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 March 31, 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
1-12609	PG&E Corporation California	California
1-2348	Pacific Gas and Electric Company	California
Pacific Gas and Electric Company	PG&E Corporation	
77 Beale Street	One Market, Spear Tower	
P.O. Box 770000	Suite 2400	
San Francisco, California 94177	San Francisco, California 94105	
(Address of principal executive offices)		(Zip Code)
Pacific Gas and Electric Company		PG&E Corporation
(415) 973-7000		(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 April 30, 2001:

PG&E Corporation	387,135,242 shares
Pacific Gas and Electric Company	Wholly owned by PG&E Corporation

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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 March 31, 2001, contains revised Consolidated Financial Statements for PG&E Corporation for the quarters ended March 31, 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.

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PG&E CORPORATION AND
PACIFIC GAS AND ELECTRIC COMPANY

Form 10-Q/A
FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2001
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PART I. FINANCIAL INFORMATION

ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

	For the three months ended March 31,	
	2001	2000
	(As revised, see Note 10)	
Operating Revenues		
Utility	$ 2,562	$2,218
Energy commodities and services	4,111	2,784
Total operating revenues	6,673	5,002
Operating Expenses		
Cost of energy for utility	3,343	796
Cost of energy commodities and services	3,839	2,472
Operating and maintenance	728	711
Depreciation, amortization, and decommissioning	103	347
Total operating expenses	8,013	4,326
Operating Income (Loss)	(1,340)	676
Interest income	35	24
Interest expense	(247)	(183)
Other income (expense), net	(9)	(9)

Income (Loss) Before Income Taxes	(1,561)	508
Income tax provision (benefit)	(610)	228
Net Income (Loss)	$ (951)	$ 280
Weighted average common shares outstanding	363	361
Earnings (Loss) Per Common Share, Basic		
Net Earnings (Loss)	$ (2.62)	$ .78
Earnings (Loss) Per Common Share, Diluted		
Net Earnings (Loss)	$ (2.62)	$ .77
Dividends Declared Per Common Share	$ -	$ .30

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	
	March 31, 2001	December 31, 2000
	(As revised, see Note 10)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 682	$ 925
Short-term investments	2,911	1,634
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $91 million and $71 million, respectively)	3,030	4,340
Regulatory balancing accounts	34	222
Price risk management assets	3,457	2,039
Inventories	370	392
Income taxes receivable	-	1,241
Prepaid expenses and other	902	406
Total current assets	11,386	11,199
Property, Plant, and Equipment		
Utility	24,030	23,872
Non-utility:		
Electric generation	2,075	2,008

Gas transmission	1,555	1,542
Construction work in progress	1,852	1,605
Other	117	147
Total property, plant, and equipment (at original cost)	29,629	29,174
Accumulated depreciation and decommissioning	(12,073)	(11,878)
Net property, plant, and equipment	17,556	17,296
Other Noncurrent Assets		
Regulatory assets	1,821	1,773
Nuclear decommissioning funds	1,328	1,328
Price risk management assets	1,101	2,026
Other	2,873	2,530
Total noncurrent assets	7,123	7,657
TOTAL ASSETS	$ 36,065	$ 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 BALANCE SHEETS
(in millions, except share amounts)

	Balance at	
	March 31, 2001	December 200
	(As revised, see Note	
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	$ 3,586	$ 4,5
Long-term debt, classified as current	2,309	2,3
Current portion of rate reduction bonds	290	2
Accounts payable:		
Trade creditors	6,299	5,8
Regulatory balancing accounts	579	1
Other	571	4
Price risk management	3,533	1,9
Other	1,739	1,5
Total current liabilities	18,906	17,3
Noncurrent Liabilities		
Long-term debt	6,606	5,5
Rate reduction bonds	1,665	1,7
Deferred income taxes	951	1,6
Deferred tax credits	182	1
Price risk management	1,354	1,8

Other	3,715	3,8
Total noncurrent liabilities	14,473	14,8
Preferred stock of subsidiaries	480	4
Utility obligated mandatorily redeemable preferred securities of trust holding soley utility subordinated debentures	300	3
Common stockholders' equity		
Common stock, no par value, authorized 800,000,000 shares, issued 387,183,478 and 387,193,727 shares, respectively	5,971	5,9
Common stock held by subsidiary, at cost, 23,815,500 shares	(690)	(6
Accumulated deficit	(3,056)	(2,1
Accumulated other comprehensive loss	(319)	
Total common stockholders' equity	1,906	3,1
Commitments and Contingencies (Notes 1, 2 and 5)	-	
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 36,065	$ 36,1

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

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

	For the three months ended March 31, 2001	2000
	(As revised, see Note 10)	
Cash Flows From Operating Activities		
Net income (loss)	$ (951)	$ 280
Adjustments to reconcile net income (loss) to net cash provided (used) by operating activities:		
Depreciation, amortization, and decommissioning	103	347
Deferred income taxes and tax credits-net	(527)	(145)
Price risk management assets and liabilities, net	25	(11)
Other deferred charges and noncurrent liabilities	(149)	(9)
Net effect of changes in operating assets and liabilities:		
Short-term investments	(1,277)	142
Accounts receivable-trade	1,310	40
Inventories	22	55
Accounts payable	515	(90)
Regulatory balancing accounts	571	254
Accrued taxes	1,241	318
Other working capital	(217)	(118)
Other-net	9	26
Net cash provided by operating activities	675	1,089

Cash Flows From Investing Activities		
Capital expenditures	(538)	(450)
Other-net	(147)	81
Net cash used by investing activities	(685)	(369)
Cash Flows From Financing Activities		
Net repayments under credit facilities	(993)	(547)
Long-term debt issued	1,105	108
Long-term debt matured, redeemed, or repurchased	(236)	(201)
Common stock issued	-	10
Dividends paid	(109)	(108)
Other-net	-	3
Net cash used by financing activities	(233)	(735)
Net Change in Cash and Cash Equivalents	(243)	(15)
Cash and Cash Equivalents at January 1	925	282
Cash and Cash Equivalents at March 31	$ 682	$ 267
Supplemental disclosures of cash flow information		
Cash paid for:		
Interest (net of amounts capitalized)	$ 235	$ 119
Income taxes paid (refunded) - net	(1,241)	3

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
CONDENSED STATEMENTS OF CONSOLIDATED OPERATIONS

(in millions)

	For the three months ended March 31, 2001	2000
Operating Revenues		
Electric	$1,259	$1,601
Gas	1,303	617
Total operating revenues	2,562	2,218
Operating Expenses		
Cost of electric energy	2,427	513
Cost of gas	916	283
Operating and maintenance	574	551
Depreciation, amortization, and decommissioning	65	301
Total operating expenses	3,982	1,648
Operating Income (Loss)	(1,420)	570
Interest income	7	6
Interest expense	201	141
Other income (expense), net	(4)	(1)

Income (Loss) Before Income Taxes	(1,618)	434
Income tax provision (benefit)	(624)	200
Net Income (Loss)	(994)	234
Preferred dividend requirement	6	6
Income (Loss) Available for (Allocated to) Common Stock	$(1,000)	$228

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
CONDENSED CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

	Balance a	
	March 31, 2001	Dec
ASSETS		
Current Assets		
Cash and cash equivalents	$ 154	$
Short-term investments	2,610	
Accounts receivable		
Customers (net of allowance for doubtful accounts of $53 million and $52 million, respectively)	1,574	
Related parties	5	
Regulatory balancing account	34	
Inventories		
Gas stored underground and fuel oil	151	
Materials and supplies	133	
Income taxes receivable	-	
Prepaid expenses and other	443	
Total current assets	5,104	
Property, Plant, and Equipment		
Electric	16,446	
Gas	7,584	
Construction work in progress	300	
Total property, plant, and equipment (at original cost)	24,330	
Accumulated depreciation and decommissioning	(11,281)	
Net property, plant, and equipment	13,049	
Other noncurrent assets		
Regulatory assets	1,780	
Nuclear decommissioning funds	1,328	
Other	1,194	
Total noncurrent assets	4,302	

TOTAL ASSETS	$ 22,455	$

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

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

	Balance	
	March 31, 2001	De
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	$ 3,051	$
Long-term debt, classified as current	2,293	
Current portion of rate reduction bonds	290	
Accounts payable:		
Trade creditors	5,226	
Related parties	177	
Regulatory balancing accounts	579	
Other	365	
Price risk management	73	
Deferred income taxes	-	
Other	719	
Total current liabilities	12,773	
Noncurrent Liabilities		
Long-term debt	3,313	
Rate reduction bonds	1,665	
Deferred income taxes	921	
Deferred tax credits	182	
Price risk management	12	
Other	2,796	
Total noncurrent liabilities	8,889	
Preferred Stock With Mandatory Redemption Provisions 6.30% and 6.57%, outstanding 5,500,000 shares, due 2002-2009	137	
Company Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures 7.90%, 12,000,000 shares due 2025	300	
Stockholders' Equity		
Preferred stock without mandatory redemption provisions		
Nonredeemable - 5% to 6%, outstanding		

5,784,825 shares	145	
Redeemable - 4.36% to 7.04%, outstanding		
5,973,456 shares	149	
Common stock, $5 par value, authorized		
800,000,000 shares, issued 321,314,760 shares	1,606	
Common stock held by subsidiary, at cost,		
19,481,213 shares	(475)	
Additional paid-in capital	1,964	
Accumulated deficit	(2,979)	
Accumulated other comprehensive loss	(54)	
Total stockholders' equity	356	
Commitments and Contingencies (Notes 1, 2, and 5)	-	
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$22,455	$

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
CONDENSED STATEMENTS OF CONSOLIDATED CASH FLOWS
(in millions)

	For the three months ended March 31,	
	2001	200
Cash Flows From Operating Activities		
Net income (loss)	$ (994)	$ 23
Adjustments to reconcile net income to		
net cash (used) provided by operating activities:		
Depreciation, amortization, and decommissioning	65	30
Deferred income taxes and tax credit-net	(170)	(4
Price risk management assets and liabilities, net	10	
Other deferred charges and noncurrent liabilities	(110)	(5
Net effect of changes in operating assets and liabilities:		
Short-term investments	(1,327)	(
Accounts receivable	138	8
Income tax receivable	1,120	
Inventories	(4)	4
Accounts payable	1,579	(30
Regulatory balancing accounts	571	25
Other working capital	(352)	20
Other-net	(6)	(3
Net cash provided by operating activities	520	68
Cash Flows From Investing Activities		
Capital expenditures	(284)	(26
Other-net	22	5
Net cash used by investing activities	(262)	(21
Cash Flows From Financing Activities		

Net repayment under credit facilities	(28)	(24
Long-term debt matured, redeemed, or repurchased	(187)	(10
Dividends paid	-	(12
Other-net	-	(
Net cash used by financing activities	(215)	(47
Net Change in Cash and Cash Equivalents	43	
Cash and Cash Equivalents at January 1	111	8
Cash and Cash Equivalents at March 31	$ 154	$ 8
Supplemental disclosures of cash flow information		
Cash paid for:		
Interest (net of amounts capitalized)	$ 109	$ 7
Income taxes paid (refunded) - net	(1,120)	

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

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 (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 4, on April 6, 2001, the Utility filed a voluntary petition for relief under 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.

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.

The Utility's financial position and results of operations are the principal factors affecting PG&E Corporation's consolidated financial position and results of operations. 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

PG&E Corporation, primarily through its subsidiaries, engages in price risk management activities for both trading and non-trading purposes, as described below.

Trading Activities

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PG&E Corporation conducts trading activities principally through its subsidiaries owned by PG&E National Energy Group (PG&E NEG). Trading activities are conducted to generate profit, create liquidity, and maintain a market presence. Net open positions (that is, positions that are not hedged) often exist or are established due to the assessment of, and response to changing market conditions.

Derivative and other financial instruments associated with electricity, natural gas, natural gas liquids, and related trading activities are accounted for using the mark-to-market method of accounting. Under mark-to-market accounting, PG&E Corporation's trading contracts, including both physical contracts and financial instruments, are recorded at market value, which approximates fair value. The market prices used to value these transactions reflect management's best estimates considering various factors, including market quotes, time value, and volatility factors of the underlying commitments. The values are adjusted to reflect the potential impact of liquidating a position in an orderly manner over a reasonable period of time under present market conditions.

Changes in the market value of these contract portfolios, resulting primarily from newly originated transactions and the impact of commodity price or interest rate movements, are recognized in operating income in the period of change. Unrealized gains and losses on these contract portfolios are recorded as assets and liabilities, respectively, from price risk management.

Non-Trading Activities

In addition to the trading activities, as discussed previously, PG&E Corporation, principally through the Utility and PG&E NEG, engages in non-trading activities using futures, forward contracts, options, and swaps to hedge the impact of market fluctuations on energy commodity prices, interest rates, and foreign currencies when there is a high degree of correlation between price movements in the derivative and the item designated as being hedged. Non-trading activities are conducted to optimize and secure the return on risk capital deployed within PG&E NEG's existing asset and contractual portfolio. In addition, non-trading activity exists within the Utility to hedge against price fluctuations of electricity and natural gas.

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, requires PG&E Corporation and the Utility to recognize all derivatives, as defined in the Statement, on the balance sheet at fair value. Derivatives are included as price risk management assets or price risk management liabilities on the balance sheet. Changes in the fair value of derivatives that do not qualify for hedge accounting treatment, as well as the ineffective portion of a particular hedge, are recognized in current period earnings. Hedge effectiveness is measured based on changes in the fair value over time between the derivative contract and the hedged item.

SFAS No. 133 recognizes three types of hedges: fair value hedges, cash flow hedges, and foreign currency hedges. A fair value hedge is a hedge of the exposure to changes in the fair value of a recognized asset or liability or of an unrecognized firm commitment, that are attributable to its fixed terms. If the derivative qualifies and is designated as a fair value hedge, the accounting treatment dictates that the changes in the fair value of the hedging instrument will be offset against the changes in fair value of the hedged assets, liabilities, or firm commitments attributable to the hedged risk and reflected in the income statement in the current period. A cash flow hedge is a hedge of the exposure to variability in the cash flows associated with a recognized asset or liability, or a forecasted transaction that is attributable to changes in variable rates or prices. If the derivative qualifies and is designated as a cash flow hedge, the accounting treatment dictates that the effective portions of the changes in the fair value of the hedging instrument will be recognized in other comprehensive income (loss), a separate component of stockholders' equity during the hedge period and will subsequently be recognized in the income statement when the hedged item affects earnings. Foreign currency hedges may either be classified as fair value or cash flow hedges and are subject to the same accounting guidelines as those described above, as applicable.

Only the Utility currently has derivatives designated as fair value hedges. These consist of swaps used to hedge commodity price risk related to purchases of natural gas. Both PG&E Corporation and the Utility currently have

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derivatives designated as cash flow hedges. For PG&E Corporation these consist of interest rate swaps associated with variable rate debt payments used to hedge interest rate risk. Additionally, PG&E Corporation has entered into forward, future, and financial swap contracts for natural gas, fuel oil, and electricity in order to hedge the commodity price risk associated with the generating activities of the unregulated subsidiaries. The Utility's cash flow hedges consist of forwards used to hedge commodity price risk related to natural gas transmission. PG&E Corporation has certain foreign exchange forwards used to economically hedge foreign currency risk associated with future purchases and sales denominated in foreign currencies, and interest rate swaps used to economically hedge interest rate risk, both of which were not designated as accounting hedges. These foreign exchange and interest rate derivative instruments not designated as hedges are accounted for using the mark-to-market method of accounting, which requires that assets and liabilities be valued through earnings.

Hedge effectiveness is measured quarterly. Any ineffectiveness is recognized in the income statement in the period that the ineffectiveness occurs. If a derivative instrument that has qualified for hedge accounting is liquidated or sold prior to maturity, the gain or loss at the time of termination remains in other comprehensive income (loss) until the hedged item impacts earnings. For derivative instruments not designated as hedges, the gain or loss is immediately recognized in earnings in the period of its change in value.

PG&E Corporation and the Utility have certain derivative commodity contracts that result in the physical delivery of commodities used in the normal course of business. At this time, these derivatives 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 Derivative Implementation Group of the Financial Accounting Standards Board has recently defined normal purchases and sales to exclude certain commodity contracts that were previously exempt under the normal purchases and sales provisions of SFAS No. 133. As such, certain derivative commodity contracts may no longer be exempt from the requirements of SFAS No. 133. PG&E Corporation and the Utility are currently evaluating the impact of the recent implementation guidance, which would be accounted for on a prospective basis, and will evaluate the impact when the final decision regarding this issue is resolved.

PG&E Corporation's transition adjustment to implement this new Statement was a non-material charge to earnings and a charge of $243 million to other comprehensive income (loss). The Utility's transition adjustment to implement this new Statement was a non-material charge to earnings and an increase of $90 million to other comprehensive income (loss).

Net gains and losses for non-trading activities recognized in earnings at March 31, 2001, were included in various places on the income statement. These were included as part of energy commodities and services revenue, cost of energy commodities and services, other income (expense), net, or interest income or interest expense on PG&E Corporation's and the Utility's Condensed Statements of Consolidated Operations for the three-month period ended March 31, 2001.

PG&E Corporation's and the Utility's derivative gains and losses included in other comprehensive income (loss) are reflected in earnings at the time of terminations or settlements of the derivative instruments, along with the amortization of the transition account. Derivative gains or losses that were reclassified from other comprehensive income (loss) to earnings were included in various places on the income statement. These were included as part of energy commodities and services revenue, cost of energy commodities and services, other income (expense), net, or interest income or interest expense on PG&E Corporation's and the Utility's Condensed Statements of Consolidated Operations for the three-month period ended March 31, 2001.

As of March 31, 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 February 2012.

The Utility had $243 million of cash flow hedges for commodity forward contracts, which were derecognized or discontinued during the three-month period ended March 31, 2001.

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 (loss) 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 March 31, 2001	2000
(in millions)		
Net Income (Loss)	$ (951)	$280
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	$(2.62)	$.78
Earnings (Loss) per common share, diluted	$(2.62)	$.77

The diluted share base for 2001 excludes incremental shares of 457 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.

Comprehensive Income (Loss)

The objective of PG&E Corporation's and the Utility's 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.

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 (AB1890). 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 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 Power Exchange (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 purchased 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 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 has 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 after hearings could be held, 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. In February 2001, the California Legislature passed California Assembly Bill 1X (AB 1X), which authorized the DWR to purchase wholesale electricity on behalf of the Utility's 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 were incurred after March 27, 2001 and could not be used to pay amounts owed to creditors. Although the rate increase is authorized immediately, the 3 cent surcharge will not be collected in rates until the CPUC establishes the rate design, which is not expected to be adopted until June 2001.

In light of the magnitude of the undercollected 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 $295 million at March 31, 2001 and believes that the funds will be adequate to maintain its operations through and beyond 2001. In addition, PG&E Corporation believes that PG&E Corporation, 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 undercollected wholesale electricity costs as of the end of the earlier determined transition period will be less than the August 31 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.) Further, it is unclear how much of the ISO's power purchases have been made by the California Department of Water Resources (DWR) on behalf of the Utility's customers. The Utility has filed a complaint in federal 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.

It is expected that the wholesale costs will continue to be extremely high through 2001 unless significant changes occur in the wholesale electricity market. The generation-related costs component, which provides for recovery of wholesale electricity purchased by the Utility and, if available, for recovery of transition costs, was approximately 6.4 cents and 5.4 cents per kWh, during the three months ended 2001 and 2000, respectively. As discussed below, the CPUC approved an average 3.0 cents per kWh surcharge for power costs incurred after March 27, 2001, but the 3-cent surcharge will not be collected in rates until the CPUC establishes an appropriate rate design for the surcharge, which is not expected to be adopted until June 2001.

During the quarter ended March 31, 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 Statement of Operations. The amount of undercollected purchased power costs incurred for the three month period ended March 31, 2001 was approximately $1.9 billion. Under current CPUC decisions, if this undercollection is not recovered through frozen rates by the end of the transition period, it cannot be recovered. 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 undercollected 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.

Transition Cost Recovery

Beginning January 1, 1998, the Utility started amortizing eligible transition costs, including most generation-related regulatory assets. These transition costs were offset by or recovered through the frozen rates, market valuation of generation assets in excess of book value, net energy sales from the Utility's electric generation facilities, and the amount by which long-term contract prices to purchase electricity were lower than the PX prices. Transition costs and associated recoveries are recorded in the Utility's Transition Cost Balancing Account (TCBA). During the transition period, a reduced rate of return on common equity of 6.77% applies to all generation assets, including those generation assets reclassified to regulatory assets.

During the transition period, the CPUC reviews the Utility's compliance with accounting methods established in the CPUC's decisions governing transition costs recovery and the amount of transition costs requested for recovery. In January 2001, the CPUC approved all transition costs that were amortized from July 1, 1998, to June 30, 1999. The CPUC currently is reviewing transition costs amortized from July 1, 1999, to June 30, 2000.

Mitigation Efforts

The Utility is actively exploring ways to reduce its exposure to the higher wholesale electricity costs and to recover its written-off undercollected wholesale electricity costs and 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 Federal Energy Regulatory Commission (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 include, 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 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.

On April 26, 2001, the FERC issued an order requiring all ISO-participating generators and nonpublic utility sellers participating in the ISO markets or using the ISO transmission system to offer their output in real-time to the ISO (except for hydroelectric facilities). The order also requires generators to justify prices above their marginal costs to generate. Further, when a stage 1, 2, or 3 emergency is in effect, price mitigation becomes effective. The real-time electric prices will no longer clear at the single highest price or at a soft cap of $150 per MWh, but will clear at a proxy price based on the highest cost units required to be used each day, and published fuel costs and emission credit information. This mitigation plan will become effective on May 29, 2001. The FERC will monitor bidding activities of generators, forward prices in the electricity and natural gas market and plant outages. Any bids that prove to be unjustified will be subject to refund. The FERC has requested comments on various aspects of its order. The FERC also has indicated that it intends to open an investigation into prices and sales into the Western United States and consider imposing price mitigation measures similar to those proposed for California markets. The order also requires that the ISO and the three California investor owned utilities file a proposal regarding the establishment of west-wide regional transmission organization (RTO) by June 1, 2001.

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 states 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 alleges 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 January 29, 2001, the Utility's lawsuit was transferred to the federal district court in Los Angeles where SCE has its identical case pending.

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.

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, authorizes 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 (QF) contracts, existing bilateral contracts, and ancillary services (the California Procurement Adjustment or CPA). The CPA is payable to the DWR by each utility upon receipt from its retail end use customers.

Initially, the DWR has 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. The ISO billed, and is expected to continue to bill the Utility for those costs. 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. It is not clear whether the Utility will ultimately be responsible for these costs from February through April 6, 2001. The Utility has expensed these costs in the accompanying Condensed Financial Statements.

By early January 2001, the Utility failed to meet the creditworthiness standards under the ISO's tariff for purchasing and scheduling power from third parties. On January 5, 2001, the ISO filed a proposed tariff amendment with the FERC to permit the Utility to continue scheduling transactions through the ISO. The ISO implemented its proposed tariff amendment immediately. On February 14, 2001, the FERC issued an order rejecting the ISO's proposed tariff amendment, prohibiting the Utility from scheduling power from a third party supplier, unless the Utility was creditworthy or was backed by creditworthy parties. 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. The ISO continued to charge the Utility for the power it buys on an emergency basis, despite the FERC ruling. 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.

The ISO has not indicated that it will comply with the FERC and cease billing the Utility for its third party power purchases. The Utility has filed a complaint against the ISO in Bankruptcy Court regarding this issue.

Rate Stabilization Plan (RSP)

On November 22, 2000, the Utility filed an application with 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 rate stabilization plan proceeding. The ruling stated that in phase one of the case, the scope of the proceeding will 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 undercollected balances in the Utility's 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 is authorized immediately, the 3.0 cents per kWh surcharge will not be collected in rates until the CPUC establishes an appropriate rate design for the surcharge, which is not expected to be adopted until June 2001. 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 overcollections, or (3) to the extent any administrative body or court denies the refunds of overcollections 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 in 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 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 cent per kWh interim surcharge adopted by the CPUC on January 5, 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 March 27, 2001, and 9.471 cents per kWh after March 27, 2001, reflecting the authorized 3-cent increase. 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. The amount of power supplied 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 provided 45 days earlier and the Utility's company-wide average generation-related rate of 9.471 cents per kWh.

The CPUC also ordered that the utilities immediately pay the sums owed to the DWR for power sold by the DWR from January 18, 2001 through January 31, 2001, under California Senate Bill 7X. Based on an estimated number of kWh sold by the DWR, the Utility paid approximately $30 million to the DWR at the rate of $0.05471 per kWh as adopted by the CPUC.

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, the CPA, 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, QFs 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 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.

To the extent the DWR does not buy enough power to cover the Utility's net open position, the ISO purchases emergency power on the high-priced spot market to meet system reliability requirements and the net open position. Despite the FERC's order prohibiting the ISO from charging non-creditworthy utilities for the ISO's third party power purchases, the ISO may continue to charge the Utility a proportionate share of the ISO's purchases. As discussed above, the Utility believes it is not responsible for such ISO charges. The DWR has advised the CPUC that its revenue requirement for the DWR's power purchases is $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-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-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).

Since the end of January 2001, the Utility has been paying only 15% of amounts due to qualifying facilities (QFs). 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 QF. 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.

The CPUC also adopted TURN's proposal to transfer on a monthly basis the balance in each Utility's TRA to the Utility's TCBA. The TRA is a regulatory balancing account that is credited with total revenue collected from ratepayers through frozen rates and which tracks undercollected 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 has filed an application for rehearing of this decision. The Utility also has requested the Bankruptcy Court to enjoin the CPUC from requiring the Utility to implement the regulatory accounting changes. A hearing is set for May 14, 2001, to consider the Utility's request.

Bilateral Contracts

Under the terms of the 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 PG&E reaching an agreement with the CPUC on reasonableness standards. After two months of unsuccessful discussions with CPUC, on October 16, 2000, PG&E 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. As of March 31, 2001, individual contracts range in size from approximately 92,000 MWhs to 3,504,000 MWhs of supply annually. The contracts extended to 2005. As a result of the downgrade in PG&E's credit rating and also its subsequent bankruptcy filing, certain of these contracts were terminated.

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 three months ended March 31, 2001, the PX credits reduced

electric revenue by $322 million. The Utility ceased paying most of these credits in December 2000, and as of March 31, 2001, the total of accumulated credits for direct access customers that have not been paid by the Utility is approximately $510 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 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 March 31, 2001, the book value of the Utility's net investment in hydroelectric generation assets was approximately $688 million.

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 audited profits 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. It is uncertain what future ratemaking will be applicable to Diablo Canyon.

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Cost of Electric Energy

For the three months ended March 31, 2001 and 2000, the cost of electric energy for the Utility, reflected on the Utility's Condensed Statement of Consolidated Operations, comprises the cost of fuel for electric generation and QF purchases, the cost of PX purchases, and ancillary services charged by the ISO, net of sales to the PX, as follows:

(in millions)	2001	2000
Cost of fuel resources at market prices	$2,631	$ 628
Proceeds from sales to the PX	(204)	(115)
Total Utility cost of electric energy	$2,427	$ 513

Note 3: LONG-TERM DEBT

On January 16 and 17, 2001, in response to the continued energy crisis, Standard and Poor's (S&P) and Moody's Investors Service (Moody's) respectively, downgraded PG&E Corporation's credit ratings to below investment grade. The downgrade, in addition to PG&E Corporation's and the Utility's non-payment of commercial paper constituted an event of default under both the $436 million and the $500 million credit facilities. In response, the banks immediately terminated their outstanding commitments under these defaulted credit facilities. Through February 28, 2001, PG&E Corporation had $501 million in outstanding commercial paper, of which $457 million came due and was not paid.

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 Capital 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 the $501 million in outstanding commercial paper, $434 million in borrowings under PG&E Corporation's long-term revolving credit facility, and $116 million to PG&E Corporation's shareholders of record on December 15, 2000 in satisfaction of the defaulted fourth quarter 2000 common stock 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.

The loans will mature on March 2, 2003 (which date may be extended at the option of PG&E Corporation for up to one year upon payment of a fee of up to 5% of the then outstanding indebtedness), or earlier, if a spin-off of the shares of PG&E NEG were to occur. As required by the credit agreement, PG&E Corporation has given the lenders a security interest in PG&E NEG. The loans prohibit PG&E Corporation from declaring dividends, making other distributions to shareholders, or incurring additional indebtedness unless it meets certain requirements. The loan also prohibits PG&E NEG from making distributions to PG&E

Corporation and restricts certain other intercompany transactions.

Further, as required by the credit agreement, NEG LLC has granted to affiliates of the lenders options that entitle these affiliates to purchase up to 3% of the shares of PG&E NEG at an exercise price of $1.00 based on the following schedule:

	Percentage of Shares Subject To PG&E NEG Options
Loans outstanding for:	
Less than six months	2.0%
Six to eighteen months	2.5%
Greater than eighteen months	3.0%

The option becomes exercisable on the date of full repayment or earlier, if an initial public offering of the shares of PG&E NEG (IPO) were to occur. PG&E NEG has the right to call the option in cash at a purchase price equal to the fair market value of the underlying shares, which right is exercisable at any time following the repayment of the loans. If an IPO has not occurred, the holders of the option have the right to require NEG LLC or PG&E Corporation to repurchase the option at a purchase price equal to the fair market value of the underlying shares, which right is exercisable at any time after the earlier of full repayment of the loans or 45 days before expiration of the option. The option will expire 45 days after the maturity of the loans. PG&E Corporation will account for the options by recording the fair value of the option at issuance as a debt issuance cost to be amortized over the expected life of the loans. The options will be marked through an increase or decrease to current earnings.

Under the credit agreement, PG&E NEG is permitted to make investments, incur indebtedness, sell assets, and operate its businesses pursuant to its business plan. Mandatory repayment of the loans will be required from the net after-tax proceeds received by PG&E NEG or any subsidiary of PG&E NEG from (1) the issuance of indebtedness, (2) the issuance or sale of any equity (except for cash proceeds from an IPO), (3) asset sales, and (4) casualty insurance, condemnation awards, or other recoveries. However, if such proceeds are retained as cash, used to pay indebtedness, or reinvested in PG&E NEG's businesses, mandatory repayment will not be required.

Any net proceeds from an IPO must be used to reduce the outstanding balance of the loans to $500 million or less. In addition, all distributions made by PG&E NEG to PG&E Corporation other than (1) to reimburse PG&E Corporation for corporate overhead expenses, (2) pursuant to any tax sharing arrangements which PG&E NEG and PG&E Corporation are parties, and (3) pursuant to any note that may be repayable to PG&E Corporation in connection with an IPO and similar arrangements must be used to pay the loans.

The credit agreement also prohibits PG&E Corporation from taking certain actions, including a restriction against declaring or paying any dividends for as long as the loans are outstanding. A breach of covenants, including requirements that (1) PG&E NEG's unsecured long-term debt have a credit rating of at least BBB- by S&P or Baa3 by Moody's, (2) the ratio of fair market value of PG&E NEG to the aggregate amount of principal then outstanding under the loans is not less than 2 to 1, and (3) PG&E Corporation maintain a cash or cash equivalent reserve of at least 15% of the total principal amount of the loans outstanding, entitles the lenders to declare the loans to be due and payable.

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.

Note 4: BANKRUPTCY FILING

The Utility had been drawing on its $1 billion facility to pay maturing commercial paper. As of January 16, 2001, the Utility had drawn down $938 million under this facility. On January 16 and 17, 2001, S&P and Moody's respectively, downgraded the Utility's credit ratings to below investment grade. This downgrade resulted in an event of default under the $850 million credit facility, while the Utility's non-payment of commercial paper exceeding $100 million constituted events of default under both the $1 billion and $850 million credit facilities.

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 15, 2001, to PG&E Corporation and PG&E Holdings, Inc., a subsidiary of the Utility. In addition, the Utility's Board of Directors decided not to declare the regular preferred stock dividends of $6.3 million for the three-month period ending 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.

The Utility has also deferred quarterly interest payments of $6.1 million 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 of $5.9 million on the 7.90% Cumulative Quarterly Income Preferred Securities, Series A (QUIPS) issued by PG&E Capital I, due on April 2, 2001, have been similarly deferred. Distributions can be deferred up to a period of five years per the indenture. Under the indenture, investors accumulate interest on the unpaid distributions at the rate of 7.90%.

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. On January 25, 2001, a California Superior Court judge granted the Utility's application for a temporary restraining order, which thereby restrained and enjoined the PX and its agents from liquidating the Utility's contracts in the block forward market, pending hearing on a preliminary injunction on February 5, 2001. Immediately before the hearing on the preliminary injunction, California Governor Gray Davis, acting under California's Emergency Services Act, commandeered the contracts for the benefit of the state. Under the Act, the DWR 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.

As a result of (1) the failure by the DWR 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 uncollected 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. 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. Subject to the approval of the bankruptcy court, the Utility's intent is to pay its ongoing costs of doing business while seeking resolution of the wholesale power crisis. It is the Utility's intention to continue to pay employees, vendors, suppliers, and other creditors to maintain essential distribution and transmission services. However, the Utility is not in a position to pay maturing or accelerated obligations, nor is the Utility in a position to pay the ISO, PX, and the QFs, the massive amounts due for the Utility's power purchases above the amount included in rates for power purchase costs. The Utility's current actions are intended to allow the Utility to continue to operate while the bankruptcy proceedings continue.

Note 5: RINGFENCING

In December 2000 and during the first quarter of 2001, PG&E Corporation and PG&E NEG undertook a corporate restructuring of PG&E NEG, known as a "ringfencing" transaction. The ringfencing complied with credit rating agency criteria designed to further separate a subsidiary from its parent and affiliates, enabling PG&E NEG, PG&E Gas Transmission, Northwest Corporation (PG&E GTN), and PG&E Energy Trading Holdings Corp. to receive or retain their own credit rating, based upon their creditworthiness. The ringfencing involved the creation of new special purpose entities (SPEs) as intermediate owners between PG&E Corporation and its non CPUC-regulated subsidiaries. These new SPEs are: NEG LLC, which owns 100% of the stock of PG&E NEG; GTN Holdings LLC, which owns 100% of the stock of PG&E GTN; and PG&E Energy Trading Holdings LLC which owns 100% of the stock of PG&E Corporation's energy trading subsidiaries, PG&E Energy Trading-Power, L.P. and PG&E Energy Trading-Gas Corporation, and their affiliates (PG&E ET). In addition, PG&E NEG's organizational documents were

modified to include the same structural elements as the SPEs to meet credit rating agency criteria. Ringfencing was undertaken to enable PG&E NEG and various of its affiliates to obtain or maintain investment grade ratings. The SPEs require unanimous approval of their respective boards of directors, which includes an independent director, before they can (a) consolidate or merge with any entity, (b) transfer substantially all of their assets to any entity, or (c) institute or consent to bankruptcy, insolvency, or similar proceedings or actions. The SPEs may not declare or pay dividends unless the respective boards of directors have unanimously approved such action and the company meets specified financial requirements.

NOTE 6: PRICE RISK MANAGEMENT

Trading and Non-Trading Activities

PG&E Corporation's net gain (loss) on trading contracts for the three-month period ended March 31, are as follows:

(in millions)	2001	2000
Swaps	$(349)	$ (23)
Options	(7)	62
Futures	32	37
Forward contracts	352	(31)
Net gain	$ 28	$ 45

Below is a table summarizing the quantitative information associated with PG&E Corporation's cash flow hedges for the three-month period ended March 31, 2001. Only the Utility currently uses fair value hedges. The Utility's fair value hedge is subject to a regulatory mechanism, and as such, it is deferred for future recovery or refund and included on the balance sheet with no immediate earnings impact. The Utility's price risk management strategies consist of the use of non-trading (hedging) financial instruments, designated as both cash flow hedges and fair value hedges. Gains and losses associated with the use of some of the Utility's financial instruments primarily affect regulatory accounts, depending on the business unit and the specific program involved. While the use of the Utility's financial 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.

(in millions)	PG&E Corporation
Amount of the hedge's ineffectiveness	$(2)
Net loss recognized in earnings	$(2)

PG&E Corporation and the Utility's estimated net derivative gains or losses included in other comprehensive loss at March 31, 2001 that will be reclassified into earnings within the next twelve months are a net derivative loss of $146 million for PG&E Corporation and a net derivative loss of $25 million for the Utility.

The schedule below summarizes the activities affecting accumulated other comprehensive income (loss) from derivative instruments for the three-month period ended March 31, 2001.

	PG&E Corporation	Utility

(in millions)		
Beginning accumulated derivative gain (loss) from SFAS No. 133 transition adjustments at January 1, 2001	$(243)	$ 90
Net change of current period hedging transactions gain (loss)	(29)	1
Net reclassification to earnings	(43)	(143)
Ending accumulated derivative gain (loss)	(315)	(52)
Foreign currency translation adjustment	(4)	(2)
Ending accumulated other comprehensive loss	$(319)	$ (54)

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 $25 million due to the nonperformance of counterparties during the three-month period ended March 31, 2001. Counterparties considered to be investment grade or higher comprise 87% of the total credit exposure. At March 31, 2001, PG&E Corporation's and the Utility's gross credit risk amounted to $2.1 billion and $758 million, respectively.

NOTE 7: 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% 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 PG&E Capital I 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 United States 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 8: 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.

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 in 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 the lower end of this range.

At March 31, 2001, the Utility expects to spend $307 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 $460 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 $307 million and $320 million at March 31, 2001 and December 31, 2000, respectively. The $307 million accrued at March 31, 2001 includes (1) $139 million related to the pre-closing remediation liability, associated with the divested generation facilities discussed further in the "Generation Divestiture" section of Note 2, and (2) $168 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 $307 million environmental remediation liability, the Utility has recovered $193 million through rates, and expects to recover another $84 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.

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) and the U.S. Department of Justice have 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, EPA visited

both facilities. PG&E NEG believes this request for information is part of EPA's industry-wide investigation of coal-fired plants' compliance with the Clean Air Act requirements governing plant modifications. PG&E NEG also believes that any changes made to the plants were routine maintenance or repairs and, therefore, did not require permits. EPA has not issued a notice of violation or filed any enforcement action against PG&E NEG at this time. Nevertheless, if EPA disagrees with PG&E NEG's conclusion with respect to the changes 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.

In addition to the EPA, states may impose more stringent air emissions requirements. On May 11, 2001, the Massachusetts Department of Environmental Protection issued regulations imposing new restrictions of certain air emissions from existing coal-fired power plants. These requirements will primarily impact PG&E NEG's Salem Harbor and Brayton Point generating facilities. Through 2008, it may be necessary to spend approximately $265 million to comply with these regulations. In addition, with respect to approximately 600 megawatts (MW) (or about 12%) of PG&E NEG's New England capacity, it may be necessary to implement fuel conversion, limit operations, or install additional environmental controls.

PG&E Gen's existing power plants, including USGenNE facilities, are subject to federal and state water quality standards with respect to discharge constituents and thermal effluents. Three of the fossil-fueled plants owned and operated by USGenNE are operating pursuant to NPDES permits that have expired. For the facilities whose NPDES permit have expired, permit renewal applications are pending, and it is anticipated that all three facilities will be able to continue to operate in substantial compliance with their prior permits until new permits are issued. It is estimated that USGenNE's cost to comply with the new permit conditions could be as much as $60 million through 2005. It is possible that the new permits may contain more stringent limitations than prior permits.

During September 2000, USGenNE signed a series of agreements that require, among other things, USGenNE to alter its existing waste water treatment at two 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 expected cost of these improvements, which are underway, is $21 million.

PG&E NEG anticipates spending up to approximately $330 million, net of insurance proceeds, through 2008, for environmental compliance at currently operating facilities, which primarily addresses: (a) new Massachusetts air regulations made public on April 23, 2001 affecting Brayton Point and Salem Harbor Stations; (b) wastewater permitting requirements that may apply to Brayton Point, Salem Harbor and Manchester Street Stations; and (c) requirements that are reflected in a consent decree concerning wastewater treatment facilities at Salem Harbor and Brayton Point stations.

LEGAL MATTERS

Utility

The Utility's Chapter 11 bankruptcy on April 6, 2001, discussed in Note 4 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

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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
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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 Pacific Gas and Electric Company 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 Assembly Bill 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 Corpora