities owning nuclear generating facilities if a costly incident occurs. If a nuclear incident results in claims in excess of $200 million, then the Utility may be assessed up to $176 million per incident, with payments in each year limited to a maximum of $20 million per incident.

Workers' Compensation Security

On May 9, 2001, the Department of Industrial Relations approved the Utility's security deposit of approximately $401 million in collateral provided by surety bonds, providing backing for the Utility's status as a self-insured for workers' compensation. This represents a decrease of approximately $55 million in security from the previous year, reflecting a reduction in estimates of

workers' compensation obligations. These bonds are backed up by an indemnity at the PG&E Corporation level.

The Utility has for several years utilized surety bonds as its method of providing security (other forms of acceptable security include LOC's, cash, or securities.) In February 2001, several of the surety bonds provided cancellation notices, citing concerns about the Utility's financial situation. However, under the state-developed bond form, the canceling sureties are not released of their obligation for workers' compensation claims occurring before the effective date of the cancellation until released by the State.

The State has continued to apply the canceled bond amounts totaling $185 million towards the $401 million requirement. The Utility was able to supplement the difference through three additional active surety bonds totaling $216 million. This cancellation has not, to date, impacted the Utility's self-insured status under California law, or its ability to meet current plan obligations.

Environmental Remediation

Utility

The Utility may be required to pay for environmental remediation at sites where it has been or may be a potentially responsible party under the Comprehensive Environmental Response, Compensation, and Liability Act, and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites, and sites used by it for the storage or disposal of potentially hazardous materials. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances, even if it did not deposit those substances on the site.

The Utility records an environmental remediation liability when site assessments indicate remediation is probable and a range of reasonably likely clean-up costs can be estimated. The Utility reviews its remediation liability quarterly for each identified site. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring, and site closure. The remediation costs also reflect (1) current technology, (2) enacted laws and regulations, (3) experience gained at similar sites, and (4) the probable level of involvement and financial condition of other potentially responsible parties. Unless there is a better estimate within the range of possible costs, the Utility records these costs at the lower end of this range.

As of June 30, 2001, the Utility expects to spend $306 million for hazardous waste remediation costs at identified sites, including divested fossil-fueled power plants. The cost of the hazardous substance remediation ultimately undertaken by the Utility is difficult to estimate. A change in estimate may occur in the near term due to uncertainty concerning the Utility's responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives. If other potentially responsible parties are not financially able to contribute to these costs or further investigation indicates that the extent of contamination or necessary remediation is greater than anticipated, the Utility could spend as much as $459 million on these costs. The Utility estimates the upper limit of the range using assumptions least favorable to the Utility, based upon a range of reasonably possible outcomes. Costs may be higher if the Utility is found to be responsible for clean-up costs at additional sites or expected outcomes change.

The Utility had an environmental remediation liability of $306 million and $320 million at June 30, 2001 and December 31, 2000, respectively. The $306 million accrued at June 30, 2001 includes (1) $139 million related to the pre-closing remediation liability, associated with the divested generation facilities discussed further in the "Generation Valuation" section of Note 2, and (2) $167 million related to remediation costs for those generation facilities that the Utility still owns, manufactured gas plant sites, and gas gathering compressor stations. Of the $306 million environmental remediation liability, the Utility has recovered $139 million through rates, and expects to recover another $86 million in future rates. The Utility is seeking recovery of the remainder of its costs from insurance carriers and from other third parties as appropriate.

On June 28, 2001 the Bankruptcy Court entered its "Order on Debtor's Motion for Authority to Continue Its Hazardous Substances Cleanup Program." The Utility is authorized to expend (1) up to $22 million in each calendar year in which this Chapter 11 case is pending to continue its hazardous substance remediation programs and procedures, and (2) any additional amounts necessary in emergency situations involving post-petition releases or threatened releases of hazardous substances, if such excess expenditures are necessary in the Utility's reasonable business judgment to prevent imminent harm to public health and safety or the environment (provided that the Utility seeks the Court's approval of such emergency expenditures at the earliest practicable time), in each case as described in the motion.

In December 1999, the Utility was notified by the purchaser of its former Moss Landing power plant that it had identified a cleaning procedure used at the plant that released heated water from the intake, and that this procedure is not specified in the plant's National Pollutant Discharge Elimination System (NPDES) permit issued by the Central Coast Regional Water Quality Control Board (Central Coast Board). The purchaser notified the Central Coast Board of its findings. In March 2000, the Central Coast Board requested the Utility to provide specific information regarding the "backflush" procedure used at Moss Landing. The

Utility's investigation indicated that while it owned Moss Landing, significant amounts of water were discharged from the cooling water intake. While the Utility's investigation did not clearly indicate that discharged waters had a temperature higher than ambient receiving water, the Utility believes that the temperature of the discharged water was higher than that of the ambient receiving water. In December 2000, the executive officer of the Central Coast Board made a settlement proposal to the Utility under which it would pay $10 million, a portion of which would be used for environmental projects and the balance of which would constitute civil penalties. Settlement negotiations are continuing.

The Utility's Diablo Canyon employs a "once through" cooling water system, which is regulated under a NPDES Permit, issued by the Central Coast Board. This permit allows Diablo Canyon to discharge the cooling water at a temperature no more than 22 degrees above ambient receiving water, and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, 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 (CDO) alleging that, although the temperature limit has never been exceeded, the Diablo Canyon's discharge was not protective of beneficial uses. In October 2000, the Central Coast Board and the Utility reached a tentative settlement of this matter pursuant to which the Central Coast Board has agreed to find that the Utility's discharge of cooling water from the Diablo Canyon plant protects beneficial uses and that the intake technology reflects the "best technology available", under Section 316(b) of the Federal Clean Water Act. As part of the settlement, the Utility will take measures to preserve certain acreage north of the plant and will fund approximately $4.5 million in environmental projects related to coastal resources. The parties are negotiating the documentation of the settlement. The final agreement will be subject to public comment and will be incorporated in a consent decree to be entered in California's Superior Court.

PG&E Corporation believes the ultimate outcome of these matters will not have a material impact on its or the Utility's financial position or results of operations.

PG&E National Energy Group

The U.S. Environmental Protection Agency ("EPA") has been conducting a nationwide enforcement investigation regarding the historical compliance of coal-fueled electric generating stations with various permitting requirements of the Clean Air Act. Specifically, the EPA and the U.S. Department of Justice have recently initiated enforcement actions against a number of electric utilities, several of which have entered into substantial settlements for alleged Clean Air Act violations related to modifications (sometimes more than 20 years ago) of existing coal-fired generating facilities. In May 2000, PG&E NEG received a request for information seeking detailed operating and maintenance histories for the Salem Harbor and Brayton Point power plants and, in November 2000, the EPA visited both facilities. PG&E NEG believes this request for information is part of the EPA's industry-wide investigation of coal-fired power plants' compliance with the Clean Air Act requirements governing plant modifications. PG&E NEG also believes that any changes it made to these plants were routine maintenance or repair and, therefore, did not require permits. The EPA has not issued a notice of violation or filed any enforcement action against PG&E NEG at this time. Nevertheless, if the EPA disagrees with PG&E NEG's conclusions with respect to the changes PG&E NEG made at the facilities, and successfully brings an enforcement action against PG&E NEG, then penalties may be imposed and further emission reductions might be necessary at these plants.

From time to time various states in which our facilities are located consider the adoption of air emissions standards that may be more stringent than those imposed by EPA. On May 11, 2001, the Massachusetts Department of Environmental Protection (DEP) issued regulations imposing new restrictions on emissions of NOx and SO2, mercury and carbon dioxide from existing coal-fired power plants. These restrictions will impose more stringent annual and monthly limits on NOx and SO2 emissions than currently exist and will take effect in stages, beginning in October 2004 if no permits are needed for the changes necessary to comply, and beginning in 2006 if such permits are needed. DEP has informed PG&E NEG that, based upon its current understanding of the facilities' plans for compliance with the new regulations, it believes that permits will be needed and that the initial compliance date will therefore be 2006. However, the need for permits triggers an obligation to meet Best Available Control Technology, or BACT, requirements. Compliance with BACT at the facilities could require implementation of controls beyond those otherwise necessary to meet the emissions standards in the new regulations. Mercury emissions are capped as a first step and must be reduced by October 2006 pursuant to standards to be developed. Carbon dioxide emissions are regulated for the first time and must be reduced from recent historical levels. PG&E NEG believes that compliance with the carbon dioxide caps can be achieved through implementation of a number of strategies, including sequestrations and offsite reductions. Various testing and recordkeeping requirements are also imposed.

By 2002, PG&E NEG plans to have approximately 5,100 MW of generating capacity in operation in New England. The new Massachusetts regulations affect primarily its

Brayton Point and Salem Harbor generating facilities, representing approximately 2,300 MW. Through 2006, it may be necessary to spend approximately $265 million to comply with these regulations. In addition, with respect to approximately 600 MW (or about 12%) of PG&E NEG's New England capacity, PG&E NEG may need to implement fuel conversion, limit operations, or install additional environmental controls. These new regulations require that

PG&E NEG achieve specified emission levels earlier than the dates included in a previous Massachusetts initiative to which it had agreed.

The Federal Clean Water Act generally prohibits the discharge of any pollutants, including heat, into any body of surface water, except in compliance with a discharge permit issued by a state environmental regulatory agency and/or EPA. All of the facilities that are required to have such permits either have them or have timely applied for extensions of expired permits and are operating in substantial compliance with the prior permit. At this time, three of the fossil-fuel plants owned and operated by PG&E NEG's affiliate USGen New England, Inc. (Manchester Street, Brayton Point and Salem Harbor stations) are operating pursuant to permits that have expired. For the facilities whose NPDES permits have expired, permit renewal applications are pending, and we anticipate that all three facilities will be able to continue to operate in substantial compliance with prior permits until new permits are issued. It is estimated that USGen New England's cost to comply with new permit conditions could be approximately $60 million through 2005. It is possible that the new permits may contain more stringent limitations than the prior permits.

PG&E NEG anticipates spending up to approximately $330 million, net of insurance proceeds, through 2006 for environmental compliance at currently operating facilities, which primarily addresses: (a) new Massachusetts air regulations made public on April 23, 2001 affecting the Brayton Point and Salem Harbor Stations; (b) wastewater permitting requirements that may apply to the Brayton Point, Salem Harbor and Manchester Street Stations; and (c) requirements, to which we agreed, that are reflected in a consent decree concerning wastewater treatment facilities at the Salem Harbor and Brayton Point Stations.

During April 2000, an environmental group served an affiliate of PG&E NEG, USGen New England, Inc., and other of its subsidiaries with a notice of its intent to file a citizen's suit under RCRA. The group stated that it planned to allege that USGen New England, as the generator of fossil fuel combustion wastes at Salem Harbor and Brayton Point, has contributed and is contributing to the past and present handling, storage, treatment and disposal of wastes at those facilities which may present an imminent and substantial endangerment to the public health or the environment. During September 2000, USGen New England signed a series of agreements with the Massachusetts DEP and the environmental group that address and resolve these matters. The agreements, which have been filed in federal court and are now incorporated in a consent decree, require, among other things, that USGen New England alter its existing wastewater treatment facilities at both facilities by replacing certain unlined treatment basins, submit and implement a plan for the closure of such basins, and perform certain environmental testing at the facilities. Although the outcome of such environmental testing could lead to higher costs, the total cost of these activities is expected to be approximately $21 million, and they are underway.

LEGAL MATTERS

Utility

The Utility's Chapter 11 bankruptcy on April 6, 2001, discussed in Note 3 automatically stayed the litigation described below against the Utility.

Chromium Litigation

Several civil suits are pending against the Utility in California State Court. The suits seek an unspecified amount of compensatory and punitive damages for alleged personal injuries resulting from alleged exposure to chromium in the vicinity of the Utility's gas compressor stations at Hinckley, Kettleman, and Topock, California. Currently, there are claims pending on behalf of approximately 1,160 individuals.

The Utility is responding to the suits and asserting affirmative defenses. The Utility will pursue appropriate legal defenses, including statute of limitations, exclusivity of worker's compensation laws, and factual defenses, including lack of exposure to chromium and the inability of chromium to cause certain of the illnesses alleged. The Utility has recorded a legal reserve in its financial statements in the amount of $160 million for these matters. PG&E Corporation and the Utility believe that, after taking into account the reserves recorded as of December 31, 2000, the ultimate outcome of this matter will not have a material adverse impact on PG&E Corporation's or the Utility's financial condition or future results of operations.

Wilson vs. PG&E Corporation and Pacific Gas and Electric Company

On February 13, 2001, two complaints were filed against PG&E Corporation and the Utility in the Superior Court of the State of California, San Francisco County: Richard D. Wilson v. Pacific Gas and Electric Company, et al. (Wilson I), and Richard D. Wilson v. Pacific Gas and Electric Company, et al. (Wilson II).

In Wilson I, the plaintiff alleges that in 1998 and 1999, PG&E Corporation violated its fiduciary duties and California Business and Professions Code Section 17200 by causing the Utility to repurchase shares of the Utility's common stock from PG&E

Corporation at an aggregate price of $2,326 million. The complaint alleges an unlawful business act or practice under Section 17200 because these repurchases allegedly violated PG&E Corporation's fiduciary duties, a first priority capital requirement allegedly imposed by the CPUC's decision approving the formation of a holding company, and also an implicit public trust imposed by AB 1890, which granted authority for the issuance of rate reduction bonds. The complaint seeks to enjoin the repurchase by the Utility of any more of its common stock from PG&E Corporation or other entities or persons unless good cause is shown, and seeks restitution from PG&E Corporation of $2,326 million, with interest, on behalf of the Utility. The complaint also seeks an accounting, costs of suit, and attorney's fees.

In Wilson II, the plaintiff alleges that PG&E Corporation, the Utility, and other subsidiaries have been parties to a tax-sharing arrangement under which PG&E Corporation annually files consolidated federal and state income tax returns for, and pays, the income taxes of PG&E Corporation and participating subsidiaries. According to the plaintiff, between 1997 and 1999, PG&E Corporation collected $2,957 million from the Utility under this tax-sharing agreement. Plaintiff alleges that these monies were held under an express and implied trust to be used by PG&E Corporation to pay the Utility's share of income taxes under the tax-sharing arrangement. Plaintiff alleges that PG&E Corporation overcharged the Utility $663 million under the tax-sharing arrangement and has declined voluntarily to return these monies to the Utility, in violation of the alleged trust, the alleged first priority capital condition, and California Business and Professions Code Section 17200. The complaint seeks to enjoin PG&E Corporation from engaging in the activities alleged in the complaint (including the tax-sharing arrangement), and seeks restitution from PG&E Corporation of $663 million, with interest, on behalf of the Utility. The complaint also seeks an accounting, costs of suit, and attorney's fees.

PG&E Corporation's and the Utility's analysis of these complaints is at a preliminary stage, but PG&E Corporation and the Utility believe them to be without merit and intend to present a vigorous defense. The Utility filed notice of automatic stay on April 11, 2001, pursuant to the Bankruptcy Code. On April 19, 2001, the court signed stipulations between PG&E Corporation and plaintiffs to stay all proceedings in the cases as against PG&E Corporation. PG&E Corporation and the Utility are unable to predict whether the outcome of this litigation, if it were to proceed, will have a material adverse effect on their financial condition or results of operation.

Federal Securities Lawsuit

A complaint, Gillam, et al v. PG&E Corporation and Pacific Gas and Electric Company, et al, is pending in the U.S. District Court for the Northern District of California. The complaint alleges that PG&E Corporation and the Utility violated federal securities laws, generally accepted accounting principles, and other regulations or accounting rules, by issuing allegedly false and misleading financial statements in the second and third quarters of 2000, reporting net income of $753 million for the nine-month period ending September 30, 2000, instead of an alleged net loss for that period of up to $2.1 billion. According to the complaint, defendants failed to properly account in the second and third quarters of 2000 for alleged under-collected power purchase costs and PG&E Corporation announced in March 2001 that it intended to take a $4.1 billion write-off. Plaintiff purports to bring the action individually and on behalf of a class of individuals who purchased PG&E Corporation's common stock during the period from June 1, 2000, to March 31, 2001, claiming that the alleged misrepresentations caused them to pay inflated prices for the stock. Plaintiff seeks damages in excess of $2.4 billion, punitive damages, interest, injunctive relief, and attorneys' fees.

The complaint was filed after the Utility filed for reorganization under Chapter 11 of the U.S. Bankruptcy Code. The Utility informed plaintiff that the action is stayed by the automatic stay provisions of the Bankruptcy Code and on or about April 23, 2001, plaintiff filed a notice of voluntary dismissal without prejudice with respect to the Utility.

Analysis of the complaint by PG&E Corporation is at a preliminary stage, but PG&E Corporation believes the allegations to be without merit and intends to present a vigorous defense. PG&E Corporation is unable to predict whether the outcome of this litigation will have a material adverse effect on its financial condition or results of operations.

PG&E National Energy Group

PG&E NEG is involved in various litigation matters in the ordinary course of its business. PG&E NEG is not currently involved in any litigation that is expected, either individually or in the aggregate, to have a material adverse effect on financial condition or results of operations of PG&E Corporation.

Recorded Liability for Legal Matters

In accordance with SFAS No. 5 "Accounting for Contingencies," PG&E Corporation makes a provision for a liability when both it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. These provisions are reviewed quarterly and adjusted to reflect the impacts of negotiations, settlements, rulings, advice of legal counsel, and other information and events pertaining to a particular case. The following table reflects the current year's activity to the recorded liability for legal matters:

(in millions)	PG&E Corporation and Utility
Beginning balance, January 1, 2001	$185
Provisions for liabilities	4
Payments	(2)
Adjustments	(3)
Ending balance, June 30, 2001	$184

NOTE 7: SEGMENT INFORMATION

PG&E Corporation has identified three reportable operating segments, which were determined based on similarities in economic characteristics, products and services, types of customers, methods of distributions, the regulatory environment, and how information is reported to PG&E Corporation's key decision makers. As discussed below, these segments represent a change in the reportable segments. In accordance with accounting principles generally accepted in the United States of America, prior year segment information has been restated to conform to the current segment presentation. The Utility is one reportable operating segment and the other two are part of PG&E NEG. These three reportable operating segments provide products and services and are subject to different forms of regulation or jurisdictions. PG&E Corporation's reportable segments are described below.

Utility

PG&E Corporation's Northern and Central California energy utility subsidiary, the Utility, provides natural gas and electric service to its customers.

PG&E National Energy Group

PG&E Corporation's subsidiary, PG&E NEG is an integrated energy company with a strategic focus on power generation, power plant development, natural gas transmission, and wholesale energy marketing and trading in North America. PG&E NEG has integrated its generation, development and energy marketing and trading activities to increase the returns from its operations, identify and capitalize on opportunities to increase its generating and pipeline capacity, create energy products in response to dynamic markets and manage risks. The newly combined business has been renamed PG&E Integrated Energy and Marketing (PG&E Energy), which includes PG&E Generating Company, LLC and its affiliates, PG&E Energy Trading Holdings Corporation which owns PG&E Energy Trading-Power, L.P., PG&E Energy Trading-Gas Corporation, and their affiliates, and PG&E Interstate Pipeline Operations (PG&E Pipeline), which includes PG&E Gas Transmission Corporation and its affiliates which includes PG&E Gas Transmission Northwest(PG&E GTN), PG&E Gas Transmission, Texas Corporation, and PG&E Gas Transmission Teco, Inc., and their subsidiaries. During the fourth quarter of 2000, PG&E NEG sold its Texas natural gas and natural gas liquids business operated through PG&E Gas Transmission, Texas Corporation and PG&E Gas Transmission Teco, Inc. and their subsidiaries. Also during 2000, PG&E NEG sold its energy services unit, PG&E Energy Services Corporation.

Segment information for the three and six months ended June 30, 2001, and 2000 was as follows:

		PG&E National Energy Group			
(in millions)	Utility	Total NEG	Integrated Energy and Marketing	Interstate Pipeline Operations	NEG Elimination
Three months ended June 30, 2001					
Operating revenues	$ 2,305	$2,705	$ 2,637	$ 55	$ 13
Intersegment revenues (1)	4	48	39	9	-
Total operating revenues	2,309	2,753	2,676	64	13
Net Income (Loss)	696	71	53	19	(1)
Three months ended June 30, 2000(4)					
Operating revenues	2,293	3,344	3,085	267	(8)
Intersegment revenues(1)	3	17	4	13	-
Total operating revenues	2,296	3,361	3,089	280	(8)
Net income	216	32	18	13	1
Six months ended June 30, 2001					
Operating revenues	4,865	6,818	6,703	111	4
Intersegment revenues (1)	6	141	123	18	-
Total operating revenues	4,871	6,959	6,826	129	4
Net Income (Loss)	(304)	125	88	38	(1)
Total assets at June 30, 2001(3)	23,216	12,990	11,343	1,172	475
Six months ended June 30, 2000(4)					
Operating revenues	4,507	6,132	5,594	537	1
Intersegment revenues (1)	7	55	30	25	-
Total operating revenues	4,514	6,187	5,624	562	1
Net Income (Loss)	444	84	56	27	1
Total assets at June 30, 2000(3)	$22,124	$9,685	$ 7,290	$2,080	$315

(1) Inter-segment electric and PG&E gas revenues are recorded at market prices, which for the Utility and PG&E Pipeline are tariffed rates prescribed by the CPUC and the FERC, respectively.

(2) Includes PG&E Corporation, Pacific Venture Capital, and elimination entries.

(3) Assets of PG&E Corporation are included in "Other & Eliminations" column exclusive of investment in its subsidiaries.

(4) Segment information for the prior year has been restated for comparative purposes as required by SFAS No. 131.

NOTE 8: LONG-TERM DEBT

During 2000 and 1999, two indirect wholly owned subsidiaries of PG&E NEG entered into two commitments relating to the acquisition of turbine equipment and two commitments relating to generation projects that are under construction, for which they act as the construction agent for the owners. Upon completion of the construction projects, expected to be in 2002, PG&E NEG will lease these facilities under lease terms of five years and three years, respectively. At the conclusion of each of these lease terms, PG&E NEG has the option to extend the leases at fair market value, purchase the projects, or act as remarketing agent for the lessors for sales to third parties. If PG&E NEG elects to remarket the projects, then PG&E NEG would be obligated to the lessors for up to 85 percent of the project costs if the proceeds are deficient to pay the lessor's investors. PG&E Corporation has committed to fund up to $604 million in the aggregate of equity to support PG&E NEG's obligation to the lessors during the construction and post-construction periods. In addition, PG&E NEG entered into operative agreements with a special purpose entity that will own and finance construction of another facility totaling $775 million. PG&E Corporation has committed to fund up to $122 million of equity support commitments to meet the obligations to the entity. PG&E NEG is attempting to replace PG&E Corporation's equity support commitments with substitute commitments of PG&E NEG. The trusts holding the assets and debt related to these facilities has been consolidated in the accompanying financial statements.

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NOTE 9: REVISION FOOTNOTE

Subsequent to the issuance of PG&E Corporation's December 31, 2000, March 31, 2001, and June 30, 2001 Consolidated Financial Statements, management determined that the assets and liabilities relating to certain leases should have been consolidated. The facilities associated with the leases were under construction during 1999, 2000, and 2001. A summary of the significant effects of the revisions to the Condensed Statements of Consolidated Operations, Condensed Consolidated Balance Sheets, and Condensed Statements of Consolidated Cash Flows are as follows:

	As Previously Reported	As Revised	As Previo Repo
	Three months ended June		
	2001		
Condensed Statements of Consolidated Operations:			
Total Operating Revenues	$ 5,013	$ 5,010	$
Total Operating Expenses	3,566	3,563	

	Six months ended		
	2001		
Total Operating Revenues	$11,688	$11,683	$1
Total Operating Expenses	11,581	11,576	

	Balance at		
Condensed Consolidated Balance Sheets:	June 30, 2001		
Cash and cash equivalents	$ 683	$ 726	
Net accounts receivable - customers	2,894	2,895	
Property, plant and equipment - Construction work-in- progress	617	1,606	
Other noncurrent Assets	3,202	3,202	
Total Assets	35,396	36,429	3
Accounts Payable - Trade	1,198	1,273	
Other current liabilities	813	820	
Long-term debt	6,398	7,349	

	Six months ended		
Condensed Statements of Consolidated Cash Flows:	2001		
Accounts receivable - trade	$ 1,448	$ 1,445	$
Accounts payable	586	621	
Capital Expenditures	(818)	(1,102)	
Other-net, cash flow from investing activities	(247)	(115)	
Long-term debt issued	2,138	2,275	
Cash and cash equivalents at June 30	683	726	

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS

PG&E Corporation is an energy-based holding company headquartered in San Francisco, California. PG&E Corporation's Northern and Central California energy utility subsidiary, Pacific Gas and Electric Company (the Utility), delivers electric service to approximately 4.6 million customers and natural gas service to approximately 3.8 million customers. On April 6, 2001, the Utility filed a voluntary petition for relief under the provisions of Chapter 11 of the U.S. Bankruptcy Code. Pursuant to Chapter 11 of the U.S. Bankruptcy Code, the Utility retains control of its assets and is authorized to operate its business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court. The factors causing the Utility to take this action are discussed in this Management's Discussion and Analysis (MD&A) and in Notes 2 and 3 of the Notes to the Condensed Consolidated Financial Statements.

PG&E Corporation's subsidiary, PG&E National Energy Group, Inc. (PG&E NEG) is an integrated energy company with a strategic focus on power generation, power plant development, natural gas transmission and wholesale energy marketing and trading in North America. PG&E NEG has integrated its generation, development and energy marketing and trading activities to increase the returns from its operations, identify and capitalize on opportunities to increase its generating and pipeline capacity, create energy products in response to dynamic markets and manage risks. The newly combined business has been renamed PG&E Integrated

Energy and Marketing (PG&E Energy), which includes PG&E Generating Company, LLC and its affiliates, and PG&E Energy Trading Holdings Corporation which owns PG&E Energy Trading-Power, L.P., PG&E Energy Trading-Gas Corporation, and their affiliates, and PG&E Interstate Pipeline Operations (PG&E Pipeline), which includes PG&E Gas Transmission Corporation, PG&E Gas Transmission Northwest Corporation (PG&E GTN), PG&E Gas Transmission, Texas Corporation and PG&E Gas Transmission Teco, Inc. and their subsidiaries. During the fourth quarter of 2000, PG&E NEG sold its Texas natural gas and natural gas liquids business operated through PG&E Gas Transmission, Texas Corporation and PG&E Gas Transmission Teco, Inc. and their subsidiaries. Also during 2000, PG&E NEG sold its energy services unit, PG&E Energy Services Corporation.

This is a combined Quarterly Report on Form 10-Q/A of PG&E Corporation and the Utility. It includes separate consolidated financial statements for each entity. The Condensed Consolidated Financial Statements of PG&E Corporation reflect the accounts of PG&E Corporation, the Utility, and PG&E Corporation's wholly owned and controlled subsidiaries. This MD&A should be read in conjunction with the condensed consolidated financial statements included herein. Further, this quarterly report should be read in conjunction with PG&E Corporation's and the Utility's Consolidated Financial Statements and Notes to the Consolidated Financial Statements incorporated by reference in their combined 2000 Annual Report on Form 10-K/A.

Subsequent to the issuance of the PG&E Corporation's 2000 and 1999 Consolidated Financial Statements and unaudited report for the quarterly period ended June 30, 2001, management determined that the assets and liabilities relating to certain leases should have been consolidated. The facilities associated with the leases were under construction during 2001 (see Note 9).

This combined Quarterly Report on Form 10-Q/A, including this MD&A, contains forward looking statements about the future that are necessarily subject to various risk and uncertainties. In addition, PG&E Corporation expects that its net income from operations for 2001 will be in the range of $2.70-$2.75 per share. Earnings from operations exclude items impacting comparability and should not be considered an alternative to net income or an indicator of a Company's operating performance. These statements are based on current expectations and assumptions which management believes are reasonable and on information currently available to management. These forward looking statements are identified by words such as "estimates," "expects," "anticipates," "plans," "believes," and other similar expressions. Actual results could differ materially from those contemplated by the forward looking statements.

Although PG&E Corporation and the Utility are not able to predict all of the factors that may affect future results, some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or historical results include:

- the outcome of the Utility's regulatory proceedings;

- whether and to what extent the Utility is determined to be responsible for the Independent System Operator's (ISO) charges billed to the Utility;

- the extent to which more information is revealed about the recently released California Department of Water Resources' revenue requirements and the impact such revenue requirements may have on the Utility's financial condition and results of operation;

- the terms and conditions of the reorganization plan that is ultimately adopted by the Bankruptcy Court and the extent to which the Utility's bankruptcy proceedings affect the operations of PG&E Corporation's other businesses;

- the regulatory, judicial, or legislative actions (including ballot initiatives) that may be taken to meet future power needs in California, mitigate the higher wholesale power prices, provide refunds for prior power costs, or address the Utility's financial condition;

- the extent to which the Utility's under-collected wholesale power purchase costs may be collected from customers;

- any changes in the amount of transition costs the Utility is allowed to collect from its customers, and the timing of the completion of the Utility's transition cost recovery;

- future market prices for electricity and future fuel prices, which in part, are influenced by future weather conditions, the availability of hydroelectric power, and the development of competitive markets;

- the method and timing of valuation and future ratemaking for the Utility's hydroelectric and other non-nuclear generation assets;

- future operating performance at the Diablo Canyon Nuclear Power Plant (Diablo Canyon), and the future ratemaking applicable to Diablo Canyon;

- legislative or regulatory changes, including the pace and extent of the ongoing restructuring of the electric and natural gas industries across the United States;

- future sales levels and economic conditions;

- the extent to which our current or planned generation, pipeline, and storage capacity development projects of PG&E NEG, a wholly owned subsidiary of PG&E Corporation, are completed and the pace and cost of such completion; including the extent to which commercial operations of these development projects are delayed or prevented because of various development and construction riskssuch as PG&E NEG's failure to obtain financing, necessary permits or equipment, the failure of third-party contractors to perform their contractual obligations, the failure of equipment to perform as anticipated, or an inability to obtain equipment or labor on acceptable terms;

- the extent and timing of generating, pipeline, and storage capacity expansion and retirement by others;

- illiquidity in the commodity energy market and PG&E NEG's ability to provide the credit enhancements necessary to support its trading activities;

- PG&E NEG's ability to obtain financing for its planned development projects and its ability to refinance PG&E NEG's and its subsidiaries' existing indebtedness on reasonable terms;

- restrictions imposed upon PG&E NEG under certain term loans of PG&E Corporation;

- fluctuations in commodity gas, natural gas liquids, and electric prices and the ability to successfully manage such price fluctuations;

- the effect of compliance with existing and future environmental laws, regulations, and policies, the cost of which could be significant; and

- the outcome of pending litigation.

As the ultimate impact of these and other factors is uncertain, these and other factors may cause future earnings to differ materially from results or outcomes we currently seek or expect. Each of these factors is discussed in greater detail in this MD&A.

In this MD&A, we first discuss the California energy crisis and its impact on our liquidity. We then discuss statements of cash flows and financial resources, and our results of operations for the three and six-month periods ended June 30, 2001 and 2000. Finally, we discuss our competitive and regulatory environment, our risk management activities, and various uncertainties that could affect future earnings. Our MD&A applies to both PG&E Corporation and the Utility.

LIQUIDITY AND FINANCIAL RESOURCES

The California Energy Crisis

The state of California is in the midst of an energy crisis. The cost of wholesale power has risen dramatically since June 2000. Rolling blackouts have occurred as a result of a broken deregulated electricity market. Because of this crisis, PG&E Corporation and the Utility have experienced a significant deterioration in their liquidity and consolidated financial position. The Utility's credit rating has deteriorated to below investment grade level. PG&E Corporation and the Utility recognized a fourth quarter charge to earnings of $6.9 billion ($4.1 billion after tax) to reflect the fact that the Utility could no longer conclude that its generation-related regulatory assets and under-collected purchased power costs were probable of recovery from ratepayers. In addition, during the first quarter of 2001, the Utility recognized after tax charges of $1.1 billion representing under-collected power costs incurred during that period. These charges resulted in accumulated deficits at March 31, 2001, of $3 billion for both the Utility and PG&E Corporation.

As more fully discussed herein, the Utility had been working with regulators and state and federal legislators and California political leaders in an effort to seek an overall solution to the California energy crisis. However, the ongoing uncertainty as to the timing and extent of any solution, in addition to increasing debt and regulatory changes, caused the Utility to seek protection from its creditors through a Chapter 11 Bankruptcy Filing. The filing for bankruptcy protection and the related uncertainty around any reorganization plan, that is ultimately adopted, will have a significant impact on the Utility's future liquidity and results of operations. See Notes 2 and 3 of the Notes to the Condensed Consolidated Financial Statements for a detailed discussion of the California Energy Crisis and the events leading up to the charge incurred by PG&E Corporation and the Utility. A discussion of the current and future liquidity and financial resources, and mitigation efforts undertaken by the Utility and PG&E Corporation follows.

Pacific Gas and Electric Company

The California energy crisis described in Note 2 of the Notes to the Condensed Consolidated Financial Statements has had a significant negative impact on the liquidity and financial resources of the Utility. Beginning in June 2000, the wholesale price of electric power in California steadily increased to an average cost of 18.2 cents per kilowatt-hour (kWh) for the seven-month period of June 2000 through December 2000, as compared to an average cost of 4.2 cents per kWh for the same period in 1999. Under California Assembly Bill 1890 (AB 1890), the Utility's electric rates were frozen at levels that allowed approximately 5.4

cents per kWh to be charged to the Utility's customers as reimbursement for power costs incurred by the Utility on behalf of its retail customers. The excess of wholesale electricity costs above the generation-related cost component available in frozen rates resulted in an under-collection at December 31, 2000, of approximately $6.6 billion, and rose to approximately $8.5 billion by March 31, 2001.

The difference between the actual costs incurred to purchase power and the amount recovered from customers was funded through a series of borrowings. In October 2000, the Utility fully utilized its existing $1 billion revolving credit facility to support the Utility's commercial paper program and other liquidity requirements. On October 18, 2000, the Utility obtained an additional $1 billion, 364-day revolving credit facility to support the issuance of additional commercial paper. On November 1, 2000, the Utility issued $1 billion of short-term floating rate notes and $680 million of five-year notes. On November 22, 2000, the Utility issued an additional $240 million of short-term floating rate notes. On December 1, 2000, the size of the $1 billion, 364-day revolving credit facility was reduced to $850 million in order to comply with the syndication agreement. At December 31, 2000, the Utility had borrowed $614 million against its five-year revolving credit agreement, had issued $1,225 million of commercial paper, and had issued $1,240 million of floating rate notes.

In response to the growing crisis, on January 4, 2001, the California Public Utilities Commission (CPUC) approved an interim 1.0 cent per kWh rate increase, which would raise approximately $70 million in cash per month for three months. Even if all this cash had been available to the Utility immediately, $210 million represented approximately one week's worth of net power purchases at the then-current prices. Thus, the rate increase did not raise enough cash for the Utility to pay its ongoing wholesale electric energy procurement bills or make further borrowing possible.

On January 10, 2001 the Board of Directors of the Utility suspended the payment of its fourth quarter 2000 common stock dividend in an aggregate amount of $110 million payable on January 18, 2001, to PG&E Corporation and PG&E Holdings, LLC, a wholly owned subsidiary of the Utility. In addition, the Utility's Board of Directors decided not to declare the regular preferred stock dividends for the three-month period ended January 31, 2001, normally payable on February 15, 2001. Dividends on all Utility preferred stock are cumulative. Until cumulative dividends on preferred stock are paid, the Utility may not pay any dividends on its common stock, nor may the Utility repurchase any of its common stock.

On January 16 and 17, 2001, the outstanding bonds of the Utility were downgraded to below-investment grade status. Standard and Poor's (S&P) stated that the downgrade reflected the heightened probability of the Utility's imminent insolvency and the

resulting negative financial implications for the PG&E Corporation and affiliated companies because, among other reasons, (1) some of the Utility's principal trade creditors were demanding that sizeable cash payments be made as a pre-condition for the purchase of natural gas and electric power necessary for on-going business operations; (2) neither legislative nor negotiated solutions to the California utilities' financial situation appeared to be forthcoming in a timely manner, which continued to impede access to financial markets for the working capital needed to avoid insolvency; and (3) Southern California Edison's (SCE) decision to default on its obligation to pay principal and interest due on January 16, 2001, diminished the prospects for the Utility's access to capital markets.

This downgrade to below investment grade status was an event of default under one of the Utility's revolving credit facilities and precluded the Utility from additional access to the capital markets. As a result, the banks stopped funding under the revolving credit facility. On January 17, 2001, the Utility began to default on maturing commercial paper obligations. In addition, the Utility was no longer able to meet its obligations to generators, qualifying facilities (QFs), the ISO, and Power Exchange (PX), and began making partial payments of amounts owed.

After the downgrade, the PX notified the Utility that the ratings downgrade required the Utility to post collateral for all transactions in the PX day-ahead market. Since the Utility was unable to post such collateral, the PX suspended the Utility's trading privileges effective January 19, 2001, in the day-ahead market. The PX also sought to liquidate the Utility's block-forward contracts for the purchase of power. In February 2001, California Governor Gray Davis, acting under California's Emergency Services Act, commandeered the contracts valued at $243 million for the benefit of the state. Under the Act, the state must pay the Utility the reasonable value of the contracts, although the PX may seek to recover the monies that the Utility owes to the PX from any proceeds realized from those contracts. Discussions and negotiations on this issue are currently ongoing between the state and the Utility. The Utility has recently filed a complaint against the state to recover the value of the seized contracts.

On January 19, 2001, the Utility was no longer able to continue purchasing power for its customers because of lack of creditworthiness and the state of California authorized the DWR to purchase electricity for the Utility's customers. Assembly Bill 1X (AB 1X) was passed on February 1, 2001, authorizing the DWR to enter into contracts for the purchase and sale of electric power and to issue revenue bonds to finance electricity purchases. The DWR has entered into long-term contracts with several generators for the supply of electricity. However, it continues to purchase amounts of power on the spot market at prevailing market prices.

As previously stated, beginning in June 2000, the Utility experienced unanticipated and massive increases in the wholesale costs of the electricity purchased from the PX and ISO on behalf of its retail customers. The Utility believes that since it has not met the creditworthiness standards under the ISO's tariff since early January 2001, the Utility should not be responsible for the ISO's purchases made to meet the Utility's net open position. (The net open position is the amount of power needed by retail electric customers that cannot be met by utility-owned generation or power under contract to the utilities.) On February 14, 2001, the Federal Energy Regulatory Commission (FERC) ordered that the ISO could only buy power on behalf of creditworthy entities. The FERC order also stated that the ISO could continue to schedule power for the Utility as long as it comes from its own generation units and is routed over its own transmission lines. Despite the FERC orders, the ISO continued to bill the Utility for the ISO's wholesale power purchases. On April 6, 2001, the FERC issued a further order directing the ISO to implement its prior order, which the FERC clarified, applies to all third-party transactions whether scheduled or not. In light of the FERC's April 6, 2001 order, the Utility has not recorded any such estimated ISO charges after April 6, 2001, except for the ISO's grid management charge, although the Utility has accrued the full amount of the ISO charges up to April 6, 2001 in the accompanying financial statement. On June 13, 2001, the FERC denied the ISO's request for rehearing of its April 6, 2001 order.

The Utility has filed a complaint in Bankruptcy Court against the ISO to prohibit the ISO from continuing to bill the Utility for the ISO's wholesale power purchases, unless and until the Utility is permitted to recover the costs of such power purchases through retail electric rates. On June 26, 2001, the

Bankruptcy Court issued a preliminary injunction prohibiting the ISO from charging the Utility for the ISO's wholesale power purchases made in violation of bankruptcy law, the ISO's tariff, and the FERC's February 14 and April 6, 2001 orders. In issuing the injunction, the Bankruptcy Court noted that the FERC orders permit the ISO to schedule transactions that involve either a creditworthy buyer or a creditworthy counterparty, but noted the existence of unresolved issues regarding how to ensure these creditworthiness requirements for real-time transactions and emergency dispatch orders issued by the ISO to power sellers. The Utility believes that its only responsibility for third party power delivered to its customers is to pay the DWR the amount collected from customers, whether the third party power is purchased by a creditworthy buyer or whether the purchase is facilitated by a creditworthy counterparty.

As a result of (1) the failure, at the time of filing, by the state to assume the full procurement responsibility for the Utility's net open position, as was provided under AB 1X, (2) the negative impact of recent actions by the CPUC that created new payment obligations for the Utility and undermined its ability to return to financial viability, (3) a lack of progress in negotiations with the state to provide a solution for the energy crisis, and (4) the adoption by the CPUC of an illegal and retroactive accounting change that would appear to eliminate the Utility's true under-collected purchased power costs, the Utility filed a voluntary petition for

relief under provisions of Chapter 11 of the U.S. Bankruptcy Code on April 6, 2001.

Under Chapter 11, the Utility retains control of its assets and is authorized to operate its business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court. Subsidiaries of the Utility, including PG&E Funding LLC (which holds Rate Reduction Bonds, discussed further in Note 2) and PG&E Holdings LLC (which holds stock of the Utility), are not included in the Utility's petition. The Utility's Consolidated Financial Statements have been prepared in accordance with the American Institute of Certified Public Accountants' Statement of Position 90-7 (SOP 90-7), "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code," and on a going concern basis, which contemplates continuity of operation, realization of assets and liquidation of liabilities in the ordinary course of business. However, as a result of the filing, such realization of assets, and liquidation of liabilities are subject to uncertainty.

Certain claims against the Utility in existence prior to the filing of the petition for relief are stayed while the Utility continues business operations as a debtor-in-possession. These claims are reflected in the June 30, 2001, balance sheet as "liabilities subject to compromise." Additional claims (liabilities subject to compromise) may arise subsequent to the filing date resulting from (1) negotiations; (2) rejection of executory contracts, including leases; (3) actions by the Bankruptcy Court; (4) further developments with respect to disputed claims; (5) proofs of claim; or (6) other events. Payment terms for these amounts will be established through the bankruptcy proceeding.

Claims secured against the Utility's assets ("secured claims") also are stayed, although the holders of such claims have the right to move the court for relief from the stay. Secured claims are secured primarily by liens on substantially all of the Utility's assets. The Bankruptcy Court has approved making the regular interest payments on the Utility's secured debt and by pledged accounts receivable from gas customers.

A creditors' committee has been appointed as an official committee and, in accordance with the provisions of the Bankruptcy Code, will have the right to be heard on all matters that come before the Bankruptcy Court. The Utility expects that the creditors' committee will play an important role in the negotiation of the terms of any plan of reorganization.

Since the filing, the Bankruptcy Court has approved various requests by the Utility to permit the Utility to carry on its normal business operations, and pay certain pre-petition obligations. Additionally, the Utility has secured approval for approximately $1.5 billion in capital expenditures for on-going business needs such as upgrading and improving transmission lines and substations. The Utility's current actions are intended to allow the Utility to continue to operate while the bankruptcy proceedings continue.

On January 10, 2001, the Utility suspended the payment of its fourth quarter 2000 common stock dividend of $110 million, declared in October 2000, to PG&E Corporation and its wholly owned subsidiary PG&E Holdings, LLC Until its financial condition is restored, the Utility is precluded from paying common stock dividends to PG&E Corporation and PG&E Holdings, LLC In addition, the Utility's Board of Directors did not declare the regular preferred stock dividends for the three-month period ended January 31, 2001, or for the three-month period ended April 30, 2001. Dividends on all Utility preferred stock are cumulative. Until cumulative dividends on preferred stock are paid, the Utility may not pay any dividends on its common stock, nor may the Utility repurchase any of its common stock.

In July 2001, the Bankruptcy Court granted a motion that the Utility had filed requesting that the court extend until December 6, 2001, the period during which the Utility has the exclusive right to file a plan of reorganization in its Chapter 11 case. Under the normal timeline, the exclusivity period would have ended on August 6, 2001, 120 days after the Utility's April 6, 2001, Chapter 11 filing. The Utility filed for an extension of the exclusivity period in the event that additional time is needed to continue discussions with creditors and to develop and file a comprehensive and feasible plan of reorganization. The Bankruptcy Court may confirm a plan of reorganization only upon making certain findings required by the Bankruptcy Code, and a plan may be confirmed over the dissent of non-accepting creditors and equity security holders if certain requirements of the Bankruptcy Code are met. The payment rights and other entitlements of pre-petition creditors and the Utility's shareholders may be substantially altered by any plan of reorganization confirmed by the Bankruptcy Court. Although it is the Utility's intent to pay all valid claims, pre-petition creditors may receive, under a plan, less than 100% of the face value of their claims, and the interests of the Utility's equity security holders may be affected. A plan of reorganization could materially change the amounts and classification reported in the consolidated financial statements.

The Utility is not able at this time to predict the outcome of its bankruptcy case, the terms and provisions of any plan of reorganization, or the effect of the Chapter 11 reorganization process on the claims of the creditors of the Utility or the interests of the Utility's preferred security holders. However, the Utility believes, based on information presently available to it, that cash available from operations will provide sufficient liquidity to allow it to continue as a going concern for the foreseeable future.

PG&E Corporation

The liquidity and financial condition crisis faced by the Utility also negatively impacted PG&E Corporation. Through December 31, 2000, PG&E Corporation funded its working capital needs primarily by drawing down on available lines of credit and other short-term credit facilities. At December 31, 2000, PG&E Corporation had borrowed $185 million against its five-year revolving credit agreement and had issued $746 million of commercial paper. Due to the credit ratings downgrades of PG&E Corporation, the banks refused any additional borrowing requests and terminated their remaining commitments under existing credit facilities. Commencing January 17, 2001, PG&E Corporation began to default on its maturing commercial paper obligations.

Commencing on March 2, 2001, PG&E Corporation refinanced its debt obligations with $1 billion in aggregate proceeds of two term loans under a common credit agreement with General Electric Corporation and Lehman Commercial Paper Inc. In accordance with the credit agreement, the proceeds, together with other PG&E Corporation cash, were used to pay $501 million in commercial paper (including $457 million of commercial paper on which PG&E Corporation had defaulted), $434 million in borrowings under PG&E Corporation's long-term revolving credit facility, and $109 million to PG&E Corporation shareholders of record as of December 15, 2000, in satisfaction of a defaulted fourth quarter 2000 dividend. Further, approximately $99 million was used to pre-pay the first year's interest under the credit agreement and to pay transaction expenses associated with the debt restructuring.

PG&E Corporation itself had cash and short-term investments of $272 million at June 30, 2001, and believes that the funds will be adequate to maintain its continuing operations throughout 2001. In addition, PG&E Corporation believes that the holding company and its non-CPUC regulated subsidiaries are protected from the bankruptcy of the Utility.

STATEMENTS OF CASH FLOWS

PG&E Corporation normally funds investing activities from cash provided by operations after capital requirements and, to the extent necessary, external financing. Our policy is to finance our investments with a capital structure that minimizes financing costs, maintains financial flexibility, and, with regard to the Utility, complies with regulatory guidelines.

PG&E Corporation Consolidated

Net cash provided by PG&E Corporation's operating activities totaled $729 million and $1,732 million for the six months ended June 30, 2001 and 2000, respectively. The decrease of $1,003 million between 2001 and 2000 is attributable to the California energy crisis previously discussed.

Cash Flows from Investing Activities

Cash used in investing activities was $1,217 million during the six months ended June 30, 2001, compared with $984 million used during the same period for 2000. In 2001, the primary use of cash for investing activities was $1,102 million for additions to property, plant, and equipment, compared with $974 million used for similar purposes in 2000.

Cash Flows from Financing Activities

Cash generated through financing activities for the six month ended June 30, 2001, was $289 million compared with $707 million used for the same period in 2000. A loan in 2001 netted $906 million in proceeds which together with cash on hand and from operating activities, were used to repay defaulted commercial paper and other loans and the $109 million in dividends. The $707 million used in 2000 resulted from reduced borrowings of $482 million and a dividend payments of $217 million.

Utility

The following section discusses the Utility's significant cash flows from operating, investing, and financing activities for the six-month periods ended June 30, 2001.

Cash Flows from Operating Activities

Net cash provided by the Utility's operating activities totaled $843 million and $1,298 million for the six months ended June 30, 2001 and 2000, respectively. The decrease of $455 million between 2001 and 2000 is primarily attributable to higher cost of gas, offset by partial down payment of pre-petition obligations.

Cash Flows from Investing Activities

The primary uses of cash for investing activities are additions to property, plant, and equipment. The Utility's capital

expenditures for the six-month ended June 30, 2001, was $575 million.

Cash Flows from Financing Activities

During the six months ended June 30, 2001, the Utility did not declare any preferred or common stock dividends, compared with a payment of dividends on its common stock of $250 million, for the six months ended June 30, 2000. The Utility has suspended payment of its common and preferred dividends due to its financial condition. Dividends on preferred stock are cumulative. Until cumulative dividends on preferred stock are paid, the Utility may not pay any dividends on its common stock. Until its financial condition is restored, the Utility is precluded from paying dividends to PG&E Corporation and PG&E Holdings, LLC

The Utility's long-term debt that either matured, was redeemed, or was repurchased during the six months ended June 30, 2001, totaled $252 million. Of this amount, $141 million related to the Utility's rate reduction bonds maturing, $93 million related to mortgage bonds maturing, and $18 million related to the maturities and redemption of various of the Utility's medium-term notes and other debt.

The Utility maintained a $1 billion credit facility, which was due to expire in November 2002. The unused portion of this facility was cancelled by the bank-lending group on January 23, 2001, citing the event of default on non-payment of material debt. This facility was previously used to support the Utility's commercial paper program and other liquidity requirements. At June 30, 2001, the Utility had drawn, and had outstanding $938 million under this facility to repay maturing commercial paper. In addition, the total defaulted commercial paper outstanding at June 30, 2001, formerly backed by both this and another, now cancelled, facility, was $873 million.

There was no new long-term debt issued in the period ended June 30, 2001. In addition, there was no additional commercial paper issued during this same period.

As of August 1, 2001, the Utility is current with all interest and sinking fund payments on its mortgage bonds.

Due to the bankruptcy filing, the Utility is unable at this time to repay unsecured pre-petition creditors. The Utility has not made interest payments on the following unsecured debt: pollution control loan agreements, the 7.375% senior notes, the $1.24 billion floating rate notes, commercial paper, bank loan drawdowns, and other unsecured debt. Due to events of default under the credit agreements with letter of credit banks, in April and May 2001, four letter of credit banks accelerated and redeemed pollution control loans totaling $454 million. All of these redemptions were funded by the letter of credit banks resulting in like obligations from the Utility to the banks.

Four other banks have made the May 1, June 1, July 1 and August 1, 2001, interest payments on the $614 million principal amount of pollution control bonds backed by letters of credit. The bond insurance company has made the June 1, 2001, interest payment for the pollution control bond backed by bond insurance.

The Utility received notice from the QUIPS trustee that the Utility's bankruptcy filing was an event of default under the trust agreement and that the trustee will take steps to liquidate the trust and distribute 7.90% deferrable interest subordinated debentures to bondholders. As of June 30, 2001, the Company Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures have been reclassified to liabilities subject to compromise on the Consolidated Balance Sheet.

PG&E National Energy Group

General

Historically, PG&E NEG has obtained cash from operations, borrowings under credit facilities, non-recourse project financing and other issuances of debt, issuances of commercial paper, and borrowings and capital contributions from PG&E Corporation. These funds have been used to finance operations, service debt obligations, fund the acquisition, development, and/or construction of generating facilities, and to start-up other businesses, finance capital expenditures, and meet other cash and liquidity needs.

The projects that PG&E NEG develops typically require substantial capital. To date, PG&E NEG has made a number of commitments associated with the planned growth of owned and controlled generating facilities, as well as pipelines. These include commitments for projects under construction, commitments for the acquisition and maintenance of equipment needed for projects under development, payment commitments for tolling arrangements, and forward sale and purchase commitments associated with PG&E NEG's energy marketing and trading activities.

On May 22, 2001, PG&E NEG completed an offering of $1 billion in senior unsecured notes and received net proceeds after bond discount of approximately $987 million. PG&E NEG used a portion of the proceeds and intends to use the balance of the senior notes issuance, net of $13 million of bond issuance costs, to pay down existing revolving debt, fund investments in generating facilities and pipeline assets, working capital requirements, and other general corporate requirements. These Senior Notes have an aggregate principal amount of $1 billion, bear interest at 10.375% per annum, and mature on May 16, 2011.

In addition, PG&E Corporation historically has provided to the PG&E NEG credit support for a range of contractual commitments. With respect to generating facilities, this collateral has included agreements to infuse equity in specific projects when these projects begin operations or when a project that has been leased is purchased. PG&E Corporation also has provided guarantees of PG&E NEG obligations under several long-term tolling arrangements and as collateral for commitments under various energy trading contracts entered into by PG&E Energy operations to provide short-term collateral to conterparties. As of June 30, 2001, except for $108 million of guarantees relating to various energy trading master contracts, all PG&E Corporation equity infusion agreements and guarantees have been replaced with PG&E NEG equity infusion agreements, guarantees or other forms of security.

In connection with the replacement of PG&E Corporation guarantees with PG&E NEG guarantees, and with the continued growth of energy trading and marketing positions, the PG&E NEG has experienced a substantial increase in the amount of cash it has been required to place on deposit with various counterparties without a commensurate increase in margin deposits received from counterparties. The cash margin deposits outstanding to counterparties net of cash margin received from counterparties increased from $10 million as of December 31, 2000 to $92 million as of June 30, 2001. On June 15, 2001, PG&E NEG established a $550 million revolving credit facility (which includes the ability to issue letters of credit) with a syndicate of banks. This new $550 million facility has an initial 364-day term that expires on June 14, 2002.

Cash Flows from Operating Activities

During the six months ended June 30, 2001, PG&E NEG generated net cash of $51 million in operating activities. Net cash from operating activities before changes in other working capital accounts was $39 million, primarily driven by net income. Net cash inflow related to certain other working capital accounts was $37 million, driven primarily deliveries of previously held forward positions in trading offset by an increase in margin deposits related to PG&E NEG's trading activities.

Cash Flows from Investing Activities

During the six months ended June 30, 2001, PG&E NEG used net cash of $675 million in investing activities. PG&E NEG's cash outflows from investing activities were primarily attributable to capital expenditures on generating projects in construction, turbine prepayments, and advanced development.

Cash Flows from Financing Activities

Net cash generated by financing activities was $704 million for the six months ended June 30, 2001 principally from the net proceeds related to the senior notes.

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RESULTS OF OPERATIONS

The table shows for the three- and six-months ended June 30, 2001 and 2000, certain items from the Statement of Consolidated Operations detailed by Utility and PG&E NEG operations of PG&E Corporation. (In the "Total" column, the table shows the combined results of operations for this group.) The information for PG&E Corporation (the "Total" column) includes the appropriate intercompany elimination. Following this table we discuss our results of operations.

PG&E National Energy Group

(in millions)	Utility	Total NEG	Integrated Energy and Marketing	Interstate Pipeline Operations	NEG Eliminat

Three months ended June 30, 2001					
Operating revenues	$2,309	$2,753	$2,676	$64	$13
Operating expenses	973	2,628	2,595	25	8
Operating income					
Reorganization interest income					
Interest income					
Interest expense					
Other income (expenses), net					
Income taxes					
Net income					
Net cash provided by operating activities					
Net cash used by investing activities					
Net cash provided by financing activities					
EBITDA (2)	1,550	163	108	49	6
Three months ended June 30, 2000(3)					
Operating revenues	2,296	3,361	3,089	280	(8
Operating expenses	1,744	3,279	3,059	229	(9
Operating income					
Interest income					
Interest expense					
Other income (expenses), net					
Income taxes					
Net income					
Net cash provided by operating activities					
Net cash used by investing activities					
Net cash provided by financing activities					
EBITDA (2)	602	111	52	58	1
Six months ended June 30, 2001					
Operating revenues	4,871	6,959	6,826	129	4
Operating expenses	4,955	6,749	6,692	50	7
Operating income					
Reorganization interest income					
Interest income					
Interest expense					
Other income (expenses), net					
Income taxes					
Net income					
Net cash provided by operating activities					
Net cash used by investing activities					
Net cash provided by financing activities					
EBITDA (2)	337	291	192	99	–
Six months ended June 30, 2000(3)					
Operating revenues	4,514	6,187	5,624	562	1
Operating expenses	3,392	5,995	5,534	460	1
Operating income					
Interest income					
Interest expense					
Other income (expenses), net					
Income taxes					
Net income					
Net cash provided by operating activities					

Net cash used by investing activities					
Net cash used by financing activities					
EBITDA (2)	$1,472	$253	$137	$116	$ -

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(1) Net income on inter-company positions recognized by segments using mark-to-market accounting is eliminated. Inter-company transactions are also eliminated.

(2) EBITDA is defined as income before provision for income taxes, interest expense, interest income, depreciation and amortization. EBITDA is not intended to represent cash flows from operations and should not be considered as an alternative to net income as an indicator of PG&E Corporation's operating performance or to cash flows as a measure of liquidity. Refer to the Statement of Cash Flows for the U.S. GAAP basis cash flows. PG&E Corporation believes that EBITDA is a standard measure commonly reported and widely used by analysts, investors, and other interested parties. However, EBITDA as presented herein may not be comparable to similarly titled measures reported by other companies.

(3) Segment information for the prior period has been restated to conform with new segment presentation (see Note 7 of the Notes to the Condensed Consolidated Financial Statements).

Overall Results

PG&E Corporation's financial position and results of operations continue to be impacted by the ongoing California energy crisis. Please see the Liquidity and Financial Resources section and Notes 2 and 3 of the Notes to the Condensed Consolidated Financial Statements for more information on the California energy crisis.

PG&E Corporation's net income for the second quarter ended June 30, 2001 was $750 million, compared to net income of $248 million for the same period in 2000, representing an increase of $502 million. The Utility's net income available for common stock for the quarter ended June 30, 2001 accounted for $480 million of the increase.

PG&E Corporation incurred a net loss of $201 million for the six-month period ended June 30, 2001 compared to net income of $528 million for the same period in 2000. Of the $729 million net decrease from the prior six-month period in 2000, the Utility was responsible for virtually all of the decrease, somewhat offset by an increase in net income at PG&E NEG.

Subject to final resolution of regulatory and judicial matters, PG&E Corporation and the Utility expect future earnings to continue to reflect increased volatility as a result of no longer being able to reflect the impact of generation-related regulatory balancing accounts in their financial statements. As previously discussed, the Utility cannot meet the accounting probability standard required to defer generation costs for future recovery. As such, costs and revenues historically deferred in regulatory balancing accounts now directly impact net income. The Utility's net income will be impacted by changes in electricity and gas costs, customer demand, weather, costs of operations, conservation and other related items.

The changes in performance for the three and six-month periods ended June 30, 2001 and 2000 are generally attributable to the following factors:

- The Utility's earnings were impacted as a result of its under-collected purchased power costs. Because of the lack of a regulatory, legislative, or judicial solution to the California energy crisis, the Utility cannot defer for future recovery its under-collected purchased power costs. These costs have been expensed as incurred. For the six-month period ended June 30, 2001, the total under-collected purchased power costs were $563 million, after-tax of which $8 million, pre-tax are professional fees and expenses and reflected within the reorganization sections of the consolidated statement of operations. During the second quarter of 2001, the Utility recognized after-tax offsets of $552 million against previously expensed purchased power costs. These offsets included $327 million related to the market value of terminated bilateral contracts and $155 million of adjustments to first quarter estimates of ISO costs. The adjusted ISO costs resulted from actual billings received in May 2001 for costs incurred in March 2001.

- As a result of the high cost of power, with no offsetting revenues, the Utility and PG&E Corporation have a net loss for California tax purposes through June 30, 2001. California law does not permit carrybacks of such losses, and only permits carryforwards of 55% of such losses. As a result, for the six-month period ended June 30, 2001, PG&E Corporation was unable to recognize $8 million of state tax benefits because of California law.

- As a result of the liquidity crisis attributable to the California energy crisis, PG&E Corporation has significantly increased its borrowings and unpaid debts accruing interest. Additionally, the effective interest rate paid on these new borrowings has also increased because of the higher risk associated with PG&E Corporation's financial position. The incremental cost of these borrowings was $61 million, after-tax, for the quarter ended June 30, 2001, and $103 million, after-tax, for the six-month period ended June 30, 2001.

- The Utility's filing of a petition of reorganization under Chapter 11 of the U.S. Bankruptcy Code has resulted in incremental external financial and legal expenses associated with the development of a plan of reorganization. For the quarter ended June 30, 2001, these fees amounted to $9 million after-tax of which $8 million, pre-tax, are professional fees and expenses reflected within the reorganization section in the consolidated statement of operations. For the six-month period ended June 30, 2001, total incremental external financial and legal fees were $25 million after-tax.

- PG&E NEG increased earnings by $34 million for the three-month period ended June 30, 2001, over the same period in 2000. The increase was a result of the impact of favorable market movements on merchant generating plants and increased pipeline utilization in the Pacific Northwest.

Dividends

PG&E Corporation's historical quarterly common stock dividend was $0.30 per common share, which corresponded to an annualized dividend of $1.20 per common share.

On January 10, 2001, the Board of Directors of PG&E Corporation suspended the payment of its fourth quarter 2000 common stock dividend of $0.30 per share declared by the Board of Directors on October 18, 2000 and payable on January 15, 2001 to shareholders of record as of December 15, 2000. The California energy crisis had created a liquidity crisis for PG&E Corporation, which led to the suspension of payments of dividends to conserve cash resources. These defaulted dividends were later paid on March 2, 2001 in conjunction with the refinancing of PG&E Corporation obligations, discussed above under the Liquidity and Financial Resources section.

Additionally, the parent company refinancing agreements mentioned above prohibit dividends from being declared or paid until the term loans have been repaid. The agreement is for a term of two years with an option on behalf of PG&E Corporation to extend the term for an additional year.

On January 10, 2001, the Utility suspended the payment of its fourth quarter 2000 common stock dividend of $110 million, declared in October 2000, to PG&E Corporation and its wholly owned subsidiary PG&E Holdings, LLC Until its financial condition is restored, the Utility is precluded from paying dividends to PG&E Corporation and PG&E Holdings, LLC

Utility

Overall Results

The Utility's net income was $696 million for the quarter ended June 30, 2001, compared to $216 million for the same period in 2000. This increase in net income was primarily the result of the recognition of the market value of terminated bilateral contracts and the change in the amount of ISO accruals for purchased power costs.

The Utility had a net loss of $304 million for the six-month period ended June 30, 2001, compared to the prior year's net income of $444 million. The change in earnings was primarily the result of the $.9 billion charge to earnings for under-collected purchased power costs in excess of the amounts provided in customer rates for recovery of such costs. The under-collected amounts include ISO charges incurred between January 1 and April 6, 2001. Generally accepted accounting principles require that the amounts be accounted for as expenses unless they can be deemed probable of recovery through the regulated rates. Due to uncertainty created by the energy crisis, the Utility cannot meet the accounting probability standard. This charge was partially offset by the recognition of the value of the terminated bilateral contracts.

Operating Income

Operating income was $1,336 million for the second quarter ended June 30, 2001, compared to operating income of $552 million for the same period in 2000. This increase in operating income is primarily attributable to the recognition of the value of the terminated bilateral contracts worth $552 million and the change in the amount of the ISO accruals for purchased power costs.

The Utility had an operating loss of $84 million for the six months ended June 30, 2001, compared to operating income of $1,122 million for the same period in 2000. This change is due to the charge to earnings for under-collected purchased power costs, as discussed above, which was partially offset by the recognition of the value of the terminated bilateral contracts.

Operating Revenues

The Utility's operating revenues for the three months ended June 30 were $2.3 billion in both 2001 and 2000. Electric revenues decreased by $304 million for the three months ended June 30, 2001, primarily due to the reduction of revenue resulting from a portion of the Utility's billed revenues being passed through to the DWR for the DWR'S electricity purchases which was partially offset by an increase in customer revenues. Beginning in April 2001, the DWR began supplying electric power to the Utility's customers in excess of that power generated by or contracted for by the Utility. The Utility acts solely as a billing agent for the DWR. Therefore, the amounts paid to the DWR for deliveries are not recorded as expense and the revenue billed by the Utility to its customers associated with this energy is excluded from revenues.

Gas revenues increased $317 million for the three months ended June 30, 2001, due to the increased revenues from commercial and residential customers due to higher gas costs resulting from high natural gas prices. Such costs are passed on directly to customers.

The Utility's operating revenues for the six months ended June 30, 2001 were $4.9 billion compared to operating revenues of $4.5 billion for the same period in 2000. Gas revenues increased $1,003 million while electric revenues decreased $646 million. The increase in gas revenues was primarily due to increased revenues from residential and commercial customers due to higher average cost of gas resulting from higher natural gas prices and increased usage during 2001.

The decrease in electric revenues of $646 million was primarily due to credits issued to direct access customers and due to the reduction of revenue resulting from a portion of the Utility's billed revenues being passed through to the DWR for the DWR's electricity purchases. As discussed above, these revenues are not included in the Utility's reported revenues.

In accordance with CPUC regulations, the Utility provides an energy credit to those customers (known as direct access customers) who have chosen to buy their electric generation energy from an energy service provider (ESP) other than the Utility. The Utility bills direct access customers based upon fully bundled rates (generation, distribution, transmission, public purpose programs, and a competition transition charge). However, the direct access customer receives an energy credit equal to the average generation price multiplied by customer energy usage for the period, with the customer being obligated to their ESP at their direct access contract rate.

For the six-month period ended June 30, 2001, the estimated total of accumulated credits for direct access customers that have not been paid by the Utility is approximately $354 million. Such amounts are reflected on the Utility's condensed consolidated balance sheet. The actual amount that will be refunded to ESPs or directly to the customer will be dependent upon the outcome of the Utility's bankruptcy proceeding, when the rate freeze ends, and whether there are any adjustments made to wholesale energy prices by FERC.

Operating Expenses

The table below summarizes the changes in the Utility's operating expenses:

	Three months ended June 30			
(in millions)	2001	2000	Increase (Decrease)	Perc Incr (Dec
Cost of electric energy	$(362)	$ 975	$(1,337)	(1
Cost of gas	429	182	247	1
Operating and maintenance	676	543	133	
Depreciation, amortization, and decommissioning	222	44	178	4

Reorganization professional fees and expenses	8	-	8	
Total operating expenses	$ 973	$1,744	$ (771)	(

	Six months ended June 30		Increase (Decrease)	Incr (Dec
	2001	2000		
Cost of electric energy	$1,955	$1,488	$ 467	
Cost of gas	1,345	465	880	1
Operating and maintenance	1,208	1,094	114	
Depreciation, amortization, and decommissioning	439	345	94	
Reorganization professional fees and expenses	8	-	8	
Total operating expenses	$4,955	$3,392	$1,563	

The cost of electric energy decreased by $1,337 million for the three months ended June 30, 2001 compared to the same period in 2000. This was attributable to the recognition of the market value of several electric bilateral contract terminations amounting to $552 million, a $261 million change in the amount of the ISO related costs previously accrued and the impact of the fact that costs of electric energy procured by the DWR are no longer reflected by the Utility. In accordance with state legislation, the Utility does not take title to the energy procured by the DWR for delivery to its customers. Rather, the Utility acts solely as a billing agent for the DWR. Therefore, the amounts paid to the DWR for deliveries are not recorded as expense and the revenue billed by the Utility to its customers associated with this energy is excluded from revenues.

The cost of electric energy increased by $467 million for the six months ended June 30, 2001 compared to the same period in 2000. This was attributable to the higher average cost of electricity in 2001. Historically, the Utility generally would have deferred such under-collected purchased power costs as a regulatory asset to be collected from customers in future rates. However, due to the lack of regulatory, legislative, or judicial relief, the Utility cannot conclude that it is probable that its under-collected purchase power costs will be collected in future rates. Therefore, in 2001 such costs are being expensed as incurred.

The higher costs were offset, in part, by the recognition of the market value of electric bilateral contract terminations and the costs being passed through to the DWR for the DWR's electricity purchases, as discussed above.

The cost of gas increased by $247 million and $880 million for the three months and six months ended June 30, 2001, respectively, compared to the same periods in 2000. The average cost of gas was $7.80 per decatherm (DTh) for the six months ended June 30, 2001 compared to $2.59 per DTh for the same period in the prior year. The procurement costs for gas are passed directly onto the customers.

The Utility's operating and maintenance expenses increased $133 million in the three-month period, and $114 million in the six-month period ending June 30, 2001 compared to the same periods in 2000. These increases are a result of a Diablo Canyon refueling outage with no such outage in the similar periods of 2000, increased customer energy efficiency expenses and higher franchise requirements fees resulting from higher electric and gas revenue.

Depreciation, amortization, and decommissioning increased by $178 million in the three-month period, and $94 million in the six-month period ending June 30, 2001 compared to the same periods in 2000. These increases are due to the elimination of regulatory asset deferrals for generation-related transition costs in 2001. In 2000, when generation-related regulatory assets were amortized to depreciation, amortization and decommissioning expense and when purchased power costs were under-collected, the Utility would defer the under- collections by reducing depreciation, amortization and decommissioning expense. Since the Utility wrote off its generation-related regulatory assets and under- collected purchased power costs in 2000 and continues to expense as incurred its under-collected purchased power costs in 2001, no such deferral and reduction to depreciation, amortization, and decommissioning expense occurs in 2001.

Dividends

The Utility has suspended payment of its common and preferred dividends. Dividends on preferred stock are cumulative. Until cumulative dividends on preferred stock are paid, the Utility may not pay any dividends on its common stock. Until its financial condition is restored, the Utility is precluded from paying dividends to PG&E Corporation and PG&E Holdings, LLC

PG&E National Energy Group

Operating Income

Operating income at PG&E NEG was $125 million for the second quarter ended June 30, 2001 compared to $82 million for the same period in 2000. For the six-month period ended June 30, 2001, operating income was $210 million, compared to $192 million for the same period in 2000.

Operating Revenues

Operating revenues were $2.8 billion in the three months ended June 30, 2001, a decrease of $.6 billion, or 18%, from the three months ended June 30, 2000.

Operating revenues for PG&E Energy decreased by $.4 billion, or 13% primarily as the result of decreased commodity sales and a decline in the market value of long-term gas transportation contracts. Operating revenues for PG&E Pipeline decreased by $216

million. Short-term firm revenues earned by PG&E Pipeline operations increased, resulting from higher usage and higher negotiated rates. However, these increases were offset by the completion of the sale of PG&E GTT in late 2000, which had revenues of $224 million for the three months ended June 30, 2000.

Operating revenues were $7.0 billion in the six months ended June 30, 2001, an increase of $.8 billion, or 12%, from the six months ended June 30, 2000. Operating revenues for PG&E Energy increased by $1.2 billion as a result of increases in the price of power and gas, and a focus of trading efforts on asset management and higher-margin trades. These increases were partially offset by decreases in commodity sales and declines in the market value of long-term gas transportation contracts during the second quarter. Operating revenues for PG&E Pipeline decreased by $433 million. Short-term firm revenues earned by pipeline increased, resulting from higher usage and higher negotiated rates. These increases were offset by the completion of the sale of PG&E GTT in late 2000, which had revenues of $449 million for the six months ended June 30, 2000.

Operating Expenses

Operating expenses were $2.6 billion in the three months ended June 30, 2001, a decrease of $.7 billion, or 20%, from the three months ended June 30, 2000. The decrease primarily resulted from the lower quantity of PG&E Energy commodity sales, overall reduced operational costs at our facilities, and the reduction of costs associated with the sale of PG&E GTT in late 2000 from PG&E Pipeline segment.

Operating expenses were $6.7 billion in the six months ended June 30, 2001, an increase of $.8 billion, or 13%, from the six months ended June 30, 2000. The increase primarily resulted from higher costs of commodities and fuel in the PG&E Energy segment, partially offset by overall reduced operational costs at PG&E NEG facilities, and the reduction of costs as a result of the sale of PG&E GTT in late 2000.

Dividends

PG&E NEG currently intends to retain any future earnings to fund the development and growth of its business. Further, PG&E NEG is precluded from paying dividends, unless it meets certain financial tests. Therefore, it is not anticipating paying any cash dividends on its common stock in the foreseeable future.

REGULATORY MATTERS

A significant portion of PG&E Corporation's operations is regulated by federal and state regulatory commissions. These commissions oversee service levels and, in certain cases, PG&E Corporation's revenues and pricing for its regulated services.

The Utility is the only subsidiary with significant regulatory proceedings at this time. The Utility's significant regulatory proceedings are discussed below. Regulatory proceedings associated with electric industry restructuring are discussed above in "The California Energy Crisis." (See Note 2 of the Notes to the Condensed Consolidated Financial Statements.)

The Utility's General Rate Case (GRC)

The CPUC authorizes an amount known as "base revenues" to be collected from ratepayers to recover the Utility's basic business and operational costs for its gas and electric distribution operations. Base revenues, which include non-fuel-related operating and maintenance costs, depreciation, taxes, and a return on invested capital, currently are authorized by the CPUC in GRC proceedings.

In March 2000, two interveners filed applications for rehearing of the Utility's 1999 GRC decision, alleging that the CPUC committed legal errors by approving funding in certain areas that were not adequately supported by record evidence. In April 2000, the Utility filed its response to these applications for rehearing, defending the GRC decision against the allegations of error. A CPUC decision on the applications for rehearing is pending.

In the 1999 GRC decision, the CPUC ordered that the Utility file a 2002 GRC. As a result of the current energy crisis, the procedural schedule has been delayed pending the CPUC's resolution of the Utility's request that it be permitted to file an alternative schedule or an alternative to the 2002 GRC. An earlier decision initially delaying the schedule affirms that rates would still become effective on January 1, 2002, although the CPUC decision may not be rendered until after that date.

Order Instituting Investigation (OII) into Holding Company Activities

On April 3, 2001, the CPUC issued an order instituting an investigation into whether the California investor-owned utilities, including the Utility, have complied with past CPUC decisions, rules, or orders authorizing their holding company formations

and/or governing affiliate transactions, as well as applicable statutes. The order states that the CPUC will investigate (1) the Utilities' transfer of money to their holding companies since deregulation of the electric industry commenced, including during times when their utility subsidiaries were experiencing financial difficulties; (2) the failure of the holding companies to financially assist the utilities when needed; (3) the transfer, by the holding companies, of assets to unregulated subsidiaries; and (4) the holding companies' action to "ringfence" their unregulated subsidiaries. The CPUC will also determine whether additional rules, conditions, or changes are needed to adequately protect ratepayers and the public from dangers of abuse stemming from the holding company structure. The CPUC will investigate whether it should modify, change, or add conditions to the holding company decisions, make further changes to the holding company structure, alter the standards under which the CPUC determines whether to authorize the formation of holding companies, otherwise modify the decisions, or recommend statutory changes to the California Legislature. As a result of the investigation, the CPUC may impose remedies (including penalties), prospective rules, or conditions, as appropriate.

PG&E Corporation and the Utility believe that they have complied with applicable statutes, CPUC decisions, rules, and orders. As described above, on April 6, 2001, the Utility filed a voluntary petition for relief under Chapter 11 of the U.S. Bankruptcy Code. PG&E Corporation and the Utility believe that to the extent the CPUC seeks to investigate past conduct for compliance purposes, the investigation is automatically stayed by the bankruptcy filing. Neither the Utility nor PG&E Corporation can predict what the outcome of the investigation will be or whether the outcome will have a material adverse effect on their results of operations or financial condition. On April 13, 2001, the Utility filed an application for rehearing of the classification of the OII as quasi-legislative, arguing that the issues of compliance, violations, and remedies for past violations must be reclassified as adjudicatory.

On May 14, 2001, the CPUC issued an interim decision that recategorized the proceeding from quasi-legislative to the ratesetting category because the ratesetting category is most appropriate for mixed factual and policy proceedings. In addition, the CPUC noted that the proceeding may be recategorized as adjudicatory at a later time if the CPUC finds that the Utility violated prior decisions and other laws. On June 14, 2001, the CPUC denied the Utility's request for rehearing of the interim decision placing this proceeding in the ratesetting category.

The Utility's 2001 Attrition Rate Adjustment (ARA)

In July 2000, the Utility filed an ARA application with the CPUC to increase its 2001 electric distribution revenues by $189 million, effective January 1, 2001. The increase reflects inflation and the growth in capital investments necessary to serve customers. The Utility did not request an increase in gas distribution revenues. In December 2000, the CPUC issued an interim order finding that a decision on the application could not be rendered by January 1, 2001, and determining that if attrition relief is eventually granted, that relief will be effective as of January 1, 2001. On May 8, 2001, the CPUC's Office of Ratepayer Advocates (ORA) submitted its report on the Utility's request, recommending that the CPUC deny the Utility's request. The Utility believes that ORA's recommendations are unjustified and challenged those recommendations in hearings in June 2001.

The Utility's Cost of Capital Proceedings

Each year, the Utility files an application with the CPUC to determine the authorized rate of return that the Utility may earn on its electric and gas distribution assets and recover from ratepayers. Since February 17, 2000, the Utility's adopted return on common equity (ROE) has been 11.22% on electric and gas distribution operations, resulting in an authorized 9.12% overall rate of return (ROR). The Utility's earlier adopted ROE was 10.6%. In May 2000, the Utility filed an application with the CPUC to establish its authorized ROR for electric and gas distribution operations for 2001. The application requests an ROE of 12.4%, and an overall ROR of 9.75%. If granted, the requested ROR would increase electric distribution revenues by approximately $72 million and gas distribution revenues by approximately $23 million. The application also requests authority to implement an Annual Cost of Capital Adjustment Mechanism for 2002 through 2006 that would replace the annual cost of capital proceedings. The proposed adjustment mechanism would modify the Utility's cost of capital based on changes in an interest rate index. The Utility also proposes to maintain its currently authorized capital structure of 46.2% long-term debt, 5.8% preferred stock, and 48% common equity. In March 2001, the CPUC issued a proposed decision recommending no change to the current 11.22% ROE for test year 2001. This authorized ROE results in a corresponding 9.12% return on rate base and no change in the Utility's electric or gas revenue requirement for 2001. A final CPUC decision is pending.

The Utility's FERC Transmission Rate Cases

Electric transmission revenues, and both wholesale and retail transmission rates are subject to authorization by the FERC. The FERC has not yet acted upon a settlement filed by the Utility that, if approved, would allow the Utility to recover $391 million in electric transmission rates for the 14-month period of April 1, 1998 through May 31, 1999. During this period, somewhat higher rates have been collected, subject to refund. A FERC order approving this settlement is expected by the end of 2001. The Utility has accrued $29 million for potential refunds related to the 14-month period ended May 31, 1999. In April 2000, the FERC

approved a settlement that permits the Utility to recover $298 million in electric transmission rates retroactively for the 10-month period from May 31, 1999 to March 31, 2000. In September 2000, the FERC approved another settlement that permits the Utility to recover $340 million annually in electric transmission rates and made this retroactive to April 1, 2000. Further, in July 2001, the FERC approved another settlement that permits, the Utility to collect $251 million annually in electric transmission rates beginning on May 6, 2001. This decrease in transmission rates relative to previous time periods is due to unusually large balances paid to the Utility from the ISO for congestion management charges and other transmission related services billed by the ISO.

In March 2001, PG&E filed at FERC to increase its power and transmission related rates to the Western Area Power Administration (Western). The majority of the increase is related to passing through market power prices billed to the Utility by the ISO and others for services, which apply to Western under a pre- existing contract between the Utility and Western. In this filing, the Utility estimates that if FERC grants its request, it will collect from Western an additional $1,125 million before the contract terminates on December 31, 2004, thereby reducing the revenue that needs to be collected through existing electric retail rates.

ENVIRONMENTAL MATTERS

We are subject to laws and regulations established to both maintain and improve the quality of the environment. Where our properties contain hazardous substances, these laws and regulations require us to remove those substances or remedy effects on the environment. See Note 6 of the Notes to the Consolidated Financial Statements for further discussion of environmental matters.

Utility

The Utility records an environmental remediation liability when site assessments indicate remediation is probable and a range of reasonably likely clean-up costs can be estimated. The Utility reviews its remediation liability quarterly for each identified site. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring, and site closure. The remediation costs also reflect (1) current technology, (2) enacted laws and regulations, (3) experience gained at similar sites, and (4) the probable level of involvement and financial condition of other potentially responsible parties. Unless there is a better estimate within this range of possible costs, the Utility records the lower end of this range.

At June 30, 2001, the Utility expects to spend $306 million, undiscounted, for hazardous waste remediation costs at identified sites, including divested fossil-fueled power plants. The cost of the hazardous substance remediation ultimately undertaken by the Utility is difficult to estimate. A change in the estimate may occur in the near term due to uncertainty concerning the Utility's responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives. If other potentially responsible parties are not financially able to contribute to these costs or further investigation indicates that the extent of contamination or necessary remediation is greater than anticipated, the Utility could spend as much as $459 million on these costs. The Utility estimates the upper limit of the range using assumptions least favorable to the Utility, based upon a range of reasonably possible outcomes. Costs may be higher if the Utility is found to be responsible for clean-up costs at additional sites or expected outcomes change.

The Utility had an environmental remediation liability of $306 million and $320 million at June 30, 2001 and December 31, 2000, respectively. The $306 million accrued at June 30, 2001 includes (1) $139 million related to the pre-closing remediation liability, associated with divested generation facilities (see further discussion in the "Generation Valuation " section of Note 2 of the Notes to the Condensed Consolidated Financial Statements), and (2) $167 million related to remediation costs for those generation facilities that the Utility still owns, manufactured gas plant sites, and gas gathering compressor stations. Of the $306 million environmental remediation liability, the Utility has recovered $139 million through rates, and expects to recover another $86 million in future rates. The Utility is seeking recovery of the remainder of its costs from insurance carriers and from other third parties as appropriate.

On June 28, 2001 the Bankruptcy Court entered its "Order on Debtor's Motion for Authority to Continue Its Hazardous Substances Cleanup Program". The Utility is authorized to expend (i) up to $22 million in each calendar year in which this Chapter 11 case is pending to continue its hazardous substance remediation programs and procedures, and (ii) any additional amounts necessary in emergency situations involving post-petition releases or threatened releases of hazardous substances, if such excess expenditures is necessary in the Utility's reasonable business judgment to prevent imminent harm to public health and safety or the environment (provided that the Utility seeks the Court's approval of such emergency expenditures at the earliest practicable time), in each case as described in the motion.

In December 1999, the Utility was notified by the purchaser of its former Moss Landing power plant that it had identified a cleaning procedure used at the plant that released heated water from the intake, and that this procedure is not specified in the plant's National Pollutant Discharge Elimination System (NPDES) permit issued by the Central Coast Regional Water Quality

Control Board (Central Coast Board). The purchaser notified the Central Coast Board of its findings. In March 2000, the Central Coast Board requested the Utility to provide specific information regarding the "backflush" procedure used at Moss Landing. The Utility provided the requested information to the Board in April 2000. The Utility's investigation indicated that while it owned Moss Landing, significant amounts of water were discharged from the cooling water intake. While the Utility's investigation did not clearly indicate that discharged waters had a temperature higher than ambient receiving water, the Utility believes that the temperature of the discharged water was higher than that of the ambient receiving water. In December 2000, the executive officer of the Central Coast Board made a settlement proposal to the Utility under which the Utility would pay $10 million, a portion of which would be used for environmental projects and the balance of which would constitute civil penalties. Settlement negotiations are continuing.

The Utility's Diablo Canyon employs a "once through" cooling water system, which is regulated under a NPDES Permit, issued by the Central Coast Board. This permit allows Diablo Canyon to discharge the cooling water at a temperature no more than 22 degrees above ambient receiving water and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, 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 (CDO) alleging that, although the temperature limit has never been exceeded, the Diablo Canyon's discharge was not protective of beneficial uses. In October 2000, the Central Coast Board and the Utility reached a tentative settlement of this matter pursuant to which the Central Coast Board has agreed to find that the Utility's discharge of cooling water from the Diablo Canyon plant protects beneficial uses and that the intake technology reflects "best technology available" under Section 316(b) of the Federal Clean Water Act. As part of the settlement, the Utility will take measures to preserve certain acreage north of the plant and will fund approximately $5 million in environmental projects related to coastal resources. The parties are negotiating the documentation of the settlement. The final agreement will be subject to public comment and will be incorporated in a consent decree to be entered in California Superior Court.

The Utility believes the ultimate outcome of these matters will not have a material impact on the Utility's financial position or results of operations.

PG&E National Energy Group

The U.S. Environmental Protection Agency (EPA) has been conducting a nationwide enforcement investigation regarding the historical compliance of coal-fueled electric generating stations with various permitting requirements of the Clean Air Act. Specifically, the EPA and the U.S. Department of Justice have recently initiated enforcement actions against a number of electric utilities, several of which have entered into substantial settlements for alleged Clean Air Act violations related to modifications (sometimes more than 20 years ago) of existing coal-fired generating facilities. In May 2000, PG&E NEG received a request for information seeking detailed operating and maintenance histories for the Salem Harbor and Brayton Point power plants and, in November 2000, the EPA visited both facilities. PG&E NEG believes this request for information is part of the EPA's industry-wide investigation of coal-fired power plants' compliance with the Clean Air Act requirements governing plant modifications. PG&E NEG also believes that any changes it made to these plants were routine maintenance or repair and, therefore, did not require permits. The EPA has not issued a notice of violation or filed any enforcement action against PG&E NEG at this time. Nevertheless, if the EPA disagrees with PG&E NEG's conclusions with respect to the changes PG&E NEG made at the facilities, and successfully brings an enforcement action against PG&E NEG, then penalties may be imposed and further emission reductions might be necessary at these plants.

From time to time various states in which our facilities are located consider the adoption of air emissions standards that may be more stringent than those imposed by the EPA. On May 11, 2001, the Massachusetts Department of Environmental Protection (DEP) issued regulations imposing new restrictions on emissions of NOx and SO2, mercury and carbon dioxide from existing coal-fired power plants. These restrictions will impose more stringent annual and monthly limits on NOx and SO2 emissions than currently exist and will take effect in stages, beginning in October 2004 if no permits are needed for the changes necessary to comply, and beginning in 2006 if such permits are needed. The DEP has informed PG&E NEG that, based upon its current understanding of the facilities' plans for compliance with the new regulations, it believes that permits will be needed and that the initial compliance date will therefore by 2006. However, the need for permits triggers an obligation to meet Best Available Control Technology (BACT) requirements. Compliance with BACT at the facilities could require implementation of controls beyond those otherwise necessary to meet the emissions standards in the new regulations. Mercury emissions are capped as a first step and must be reduced by October 2006 pursuant to standards to be developed. Carbon dioxide emissions are regulated for the first time and must be reduced from recent historical levels. PG&E NEG believes that compliance with the carbon dioxide caps can be achieved through implementation of a number of strategies, including sequestrations and offsite reductions. Various testing and recordkeeping requirements are also imposed.

By 2002, PG&E NEG plans to have approximately 5,100 MW of generating capacity in operation in New England. The new Massachusetts regulations affect primarily its Brayton Point and Salem Harbor generating facilities, representing approximately

2,300 MW. Through 2006, it may be necessary to spend approximately $265 million to comply with these regulations. In addition, with respect to approximately 600 MW (or about 12%) of PG&E NEG's New England capacity, PG&E NEG may need to implement fuel conversion, limit operations, or install additional environmental controls. These new regulations require that PG&E NEG achieve specified emission levels earlier than the dates included in a previous Massachusetts initiative to which it had agreed.

The Federal Clean Water Act generally prohibits the discharge of any pollutants, including heat, into any body of surface water, except in compliance with a discharge permit issued by a state environmental regulatory agency and/or the EPA. All of the facilities that are required to have such permits either have them or have timely applied for extensions of expired permits and are operating in substantial compliance with the prior permit. At this time, three of the fossil-fuel plants owned and operated by an affiliate of PG&E NEG USGen New

England, Inc. (Manchester Street, Brayton Point and Salem Harbor stations) are operating pursuant to permits that have expired. For the facilities whose NPDES permits have expired, permit renewal applications are pending, and PG&E NEG anticipates that all three facilities will be able to continue to operate in substantial compliance with prior permits until new permits are issued. It is estimated that USGen New England's cost to comply with new permit conditions could be approximately $60 million through 2005. It is possible that the new permits may contain more stringent limitations than the prior permit.

PG&E NEG anticipates spending up to approximately $330 million, net of insurance proceeds, through 2006 for environmental compliance at currently operating facilities, which primarily addresses: (a) new Massachusetts air regulations made public on April 23, 2001 affecting the Brayton Point and Salem Harbor Stations; (b) wastewater permitting requirements that may apply to the Brayton Point, Salem Harbor and Manchester Street Stations; and (c) requirements, to which PG&E NEG agreed, that are reflected in a consent decree concerning wastewater treatment facilities at the Salem Harbor and Brayton Point Stations.

During April 2000, an environmental group served USGen New England, Inc., and other subsidiaries with a notice of its intent to file a citizen's suit under RCRA. The group stated that it planned to allege that USGen New England, Inc. as the generator of fossil fuel combustion wastes at Salem Harbor and Brayton Point, has contributed and is contributing to the past and present handling, storage, treatment and disposal of wastes at those facilities which may present an imminent and substantial endangerment to the public health or the environment. During September 2000, USGen New England, Inc. signed a series of agreements with the Massachusetts Department of Environmental Protection and the environmental group that address and resolve these matters. The agreements, which have been filed in federal court and are now incorporated in a consent decree, require, among other things, that USGen New England, Inc. alter its existing wastewater treatment facilities at both facilities by replacing certain unlined treatment basins, submit and implement a plan for the closure of such basins, and perform certain environmental testing at the facilities. Although the outcome of such environmental testing could lead to higher costs, the total cost of these activities is expected to be approximately $21 million, and they are underway.

PRICE RISK MANAGEMENT ACTIVITIES

PG&E Corporation and its subsidiaries have established risk management policies that allow derivatives to be used for both trading and non-trading purposes (a derivative is a contract whose value is dependent on or derived from the value of some underlying asset). We use derivatives for non-trading (hedging) purposes primarily to offset our primary market risk exposures, which include commodity price risk, interest rate risk, and foreign currency risk. We also use derivatives, including those used for trading (non-hedging) purposes, to participate in markets to gather market intelligence, create liquidity, maintain a market presence, and enhance the value of our trading portfolio. Such derivatives include forward contracts, futures, swaps, options, and other contracts. Net open positions (that is, positions that are either not hedged or only partially hedged) often exist due to ownership of physical assets (such as power plants, gas pipelines, etc.) and the obligation to serve customers. Net open positions may also be established based on the assessment of market conditions, business objectives, and risk tolerance limits set by management. To the extent that PG&E Corporation and its subsidiaries have an open position, they are exposed to the risk that fluctuating commodity prices, interest rates, and foreign currency exchange rates may adversely impact their financial results.

PG&E Corporation and its subsidiaries may only engage in the trading of derivatives in accordance with policies established by the PG&E Corporation Risk Policy Committee. Trading is permitted only after the Risk Policy Committee authorizes such activity subject to appropriate financial exposure limits. Under PG&E Corporation, both PG&E NEG and the Utility have their own Risk Management Committees that address matters relating to those companies' respective businesses. These Risk Management Committees are comprised of senior officers.

Market Risk

Commodity Price Risk

Commodity price risk is the risk that changes in market prices will adversely affect earnings and cash flows. PG&E Corporation

is primarily exposed to the commodity price risk associated with energy commodities such as electricity and natural gas. Therefore, PG&E Corporation's strategy for reducing its commodity price risk exposure for its price risk management activities primarily involves buying and selling fixed-price commodity commitments into the future.

In compliance with regulatory requirements, the Utility manages price risk independently from the activities in PG&E Corporation's unregulated business. Because of different regulatory incentives and rate-making methods, the Utility reports its commodity price risk separately for its electricity and natural gas businesses. Price risk management strategies primarily consist of the use of non-trading (hedging) financial instruments to attain our objective of reducing the impact of commodity price fluctuations for electricity and natural gas associated with the Utility's procurement obligations to meet its retail electricity and natural gas loads. While the use of these instruments has been authorized by the CPUC, the CPUC has yet to establish rules around how it will judge the reasonableness of these instruments for electricity purchases. Gains and losses associated with the use of the majority of these financial instruments primarily affect regulatory accounts, depending on the business unit and the specific program involved.

Utility Electric Commodity Price Risk

The Utility has had a very limited ability to enter into forward contracts to hedge their exposure to commodity price fluctuations because of the reluctance of counterparties to extend credit. As the Utility's credit rating dropped below investment grade in January 2001, the DWR began purchasing wholesale power for electric customers on behalf of the State of California. In February 2001, because the Utility was unable to make payment to the PX for existing power purchases, the PX sought to liquidate the Utility's remaining block-forward contracts. Before they could do so, the PX block-forward contracts were seized by California Governor Gray Davis for the benefit of the State, acting under California's Emergency Services Act. As a result of continued increasing purchased power costs in excess of revenues from customers and lack of solutions to the energy crises, on April 6, 2001, the Utility sought protection from its creditors through a Chapter 11 bankruptcy filing. Many existing bilateral contracts were terminated in the first and second quarter of 2001 due to the downgrade of the Utility's credit rating and its subsequent bankruptcy filing. As explained in Note 2 of the Notes to the Condensed Consolidated Financial Statements, the Utility believes that it is no longer responsible for purchases made by DWR to meet the Utility's net open position. The Utility is currently paying DWR the amount of money it collects in retail rates for electricity (that is, excluding transmission, distribution, and other costs). The Utility believes that it is only obligated to pass through the amount it collects in electricity rates, and therefore, there is no price risk for electricity purchases to serve the net open position.

Although responsibility for the net open position currently lies with the DWR, it is anticipated that this responsibility will be transferred back to the Utility at an unknown future date. As explained in Note 2 of the Notes to the Condensed Consolidated Financial Statements, the Utility believes that the conditions required to end the rate freeze on retail electricity rates were met in 2000, after which time power purchase costs would be included in retail electricity rates. Electricity commodity price risks after the rate freeze ends would depend on how retail rates are determined. If traditional cost-of-service ratemaking methods are used, electricity commodity price risks would not have a material impact on PG&E Corporation's financial results.

Utility Natural Gas Commodity Price Risk

Under a rate-making method called the Core Procurement Incentive Mechanism (CPIM), the Utility recovers in retail rates the cost of procuring natural gas for its customers as long as the costs are within a 99% to 102% "dead-band" of a benchmark price. The benchmark price reflects a weighting of spot and forward gas prices that are representative of Utility gas purchases. Ratepayers and shareholders share costs or savings outside the dead-band equally. In addition, the Utility has contracts for capacity on the Transwestern gas pipeline. There is price risk related to the Transwestern gas pipeline to the extent that unused portions of the pipeline are brokered at floating rates.

Under a ratemaking method called the Gas Accord, shareholders are at risk for any revenues from the sale of capacity on the Utility's pipelines and gas storage fields held by the California Gas Transmission (CGT) business unit. The Utility is generally exposed to reduced revenues when price spreads narrow, although this exposure is mitigated through forward contracts.

PG&E NEG Commodity Price Risk

PG&E NEG is exposed to commodity price risk of its portfolio of electric generation assets and supply contracts that serve wholesale and industrial customers, in addition to various merchant plants currently in development. PG&E NEG manages such risks using a cost effective risk management program that primarily includes the buying and selling of fixed-price commodity commitments to lock in future cash flows of their forecasted generation. PG&E NEG is also exposed to commodity price risk of net open positions within their trading portfolio due to the assessment of and response to changing market conditions.

PG&E Corporation and its subsidiaries measure commodity price risk exposure using value-at-risk and other methodologies that

simulate future price movements in the energy markets to estimate the size and probability of future potential losses. We quantify market risk using a variance/co-variance value-at-risk model that provides a consistent measure of risk across diverse energy markets and products. The use of this methodology requires a number of important assumptions, including the selection of a confidence level for losses, volatility of prices, market liquidity, and a holding period.

PG&E Corporation uses historical data for calculating the price volatility of our contractual positions and how likely the prices of those positions will move together. The model includes all derivatives and commodity instruments in our trading and non-trading portfolios and only derivative commodity instruments for PG&E NEG's non-trading portfolio (not the related underlying hedged position). PG&E Corporation and the Utility express value-at-risk as a dollar amount of the potential loss in the fair value of our portfolios based on a 95% confidence level using a one-day liquidation period. Therefore, there is a 5% probability that PG&E Corporation and its subsidiaries portfolios will incur a loss in one day greater than its value-at-risk.

The Utility's daily value-at-risk commodity price risk exposure for non-trading activities as of June 30, 2001, was $11 million for its natural gas business. The Utility believes that there is currently no commodity price risk associated with fluctuating electric power prices, because these costs should be fully reflected in future retail rates.

PG&E NEG's daily value-at-risk commodity price risk exposure as of June 30, 2001, was $15 million for trading activities and $36 million for non-trading activities.

Value-at-risk has several limitations as a measure of portfolio risk, including, but not limited to, underestimation of the risk of a portfolio with significant options exposure, inadequate indication of the exposure of a portfolio to extreme price movements, and the inability to address the risk resulting from intra-day trading activities. Value-at-risk also does not reflect the significant regulatory, legislative, and legal risks currently facing the Utility due to the Utility's bankruptcy proceedings and the current California energy crisis.

Interest Rate Risk

PG&E Corporation is exposed to changes in interest rates primarily as a result of its variable rate commercial paper, bonds, bank loans, floating rate notes, project financing, and investing activities. In addition, PG&E Corporation is exposed to changes in interest rates on interest accruing on loan payments and trade payables currently in default. For a complete discussion of the risk management strategies and financial instruments used to manage interest rate risk, see PG&E Corporation's 2000 Annual Report on Form 10-K. PG&E Corporation uses sensitivity analysis to measure its interest rate price risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. As of June 30, 2001, if interest rates had averaged 1% higher, PG&E Corporation's earnings would have decreased by approximately $17 million.

Foreign Currency Risk

PG&E Corporation is exposed to foreign currency risk associated with the Canadian dollar. For a complete discussion of the risk management strategies and financial instruments used to manage foreign currency risk, see PG&E Corporation's 2000 Annual Report on Form 10-K. PG&E Corporation uses sensitivity analysis to measure its foreign currency exchange rate exposure to the Canadian dollar. As of June 30, 2001, if the Canadian dollar experienced a 10% devaluation, estimated losses would not have had a material impact on PG&E Corporation's consolidated financial statements.

LEGAL MATTERS

In the normal course of business, both the Utility and PG&E Corporation are named as parties in a number of claims and lawsuits. See Note 6 of the Notes to the Condensed Consolidated Financial Statements for further discussion of significant pending legal matters.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PG&E Corporation's and Pacific Gas and Electric Company's primary market risk results from changes in energy prices and interest rates. We engage in price risk management activities for both trading and non-trading purposes. Additionally, we may engage in trading and non-trading activities using forwards, futures, options, and swaps to hedge the impact of market fluctuations on energy commodity prices, interest rates, and foreign currencies. (See Risk Management Activities, included in Management's Discussion and Analysis above.)

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Pacific Gas and Electric Company Bankruptcy

As previously reported, on April 6, 2001, the Utility filed a voluntary petition for relief under the provisions of Chapter 11 of the United States Bankruptcy Code. Bankruptcy law imposes an automatic stay to prevent parties from making certain claims or taking certain actions that would interfere with the estate or property of a Chapter 11 debtor. In general, the Utility may not pay pre-petition debts without the Bankruptcy Court's permission. Under the Bankruptcy Code, the Utility has the right to reject or assume executory contracts (contracts that require future performance). The last day for non-governmental unit creditors to file proofs of claim is September 5, 2001 and the last day for government entities to file proof of claims is October 3, 2001.

Since the filing, the Bankruptcy Court has approved various requests by the Utility to permit the Utility to carry on its normal business operations and to pay certain pre-petition obligations. For a discussion of some of these proceedings see the Quarterly Report on Form 10-Q filed by PG&E Corporation and Pacific Gas and Electric Company for the quarter ended March 31, 2001. More recently, the Bankruptcy Court has approved the Utility's assumption of various hydroelectric contracts with water agencies and irrigation districts, the implementation of a management retention program, and the continuation of environmental remediation and capital expenditure programs. Other recent proceedings are discussed below.

On May 18, 2001, the Bankruptcy Court vacated the United States Trustee's appointment of a ratepayers' committee finding that the Bankruptcy Code does not authorize the creation of such a committee. Under the Bankruptcy Code, only creditors and equity security holders are eligible for appointment to a committee by the U.S. Trustee. The Bankruptcy Court noted that under the Bankruptcy Code, there are legitimate ways by which the ratepayers can be represented and heard in the process, for example, through the California Attorney General's Office. In addition, the Bankruptcy Code provides flexibility and discretion to the court to allow parties to intervene in the case when they have standing to do so. On July 10, 2001, the Bankruptcy Court denied the U.S. Trustee's motion to reconsider its earlier order.

On June 1, 2001, the Bankruptcy Court issued a decision denying the Utility's request for an injunction against the California Public Utilities Commission (CPUC) and its Commissioners to prohibit the implementation or enforcement of the CPUC's March 27, 2001 decision adopting changes to the transition period accounting mechanisms. The Court also granted the CPUC's motion to dismiss the complaint. Although the Court held that the Eleventh Amendment to the U.S. Constitution did not bar the Utility's suit against the individual Commissioners, the Court concluded that the Utility was not entitled to a stay or an injunction to prevent implementation and enforcement of the regulatory accounting order. First, the Court held that, assuming the Bankruptcy Code provision imposing an automatic stay on pre-petition proceedings might ordinarily apply (an issue that the Court expressly declined to decide), the Court determined that the Commissioners were acting pursuant to their police and regulatory power when issuing the order. Accordingly, the Court found that the order was exempt from the automatic stay provision pursuant to a statutory exemption for the commencement or continuation of an action or proceeding by a governmental unit to enforce such governmental unit's police and regulatory power. Second, the Court held that the Utility had not shown any actual or threatened violation of federal law sufficient to warrant injunctive relief, nor did the balance of equities favor an injunction. The Utility's application for rehearing of the CPUC's decision remains pending at the CPUC. The Utility has initiated an appeal of the Bankruptcy Court's decision to the United States District Court for the Northern District of California, and the CPUC and its Commissioners have initiated a cross-appeal, both of which are pending.

The first meeting of creditors was held as scheduled on June 7, 2001. Senior executives of the Utility made themselves available to respond to questions from the U.S. Trustee and participating creditors about the Utility's assets, liabilities and administration of the Chapter 11 estate.

As previously disclosed, the Utility filed a complaint for injunctive and declaratory relief in the Bankruptcy Court asking the court to prohibit the ISO from charging the Utility for the ISO's wholesale power purchases made in violation of bankruptcy law, the ISO's tariff, and the FERC's February 14 and April 6, 2001 orders. In the order issued on February 14, 2001, the FERC rejected the ISO's January 5, 2001 proposed tariff amendment which would have waived certain credit standards relating to third party transactions and ordered that the ISO could only engage in power purchases on behalf of creditworthy entities. The Utility has not met the creditworthiness standards of the ISO tariff since January 4, 2001. Despite the FERC orders, the ISO has continued to bill the Utility for the ISO's wholesale power purchases.

On June 18, 2001 the Bankruptcy Court granted a motion by Reliant Energy, Inc. and Reliant Energy Services, Inc. (collectively, Reliant) to intervene in the Utility's action against the ISO. Reliant has intervened in the action to seek a permanent injunction barring the ISO from procuring power to meet the Utility's net short position in violation of its tariff and applicable FERC orders. If the Bankruptcy Court declines to issue such an injunction, Reliant has asked the Bankruptcy Court in the alternative to declare that the Utility is liable to Reliant for power procured by the ISO from Reliant and delivered to the Utility's service area.

On June 26, 2001, the Bankruptcy Court issued a preliminary injunction in the Utility's action against the ISO, prohibiting the ISO from violating the FERC orders discussed above and from filing administrative claims against the Utility in the bankruptcy for ISO charges for wholesale power purchases and other services in the ISO market. In issuing the injunction, the Bankruptcy Court noted that the FERC orders permit the ISO to schedule transactions that involve either a creditworthy buyer or a creditworthy counterparty, and noted the existence of unresolved issues regarding how to ensure these creditworthiness requirements for real-time transactions and emergency dispatch orders issued by the ISO to power sellers. The Utility believes that its only responsibility for third party power delivered to its customers and related costs since it ceased to be creditworthy is to pay the DWR the amount collected from customers pursuant to AB 1X.

In addition to alleging violations of the FERC orders and the creditworthiness provisions of the ISO tariff, the Utility's complaint also seeks to have the court declare that any action by the ISO to purchase wholesale power for or on behalf of the Utility at costs the Utility is not permitted to fully recover through the generation- related cost component of retail rates, to compel the Utility to accept and pay for such purchases, or to accrue post-petition debt for such purchases (i.e., to accrue debts after April 6, 2001, when the Utility filed its petition under Chapter 11 of the federal Bankruptcy Code), is automatically stayed by bankruptcy law and violates other provisions of the Bankruptcy Code. In addition, the complaint seeks a permanent injunction prohibiting the ISO from taking such actions.

On July 20, 2001, the Bankruptcy Court granted the Utility's unopposed motion to extend the period during which the Utility has the exclusive right to file with the Bankruptcy Court a plan of reorganization that specifies, among other things, the treatment of claims. Although the initial 120-day period was to expire on August 6, 2001, the court extended the exclusivity period until December 6, 2001. If the Utility files a plan of reorganization before December 6, 2001, the exclusivity period will be extended automatically until February 4, 2002, giving the Bankruptcy Court time to consider confirmation of the Utility's plan. After the exclusivity period, and assuming the Bankruptcy Court has not yet confirmed the Utility's plan of reorganization, creditors and other parties in interest may file their own plan of reorganization.

Further, during July 2001, the Utility reached agreements with 131 of the Utility's QF suppliers, representing about 1,600 MW of the average annual 2,400 MW that the Utility receives from its QFs. Under the agreements, the Utility will assume the existing QF contracts, as modified to require the Utility to pay the QFs a fixed average energy price of 5.37 cents per kWh for five years. Currently, the contracts require the Utility to pay the QFs a price that fluctuates with natural gas prices. In addition, the Utility has agreed to pay the pre-petition debt on these 131 contracts, approximately $740 million, on the effective date of the plan of reorganization. The total amount of debt the Utility owed to QFs when it filed bankruptcy was approximately $1 billion. For certain QFs, if the effective date has not occurred by July 15, 2003, the Utility has agreed to pay 2% of the principal amount of the pre-petition debt per month until the effective date of the plan of reorganization or until July 15, 2005, when the Utility would pay the remaining pre-petition debt. The agreements require the approval of the Bankruptcy Court before they can become effective. Most of the agreements have already been approved and the Utility has filed or will file motions asking the Bankruptcy Court to approve the remaining agreements. The proposed agreements contain modifications approved by the CPUC in a decision issued on June 13, 2001, whereby certain QFs under Standard Offer contracts with the Utility who establish hardship may request that their contracts be modified to replace the energy pricing term with a one- year energy price that establishes the Utility's full short-run avoided operating costs as the lesser of (a) the energy price determined under the short-run avoided energy price formula previously adopted by the CPUC for the Utility, as in effect on March 1, 2001, or (b) the energy price determined under the short-run avoided energy price formula previously adopted by the CPUC for the Utility, as in effect on March 1, 2001, but with the QFs' actual California border gas costs substituted for the Malin and Topock gas index prices otherwise used in such formula.

Federal Securities Lawsuit

By order entered on or about May 31, 2001, the action entitled Jack Gillam; DOES 1 TO 5, Inclusive, and All Persons similarly situated vs. PG&E Corporation, Pacific Gas and Electric Company; and DOES 6 to 10, Inclusive, described in the Quarterly Report on Form 10-Q filed by PG&E Corporation and Pacific Gas and Electric Company for the quarter ended March 31, 2001, was transferred from the U.S. District Court for the Central District of California to the U.S. District Court for the Northern District of California.

For a discussion of other pending legal proceedings, see the Annual Report on Form 10-K filed by PG&E Corporation and Pacific Gas and Electric Company for the year ended December 31, 2000, and the Quarterly Report on Form 10-Q filed by PG&E Corporation and Pacific Gas and Electric Company for the quarter ended March 31, 2001,

Item 3. Defaults Upon Senior Securities

The Utility has authorized 75 million shares of First Preferred Stock ($25 par value) and 10 million shares of $100 First Preferred Stock ($100 par value), which may be issued as redeemable or non-redeemable preferred stock. (The Utility has not issued any $100 First Preferred Stock.) At June 30, 2001, the Utility had issued and outstanding 5,784,824 shares of non-redeemable preferred stock and 5,973,456 shares of redeemable preferred stock. The Utility's redeemable preferred stock is subject to redemption at the Utility's option, in whole or in part, if the Utility pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. The Utility's redeemable preferred stock with mandatory redemption provisions consists of 3 million shares of the 6.57 percent series and 2.5 million shares of the 6.30 percent series at December 31, 2000. The 6.57 percent series and 6.30 percent series may be redeemed at the Utility's option beginning in 2002 and 2004, respectively, at par value plus accumulated and unpaid dividends through the redemption date. These series of preferred stock are subject to mandatory redemption provisions entitling them to sinking funds providing for the retirement of stock outstanding. At December 31, 2000, the redemption requirements for the Utility's redeemable preferred stock with mandatory redemption provisions are $4 million per year beginning 2002, and $3 million per year beginning 2004, for the series 6.57 percent and 6.30 percent, respectively.

Holders of the Utility's non-redeemable preferred stock 5 percent, 5.5 percent, and 6 percent series have rights to annual dividends per share ranging from $1.25 to $1.50.

Due to the California energy crisis, the Utility's Board of Directors did not declare the regular preferred stock dividends for the three-month periods ending January 31, 2001 (normally payable on February 15, 2001), April 30, 2001 (normally payable May 15, 2001), and July 31, 2001 (normally payable August 15, 2001).

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and equal preference in dividend and liquidation rights. Accumulated and unpaid dividends for the three-month periods ending January 31 and April 30, 2001, amounted to $12.7 million. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series. Until cumulative dividends on its preferred stock are paid, the Utility may not pay any dividends on its common stock, nor may the Utility repurchase any of its common stock.

The Utility's total defaulted commercial paper outstanding as of June 30, 2001, was $873 million. As of June 30, 2001, the Utility had drawn and had outstanding $938 million under the bank credit facility, which was also in default. For the quarter ending June 30, 2001, the Utility has not made any payments on its bank loan drawdowns or defaulted commercial paper.

With regard to certain pollution control bond-related debt of the Utility, the Utility has been in default under the credit agreements with the banks that provide letters of credit as credit and liquidity support for the underlying pollution control bonds. These defaults included the Utility's non-payment of other debt in excess of $100 million, the Utility's filing of a petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code and non-payment of interest. As a result of these defaults, several of the letter of credit banks caused the acceleration and redemption of four series of pollution control bonds. All of these redemptions were funded by the letter of credit banks resulting in like obligations from the Utility to the banks, which have not been paid. As of June 30, 2001, the total principal of the bonds (and related loans) accelerated and redeemed was $454 million. As of June 30, 2001, the Utility did not make interest payments of $5.2 million on pollution control bonds series 96C, E, F and 97B. As of June 30, 2001, the Utility did not make an interest payment of $2.7 million on pollution control bond series 96A backed by bond insurance. With regard to certain pollution control bond-related debt of the Utility backed by the Utility's mortgage bonds, an event of default has occurred under the relevant loan agreements with the California Pollution Control Financing Authority due to the Utility's bankruptcy filing.

The Utility's filing of a petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code also constitutes a default under the indenture that governs its medium term notes ($287 million aggregate amount outstanding), five-year 7.375% senior notes ($680 million aggregate amount outstanding), and floating rate notes ($1.24 billion aggregate amount outstanding). In addition, as of June 30, 2001, the Utility has not made interest payments on its 7.375% senior notes and its $1.24 billion floating rate notes. As of June 30, 2001, the total arrearage of these interest payments was $48.3 million. Also as of June 30, 2001, the Utility did not make interest payments on other long-term debt of $.5 million.

With regard to the 7.90% Quarterly Income Preferred Securities (QUIPS) and the related 7.90% Deferrable Interest Debentures (debentures), the Utility's filing of a petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code is an event of default under the applicable indenture. Pursuant to the related trust agreement, the trustee is required to take steps to liquidate the trust and distribute the debentures to the QUIPS holders.

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

PG&E Corporation:

On May 16, 2001, PG&E Corporation held its annual meeting of shareholders. At that meeting, the shareholders voted as indicated below on the following matters:

1. Election of the following directors to serve until the next annual meeting of shareholders or until their successors are elected and qualified (included as Item 1 in proxy statement):

	For
David R. Andrews	258,499,976
David A. Coulter	261,767,229
C. Lee Cox	261,954,208
William S. Davila	261,901,022
Robert D. Glynn, Jr.	261,618,101
David M. Lawrence, MD	261,873,600

Mary S. Metz	261,742,063
Carl E. Reichardt	261,752,099
Barry Lawson Williams	261,728,932

2. Ratification of the appointment of Deloitte & Touche LLP as independent public accountants for 2001 (included as Item 2 in proxy statement):

For:	266,161,911
Against:	7,186,368
Abstain:	3,090,821

The proposal was approved by a majority of the shares represented and voting (including abstentions) which shares voting affirmatively also constituted a majority of the required quorum.

3. Management proposal regarding increase in shares available to be issued under the PG&E Corporation Long Term Incentive Program (included as Item 3 in proxy statement).

For:	227,672,764
Against:	44,286,370
Abstain:	4,479,966
Broker non-vote:	0

The proposal was approved by a majority of the shares represented and voting (including abstentions) which shares voting affirmatively also constituted a majority of the required quorum.

4. Consideration of a shareholder proposal regarding confidential shareholder voting (included as Item 4 in proxy statement):

For:	57,869,881
Against:	165,503,947
Abstain:	6,072,815
Broker non-vote: (1)	46,992,457

This shareholder proposal was defeated, as the number of shares voting affirmatively on the proposal constituted less than a majority of the shares represented and voting (including abstentions but excluding broker non- votes) with respect to the proposal.

5. Consideration of a shareholder proposal regarding the treatment of abstentions (included as Item 5 in proxy statement):

For:	36,456,683
Against:	186,712,779

Abstain:	6,277,181
Broker non-vote: (1)	46,992,457

This shareholder proposal was defeated, as the number of shares voting affirmatively on the proposal constituted less than a majority of the shares represented and voting (including abstentions but excluding broker non- votes) with respect to the proposal.

6. Consideration of a shareholder proposal regarding cumulative voting (included as Item 6 in proxy statement):

For:	32,248,291
Against:	190,607,501
Abstain:	6,590,851
Broker non-vote: (1)	46,992,457

This shareholder proposal was defeated, as the number of shares voting affirmatively on the proposal constituted less than a majority of the shares represented and voting (including abstentions but excluding broker non- votes) with respect to the proposal.

7. Consideration of a shareholder proposal regarding the minimum number of directors (included as Item 7 in proxy statement):

For:	18,633,524
Against:	204,574,825
Abstain:	6,238,294
Broker non-vote: (1)	46,992,457

This shareholder proposal was defeated, as the number of shares voting affirmatively on the proposal constituted less than a majority of the shares represented and voting (including abstentions but excluding broker non- votes) with respect to the proposal.

8. Consideration of a shareholder proposal regarding the fair price provision (Article Eighth of the Articles of Incorporation) (included as Item 8 in proxy statement):

For:	127,746,676
Against:	95,311,869
Abstain:	6,238,294
Broker non-vote: (1)	46,992,457

This shareholder proposal was approved as the number of shares voting affirmatively on the proposal constituted more than a majority of the shares represented and voting (including abstentions but excluding broker non- votes) with respect to the proposal, and the affirmative votes constituted a majority of the required quorum.

9. Consideration of a shareholder floor proposal introduced at the annual meeting regarding company statements in opposition to shareholder proposals was duly and properly conducted by ballot.

For:	26,744
Against:	276,403,728
Abstain:	874
Broker non-vote: (1)	0

This shareholder proposal was defeated, as the number of shares voting affirmatively on the proposal constituted less than a majority of the shares represented and voting (including abstentions) with respect to the proposal.

10. Consideration of a shareholder floor proposal introduced at the annual meeting regarding company recommendations for voting on shareholder proposals was duly and properly conducted by ballot.

For:	27,472
Against:	276,403,492
Abstain:	774
Broker non-vote: (1)	0

(1) A non-vote occurs when a broker or other nominee holding shares for a beneficial owner indicates a vote on one or more proposals, but does not indicate a vote on other proposals because the broker or other nominee does not have discretionary voting power as to such proposals and has not received voting instructions from the beneficial owner as to such proposals.

This shareholder proposal was defeated, as the number of shares voting affirmatively on the proposal constituted less than a majority of the shares represented and voting (including abstentions) with respect to the proposal.

11. Consideration of a shareholder floor proposal introduced at the annual meeting regarding information on directors' business relationships with PG&E Corporation was duly and properly conducted by ballot.

For:	29,824
Against:	276,401,140
Abstain:	774
Broker non-vote: (1)	0

This shareholder proposal was defeated, as the number of shares voting affirmatively on the proposal constituted less than a majority of the shares represented and voting (including abstentions) with respect to the proposal.

12. Consideration of a shareholder floor proposal introduced at the annual meeting regarding information on executive and director compensation was duly and properly conducted by ballot.

For:	29,804
Against:	276,401,160
Abstain:	774
Broker non-vote: (1)	0

This shareholder proposal was defeated, as the number of shares voting affirmatively on the proposal constituted less than a majority of the shares represented and voting (including abstentions) with respect to the proposal.

13. Consideration of a shareholder floor proposal introduced at the annual meeting regarding information on 2001 executive compensation was duly and properly conducted by ballot.

For:	29,032
Against:	276,401,760
Abstain:	506
Broker non-vote: (1)	0

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This shareholder proposal was defeated, as the number of shares voting affirmatively on the proposal constituted less than a majority of the shares represented and voting (including abstentions) with respect to the proposal.

Pacific Gas and Electric Company:

On May 16, 2001, Pacific Gas and Electric Company held its annual meeting of shareholders. Shares of capital stock of Pacific Gas and Electric Company consist of shares of common stock and shares of first preferred stock. As PG&E Corporation and a subsidiary own all of the outstanding shares of common stock, they hold approximately 95% of the combined voting power of the outstanding

capital stock of Pacific Gas and Electric Company. PG&E Corporation and the subsidiary voted all of their respective shares of common stock for the nominees named in the 2001 joint proxy statement and for the ratification of the appointment of Deloitte & Touche LLP as independent public accountants for 2001. The balance of the votes shown below were cast by holders of shares of first preferred stock. At the annual meeting, the shareholders voted as indicated below on the following matters:

1. Election of the following directors to serve until the next annual meeting of shareholders or until their successors are elected and qualified:

	For	Withheld
David R. Andrews	338,304,620	637,790
David A. Coulter	338,321,293	621,117
C. Lee Cox	338,324,918	617,492
William S. Davila	338,331,671	610,739
Robert D. Glynn, Jr.	337,063,120	1,879,290

David M. Lawrence, MD	338,330,527	611,883
Mary S. Metz	338,327,998	614,412
Carl E. Reichardt	338,328,014	614,396
Gordon R. Smith	337,063,937	1,878,473
Barry Lawson Williams	338,324,783	617,627

2. Ratification of the appointment of Deloitte & Touche LLP as independent public accountants for 2001:

For:	338,679,391
Against:	111,360
Abstain:	151,659

Item 5. Other Information

Ratio of Earnings to Fixed Charges and Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends

Pacific Gas and Electric Company's earnings to fixed charges ratio for the six months ended June 30, 2001, was a negative 0.06. Pacific Gas and Electric Company's earnings to combined fixed charges and preferred stock dividends ratio for the six months ended June 30, 2001, was a negative 0.05. The negative ratios of earnings to fixed charges and earnings to combined fixed charges and preferred stock dividends indicates a deficiency in earnings of $492 million and $510 million respectively. The statement of the foregoing ratios, together with the statements of the computation of the foregoing ratios filed as Exhibits 12.1 and 12.2 hereto, are included herein for the purpose of incorporating such information and exhibits into Registration Statement Nos. 33-62488, 33-64136, 33-50707, and 33-61959, relating to Pacific Gas and Electric Company's various classes of debt and first preferred stock outstanding.

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits:

Exhibit 10 PG&E Corporation Long-Term Incentive Program, as amended effective May 16, 2001 (incorporated by reference from PG&E Corporation and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001, Exhibit 10.)

Exhibit 11 Computation of Earnings Per Common Shares (incorporated by reference from PG&E Corporation and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001, Exhibit 11.)

Exhibit 12.1 Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company (incorporated by reference from PG&E Corporation and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended June 30, Exhibit 12.1.)

Exhibit 12.2 Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company (incorporated by reference from PG&E Corporation and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001, Exhibit 12.2.)

(b) The following Current Reports on Form 8-K were filed during the first quarter of 2001 and through the date hereof (2):

1. April 6, 2001 (as amended) filed by PG&E Corporation only Item 5. Other Events - Pacific Gas and Electric Company Bankruptcy

2. April 6, 2001 (as amended) filed by Pacific Gas and Electric Company only Item 3. Other Events - Bankruptcy or Receivership.

3. May 2, 2001 Item 9. Regulation FD Disclosure

4. May 7, 2001 - filed by PG&E Corporation only Item 9. Regulation FD Disclosure

5. May 8, 2001 Item 5. Other Events A. Federal Lawsuit B. Pacific Gas and Electric Company Bankruptcy

6. June 6, 2001 Item 5. Other Events Pacific Gas and Electric Company Bankruptcy Item 9. Regulation FD Disclosure

7. July 9, 2001 Item 5. Other Events

8. July 30, 2001 Item 5. Other Events

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this report to be signed on their behalf by the undersigned thereunto duly authorized.

PG&E CORPORATION

By /s/ CHRISTOPHER P. JOHNS

CHRISTOPHER P. JOHNS
Senior Vice President and Controller
(duly authorized officer and principal accounting officer)

PACIFIC GAS AND ELECTRIC COMPANY

By /s/ KENT M. HARVEY

KENT M. HARVEY
Senior Vice President, Chief Financial Officer, and Treasurer (duly authorized officer and principal financial officer)

Dated: March 5, 2002

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Exhibit Index

Exhibit No. Description of Exhibit

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