PG&E CORP
Form 10-Q/A
August 02, 2002
(Mark One)

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C., 20549
FORM 10-Q/A
Amendment No. 1 to

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

For the quarterly period ended June 30, 2002

OR

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

For the transition period from ___________ to __________

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

Pacific Gas and Electric Company 77 Beale Street P.O. Box 770000 San Francisco, California 94177	PG&E Corporation One Market, Spear Tower Suite 2400 San Francisco, California 94105
(Address of principal executive offices)	(Zip Code)

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

Registrant's telephone number, including area code

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

Yes x	No

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

Common Stock Outstanding, July 30, 2002:

PG&E Corporation	393,183,174 shares
Pacific Gas and Electric Company	Wholly owned by PG&E Corporation

INTRODUCTORY NOTE

Subsequent to the issuance of its Quarterly Report on Form 10-Q for the quarter ended June 30, 2002, PG&E Corporation discovered a mathematical error in the compilation of a table in Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Financial Resources - Liquidity Resources. The error results in a change in the amounts included in the rows titled "Operating and debt service cost" and "Capital requirements for current construction program", and the resultant subtotals and totals. This Amendment No. 1 to PG&E Corporation's and Pacific Gas and Electric Company's joint Quarterly Report on Form 10-Q/A for the quarter ended June 30, 2002, contains a revised table to reflect the correction of the mathematical error. To reflect the change, this Amendment No. 1 hereby amends Part I. Item 2 Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Financial Resources - Liquidity Resources of the original filing. Although the full text of the amended Form 10-Q is contained herein, this Amendment No. 1 does not update any other disclosures to reflect developments since the original date of filing.

PG&E CORPORATION AND
PACIFIC GAS AND ELECTRIC COMPANY,
FORM 10-Q/A
FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2002
TABLE OF CONTENTS

PART I. FINANCIAL INFORMATION
ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

PG&E CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per share amounts)

	Three months ended June 30, 2002	Three months ended June 30, 2001	Six months ended June 30, 2002	Six months ended June 30, 2001
Operating Revenues				
Utility	$ 2,714	$ 2,309	$5,167	$ 4,871
Energy commodities and services	3,038	2,701	5,352	6,812
Total operating revenues	5,752	5,010	10,519	11,683
Operating Expenses				
Cost of energy for utility	703	67	852	3,300
Cost of energy commodities and services	2,823	2,335	4,876	6,174
Operating and maintenance	833	894	1,756	1,580
Impairments and write-offs	265	-	265	-
Depreciation, amortization, and decommissioning	336	259	656	514
Reorganization professional fees and expenses	18	8	34	8
Total operating expenses	4,978	3,563	8,439	11,576
Operating Income	774	1,447	2,080	107
Reorganization interest income	19	32	41	32
Interest income	24	42	44	77
Interest expense	(361)	(312)	(695)	(559)
Other income (expense), net	(21)	4	(3)	(5)
Income (Loss) Before Income Taxes	435	1,213	1,467	(348)
Income taxes provision (benefit)	156	463	557	(147)
Income (Loss) From Continuing Operations	279	750	910	(201)
Cumulative effect of a change in an accounting principle (net of income taxes of $42 million)	(61)	-	(61)	-
Net Income (Loss)	$ 218	$ 750	$ 849	$ (201)
Weighted Average Common Shares Outstanding	366	363	365	363
Earnings (Loss) Per Common Share,				

from Continuing Operations, Basic	$ 0.76	$ 2.07	$2.50	$ (0.55)
	=======	=======	=======	=======
Net Earnings (Loss) Per Common Share, Basic	$ 0.60	$ 2.07	$2.33	$ (0.55)
	=======	=======	=======	=======
Earnings (Loss) Per Common Share,				
from Continuing Operations, Diluted	$ 0.75	$ 2.07	$2.46	$ (0.55)
	=======	=======	=======	=======
Net Earnings (Loss) Per Common Share, Diluted	$ 0.59	$ 2.07	$2.29	$ (0.55)
	=======	=======	=======	=======

The accompanying Notes to the Consolidated Financial Statements are an integral part of these statements.

PG&E CORPORATION
CONSOLIDATED BALANCE SHEETS
(in millions)

	Balance at	
	June 30, 2002	December 31, 2001
ASSETS		
Current Assets		
Cash and cash equivalents	$ 5,100	$ 5,421
Restricted cash	372	195
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $95 million and $89 million, respectively)	3,117	3,016
Regulatory balancing accounts	133	75
Price risk management	508	381
Inventories	444	462
Prepaid expenses and other	436	223
Total current assets	10,110	9,773
Property, Plant and Equipment		
Utility	26,585	25,963
Non-utility:		
Electric generation	3,022	2,848
Gas transmission	1,520	1,514
Construction work in progress	2,867	2,426

Other	202	195
Total property, plant and equipment (at original cost)	34,196	32,946
Accumulated depreciation and decommissioning	(14,295)	(13,831)
Net property, plant and equipment	19,901	19,115
Other Noncurrent Assets		
Regulatory assets	2,200	2,319
Nuclear decommissioning funds	1,345	1,337
Price risk management	574	426
Other	2,649	2,892
Total other noncurrent assets	6,768	6,974
TOTAL ASSETS	$ 36,779	$ 35,862

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

	Balance at	
	June 30, 2002	December 31, 2001
LIABILITIES AND STOCKHOLDERS' EQUITY		
Liabilities Not Subject to Compromise		
Current Liabilities		
Short-term borrowings	$ 344	$ 330
Long-term debt, classified as current	48	381
Current portion of rate reduction bonds	290	290
Accounts payable:		
Trade creditors	2,076	1,289
Regulatory balancing accounts	239	228
Other	629	530
Interest payable	355	26
Income taxes payable	1,049	610
Price risk management	548	277

Other	925	905
Total current liabilities	6,503	4,866
Noncurrent Liabilities		
Long-term debt	8,227	7,297
Rate reduction bonds	1,310	1,450
Deferred income taxes	1,491	1,666
Deferred tax credits	149	153
Price risk management	751	434
Other	3,698	3,688
Total noncurrent liabilities	15,626	14,688
Liabilities Subject to Compromise		
Financing debt	5,611	5,651
Trade creditors	3,356	5,555
Total liabilities subject to compromise	8,967	11,206
Commitments and Contingencies (Notes 1, 2, 3, and 6)	-	-
Preferred Stock of Subsidiaries	480	480
Utility Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures	-	300
Common Stockholders' Equity		
Common stock, no par value, authorized 800,000,000 shares, issued 390,713,785 and 387,898,848 shares, respectively	6,093	5,986
Common stock held by subsidiary, at cost, 23,815,500 shares	(690)	(690)
Accumulated deficit	(155)	(1,004)
Accumulated other comprehensive income (loss)	(45)	30
Total common stockholders' equity	5,203	4,322
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 36,779	$ 35,862

The accompanying Notes to the Consolidated Financial Statements are an integral part of these statements.

PG&E CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Six months ended June 30, 2002	Six months ended June 30, 2001
Cash Flows From Operating Activities		
Net income (loss)	$ 849	$ (201)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	656	514
Deferred income taxes and tax credits, net	(178)	120
Price risk management assets and liabilities, net	238	(30)
Other deferred charges and noncurrent liabilities	620	(174)
Loss on impairment of assets	265	-
Cumulative effect of a change in accounting principle	61	-
Reversal of ISO accrual (Note 2)	(970)	-
Net changes in operating assets and liabilities :		
Accounts receivable	(55)	1,445
Accounts payable	106	621
Inventories	18	(109)
Income taxes payable	439	1,241
Regulatory balancing accounts, net	(47)	332
Other working capital	(168)	(791)
Net change in liabilities subject to compromise (Note 2)	(972)	-
Other, net	(468)	(116)
Net cash provided by operating activities	394	2,852
Cash Flows From Investing Activities		
Capital expenditures	(1,680)	(1,102)
Proceeds from sale-leaseback	340	-
Other, net	85	(115)
Net cash used by investing activities	(1,255)	(1,217)
Cash Flows From Financing Activities		

Net borrowings (repayments) under credit facilities and short-term borrowings	14	(1,033)
Long-term debt issued	1,546	2,275
Long-term debt matured, redeemed, or repurchased	(1,081)	(844)
Common stock issued	61	-
Dividends paid	-	(109)
Net cash provided by financing activities	540	289
Net change in cash and cash equivalents	(321)	1,924
Cash and cash equivalents at January 1	5,421	2,430
Cash and cash equivalents at June 30	$ 5,100	$ 4,354
Supplemental disclosures of cash flow information		
Cash received for:		
Reorganization interest income	$ 42	$ 32
Cash paid for:		
Interest (net of amounts capitalized)	874	302
Income taxes (net of refunds)	294	(1,241)
Reorganization professional fees and expenses	9	-
Transfer of liabilities and other payables subject to compromise (to) from operating payables and liabilities	(475)	10,960

The accompanying Notes to the Consolidated Financial Statements are an integral part of these statements.

PACIFIC GAS AND ELECTRIC COMPANY, A DEBTOR-IN-POSSESSION

CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions)

	Three months ended June 30,		Six months ended June 30,	
	2002	2001	2002	2001
Operating Revenues				
Electric	$ 2,193	$ 1,497	$ 3,971	$ 2,756
Gas	521	812	1,196	2,115
Total operating revenues	2,714	2,309	5,167	4,871

Operating Expenses				
Cost of electric energy	505	(362)	339	1,955
Cost of gas	198	429	513	1,345
Operating and maintenance	640	676	1,409	1,208
Depreciation, amortization, and decommissioning	294	222	565	439
Reorganization professional fees and expenses	18	8	34	8
Total operating expenses	1,655	973	2,860	4,955
Operating Income (Loss)	1,059	1,336	2,307	(84)
Reorganization interest income	19	32	41	32
Interest income	-	17	-	24
Interest expense				
Contractual interest expense	(229)	(195)	(443)	(396)
Noncontractual interest expense	(54)	(62)	(103)	(62)
Other expense, net	(1)	(2)	(6)	(6)
Income (Loss) Before Income Taxes	794	1,126	1,796	(492)
Income tax provision (benefit)	325	424	731	(200)
Net Income (Loss)	469	702	1,065	(292)
Preferred dividend requirement	6	6	12	12
Income (Loss) Available for (Allocated to) Common Stock	$ 463	$ 696	$ 1,053	$ (304)

The accompanying Notes to the Consolidated Financial Statements are an integral part of these statements.

PACIFIC GAS AND ELECTRIC COMPANY, A DEBTOR-IN-POSSESSION

CONSOLIDATED BALANCE SHEETS

(in millions)

	Balance at	
	June 30, 2002	December 31, 2001
ASSETS		

Current Assets		
Cash and cash equivalents	$ 3,771	$ 4,341
Restricted cash	54	53
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $50 million and $48 million, respectively)	1,879	1,931
Related parties	17	18
Regulatory balancing accounts	133	75
Inventories:		
Gas stored underground and fuel oil	170	218
Materials and supplies	120	119
Prepaid expenses and other	66	80
Total current assets	6,210	6,835
Property, Plant and Equipment		
Electric	18,613	18,153
Gas	7,972	7,810
Construction work in progress	356	323
Total property, plant and equipment (at original cost)	26,941	26,286
Accumulated depreciation and decommissioning	(13,325)	(12,929)
Net property, plant and equipment	13,616	13,357
Other Noncurrent Assets		
Regulatory assets	2,169	2,283
Nuclear decommissioning funds	1,345	1,337
Other	1,308	1,325
Total other noncurrent assets	4,822	4,945
TOTAL ASSETS	$ 24,648	$ 25,137

PACIFIC GAS AND ELECTRIC COMPANY, A DEBTOR-IN-POSSESSION
CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)

	Balance at	
	June 30, 2002	December 31, 2001
LIABILITIES AND STOCKHOLDERS' EQUITY		
Liabilities Not Subject to Compromise		
Current Liabilities		
Long-term debt, classified as current	$ -	$ 333
Current portion of rate reduction bonds	290	290
Accounts payable:		
Trade creditors	966	333
Related parties	102	86
Regulatory balancing accounts	239	228
Other	288	289
Interest payable	352	26
Income taxes payable	788	295
Deferred income taxes	4	65
Other	529	599
Total current liabilities	3,558	2,544
Noncurrent Liabilities		
Long-term debt	3,019	3,019
Rate reduction bonds	1,310	1,450
Deferred income taxes	970	1,028
Deferred tax credits	149	153
Other	2,882	2,724
Total noncurrent liabilities	8,330	8,374
Liabilities Subject to Compromise		
Financing debt	5,611	5,651
Trade creditors	3,559	5,733
Total liabilities subject to compromise	9,170	11,384
Commitments and Contingencies (Notes 1, 2, 3, and 6)	-	-
Preferred Stock With Mandatory Redemption Provisions		

6.30% and 6.57%, outstanding 5,500,000 shares, due 2002-2009	137	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	145
Redeemable, 4.36% to 7.04%, outstanding 5,973,456 shares	149	149
Common stock, $5 par value, authorized 800,000,000 shares,		
issued 326,926,667 shares	1,606	1,606
Common stock held by subsidiary, at cost, 19,481,213 shares	(475)	(475)
Additional paid-in capital	1,964	1,964
Reinvested earnings (Accumulated deficit)	64	(989)
Accumulated other comprehensive income (loss)	-	(2)
	--------------	-----------------
Total stockholders' equity	3,453	2,398
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TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 24,648	$ 25,137
	=========	===========

The accompanying Notes to the Consolidated Financial Statements are an integral part of these statements.

PACIFIC GAS AND ELECTRIC COMPANY, A DEBTOR-IN-POSSESSION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Six months ended June 30,	
	2002	2001
Cash Flows From Operating Activities		
Net income (loss)	$ 1,065	$ (292)
Adjustments to reconcile net income (loss) to		
net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	565	439
Deferred income taxes and tax credits, net	(123)	12
Price risk management assets and liabilitites, net	-	(38)

Other deferred charges and noncurrent liabilities	592	(272)
Reversal of ISO accrual (Note 2)	(970)	-
Net changes in operating assets and liabilities:		
Accounts receivable	99	619
Income taxes receivable	-	1,120
Inventories	47	(108)
Accounts payable	(132)	606
Income taxes payable	493	-
Regulatory balancing accounts payable, net	(47)	332
Other working capital	(35)	(120)
Net change in liabilities subject to compromise (Note 2)	(947)	-
Other, net	23	366
Net cash provided by operating activities	630	2,664
Cash Flows From Investing Activities		
Capital expenditures	(743)	(575)
Net proceeds from sale of assets	5	-
Other, net	13	34
Net cash used by investing activities	(725)	(541)
Cash Flows From Financing Activities		
Net borrowings (repayments) under credit facilities and short-term borrowings	-	(28)
Long-term debt matured, redeemed, or repurchased	(474)	(252)
Other, net	(1)	(1)
Net cash used by financing activities	(475)	(281)
Net change in cash and cash equivalents	(570)	1,842
Cash and cash equivalents at January 1	4,341	1,344
Cash and cash equivalents at June 30	$ 3,771	$ 3,186
Supplemental disclosures of cash flow information		
Cash received for:		
Reorganization interest income	$ 42	$ 32
Cash paid for:		
Interest (net of amount capitalized)	683	265

Income taxes (net of refunds)	353	(1,120)
Reorganization professional fees and expenses	9	-
Transfer of liabilities and other payables subject to		
Compromise (to) from operating payables and liabilities	(297)	11,148

The accompanying Notes to the Consolidated Financial Statements are an integral part of these statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1: GENERAL

Organization and Basis of Presentation

PG&E Corporation was incorporated in California in 1995 and became the holding company of Pacific Gas and Electric Company, a debtor-in-possession, and its subsidiaries (the Utility) on January 1, 1997. The Utility, incorporated in California in 1905, is the predecessor of PG&E Corporation. The Utility delivers electric service to approximately 4.8 million customers and natural gas service to approximately 4.0 million customers in Northern and Central California. Both PG&E Corporation and the Utility are headquartered in San Francisco. As discussed further in Note 2, on April 6, 2001, the Utility filed a voluntary petition for relief under the provisions of Chapter 11 of the United States Bankruptcy Code (Bankruptcy Code) in the United States Bankruptcy Court for the Northern District of California (Bankruptcy Court). Pursuant to Chapter 11, the Utility retains control of its assets and is authorized to operate its business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court.

PG&E Corporation's other significant subsidiary is PG&E National Energy Group, Inc. (PG&E NEG) and its subsidiaries, headquartered in Bethesda, Maryland. PG&E NEG was incorporated on December 18, 1998, as a wholly owned subsidiary of PG&E Corporation. Shortly thereafter, PG&E Corporation contributed various subsidiaries to PG&E NEG. PG&E NEG and its subsidiaries are principally located in the United States and Canada, and are engaged in power generation and development, wholesale energy marketing and trading, risk management, and natural gas transmission. PG&E NEG's principal subsidiaries include: PG&E Generating Company, LLC, and its subsidiaries (collectively, PG&E Gen), PG&E Energy Trading Holdings Corporation and its subsidiaries (collectively, PG&E ET), and PG&E Gas Transmission Corporation and its subsidiaries (collectively, PG&E GTC), which includes PG&E Gas Transmission, Northwest Corporation and its subsidiaries (collectively, PG&E GTN) and North Baja Pipeline, LLC (NBP). PG&E NEG also has other less significant subsidiaries.

This Quarterly Report on Form 10-Q/A is a combined report of PG&E Corporation and the Utility. Therefore, the Notes to the unaudited Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation's unaudited Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, PG&E NEG, and other wholly owned and controlled subsidiaries. The Utility's unaudited Consolidated Financial Statements include its accounts and those of its wholly owned and controlled subsidiaries.

PG&E Corporation and the Utility believe that the accompanying unaudited Consolidated Financial Statements reflect all adjustments that are necessary to present a fair statement of the 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 unaudited Consolidated Financial Statements.

This quarterly report should be read in conjunction with PG&E Corporation's and the Utility's Consolidated Financial Statements and Notes to the Consolidated Financial Statements incorporated by reference in their combined 2001

Annual Report on Form 10-K, and PG&E Corporation's and the Utility's other reports filed with the Securities and Exchange Commission (SEC) since their combined 2001 Annual Report on Form 10-K 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.

At December 31, 2001, amounts previously classified as short-term investments were reclassified as cash equivalents in the balance sheets and statements of cash flows of PG&E Corporation and the Utility. As a result, such amounts have been reclassified in the accompanying statements of cash flows for the six months ended June 30, 2001, to be consistent with the current year presentation.

Earnings (Loss) Per Share

Basic earnings (loss) per share are computed by dividing net income (loss) by the weighted average number of common shares outstanding during the period. Diluted earnings per share are computed by dividing net income, adjusted for convertible note interest and amortization, by the weighted average number of common shares outstanding plus the assumed issuance of common shares for all dilutive securities.

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

		Three months ended June 30,		Six months ended June 30,	
(in millions, except per share amounts)		2002	2001	2002	2001
Income (Loss) from continuing operations		$ 279	$ 750	$ 910	$ (201)
Cumulative effect of accounting change		(61)	-	(61)	-
Net Income (Loss)		218	750	849	(201)
Interest expense on 7.50% Convertible Subordinated Notes (1)		-	-	-	-
Net Income (Loss) for Diluted Calculations		$ 218	$ 750	$ 849	$ (201)
Weighted average common shares outstanding, basic		366	363	365	363
Add:	Employee Stock Options and PG&E Corporation shares held by grantor trusts	5	-	5	-
	PG&E Corporation Warrants (2)	-	-	-	-

7.50% Convertible Subordinated Notes	1	-	-	-
Shares outstanding for diluted calculations	372	363	370	363
Earnings (Loss) Per Common Share, Basic				
Income (Loss) from continuing operations	$ 0.76	$ 2.07	$ 2.50	$ (0.55)
Cumulative effect of accounting change	(0.16)	-	(0.17)	-
Net earnings (loss)	$ 0.60	$ 2.07	$ 2.33	$ (0.55)
Earnings (Loss) Per Common Share, Diluted				
Income (Loss) from continuing operations	$ 0.75	$ 2.07	$ 2.46	$ (0.55)
Cumulative effect of accounting change	(0.16)	-	(0.17)	-
Net earnings (loss)	$ 0.59	$ 2.07	$ 2.29	$ (0.55)

(1)

Interest expense, including amortization of the discount, on the 7.50% Convertible Subordinated Notes for the three and six months ended June 30, 2002, was $232,276, net of income tax of $159,724. These notes were issued in connection with the PG&E Corporation's amended and restated credit agreement on June 25, 2002.

(2)

The incremental shares associated with PG&E Corporation Warrants, issued in connection with Tranche B of PG&E Corporation's amended and restated credit agreement (see Note 4), for the three and six months ended June 30, 2002, were 157,995 and 79,433 shares, respectively.

The diluted share base for the six months ended June 30, 2001, excludes incremental shares of 290,365 related to employee stock options and PG&E Corporation shares held by grantor trusts, due to the antidilutive effect of the loss from continuing operations. PG&E Corporation reflects the preferred dividends of subsidiaries as other expense for computation of both basic and diluted earnings per share.

Stock-Based Compensation

PG&E Corporation accounts for stock-based compensation using the intrinsic value method in accordance with the provisions of Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," as allowed by Statement of Financial Accounting Standards (SFAS) No. 123, "Accounting for Stock-Based Compensation." Under the intrinsic value method, PG&E Corporation does not recognize any compensation expense, as the exercise price of all stock options is equal to the fair market value at the time the options are granted. Had compensation expense been recognized using the fair value-based method under SFAS No. 123, PG&E Corporation's pro-forma consolidated earnings (loss) and earnings (loss) per share would be as follows:

(in millions, except per share amounts)	Three months ended June 30, 2002	Three months ended June 30, 2001	Six months ended June 30, 2002	Six months ended June 30, 2001
Net Income (loss):				
As reported	$ 218	$ 750	$ 849	$ (201)
Pro-forma	213	745	839	(210)
Basic Earnings (loss) per share:				
As reported	0.60	2.07	2.33	(0.55)
Pro-forma	0.58	2.05	2.30	(0.58)
Diluted earnings (loss) per share:				
As reported	0.59	2.07	2.29	(0.55)
Pro-forma	0.57	2.05	2.27	(0.58)

Comprehensive Income (Loss)

PG&E Corporation's and the Utility's comprehensive income (loss) consists principally of changes in the market value of certain cash flow hedges under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities."

(in millions)	PG&E Corporation 2002	PG&E Corporation 2001	Utility 2002	Utility 2001
Three months ended June 30				
Net income available for common stock	$ 218	$ 750	$ 463	$ 696
Net gain (loss) in other comprehensive income (OCI) from current period hedging transactions and price changes in accordance with SFAS No. 133	(9)	178	-	(8)
Net reclassification from OCI to earnings	-	31	-	19
Comprehensive income (loss)	$ 209	$ 959	$ 463	$ 707

Six months ended June 30,

Net income (loss) available for (allocated to) common stock	$ 849	$ (201)	$ 1,053	$ (304)
Cumulative effect of adoption of SFAS No. 133	-	(243)	-	90
Net gain (loss) in OCI from current period hedging transactions and price changes in accordance with SFAS No. 133	(84)	149	-	(7)
Net reclassification from OCI to earnings	5	(12)	-	(124)
Comprehensive income (loss)	$ 770	$ (307)	$ 1,053	$ (345)

Significant Accounting Policies

Accounting principles used include those necessary for rate-regulated enterprises, which reflect the ratemaking policies of the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC). Except as disclosed below, PG&E Corporation and the Utility are following the same accounting principles discussed in their 2001 Annual Report on Form 10-K.

Adoption of New Accounting Policies

Accounting for Goodwill and Other Intangible Assets

- On January 1, 2002, PG&E Corporation adopted SFAS No. 142, "Goodwill and Other Intangible Assets." This Statement eliminates the amortization of goodwill and requires that goodwill be reviewed at least annually for impairment. Upon implementation of this Statement, the transition impairment test for goodwill was performed as of January 1, 2002, and no impairment loss was recorded. Goodwill amortization expense for the three and six months ended June 30, 2001, was $1 million and $2 million, respectively. Prospective elimination of goodwill amortization will not have a significant impact on the Consolidated Financial Statements. The Utility has no goodwill on its balance sheet at December 31, 2001, or June 30, 2002.

This Statement also requires that the useful lives of previously recognized intangible assets be reassessed and the remaining amortization periods be adjusted accordingly. Adoption of this Statement did not require any adjustments to be made to the useful lives of existing intangible assets and no reclassifications of intangible assets to goodwill were necessary.

Intangible assets other than goodwill are being amortized on a straight-line basis over their estimated useful lives, and are reported under noncurrent assets in the Consolidated Balance Sheets.

The schedule below summarizes the amount of intangible assets by major classes.

	Balance at	
	June 30, 2002	December 31, 2001

(in millions)	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
PG&E NEG:				
Service agreements	$ 33	$ 6	$ 33	$ 6
Power sale agreements	41	9	44	8
Other agreements	26	7	27	5
Utility:				
Hydro licenses and other agreements	66	15	66	14
PG&E Corporation-Consolidated	$ 166	$ 37	$ 170	$ 33

PG&E NEG's amortization expense on intangible assets for the three and six months ended June 30, 2002, was $2 million and $3 million, respectively, compared to $1 million and $2 million for the same periods in 2001. These amounts do not include amortization expense related to intangibles for certain power sale agreements, which are recorded against the related revenue or expense. The Utility's amortization expense of intangible assets was $1 million for both the three and six months ended June 30, 2002, and also for the same periods in 2001.

The following schedule shows the estimated amortization expenses for intangible assets for full years 2002 through 2006.

(in millions)	2002	2003	2004	2005	2006
PG&E NEG	$ 6	$ 6	$ 6	$ 6	$ 6
Utility	3	3	3	3	3

Accounting for the Impairment or Disposal of Long-Lived Assets

- On January 1, 2002, PG&E Corporation adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS No. 144 supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of," but retains its fundamental provision for recognizing and measuring impairment of long-lived assets to be held and used. This Standard requires that all long-lived assets to be disposed of by sale are carried at the lower of carrying amount or fair value less cost to sell, and that depreciation should cease to be recorded on such assets. SFAS No. 144 standardizes the accounting and presentation requirements for all long-lived assets to be disposed of by sale, and supersedes previous guidance for discontinued operations of business segments. The adoption of the Statement did not have any impact on the Consolidated Financial Statements of PG&E Corporation and the Utility.

Changes to Accounting for Certain Derivative Contracts

- On April 1, 2002, PG&E Corporation implemented two interpretations issued by the Financial Accounting Standard Board's (FASB) Derivatives Implementation Group (DIG). DIG Issues C15 and C16 changed the definition of normal purchases and sales included in 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" (collectively, SFAS No. 133). Previously, certain derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business were exempt from the requirements of SFAS No. 133 under the normal purchases and sales exception, and thus were not marked to market and reflected on the balance sheet like other derivatives. Instead, these contracts were recorded on an accrual basis.

DIG C15 changed the definition of normal purchases and sales for certain power contracts. DIG C16 disallowed normal purchases and sales treatment for commodity contracts (other than power contracts) that contain volumetric variability or optionality. PG&E NEG determined that five of its derivative commodity contracts for the physical delivery of power and purchase of fuel no longer qualified for normal purchases and sales treatment under these interpretations. Beginning April 1, 2002, these five contracts were required to be recorded on the balance sheet at fair value and marked to market through earnings. Three of the contracts had positive market values and resulted in pre-tax income of $125 million. The remaining two contracts had negative market values that resulted in a pre-tax charge of $127 million. The cumulative effects of implementation of these accounting changes at April 1, 2002, resulted in PG&E Corporation recording price risk management assets of $37 million, price risk management liabilities of $255 million, and a reduction of out-of-market obligations of $129 million reclassified to net price risk management liabilities.

One of the contracts with a positive market value included above is for a power sales contract at a partnership in which PG&E NEG has a 50% ownership interest. PG&E NEG reflects its investment in this partnership on an equity basis (Investments in Unconsolidated Affiliates). Upon adoption of C15 and C16, PG&E NEG recognized its equity share of the gain from the cumulative change in accounting method and correspondingly increased the book value of its equity investment in the partnership. However, the future net cash flows from the partnership do not support the increased equity investment balance. Therefore, PG&E NEG has recognized an impairment charge of $101 million to reduce its equity-method investment to fair value. The cumulative effect of the change in accounting principle for DIG C15 and C16 was a net charge of $61 million, after-tax, and included the recognition of the fair market value of the five contracts impacted by C15 and C16 and the resultant impairment charge. The Utility was not impacted by these accounting changes.

Implementation of these accounting changes will not impact the timing and amount of cash flows associated with the affected contracts; however, it will impact the timing and magnitude of future earnings. Future earnings will reflect the gradual reversal of the assets and liabilities recorded upon adoption over the contracts' lives, as well as any prospective changes in the market value of the contracts. Prospective changes in the market value of these contracts could result in significant volatility in earnings. However, over the total lives of the contracts, there will be no net impact to total operating results after netting the cumulative effect of adoption against the subsequent years' impacts (assuming that the affected contracts are held to their expiration).

Related Party Transactions

In accordance with various agreements, the Utility and other subsidiaries provide and receive various services to and from their parent, PG&E Corporation. The Utility and PG&E Corporation exchange administrative and professional support services in support of operations. These services are priced either at the fully loaded cost or at the higher of fully loaded cost or fair market value depending on the nature of the services provided. PG&E Corporation also allocates certain other corporate administrative and general costs to the Utility and other subsidiaries using a variety of factors that are based upon the number of employees, operating expenses excluding fuel purchases, total assets, and other cost causal methods. Additionally, the Utility purchases gas commodity and transmission services from, and sells reservation and other ancillary services to, PG&E NEG. These services are priced at either tariff rates or fair market value depending on the nature of the services provided. Intercompany transactions are eliminated in consolidation and no profit results from these transactions. The Utility's significant related party transactions were as follows:

	Three months ended June 30,		Six months ended June 30,	
	-------------------------		-------------------------	
	2002	2001	2002	2001
(in millions)				

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Utility revenues from:				
Administrative services provided to PG&E Corporation	$ 2	$ 2	$ 3	$ 4
Gas reservation services provided to PG&E ET	3	4	6	6
Utility expenses from:				
Administrative services received from PG&E Corporation	$ 23	$ 13	$ 50	$ 38
Gas commodity and transmission services received from PG&E ET	9	39	28	123
Transmission services received from PG&E GT	10	9	22	18

NOTE 2: THE UTILITY CHAPTER 11 FILING

Overview of Electric Industry Restructuring

In 1998, California implemented electric industry restructuring and established a market framework for electric generation in which generators and other power providers were permitted to charge market-based prices for wholesale power. The restructuring of the electric industry was mandated by the California Legislature in Assembly Bill (AB) 1890. The mandate included a rate freeze and a plan for recovery of generation-related costs that were expected to be uneconomic under the new market framework (transition costs). Additionally, the CPUC encouraged the Utility to divest more than 50 percent of its fossil generation facilities and discouraged the Utility from continuing to operate remaining generation facilities by reducing the allowed return on such assets. The new market framework called for the creation of the Power Exchange (PX) and the Independent System Operator (ISO). Before it ceased operating in January 2001, 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 generation to, and purchase all electricity for its retail 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 spot prices for electricity sold through the PX and ISO began to escalate. While forward and spot prices moderated somewhat in September and October 2000, such prices increased in November and December 2000 to levels substantially higher than during the summer months. The increased cost of the purchased electricity strained the financial resources of the Utility because the CPUC applied the rate freeze in a way which prohibited the Utility from passing on the increases in power costs to its customers. The Utility financed the higher costs of wholesale electric power while interested parties evaluated various solutions to the California energy crisis. Consequently, by December 31, 2000, the Utility had borrowed more than $3 billion under its various credit facilities to finance its wholesale energy purchases.

Because of escalating wholesale electricity costs and the inability to pass on these costs to retail customers, the Utility accumulated approximately $6.9 billion (pre-tax) in under-collected purchased power costs and generation-related transition costs as of December 31, 2000. The under-collected purchased power costs historically were deferred for future recovery as a regulatory asset subject to future collection from customers in rates. However, due to the lack of regulatory, legislative, and judicial relief, the Utility determined that it could no longer conclude that its under-collected purchased power costs and remaining transition costs were probable of recovery in future rates. Therefore, the Utility charged $6.9 billion to expense for its under-collected purchased power costs and its remaining unamortized transition costs at December 31, 2000.

In January 2001, the CPUC increased electric rates, by $0.01 per kilowatt hour (kWh), and in March 2001 by another $0.03 per kWh. In addition, the price of wholesale electricity stabilized. Accordingly, in 2001, the Utility's total generation-related electric revenues were greater than its generation-related costs, resulting in earnings of $458 million (after-tax), which represented a partial recovery of previously written-off under-collected purchased power and transition costs, and included $327 million related to the market value of terminated bilateral contracts. On July 1, 2002, a CPUC Commissioner issued an Assigned Commissioner's Ruling seeking comments on whether the restrictions on applying the $0.01 per kWh and $0.03 per kWh surcharge revenues to "ongoing procurement costs" and "future power purchases" should be modified to allow the surcharge amount to be applied to improve the financial health of the Utility. The ruling suggests that one potentially just and reasonable use of surcharge revenues is any purpose necessary to restore financial health to the Utility. The Utility has filed comments in support of this suggestion. However, other parties have filed comments requesting that the CPUC reduce the Utility's retail electric rates, terminate the surcharges, or change the accounting for the surcharge revenues in a manner which would reduce the Utility's headroom revenues. It is possible that at some future date the CPUC may change the surcharges or the application of the surcharges, either prospectively or retroactively, and any such change could materially affect the Utility's earnings. The CPUC has not set a schedule for deciding these issues, and the Utility cannot predict the outcome of these matters.

During the six months ended June 30, 2002, the Utility's total generation-related revenues exceeded its generation-related costs by $542 million (after-tax). The Utility's previously written-off under-collected purchased power and transition costs amounted to $4.7 billion and $6.2 billion (pre-tax) at June 30, 2002, and December 31, 2001, respectively. The recovery of these remaining under-collected purchased power costs and transition costs is dependent on a number of factors, including but not limited to the ultimate outcome of the Utility's bankruptcy and future regulatory proceedings.

Under AB 1890, the rate freeze was scheduled to end on the earlier of March 31, 2002, or the date the Utility recovered all of its generation-related transition costs as determined by the CPUC. However, on January 2, 2002, the CPUC issued a decision which found that new California legislation, AB 6X, had materially affected the implementation of AB 1890. Therefore, the CPUC scheduled further proceedings to address the impact of AB 6X on the AB 1890 rate freeze for the Utility and to determine the extent and disposition of the Utility's remaining unrecovered transition costs. Additionally, on January 11, 2002, in a court proceeding involving a settlement between Southern California Edison Company (SCE) and the CPUC, the CPUC represented to the court that it has the authority to allow the Utility and SCE to recover their under-collected purchased power and transition costs beyond the end of the AB 1890 rate freeze. In fact, the settlement reached by the CPUC and SCE stipulated that SCE would maintain rates at their current levels (beyond the end of the AB 1890 rate freeze) until the earlier of the date that SCE recovered its previously incurred transition costs or December 31, 2003. To the extent SCE's costs are not recovered by December 31, 2003, they are to be amortized and recovered over a period ending December 31, 2005.

On April 15, 2002, the CPUC filed an alternative plan of reorganization (Alternative Plan) in the Utility's bankruptcy proceeding in U.S. Bankruptcy Court, proposing that the Utility's overall retail electric rates be maintained at current levels through January 31, 2003, in order to generate cash to repay in part the Utility's creditors under the CPUC's plan. The CPUC represented to the Bankruptcy Court that it was authorized to propose and implement its plan under state law. On July 12, 2002, in response to a lawsuit filed in state court by a consumer group challenging the legal authority of the CPUC to propose its plan, the CPUC represented that since utilities are now required under the state law to retain their generating assets, and the CPUC has regained its traditional rate authority over those assets, costs associated with those assets may be recovered by the utilities in the traditional way, under cost-based regulation. In addition, the CPUC represented that its failure to exercise its discretion to change rates to reflect changes in the Utility's costs after the AB 1890 rate freeze does not violate procedural requirements of state law. Based on these CPUC decisions and representations, the Utility believes it can continue to record revenues collected under its existing overall retail rates, subsequent to the statutory end of the rate freeze. However, the CPUC's further proceedings to consider the impact of AB 6X on the AB 1890 rate freeze and the disposition of the Utility's unrecovered transition costs are still pending, and it is possible that at some future date the CPUC may change its interpretation of law or otherwise seek to change the Utility's overall retail electric rates retroactively. Any such change could materially affect the Utility's earnings.

Finally, in one of the March 2001 decisions, the CPUC adopted an accounting proposal by The Utility Reform Network (TURN), which retroactively restates the way in which the Utility's transition costs are recovered. This retroactive change had the effect of extending the AB 1890 rate freeze and reducing the amount of past wholesale power costs that could be eligible for recovery from customers. The CPUC denied the Utility's application for rehearing of this retroactive accounting change. The Utility also filed a petition for a writ of review with the California Court of Appeal which also was denied. The Utility has filed a petition with the California Supreme Court to review the appellate court action. Further, the Bankruptcy Court denied the Utility's request for an order enjoining the CPUC from enforcing its retroactive order. The Utility has appealed the Bankruptcy Court's denial of injunctive relief to the U.S. District Court for the Northern District of California. The Utility cannot predict the outcome of this matter.

Electricity Purchases

As a result of the Utility's inability to pass through wholesale electricity costs to customers and the resulting impact on the Utility's financial resources, the Utility's credit rating deteriorated to below investment grade in January 2001. This credit downgrade precluded the Utility from access to capital markets. The Utility had no credit under which it could purchase wholesale electricity on behalf of its customers on a continuing basis. Consequently, generators were selling to the Utility only under emergency action taken by the U.S. Secretary of Energy.

In January 2001, the California Legislature and the Governor of California authorized the Department of Water Resources (DWR) to begin purchasing wholesale electric energy on behalf of the Utility's retail customers. On February 1, 2001, the Governor signed into law California AB 1X authorizing the DWR to purchase power to meet the Utility's net open position (the amount of power needed by retail electric customers that cannot be met by utility-owned generation or power under contract to the Utility). The DWR purchased energy on the spot market until it was able to enter into contracts for the supply of electricity. In addition to certain contracts that it has subsequently entered into, the DWR continues to purchase power on the spot market at prevailing market prices.

Initially, the DWR indicated that it intended to buy power only at "reasonable prices" to meet the Utility's net open position, leaving the ISO to purchase the remainder in order to avoid blackouts. The ISO billed the Utility for its costs to purchase power to cover the amount of the Utility's net open position not covered by the DWR. In 2001, the Utility accrued approximately $1 billion for these ISO purchases for the period from January 17, 2001, through April 6, 2001. However, in February, April, and November 2001, the FERC issued a series of orders directing the ISO to buy power only on behalf of creditworthy entities. In its November 2001 order, the FERC directed the ISO to invoice the DWR for all ISO transactions that the ISO entered into on behalf of the Utility. On December 7, 2001, the DWR filed an application for rehearing of the November 7, 2001, FERC order alleging, among other things, that the FERC order was illegal and unconstitutional because it restricted the DWR's unilateral discretion to determine the prices it would pay for the third-party power under the ISO invoices. On March 27, 2002, the FERC denied the DWR's application for rehearing and reaffirmed its previous orders finding that the DWR is responsible for paying such ISO charges.

On February 21, 2002, the CPUC approved a decision adopting rates for the DWR that will allow the DWR to collect power charges and financing charges from ratepayers to pay for the $19 billion in revenues needed by the DWR to procure electricity for the customers of the Utility and other California investor-owned utilities for the two-year period ending December 31, 2002. These revenues needed by the DWR will be financed partially through a DWR bond issuance and partially through the DWR's total statewide revenue requirement, which is allocated among the Utility and the other California investor-owned utilities. Accordingly, the CPUC established a total statewide revenue requirement for power charges of the DWR for the two-year period ending December 31, 2002, of $9 billion and allocated $4.5 billion to the Utility's customers. The February 21, 2002, CPUC order noted that the DWR had been found by the FERC to be responsible for ISO imbalance energy (energy obtained from the market) purchases for 2001, and authorized the DWR to collect rates from the Utility's customers sufficient to reimburse the DWR for these costs. In addition, on February 28, 2002, the DWR and SCE entered into an agreement under which the DWR has assumed financial responsibility for similar imbalance energy costs incurred by SCE.

On March 21, 2002, the CPUC modified its February 21, 2002, revenue requirement decision, effectively lowering the amount allocated to the customers of the Utility to $4.4 billion for the period from January 2001 through December 2002. Based on the March 21, 2002, CPUC decision, the Utility estimates that its total DWR revenue requirement allocation for 2001 is $2.5 billion. The Utility believes that the DWR's revenue requirement incorporates the procurement charges previously billed by the ISO and accrued by the Utility. In light of the March 27, 2002, FERC order and the February 21 and March 21, 2002, CPUC orders, in the first quarter of 2002, the Utility reversed the excess of the ISO accrual (for the period from January 17, 2001, through April 6, 2001) over the amount of the DWR revenue requirement applicable to 2001, for a net reduction of accrued purchased power costs of approximately $595 million, pre-tax.

The February 21, 2002, DWR revenue requirement decision, as modified by the March 21, 2002, decision, requires the DWR to submit true-ups of differences between forecasted and actual data contained in its 2001-2002 revenue requirement when it submits its 2003 revenue requirement. On June 14, 2002, the DWR released its proposed 2003 revenue requirement. In this proposed 2003 revenue requirement, the DWR requested an increase in its revenue requirement for the period from January 17, 2001, through December 31, 2002, to $9.1 billion, a slight increase from the $9.0 billion originally forecast. This revenue requirement reflects actual costs through April 2002 and projected costs for the remainder of 2002. Under AB 1X, the DWR is prohibited from entering into new agreements to purchase power to meet the net open position of the California investor-owned utilities (IOUs) after January 1, 2003. Under current FERC tariffs, in order to purchase power through the ISO, the IOUs must meet the ISO's creditworthiness standards for third party transactions, which require that the IOUs have an investment grade credit rating or meet certain collateral or prepayment requirements. The CPUC has initiated a proceeding which is expected to result in decisions in the second half of 2002 which will address the regulatory obligations and standards under which the IOUs may be required to resume procurement for the net open after January 1, 2003, including whether the IOUs will be required to procure power even if they are not investment grade; the allocation of power and operating responsibility for DWR's existing power contracts among the IOUs; and the reasonableness standards applicable to the IOUs' procurement. In addition, it is possible that the CPUC may seek to compel each IOU to accept assignment of legal and financial responsibility for existing DWR power contracts once the IOU's investment grade credit rating is restored. The Utility believes any such compelled assignment of the DWR contracts would be unlawful, and intends to challenge vigorously any such attempt by the CPUC. If an IOU is unable to meet the ISO's creditworthiness standards, the IOU may be required to post significant collateral or make significant cash prepayments to meet its net open position. It is possible that the Utility will be required to post collateral or make prepayments in order to resume procurement for the net open prior to regaining its investment grade credit rating, and procurement under such conditions could materially affect the Utility's earnings and the amount of cash projected to be available for payment of creditors' bankruptcy claims under the Utility's proposed plan of reorganization or the CPUC's alternative proposed plan of reorganization.

Chapter 11 Filing

On April 6, 2001, as a result of (1) the failure of the DWR to assume the full procurement responsibility for the Utility's net open position, (2) the negative impact of a CPUC decision that created new payment obligations for the Utility and undermined its ability to return to financial viability, (3) the lack of progress in negotiations with the State of California to provide a solution for the energy crisis, and (4) the adoption by the CPUC of a retroactive accounting change that would appear to eliminate the Utility's true under-collected wholesale electricity costs, the Utility filed a voluntary petition for relief under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court for the Northern District of California. Under Chapter 11, the Utility retains control of its assets and is authorized to operate its business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court. Subsidiaries of the Utility, including PG&E Funding LLC (which holds Rate Reduction Bonds) and PG&E Holdings, LLC (which holds stock of the Utility), are not included in the Utility's petition. While the Utility's parent, PG&E Corporation, and PG&E NEG have not filed for relief under Chapter 11 and are not included in the Utility's petition, PG&E Corporation is a co-proponent of the Utility's proposed Plan of Reorganization.

The Utility's Consolidated Financial Statements have been prepared in accordance with the American Institute of Certified Public Accountants' Statement of Position (SOP) 90-7, "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code," and on a going-concern basis, which contemplates continuity of operation, realization of assets, and liquidation of liabilities in the ordinary course of business. However, as a result of the Chapter 11 filing, such realization of assets and liquidation of liabilities are subject to uncertainty.

Certain claims against the Utility in existence prior to its filing for bankruptcy are stayed while the Utility continues business operations as a debtor-in-possession. The Utility has reflected its total estimate of all such valid claims on the June 30, 2002, Consolidated Balance Sheets as $9.2 billion of Liabilities Subject to Compromise and as $3.0 billion of Long-Term Debt. The following schedule summarizes the activity of the Utility's Liabilities Subject to Compromise from the period of December 31, 2001, to June 30, 2002 (in billions):

Liabilities Subject to Compromise at December 31, 2001	$ 11.4
Interest accrual for the six months ended June 30, 2002	0.3
Claims paid pursuant to Bankruptcy Court order	(0.9)
Claims authorized by the Bankruptcy Court to be paid (transferred to accounts payable or interest payable)	(0.9)
Reclassification of debt upon liquidation of trust holding solely Utility Subordinated Debentures (Note 5)	0.3
Reversal of first quarter 2001 ISO accrual	(1.0)

Liabilities Subject to Compromise at June 30, 2002	$ 9.2
	========

Additional claims or changes to Liabilities Subject to Compromise may subsequently arise from, among other things, resolution of disputed claims and Bankruptcy Court actions. Payment terms for these amounts will be established through the bankruptcy proceedings. Secured claims also are stayed, although the Utility has received authorization from the Bankruptcy Court to make certain principal payments that have matured. Secured claims are secured primarily by liens on substantially all of the Utility's assets and by pledged accounts receivable from natural gas customers. The Bankruptcy Court has approved certain payments and actions necessary for the Utility to carry on its normal business operations (including payment of employee wages and benefits, refunds of certain customer deposits, use of certain bank accounts and cash collateral, assumption of various hydroelectric contracts with water agencies and irrigation districts, certain qualifying facilities (QF) payments, interest on secured debt, and continuation of environmental remediation and capital expenditure programs) and to fulfill certain post-petition obligations to suppliers and creditors. In addition, the Bankruptcy Court has authorized the payment of pre- and post-petition interest and low dollar items on certain claims prior to the Utility's emergence from bankruptcy under a confirmed plan.

Through June 30, 2002, $49.1 billion of claims had been filed. This amount includes claims filed by generators (which the Utility believes have been significantly overstated) and claims filed by certain financial creditors (some of which have been disallowed by the Bankruptcy Court, based on a finding that such claims are duplicative of claims filed by indenture trustees and other claimants or, in the case of commercial paper, claims scheduled by the Utility). This amount also includes governmental claims which include, but are not limited to, contingent environmental claims, claims for federal, state and local taxes, and claims submitted by the DWR for approximately $430 million of energy purchases made on behalf of the Utility's retail customers. The Bankruptcy Court has, at present, disallowed $170 million of DWR energy purchases as duplicative.

Approximately $20.4 billion of claims have been disallowed by the Bankruptcy Court, confirmed as duplicative, or withdrawn. Additional objections to claims have been filed in the Bankruptcy Court which the Utility believes to have merit. These objections will be ruled upon by the court in the future, which the Utility believes will further reduce the amount of the claims.

The claims resolution process in bankruptcy involves the determination by the Bankruptcy Court of the validity of the claim. In addition, it is common to negotiate with creditors to achieve settlement. The Utility intends to explore settlement of claims wherever possible.

On September 20, 2001, the Utility and its parent company, PG&E Corporation, jointly filed with the Bankruptcy Court a proposed plan of reorganization (Plan) of the Utility under the Bankruptcy Code and a related disclosure statement. The Utility and PG&E Corporation filed amendments to the Plan and the disclosure statement on several occasions after the initial filing in an effort to resolve objections filed by various parties, to respond to the Bankruptcy Court's February 7, 2002, decision regarding Federal preemption of state law, and to update the information in the Plan and disclosure statement to reflect other developments with respect to the Utility's business and restructuring efforts. On April 24, 2002, the Bankruptcy Court entered an order approving the Utility's disclosure statement dated April 19, 2002. '

On June 7, 2002, PG&E Corporation and the Utility filed a motion with the Bankruptcy Court to extend, until December 2002, the period during which no third parties, other than the CPUC, may submit an alternate proposed plan of reorganization. The exclusivity period was scheduled to end on June 30, 2002, unless extended. On June 24, 2002, the Official Committee of Unsecured Creditors (OCC) requested that the exclusivity period be modified to enable the OCC to formulate and be in a position to file an alternative plan of reorganization if the proponents of the Utility's Plan and the CPUC's Alternative Plan fail to come to terms on a consensual plan and it appears that neither plan as currently proposed is likely to be confirmed by the court or implemented in an expeditious fashion. On July 9, 2002, the Bankruptcy Court issued an order granting the OCC's request and extending the exclusivity period to December 31, 2002, (except as to the CPUC and the OCC).

If the Utility's Plan, as amended, is confirmed and becomes effective, it would allow the Utility to restructure its businesses, refinance the restructured businesses, and use the proceeds from the refinancing to pay all allowed claims, with interest.

The Utility's Plan proposes that all allowed creditor claims would be paid in full with interest, using a combination of cash and long-term notes. Creditors would receive payment as follows:

	On the Effective Date of the Plan, Creditors Would Receive Payment In

	Cash	Long-term Notes
Majority of secured creditors	100%	-
Majority of unsecured creditors with allowed claims of $100,000 or less	100%	-
Unsecured creditors with allowed claims in excess of $100,000	60%	40%

The Utility, through a Bankruptcy Court approved settlement with a group of senior debtholders, has agreed to pay the holders of certain allowed claims pre- and post-petition interest on the principal amount of such claims at rates of interest as follows:

	Amount Owed (in millions)	Agreed Upon Rate (per annum)	
Commercial Paper claims	$ 873	7.466%	
Floating Rate Notes	1,240	7.583%	(Implied yield of 7.690%)
Senior Notes	680	9.625%	
Medium-Term Notes	287	5.810% to 8.450%	
Revolving line of credit claims	938	8.000%	

In addition, if the date on which the Plan becomes effective (Effective Date) does not occur on or before February 15, 2003, these interest rates will be increased by 37.5 basis points. If the Effective Date does not occur on or before September 15, 2003, the agreed rates will be increased by an additional 37.5 basis points. Finally, if the Effective Date does not occur on or before March 15, 2004, the agreed rates will be increased by an additional 37.5 basis points. For other claims, the Utility has recorded the contractual or FERC tariffed interest rate, or when those rates do not apply, the Utility has recorded the Federal Judgment Rate.

Since December 2001, the Bankruptcy Court has approved supplemental agreements entered into between the Utility and many QFs to resolve the issue of the applicable interest rate to be applied to pre-petition amounts owed to QFs. The supplemental agreements (1) set the interest rate for pre-petition payables at 5 percent, (2) provide for a "catch-up payment" of all accrued and unpaid interest through the initial payment date, and (3) depending on the amount owed, either provide for the immediate payment of the principal amount of the pre-petition payables (and interest thereon) or payment in 12 equal monthly payments commencing on the last business day of the month during which Bankruptcy Court approval was granted, and continuing for 11 subsequent months. In the event the Effective Date of the Plan occurs before the last monthly payment is made, the remaining unpaid principal and accrued but unpaid interest thereon shall be paid in full on the Effective Date. Additionally, since January 2002, the Utility has entered into agreements with additional QFs to assume their power purchase agreements, which agreements also contained the same interest and payment terms contained in the supplemental agreements described above. At June 30, 2002, $474 million and $55 million in principal and interest, respectively, have been paid to the QFs. Through June 30, 2002, 253 of 313 active QFs have signed supplemental agreements. The Utility believes that some of the remaining QFs also will wish to enter into similar supplemental agreements.

On March 27, 2002, the Bankruptcy Court authorized payments of pre- and post-petition interest to holders of certain other undisputed claims, including creditors holding certain financial instruments issued by the Utility (including certain senior debtholders, as described above), trade creditors, and other general unsecured creditors, and authorized payment of fees and expenses of indenture trustees and other paying agents (subject to a procedure to permit objections to fees to be made and resolved). Through July 1, 2002, the Utility has paid approximately $562 million in pre- and post-petition interest related to these claims. The Utility estimates that payments pursuant to this authorization could be as much as approximately $700 million, through the third quarter of 2002, based on the claim amounts estimated in the Utility's disclosure statement; however, the Utility has withheld $150 million of this amount because it disputes the underlying claims and will not pay interest on those disputed claims until the disputes are resolved. The actual amount of pre- and post-petition interest eventually payable may be different than the Utility's estimates, depending on the amount of claims ultimately allowed by the Bankruptcy Court. The Utility also repaid advances and interest on advances of $21 million to banks providing letters of credit backing pollution control bonds, which were separately authorized by the Bankruptcy Court.

On March 25, 2002, the Bankruptcy Court authorized the Utility to pay all undisputed creditor claims that are $5,000 or less and undisputed mechanics' liens and reclamation claims, for an aggregate amount of approximately $8 million. These amounts will be paid in the third quarter of 2002.

The Utility's Plan is designed to align the businesses under the regulators that best match the business functions. Retail assets would remain under the retail regulator, the CPUC, and wholesale assets would be placed under wholesale regulators, the FERC and the Nuclear Regulatory Commission (NRC). After this alignment, the retail-focused, state-regulated business would be a gas and electric distribution company (Reorganized Utility) representing approximately 70 percent of the book value of the Utility's assets and having approximately 16,000 employees. The wholesale businesses, which would be federally regulated (as to price, terms, and conditions), would consist of electric transmission (ETrans), interstate gas transmission (GTrans), and generation (Gen).

The Utility's Plan proposes that certain other assets of the Utility deemed not essential to operations would be sold to third parties or transferred to Newco Energy Corporation (Newco), a consolidated subsidiary created by the Utility to hold the investments in ETrans, GTrans, and Gen. Additionally, the Utility would declare and, after the assets are transferred to the newly formed entities, pay a dividend to PG&E Corporation of all of the outstanding common stock of Newco. Each of ETrans, GTrans, and Gen would continue to be an indirect wholly owned subsidiary of PG&E Corporation.

The Utility's 18,500 circuit miles of electric transmission lines and cable would be transferred to ETrans, a California company. ETrans would operate as an independent transmission company selling transmission services to wholesale customers (utilities) and to electric generators.

The Utility's 6,300 miles of gas transmission pipelines and three gas storage facilities would be transferred to GTrans, a California company. GTrans would hold the majority of the land, rights of way, and access rights currently associated with Utility gas transmission pipelines. GTrans also would assume certain continuing contractual obligations currently held by the Utility's gas transmission operation. In addition, the Reorganized Utility would hold a 10- to 15-year transportation and gas storage contract with GTrans.

The Utility's hydroelectric and nuclear generation assets, and associated lands and the power contracts with irrigation districts would be transferred to Gen, a California company. In total, Gen would have approximately 7,100 megawatts (MW) of generation. The facilities would be operated in accordance with all current FERC and NRC licenses. Gen would sell its power back to the Reorganized Utility under a 12-year contract at a stable market-based rate approved by the FERC.

The Utility's Plan relies on the FERC and the Bankruptcy Court to authorize certain actions which are outside of management's control. These actions include allowing a shift in regulatory jurisdiction of certain of the Utility's assets, approving contracts between and among the newly formed entities, and preempting certain state and local laws. Specifically, the Plan asks the Bankruptcy Court to:

- ♦ Approve the Utility's Plan, authorizing the Utility to execute, implement, and take all actions necessary or appropriate to give effect to the transactions contemplated by the Plan and the Plan documents;
- ♦ Approve the execution of, and find reasonable the terms and conditions of, the proposed service and sales contracts between the Reorganized Utility and one or more of the disaggregated entities;
- ♦ Find that the CPUC affiliate transaction rules are not applicable to the restructuring transactions contemplated under the Plan; and
- ♦ Find that neither PG&E Corporation nor the Utility is required to comply with certain provisions of the California Corporations Code relating to corporate distributions and the sale of substantially all of a corporation's assets because the Bankruptcy Code preempts such state law.

Further, if the Bankruptcy Court determines that the CPUC and/or the State as a whole have not waived their sovereign immunity with respect to the Plan, PG&E Corporation and the Utility intend to amend the conditions to Plan confirmation to substitute findings of fact or conclusions of law for any declaratory or injunctive relief presently sought against the CPUC or the State.

Finally, the Utility's Plan contemplates that on or as soon as practicable after the Effective Date, PG&E Corporation would distribute the shares of the Reorganized Utility's common stock it holds to the holders of PG&E Corporation common stock on a pro rata basis (Spin-Off). The preferred stock of the Utility that is currently outstanding would remain outstanding preferred stock of the Reorganized Utility. It is contemplated that holders of preferred stock of the Utility would receive in cash on the Effective Date, any dividends unpaid and sinking fund payments accrued in respect of such preferred stock through the last scheduled payment date before the Effective Date. The common stock of the Reorganized Utility would be registered under federal securities laws, and would be freely tradable by the recipients on the Effective Date or as soon as practicable thereafter. The Reorganized Utility would apply to list the common stock of the Reorganized Utility on the New York Stock Exchange.

Key aspects of the Utility's Plan include: (1) the issuance of investment-grade registered debt by ETrans, GTrans, and Gen, the proceeds of which, along with additional notes, would be distributed to the Reorganized Utility so that it could pay creditors, (2) a 12-year bilateral contract whereby Gen would provide the Reorganized Utility firm capacity and energy at an average rate of approximately $50 per megawatt-hour (MWh), and (3) the assumption by the Reorganized Utility of responsibility for the net open position only after certain conditions specified in detail below are met.

In order to ensure the financial viability of the Utility's Plan, the Plan provides that the following conditions must be fulfilled before the Reorganized Utility will reassume the responsibility to purchase power to meet the net open position not already provided through the DWR's power purchase contracts:

1. The Reorganized Utility receives an investment grade credit rating and receives assurances from the rating agencies that its credit rating will not be downgraded as a result of the reassumption of the obligation to meet the net open position;
2. There is an objective retail rate recovery mechanism in place pursuant to which the Reorganized Utility is able to fully recover in a timely manner its wholesale costs of purchasing electricity to satisfy the net open position;
3. There are objective standards in place regarding pre-approval of procurement transactions; and
4. After reassumption of the obligation to meet the net open position, the conditions in clauses (2) and (3) remain in effect.

The CPUC has initiated a proceeding which is intended to address the Utility's resumption of the net open obligation as early as January 1, 2003.

On November 30, 2001, the Utility and PG&E Corporation on behalf of its subsidiaries ETrans, GTrans, and Gen, filed various applications with the FERC seeking approval to implement the proposed reorganization and the securities issuances and debt financings contemplated by the Plan. The FERC also must approve some of the various service agreements to be entered into between the Reorganized Utility and one or more of the disaggregated entities. Additionally, the SEC, as administrator of the Public Utility Holding Company Act (PUHCA), must approve the Plan. An application under PUHCA was filed with the SEC on January 31, 2002.

Also, on November 30, 2001, the Utility filed applications with the NRC for approval to transfer the NRC operating licenses for the Diablo Canyon Nuclear Power Plant (Diablo Canyon) to Gen and one of its subsidiaries, and for the indirect transfer of the Humboldt Bay Nuclear Power Plant, which is in the early stages of decommissioning, to the Reorganized Utility.

Additionally, because the reorganization is intended to qualify as a tax-free reorganization and the Spin-Off is intended to qualify as a tax-free spin-off, PG&E Corporation and the Utility have sought a private letter ruling from the Internal Revenue Service (IRS) confirming the tax-free treatment of these transactions.

The Utility's Plan provides that it will not become effective unless and until the following conditions have been satisfied or waived:

1. The Effective Date shall have occurred on or before January 1, 2003;
2. All actions, documents, and agreements necessary to implement the Plan shall have been effected or executed;
3. PG&E Corporation and the Utility shall have received all authorizations, consents, regulatory approvals, rulings, letters, no-action letters, opinions, or documents that are determined by PG&E Corporation and the Utility to be necessary to implement the Plan;
4. Standard & Poor's (S&P) and Moody's Investors Service (Moody's) shall have established credit ratings for each of the securities to be issued by the Reorganized Utility, ETrans, GTrans, and Gen of not less than BBB- and Baa3, respectively;
5. The Plan shall not have been modified in a material way since the confirmation date; and
6. The registration statements pursuant to which the new securities will be issued shall have been declared effective by the SEC, the Reorganized Utility shall have consummated the sale of its new securities to be sold under the Plan, and the new securities of each of ETrans, GTrans, and Gen shall have been priced and the trade date with respect to each shall have occurred.

If one or more of the conditions described above have not occurred or been waived by January 1, 2003, the confirmation order shall be vacated and the Utility's obligations with respect to claims and equity interests shall remain unchanged.

In a February 7, 2002, decision, the Bankruptcy Court rejected PG&E Corporation's and the Utility's (Proponents) contentions that bankruptcy law permits express preemption of state law in connection with the implementation of a plan of reorganization. The Bankruptcy Court nonetheless held that "the Plan could be confirmed if Proponents are able to establish with particularity the requisite elements of implied preemption." The Bankruptcy Court stated that Proponents must show facts that would lead the Bankruptcy Court to find that the "application of those laws to the facts of the Debtor's proposed reorganization are economic in nature rather than directed at protecting public safety or other non-economic concerns, and that those particular laws stand as an obstacle to the accomplishment and execution of the purposes and objectives of Congress and the Bankruptcy Code." The Bankruptcy Court noted that if the disclosure statement were amended consistent with the court's memorandum decision, the court would approve it and let the Proponents test preemption at confirmation.

On March 18, 2002, the Bankruptcy Court entered an order disapproving the disclosure statement for the reasons set forth in the February 7, 2002, decision. On March 22, 2002, PG&E Corporation and the Utility appealed the Bankruptcy Court's March 18, 2002, order to the United States District Court for the Northern District of California. The CPUC, the City and County of San Francisco (City), and the California Attorney General filed a motion to dismiss the appeal arguing, among other matters, that the District Court lacked appellate jurisdiction because the Bankruptcy Court erred in certifying its March 18, 2002, order as immediately appealable. On June 24, 2002, the District Court issued a ruling finding that the Bankruptcy Court's certification of its preemption order was proper and that the District Court had appellate jurisdiction. The District Court set a hearing for August 16, 2002, to hear arguments regarding the appeal.

The Utility's disclosure statement and Plan were amended consistent with the Bankruptcy Court's February 7, 2002, preemption decision. On April 24, 2002, the Bankruptcy Court approved the Utility's disclosure statement dated April 19, 2002, describing the Utility's Plan. The Bankruptcy Court's approval of the Utility's disclosure statement does not constitute approval of the Plan.

As authorized by the Bankruptcy Court, on April 15, 2002, the CPUC filed its proposed Alternative Plan and disclosure statement with the Bankruptcy Court, followed by an amendment on May 15, 2002. The Bankruptcy Court approved 'the CPUC's disclosure statement on May 17, 2002. The CPUC's Alternative Plan does not call for realignment of the Utility's business, but instead provides for the continued regulation of all of the Utility's current operations by the CPUC. The CPUC's Alternative Plan also includes the following significant components:

- Provides for shareholders to contribute a projected $1.6 billion in cash earned by the Utility from its return on equity for Utility operations during 2001, 2002, and January 2003;
- Proposes to raise $3.9 billion through the issuance of new subordinated debt;
- Proposes to raise $1.75 billion through the sale of Utility common stock;
- Assumes the Utility will satisfy the FERC's creditworthiness requirements and will resume purchasing the net open position no later than January 31, 2003;
- Requires the Utility to dismiss all claims against the state, with prejudice;
- Assumes all valid claims (together with applicable post-petition interest at the lowest non-default contract rate, or if no contract or non-default rate exists, then the Federal Judgment Rate) totaling approximately $13.5 billion will be satisfied in full through a combination of cash (inclusive of the net proceeds from the proposed sale of the new subordinated notes) and reinstatement of certain of the Utility's long-term indebtedness and other obligations (approximately $4.3 billion);
- Becomes effective only if the Utility's new and reinstated debt securities receive investment grade credit ratings; however, the CPUC would retain the right to waive this condition; and
- Assumes the Utility will obtain a $1.9 billion credit facility to fund operating expenses and seasonal fluctuations of capital. A portion of this facility will be used for letters of credit that may be needed to pay collateral for post-petition workers' compensation liabilities.

The CPUC's proposed timeline for its Alternative Plan provides for a confirmation order to be issued on or before October 31, 2002, and for the Alternative Plan to become effective on or before January 31, 2003.

PG&E Corporation and the Utility believe the CPUC's Alternative Plan is not credible or confirmable. PG&E Corporation and the Utility also do not believe the CPUC's Alternative Plan would restore the Utility to investment grade status if the Alternative Plan were to become effective. Additionally, PG&E Corporation and the Utility believe the CPUC's proposal to require the Utility to issue common stock, which would significantly dilute equity and the Alternative Plan component seeking to eliminate any return on equity for a 25-month span violate federal and state law.

Further, on April 22, 2002, the CPUC initiated a regulatory proceeding to consider the rate impacts of its Alternative Plan and the Utility's Plan and invited parties to file comments. The order followed a legal challenge before the California Supreme Court by the Foundation for Taxpayers and Consumer Rights (FTCR) that the CPUC did not have the authority to propose a plan in Bankruptcy Court. Also, on July 17, 2002, the CPUC instituted a proceeding regarding the securities authorization necessary to implement the CPUC Alternative Plan.

On June 17, 2002, solicitations of creditor approval of the competing plans began. Most creditors will have the option of approving one plan, both plans (with an option to indicate a preference for one over the other), or neither plan. Acceptance or rejection of a plan is determined by creditor class. The voting period is scheduled to end on August 12, 2002. In determining whether to confirm either plan, the Bankruptcy Court will consider creditor and equity preference, plan feasibility, distributions to creditors and equity, and the financial viability of the reorganized entities. Various parties have filed objections to confirmation of either or both plans. PG&E Corporation and the Utility filed objections to the CPUC Alternative Plan stating their belief that the Alternative Plan is neither feasible nor confirmable for the reasons discussed above. The CPUC also filed an objection to the Utility's Plan. In May 2002, the OCC issued a report recommending that creditors vote in favor of both plans, but declined to state a preference for either plan.

The Utility and the CPUC each have filed a proposed form of protocol for the parties to follow in conducting discovery in preparation for the confirmation hearings, and they each have requested that the Bankruptcy Court begin the confirmation trial on November 12, 2002. The Bankruptcy Court is expected to address the discovery protocol and scheduling matters at the status conference to be held on August 1, 2002.

Neither the Utility nor PG&E Corporation are able to predict which plan the creditors will approve, or which plan, if any, the Bankruptcy Court will confirm. Whichever plan is confirmed, implementation of the confirmed plan may be delayed due to appeals, CPUC actions or proceedings, or other regulatory hearings that could be required in connection with the regulatory approvals necessary to implement the plan, and other events. Further, neither the Utility nor PG&E Corporation can predict whether the OCC will submit an alternative plan nor what the terms of any such plan would be. Consideration of an alternative plan could cause delays in the current schedule contemplated under the Utility's Plan. The pendency of the bankruptcy proceeding and the related uncertainty around the plan of reorganization that is ultimately adopted and implemented will have a significant impact on the Utility's future liquidity and results of operations. PG&E Corporation and the Utility are not able at this time to predict the outcome of the Utility's bankruptcy case or the effect of the reorganization process on the claims of the Utility's creditors or the interests of the Utility's preferred shareholders. However, the Utility believes, based on information presently available to it, that cash and cash equivalents on hand at June 30, 2002, of $3.8 billion and cash available from operations will provide sufficient liquidity to allow it to continue as a going concern through 2002.

NOTE 3: PRICE RISK MANAGEMENT

PG&E Corporation, primarily through its subsidiaries, engages in price risk management (PRM) activities for both non-trading and trading purposes. 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. PG&E Corporation conducts trading activities principally through its unregulated lines of business. Trading activities are conducted to generate profit, create liquidity, and maintain a market presence. Net open positions often exist or are established due to PG&E NEG's assessment of and response to changing market conditions. In addition, non-trading activities existed within the Utility in prior years to hedge against price fluctuations of electricity and natural gas.

Derivative instruments associated with non-trading activities are accounted for in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended (SFAS No. 133) and ongoing interpretations of the FASB's DIG. Derivatives and other financial instruments associated with trading activities in electric power and other energy commodities are accounted for using the mark-to-market method of accounting in accordance with FASB's Emerging Issues Task Force (EITF) Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities."

Non-Trading Activities

At June 30, 2002, PG&E Corporation had cash flow hedges of varying durations associated with commodity price risk, foreign currency risk, and interest rate risk, the longest of which extend through December 2011, December 2004, and March 2014, respectively. The fair value of commodity hedges included in Accumulated Other Comprehensive Income or Loss (OCI), net of taxes, at June 30, 2002, was a gain of $98 million. The fair value of interest rate hedges included in OCI, net of taxes, at June 30, 2002, was a loss of $139 million. The fair value of foreign currency hedges included in OCI, net of taxes, at June 30, 2002, was a loss of $2 million.

PG&E Corporation's ineffective portion of changes in fair values of cash flow hedges was a $2 million gain after taxes for the three and six months ended June 30, 2002, and an immaterial amount for the three and six months ended June 30, 2001. PG&E Corporation's estimated net derivative losses included in OCI at June 30, 2002, are $43 million, of which net losses of $8 million are expected to be reclassified into earnings within the next 12 months. The actual amounts reclassified from accumulated other comprehensive loss to earnings will differ as a result of market price changes. The Utility had no cash flow hedges and therefore no balances in OCI for the three and six months ended June 30, 2002.

The schedule below summarizes the activities affecting accumulated other comprehensive loss net of tax, from derivative instruments:

	Three months ended June 30, 2002		Six months ended June 30, 2002	
(in millions)	PG&E Corporation	Utility	PG&E Corporation	Utility
Derivative gains (losses) included in accumulated other comprehensive income (loss) at beginning of period	$ (34)	$ -	$ 36	$ -
Net loss of current period hedging transactions and price changes	(9)	-	(84)	-
Net reclassification to earnings	-	-	5	-
Derivative losses included in accumulated other comprehensive loss at end of period	(43)	-	(43)	-
Foreign currency translation adjustment	(2)	-	(2)	-
Accumulated other comprehensive loss at end of period	$ (45)	$ -	$ (45)	$ -

	Three months ended June 30, 2001		Six months ended June 30, 2001	
(in millions)	PG&E Corporation	Utility	PG&E Corporation	Utility
Derivative gains (losses) included in accumulated other comprehensive income (loss) at beginning of period	$ (315)	$ (52)	$ -	$ -

Cumulative effect of adoption of SFAS No. 133	-	-	(243)	90
Net loss of current period hedging transactions and price changes	178	(8)	149	(7)
Net reclassification to earnings	31	19	(12)	(124)
Derivative losses included in accumulated other comprehensive loss at end of period	(106)	(41)	(106)	(41)
Foreign currency translation adjustment	(3)	(1)	(3)	(1)
Accumulated other comprehensive loss at end of period	$ (109)	$ (42)	$ (109)	$ (42)

Trading Activities

PG&E Corporation's net gains (losses) on trading activities, recognized on a fair value basis, were as follows:

	Three months ended June 30,		Six months ended June 30,	
(in millions)	2002	2001	2002	2001
Trading activities (1):				
Unrealized gains and losses, net	(48)	62	(53)	16
Realized gains, net	34	31	78	105
Total	$ (14)	$ 93	$ 25	$ 121

(1)

The Utility did not engage in trading activities.

Net unrealized gains and losses, including the reversal of unrealized gains and losses previously recognized on contracts that go to settlement or delivery, are presented on a net basis in operating revenues. Realized gains and losses are currently presented on a gross basis in operating income. The realized amounts for sale contracts are presented as operating revenues and the realized amounts for purchase contracts are presented in operating expenses as costs of commodity sales and fuel. The net realized gains of $34 million and $78 million for the three and six months ended June 30, 2002, are composed of operating revenues of $2,387 million and $4,073 million, respectively, and operating expenses of $2,353 million and $3,995 million, respectively. Beginning in the third quarter of 2002, these realized gains and losses on trading activities will be retroactively presented on a net basis in the income statement to comply with the consensus reached by FASB's EITF, Issue on No. 02-03, "Recognition and Reporting of Gains and Losses on Energy Trading Contracts under EITF Issues No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities", and No. 00-17, "Measuring the Fair Value of Energy-Related Contracts in Applying Issue No. 98-10." PG&E Corporation has reviewed its trading activities for 2001 and 2002 for potential instances of so-called "wash trades," and determined that such trades in the aggregate did not have a significant impact on revenues or expenses in any of the quarters in that period.

Gains and losses on trading contracts affect PG&E Corporation's gross margin in the accompanying PG&E Corporation unaudited Consolidated Statements ofOperations on an unrealized mark-to-market basis as the fair value of the forward positions on these contracts fluctuates. Settlement or delivery on a contract is generally not an event that results in incremental net income recognition, as the profit or loss on a contract is recognized in income on an unrealized mark-to-market basis during the periods before settlement occurs.

Gains and losses on trading contracts affect PG&E Corporation's cash flow when these contracts are settled. Net realized gains reported in the table above primarily reflect the net effect of contracts that have been settled in cash. Net realized gains also include certain non-cash items, including amortization of option premiums that were paid or received in cash in earlier periods but are considered realized when the related options are exercised or expire.

Price Risk Management Assets and Liabilities

Price risk management assets and liabilities on the accompanying PG&E Corporation Consolidated Balance Sheets reflect the aggregation of the fair values of outstanding contracts. These fair values are calculated on a mark-to-market basis for contracts that will be settled in future periods. Price risk management assets and liabilities at June 30, 2002, include amounts for trading and non-trading activities, as described below.

	Assets		Liabilities		Net
(in millions)	Current	Noncurrent	Current	Noncurrent	(Liabilities)
Trading activities	$ 220	$ 193	$ (186)	$ (228)	$ (1)
Non-trading activities:					
Cash flow hedges - offset to OCI	283	311	(331)	(286)	(23)
Derivatives marked to market through earnings	5	70	(31)	(237)	(193)
Total consolidated PRM Assets and Liabilities	$ 508	$ 574	$ (548)	$ (751)	$ (217)

Non-trading activities include certain long-term contracts that are not included in PG&E Corporation's trading portfolio but that, due to certain pricing provisions and volumetric variability, are unable to receive hedge accounting treatment or the normal purchases and sales exception, as outlined by interpretations of SFAS No. 133. PG&E

Corporation has certain other non-trading derivative commodity contracts for the physical delivery of purchases and sales quantities transacted in the normal course of business. These other non-trading activities include contracts that are exempt from SFAS No. 133 fair value requirements under the normal purchases and sales exemption, as described previously. Although the fair value of these other non-trading contracts is not required to be presented on the balance sheet, revenues and expenses are generally recognized in income using the same timing and basis as is used for the non-trading activities accounted for as cash flow hedges. Hence, revenues are recognized as earned and expenses are recognized as incurred.

Credit Risk

Credit risk is the risk of loss that PG&E Corporation and the Utility would incur if counterparties fail to perform their contractual obligations (accounts receivable, notes receivable, and PRM assets reflected on the balance sheets). PG&E Corporation and the Utility conduct business primarily with customers in the energy industry, such as investor-owned and municipal utilities, energy trading companies, financial institutions, and oil and gas production companies, located in the United States and Canada. This concentration of counterparties may impact PG&E Corporation's and the Utility's overall exposure to credit risk in that their counterparties may be similarly affected by changes in economic, regulatory, or other conditions. PG&E Corporation and the Utility mitigate potential credit losses in accordance with established credit approval practices and limits by dealing primarily with creditworthy counterparties (counterparties considered investment grade or higher). PG&E Corporation and the Utility review credit exposure in relation to specified counterparty limits daily and, to the maximum extent possible, require that all derivative contracts take the form of master agreements that contain credit support provisions that require the counterparty to post security in the form 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 and the Utility calculate gross credit exposure as the current fair value (what would be lost if the counterparty defaulted today) plus any outstanding net receivables, prior to the application of credit collateral. In the past year, PG&E Corporation's and the Utility's credit risk has increased partially due to credit rating downgrades of some of the counterparties in the energy industry to below investment grade.

At June 30, 2002, PG&E Corporation had no single counterparty that represented greater than 10 percent of PG&E Corporation's net credit exposure. At June 30, 2002, the Utility had two investment grade counterparties and one below investment grade counterparty that each represented greater than 10 percent of the Utility's net credit exposure.

The schedule below summarizes the exposure to counterparties that are in a net asset position, with the exception of exchange-traded futures (the exchange provides for contract settlement on a daily basis), at June 30, 2002:

(in millions)	Gross Exposure (1)	Credit Collateral (2)	Net Exposure (2)
PG&E Corporation	$ 1,084	$ 183	$ 901
Utility (3)	143	101	42

(1) Gross credit exposure equals fair value (adjusted for appropriate credit reserves), notes receivable, and net (payables) receivables where netting is allowed.

(2)

Net exposure is the gross exposure minus credit collateral (cash deposits and letters of credit).

(3) The Utility's gross exposure includes wholesale activity only. Retail activity and payables prior to the Utility's bankruptcy filing are not included. Retail activity at the Utility consists of the accounts receivable from the sale of gas and electricity to millions of residential and small commercial customers. Reserves for uncollectible accounts receivable are calculated for the potential loss from nonpayment by these customers based on historical experience.

At June 30, 2002, approximately $121 million or 13 percent of PG&E Corporation's net credit exposure is to entities that have credit ratings below investment grade. Approximately $17 million or 41 percent of the Utility's net credit exposure is to below investment grade entities. Investment grade is determined using publicly available information including an S&P rating of at least BBB-. Approximately $206 million or 23 percent of PG&E Corporation's net credit exposure at PG&E NEG is not rated Subsequent to June 30, 2002, the credit ratings of two large counterparties (Williams Companies, Inc. and Dynegy Holdings, Inc) were reduced to below investment grade. At June 30, 2002, PG&E Corporation's and the Utility's net credit exposure to these companies was $36 million and $2 million, respectively. By July 29, 2002, the net exposure to these companies was reduced to less than $1 million for both PG&E Corporation and the Utility. PG&E Corporation's regional concentrations of credit exposure are to counterparties that conduct business primarily in the western United States and also to counterparties that conduct business primarily throughout North America. In addition to the Utility's concentration of credit risk due to receivables from residential and small commercial customers in the northern California, the Utility has a net regional concentration of credit exposure totaling $42 million to counterparties that conduct business primarily throughout North America.

NOTE 4: DEBT FINANCING

PG&E Corporation

In November 2001 and March 2002, PG&E Corporation amended its March 1, 2001, Credit Agreement (Old Credit Agreement) with General Electric Capital Corporation (GECC) and Lehman Commercial Paper Inc. (LCPI) and their assignees (Existing Lenders). The amendments provided PG&E Corporation the option to extend the original $1 billion aggregate term loan credit facility for two one-year periods so that the maturity date could be extended until as late as March 2, 2006, contingent upon PG&E Corporation making a principal repayment of $308 million by June 3, 2002. On June 3, 2002, PG&E Corporation made the principal repayment of $308 million, utilizing current working capital and reducing the principal balance outstanding under the Old Credit Agreement to $692 million.

On June 25, 2002, PG&E Corporation entered into an Amended and Restated Credit Agreement (New Credit Agreement) with GECC (Tranche A Lender) and LCPI and others (collectively, the Tranche B Lenders), which amended and restated the Old Credit Agreement. The New Credit Agreement provides for loans in two tranches. The Tranche A has a principal amount of $600 million (Tranche A Loan), representing the $692 million outstanding under the Old Credit Agreement less $92 million that has been converted to a Tranche B Loan. The Tranche B consists of the $92 million converted loan plus $328 million of new borrowings, for a total of $420 million (Tranche B Loan). The Tranche A Loan will continue to have the same maturity date and extension provisions as the Old Credit Agreement. The Tranche B Loan will mature on the earlier of (1) September 2, 2006, or (2) the date of any spin-off of the shares of PG&E NEG by its indirect parent, PG&E Corporation. The interest rate for the Tranche A Loan is the Eurodollar Rate plus 2.5 percent for the period through August 31, 2002 and will increase to the Eurodollar Rate plus 4.0 percent beginning September 1, 2002. The Tranche B Loan has an interest rate of the Eurodollar Rate plus 4.0 percent. In addition, the Tranche B Loan has a 4.0 percent payment-in-kind interest compounded annually and added to the principal of the note at maturity. The Tranche A Loan and the Tranche B Loan are collectively referred to as the "Loans."

The Tranche A Loan continues to be secured by a first priority lien on (1) PG&E Corporation's equity interest in PG&E National Energy Group, LLC, a Delaware limited liability company (NEG LLC, and together with its direct and indirect subsidiaries, the NEG Group) and (2) NEG LLC's equity interest in PG&E NEG. The Tranche A Loan is also secured by a first priority lien on certain cash interest reserves. The Tranche B Loan is secured by a second priority lien on the equity interests in NEG LLC and PG&E NEG and by a first priority lien on certain other cash interest reserves. In addition, the Tranche B Loan is subordinated to the Tranche A Loan.

PG&E Corporation issued to the Tranche B Lenders warrants to purchase approximately 2.4 million shares of common stock of PG&E Corporation for an exercise price of $0.01 per share (Warrants). The Warrants are recorded at their fair value as an unamortized discount to long-term debt, and as additional paid-in capital on the accompanying PG&E Corporation Consolidated Balance Sheet at June 30, 2002.

In connection with the Old Credit Agreement, affiliates of the Existing Lenders received an option to purchase 3 percent of the shares of PG&E NEG, determined on a fully diluted basis, at an exercise price of $1.00. The option may be exercised at any time until 45 days after the full repayment of the Tranche A Loan. In addition, under the Old Credit Agreement, PG&E Corporation's exercise of each of its one-year extensions of the loan was conditioned upon NEG LLC granting affiliates of the Existing Lenders an additional option to purchase 1 percent of the common stock of PG&E NEG, determined on a fully diluted basis, at an exercise price of $1.00. As a result of the reduction in the principal amount of the Tranche A Loan to $600 million from the $692 million in loans outstanding under the Old Credit Agreement, the 1 percent has been reduced to approximately .87 percent of the common stock of PG&E NEG. The option may be exercised at any time from the relevant extension date until 45 days after full repayment or maturity of the Tranche A Loan. The fair value of the options granted are recorded as a debt issuance cost on the balance sheet and amortized over the expected life of the loans. After the initial recording, the options are marked to market through an increase or decrease in earnings.

NEG LLC has the right to call the option after repayment of the Tranche A Loan in full at a cash purchase price equal to the fair market value of the underlying shares or, at the election of NEG LLC if an initial public offering of the shares of PG&E NEG (IPO) has occurred, by delivering the underlying shares. If an IPO has not occurred prior to repayment of the Tranche A Loan in full, 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 (Put Price), which right is exercisable at any time after the earlier of full repayment of the Tranche A Loan or 45 days before expiration of the option. In addition to the grant of the additional option, PG&E Corporation must pay a fee of 3 percent of the then outstanding balance of the Tranche A Loan as a condition of PG&E Corporation's exercise of each of the one-year extensions.

The New Credit Agreement contains certain limitations on the ability of PG&E Corporation and certain of its subsidiaries to grant liens, consolidate, merge, purchase or sell assets, declare or pay dividends, incur indebtedness, or make advances, loans and investments. However, the New Credit Agreement does not limit (1) PG&E Corporation's ability to spin off its subsidiary, the Utility, substantially in accordance with the Utility's proposed plan of reorganization; (2) the ability of the members of the PG&E NEG Group to grant liens, purchase or sell assets, make investments, and incur indebtedness in accordance with PG&E NEG's business plan or, (3) PG&E Corporation's ability to make investments in the Utility to the extent required by law or regulatory requirements.

The New Credit Agreement also generally requires mandatory prepayments of the Loans with the net cash proceeds from incurrence of indebtedness, issuance or sale of equity and sales of assets, the receipt of condemnation or insurance proceeds, and distributions or dividends paid to PG&E Corporation; provided, however, that (1) PG&E

Corporation may make investments in the Utility with cash proceeds from equity sales or issuances to the extent required by law or regulatory requirements, and (2) the PG&E NEG Group may use such proceeds, or hold such proceeds in cash, to purchase assets or make investments in accordance with PG&E NEG's business plan, except that proceeds from an IPO must be used to the extent required to repay the Tranche A Loan plus $20 million of the Tranche B Loan. Any mandatory prepayments of the Loans will be applied first to the principal amount of the Tranche A Loan, and after the Tranche A Loan is paid in full, to the principal amount of the Tranche B Loan.

The New Credit Agreement also requires PG&E Corporation to maintain an interest reserve account for each of the Tranche A Loan and the Tranche B Loan in an amount equal to one year's estimated interest. At June 30, 2002, the Tranche A Loan and the Tranche B Loan interest reserve balances, included in restricted cash, were $38 million and $27 million, respectively.

A breach of any covenants would entitle the Lenders to declare the Loans to be due and payable. The covenants include requirements that (1) PG&E NEG's unsecured long-term debt have a credit rating of at least BBB- by S&P's or Baa3 by Moody's, (2) the ratio of the fair market value of PG&E NEG to the aggregate amount of principal then outstanding under the Loans be not less than 2 to 1, and (3) PG&E Corporation maintain cash or cash equivalents (including amounts held in the interest reserves) of either 15 percent or 10 percent (depending upon when applicable) of the total principal amount of the Loans outstanding plus the principal amount of the Notes (as described below).

Concurrent with the refinancing described above, on June 25, 2002, PG&E Corporation issued $280 million aggregate principal amount of 7.50% Convertible Subordinated Notes (Notes) due June 30, 2007, in a private offering. The Notes are unsecured and are subordinate to the Loans. PG&E Corporation will pay interest on the Notes semi-annually at a rate of 7.50 percent per year. PG&E Corporation has the right, subject to certain limitations, to pay interest by issuing additional Notes in lieu of paying cash. The New Credit Agreement prohibits PG&E Corporation from paying cash interest on the Notes (1) for 240 days after receipt by the Note trustee of notice delivered by the administrative agent or the Tranche A Lender stating that a default that would permit acceleration has occurred under the New Credit Agreement, or (2) if, after such interest payment, PG&E Corporation's cash and cash equivalents are less than 20 percent of the total principal amount of the Loans outstanding plus the principal amount of the Notes, or 15 percent of such amount upon any extension of the Loans. PG&E Corporation would nevertheless retain its right to issue new Notes in lieu of paying cash interest.

In addition to interest, if PG&E Corporation pays cash dividends to holders of its common stock, Note holders are entitled to receive cash equal to the dividends that would have been paid with respect to the number of shares that the holder would be entitled to receive if the Notes had been converted on the dividend record date. The Notes may be converted by the holders into shares of PG&E Corporation's common stock at a conversion price equal to 119 percent of the volume-weighted average price of the common stock of PG&E Corporation for each of 43 trading days beginning June 28, 2002. The conversion price is subject to adjustment under certain circumstances, including upon consummation of any spin-off transaction of the Utility as proposed in its plan of reorganization or a spin-off of the shares of PG&E NEG. Depending on the value of PG&E Corporation common stock used in the adjustment calculation, such an adjustment could have a material adverse impact on PG&E Corporation's results of operation or financial condition.

The dilutive shares calculations for the three months ended June 30, 2002, include 1,014,332 shares of assumed conversion from the 7.50 percent Convertible Subordinated Notes and 157,995 incremental shares related to warrants issued under the Old Credit Agreement. For the six months ended June 30, 2002, the dilutive shares calculations include 509,968 shares of assumed conversion from the 7.50 percent Convertible Subordinated Notes and 79,433 incremental shares related to warrants issued under the Old Credit Agreement.

PG&E NEG

On April 5, 2002, GenHoldings I, LLC, an indirect subsidiary of PG&E NEG, increased its committed financing from $1.075 billion to $1.460 billion. The outstanding balance at June 30, 2002, was approximately $981 million. The increase in the facility provides for additional borrowing capacity and will provide funding for, and be secured by, an additional project, Covert, which is currently under construction. No other terms of the facility were changed.

On May 2, 2002, PG&E GTN closed on a new $125 million revolving credit facility with a term of three years and an interest rate based on the London Inter-bank Offer Rate (LIBOR) plus a credit spread of initially 0.725 percent. The credit spread percentage corresponds to a rating issued from time to time by Standard and Poor's (S&P) or Moody's on PG&E NEG's senior unsecured long-term debt. This three-year facility replaced a $100 million bank facility that was scheduled to expire. At June 30, 2002, there were no outstanding borrowings under this facility.

On June 6, 2002, PG&E GTN issued $100 million of 6.62 percent senior notes in a private placement. Proceeds were used to repay $90 million of debt on its revolving credit facility and the balance retained to meet general corporate needs.

Interest is capitalized as a component of projects under construction. For the six months ended June 30, 2002, and 2001, PG&E NEG capitalized interest of approximately $86 million and $55 million, respectively.

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

On November 28, 1995, PG&E Capital I (Trust), a wholly owned subsidiary of the Utility, issued 12 million shares of 7.90 percent Cumulative Quarterly Income Preferred Securities (QUIPS) with an aggregate liquidation value of $300 million. Concurrent with the issuance of the QUIPS, the Trust issued to the Utility 371,135 shares of common securities with an aggregate liquidation value of $9 million. The Trust, in turn, used the net proceeds from the QUIPS offering and the proceeds from issuance of the common stock securities to purchase 7.90 percent Deferrable Interest Subordinated Debentures (QUIDS), due 2025, issued by the Utility with a face value of $309 million.

Distribution may be deferred up to 20 consecutive quarters under the terms of the indenture. Pursuant to the indenture, investors will accumulate interest on the unpaid distributions at the rate of 7.90 percent. Upon liquidation or dissolution of the Utility, holders of 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 QUIDS until further notice in accordance with the indenture. The corresponding quarterly payments on the 7.90 percent QUIPS issued by the Trust, due on April 2, 2001, were similarly deferred.

As discussed in Note 2, on March 27, 2002, the Bankruptcy Court issued an order authorizing the Utility to pay pre- and post-petition interest to holders of certain undisputed claims, including QUIPS, within 10 business days after Bankruptcy Court approval of the Utility's disclosure statement. The disclosure statement was approved on April 24, 2002, and on May 6, 2002, the Utility made payments to holders of QUIPS representing interest accrued through February 28, 2002. On May 31, 2002, and July 1, 2002, the Utility also paid interest for the month ended March 31, 2002, and for the three months ended June 30, 2002. Interest payments will continue to be made on a quarterly basis.

On April 12, 2001, Bank One, N.A., as successor-in-interest to The First National Bank of Chicago (Trustee), gave notice that an event of default exists under the Trust Agreement due to the Utility's Chapter 11 filing on April 6, 2001 (see Note 2). As a result of the event of default, the Trust Agreement required the Trust to be liquidated by the Trustee by distributing, after satisfaction of liabilities to creditors of the Trust, the QUIDS to the holders of the QUIPS. Pursuant to the Trustee's notice dated April 24, 2002, the Trust was liquidated on May 24, 2002. Upon liquidation of the Trust, the former holders of QUIPS received a like amount of QUIDS. The terms and interest payments of the QUIDS correspond to the terms and dividend payments of the QUIPS.

The QUIDS are included in financing debt classified as a liability subject to compromise in the accompanying PG&E Corporation's and the Utility's Consolidated Balance Sheets at June 30, 2002.

NOTE 6: COMMITMENTS AND CONTINGENCIES

Commitments

PG&E Corporation has substantial financial commitments in connection with agreements entered into supporting the Utility's and PG&E NEG's operating, construction, and development activities. These commitments are discussed more fully in the PG&E Corporation and Utility combined 2001 Annual Report on Form 10-K. The following summarizes significant changes to commitments since the combined 2001 Annual Report on Form 10-K was filed.

Utility

Natural Gas Supply and Transportation Commitments

- Under current CPUC regulations, the Utility purchases natural gas from its various suppliers based on economic considerations, consistent with regulatory, contractual, and operational constraints. The Utility has long-term gas transportation service agreements with various Canadian and interstate pipeline companies. The total demand charges that the Utility will pay each year may change due to changes in tariff rates. These agreements include provisions for payment of fixed demand charges for reserving firm capacity on the pipelines.

The Utility also has long-term gas supply contracts with various Canadian and interstate gas companies. The contracts commit the Utility to purchase gas through May 2003, and total $238 million. On March 6, 2002, the CPUC authorized the Utility to pledge its gas customer accounts receivable and core gas inventory for the purpose of procuring core gas supplies until the earlier of:

- May 1, 2003;
- 15 days after an upgrade of the credit rating of the Utility's mortgage bonds to at least BBB- by S&P or Baa3 by Moody's;
- the effective date of the Plan of Reorganization; or
- the dismissal or conversion of the Utility's bankruptcy proceeding.

At June 30, 2002, total gas accounts receivable pledged amounted to $105 million.

At June 30, 2002, the Utility's obligations related to natural gas transportation and supply commitments held pursuant to long-term contracts were as follows (in millions):

2002	$ 258
2003	188
2004	88
2005	77
2006	21
Thereafter	5

Total	$	637

The Utility uses a $10 million standby letter of credit to facilitate natural gas purchases in addition to other credit arrangements with natural gas suppliers.

El Paso Capacity Decision

- In May 2002, a FERC order directed El Paso Natural Gas Company (El Paso) to change the way it allocates space on its pipeline. The order required El Paso's East of California customers to convert their capacity rights from unlimited "full requirement" to a limited Contract Demand amount of firm capacity. These customers must decide by July 31, 2002, how much El Paso capacity rights they will need in contract demand contracts and how much capacity they will relinquish.

In response, on July 17, 2002, the CPUC issued a decision that requires California IOUs to sign up for El Paso pipeline capacity relinquished by the shippers and not subscribed to by replacement shippers serving California, and pre-approves such costs as just and reasonable. The IOUs are required to purchase a proportionate amount of the released capacity. The decision stated that this requirement would spread El Paso reservation charges over as many ratepayers as possible to minimize the impact on any particular customers. The decision also addressed current capacity issues. The decision ordered that current capacity held by the IOUs on any interstate pipeline cannot be turned back and must be retained for the benefit of California ratepayers. Any capacity in excess of the IOU's need should be released under short-term capacity release arrangements. The IOU's short-term capacity releases ensure that the capacity is not withheld from the California market. The decision also finds that to the extent the IOUs comply with the decision, they shall also receive full cost recovery for their costs associated with existing capacity contracts.

In a future proceeding, the CPUC will address other issues that relate to these proposed rules. Issues to be resolved include cost allocation of turned back capacity among the California IOUs' customers for recovery, capacity releases, and details concerning the guaranteed recovery in rates of the IOUs' costs for subscription to interstate pipeline capacity.

In 1995, the CPUC issued a decision concluding that it was unreasonable for the Utility to commit to purchase gas pipeline capacity from Transwestern Pipeline Company (Transwestern). The decision ordered that costs for the capacity commitments in subsequent years of the contract, be disallowed unless the Utility can demonstrate that the benefits of the capacity commitment outweigh the costs. As discussed below, under the Gas Accord, the Utility could not recover any costs paid to Transwestern through 1997 and would have limited recovery during the period 1998 through 2002. In view of the El Paso decision which directs the utilities to retain their existing capacity contracts and allows for the recovery of the costs of existing capacity contracts, the Utility expects to fully recover its future purchases of gas pipeline capacity. This recovery is expected to result in additional revenues of approximately $90 million over the remaining contract period that ends in March of 2007.

PG&E NEG

Credit Ratings

- On July 31, 2002, S&P downgraded PG&E NEG's credit rating to BB+ with CreditWatch with negative implications from BBB with a stable outlook. As a result of this downgrade, PG&E NEG may be required to post replacement collateral or fund cash under those guarantees that either require an investment grade rating or contain more subjective thresholds.

Trading and non-trading hedging guarantees -

PG&E NEG and its rated subsidiaries have provided $2.9 billion of guarantees to approximately 250 counterparties in support of its energy trading and non-trading hedging operations. Typically, the overall exposure under these guarantees is only a fraction of the face value of these guarantees, since not all counterparty credit limits are fully utilized at any time. As of July 31, 2002, PG&E NEG and its rated subsidiaries' aggregate exposure under these guarantees was approximately $360 million. Of this exposure, the amounts subject to securitization requirements as a result of a downgrade to below investment grade of PG&E NEG by S&P are $115 million; of PG&E ET are $16 million; and of USGenNE are $1 million. In addition, $37 million of this exposure is under guarantees that have been issued by PG&E GTN with a ratings trigger. However, the ratings trigger for PG&E GTN is not affected by S&P's actions on July 31, 2002. The remaining $191 million could be subject to securitization requirements due to a counterparty's concern with PG&E NEG's or its subsidiary's creditworthiness. As of July 31, 2002, PG&E ET had sufficient cash to cover these obligations.

Equity Commitments and Debt Repayment Guarantees -

PG&E NEG has guaranteed debt or equity commitments in connection with the following (in millions):

Lake Road	$	230
La Paloma		379
Equipment Revolving Credit Facility		230
GenHoldings I		505

PG&E NEG has replaced the ratings triggers in these facilities with financial covenants that are consistent with those contained in PG&E NEG's revolving credit and other loan facilities. These covenants include requirements to exceed a specified cash flow to fixed charges ratio and a specified net worth as well as maintain less than a specified total debt to total capitalization ratio and are set forth in PG&E NEG's revolving credit agreement filed as Exhibit 10.21 to PG&E NEG's Annual Report on Form 10-K filed with the SEC on March 5, 2002. PG&E NEG is in compliance with these covenants.

Not withstanding the above, if PG&E NEG is also downgraded to below investment grade by Moody's, PG&E NEG would be required to fund construction draws under the GenHoldings I financing entirely with equity until the equity commitment is fulfilled. This would result in PG&E NEG being obligated to fund approximately $270 million of additional equity through December 2002 that would have otherwise been funded through June 2003. After December 2002, the lenders would fund the construction draws pursuant to the credit agreement. Failure by PG&E NEG to fund any required equity would result in a default under the GenHoldings I credit facility as well as a default under PG&E NEG's revolving credit facility.

Tolling arrangements -

PG&E NEG has entered into five long-term tolling transactions with third parties. Each tolling agreement is supported by a separate guarantee backing the payment obligations of the PG&E NEG affiliate over the term of these long-term contracts (9-25 years). PG&E NEG or its rated subsidiaries has extended approximately $620 million of such guarantees. Of these guarantees, $575 million have been issued by PG&E NEG and contain a ratings trigger that requires PG&E NEG to replace the guarantee or provide alternative collateral as a result of its credit rating dropping below BBB or Baa2. This amount increases by an additional $20 million if PG&E NEG's credit rating is also downgraded to below investment grade by Moody's. In addition, $24 million of these guarantees have been issued by PG&E GTN with a ratings trigger. However, the ratings trigger for PG&E GTN is not affected by S&P's actions on July 31, 2002. The ratings downgrade by S&P on July 31, 2002, has triggered the need for additional guarantees, alternative collateral or other acceptable arrangements under these agreements within a ten to 30 day cure period. In the event that PG&E NEG does not replace the guarantee, provide alternative collateral or agree on other acceptable arrangements as required, the counterparty has the right to terminate the related tolling agreement and seek recovery of damages to be determined in arbitration. It is not known whether the counterparties to the tolling agreement would exercise their rights to terminate the agreements. If a party did exercise its right to terminate a tolling agreement, the agreements generally provide that any damages are to be awarded based upon the difference in the contract price for the power under the agreement and the market price for the power, estimated by PG&E NEG to be $20 million under current conditions. In the event of a dispute over the amount of any termination payment that the parties are unable to resolve by negotiation, the tolling agreements provide for mandatory arbitration, which could take as long as six months to more than a year to complete, depending on the specific procedures detailed in the tolling agreements.

Other Guarantees -

PG&E NEG has provided approximately $1.3 billion of guarantees related to other obligations by PG&E NEG companies to counterparties for goods or services. Of this $1.3 billion, the amount subject to securitization requirements as a result of a downgrade to below investment grade of PG&E NEG is $770 million and of PG&E Gen is $9 million. The most significant of these guarantees relate to performance under certain construction and equipment procurement contracts. In the event PG&E NEG is unable to provide the additional or replacement security required in the event of such a downgrade, the counterparty providing the goods or services could suspend performance or terminate the underlying agreement and seek recovery of damages.

These guarantees represent guarantees of subsidiary obligations for transactions entered into in the ordinary course of business. The first is for guarantees related to the construction or development of PG&E NEG's power plants and pipelines. Specifically, these include guarantees for the performance of the contractor building the Harquahala and Covert power projects amounting to $545 million. Any exposure under the guarantees for construction completion is mitigated by guarantees in favor of PG&E NEG from the constructor and equipment vendors related to performance, schedule and cost. Since the constructor and various equipment vendors are performing under their underlying contracts, PG&E NEG does not believe that it has significant exposure under these guarantees. Further, although these guarantees contain ratings triggers, the same lenders who are the beneficiaries of these guarantees are the funding banks for GenHoldings I.

PG&E NEG has provided $343 million in guarantees in favor of the various contractors and equipment vendors for the payment of any cancellation penalties in the event that projects or equipment contracts are cancelled and there remain unpaid amounts. Of this amount, approximately $58 million will be paid to these vendors for cancellation of equipment contracts. In the event that these vendors seek to terminate the contracts sooner, this amount would also represent PG&E NEG's maximum exposure. Included in the above amount is $100 million of guarantees to the constructor of the Harquahala and Covert projects to cover certain separate cost-sharing arrangements. Failure to fund a demand for collateralization would permit the constructor to terminate those separate cost sharing arrangements. This would not have an impact on the constructors' obligations to complete the Harquahala and Covert projects pursuant to the contracts. Therefore, this would not have a financial impact on PG&E NEG or its subsidiaries.

PG&E NEG has provided a $300 million guarantee to support a tolling agreement that a wholly owned subsidiary, Attala Energy Company, has entered into with Attala Generating Company. Attala Generating Company entered into a $340 million sale-lease back transaction. The tolling payments provide the lessee with sufficient cash flows to pay rent under the lease. So long as Attala Energy Company continues to perform under the tolling agreement PG&E NEG does not believe it has any incremental liability or exposure under this guarantee.

The balance of the guarantees are for commitments undertaken by PG&E NEG or subsidiaries in the ordinary course of business for services such as facility and equipment leases, pipe capacity, ash disposal rights, and surety bonds.

Other Commitments -

There is a total of $149 million in potential additional liquidity requirements related to other commitments.

In addition to the $360 million in trading exposure that is covered by guarantees and addressed above, there is an additional $73 million of current exposure under trading agreements at July 31, 2002. Some portion of this exposure is related to agreements that contain subjective language requiring additional securitization.

The remaining commitments included in the $149 million, are up to $16 million of surety bonds outstanding on behalf of PG&E NEG that may need to be replaced; transportation and storage agreement tariff provisions that may require an additional $38 million in security; incremental security to power pools that could be as much as $11 million, and; miscellaneous guarantees for land options and other contracts of $11 million.

The summary above identifies the potential demands on PG&E NEG's liquidity as a result of S&P's actions taken on July 31, 2002. As noted above, only the GenHoldings I equity commitment and one additional tolling agreement will be further impacted if Moody's reduces PG&E NEG's credit rating to below investment grade. The actual calls on PG&E NEG's liquidity will depend largely upon counterparties' reactions to the downgrade, the continued performance of PG&E NEG companies under the underlying agreements and the counterparties' other commercial considerations. Therefore, PG&E NEG cannot quantify with any certainty the actual calls on PG&E NEG's liquidity. In the past, PG&E NEG has been able to negotiate acceptable arrangements and reduce its overall exposure to counterparties when PG&E NEG or its counterparties have faced similar situations. However, there can be no assurance that PG&E NEG could negotiate acceptable arrangements in the current circumstances.

As of July 31, 2002, PG&E NEG had $728 million in unrestricted cash and $796 million of unused credit lines and letter of credit facilities. Certain of PG&E NEG's financing instruments are due to mature in the near future. PG&E NEG is currently seeking bank commitments to renew $750 million of revolving credit that expires on August 22, 2002. As of July 31, 2002, PG&E NEG had $431 million outstanding under this facility. PG&E NEG is seeking to replace this short-term facility with a $750 million credit facility containing a $500 million two-year tranche and a $250 million 364-day tranche. In addition, PG&E NEG is seeking to refinance $609 million of debt guaranteed by PG&E NEG in connection with the Lake Road and La Paloma facilities that matures on March 31, 2003. PG&E NEG may be unable to obtain commitments for substantial portions of these financings. If PG&E NEG is unable to do so or otherwise effect acceptable arrangements, PG&E NEG's liquidity position will be materially and adversely impacted, and PG&E NEG may be unable to satisfy demands on its liquidity.

As described above, the downgrade of PG&E NEG's credit ratings impacts certain PG&E NEG's guarantees and financial arrangements that require PG&E NEG to maintain certain credit ratings from S&P and/or Moody's. With respect to certain guarantees issued by PG&E NEG and its affiliates to project lenders and tolling counterparties, the downgrade of PG&E NEG's credit rating to below investment grade by S&P triggers a requirement that PG&E NEG replace the guarantees or provide alternative collateral within a ten to thirty day cure period. The failure of PG&E NEG to do so would entitle the holders of the guarantees to demand payment of the guaranteed amounts, or, in the case of tolling counterparties, to terminate the tolling agreements and seek damage payments to be determined by arbitration. To the extent that PG&E NEG's lenders or counterparties have the right to make such demands on PG&E NEG in an aggregate amount of $100 million or more, this would constitute an event of default under PG&E Corporation's New Credit Agreement with respect to the aggregate $1.02 billion in Tranche A and Tranche B loans outstanding thereunder, as discussed in Note 4 in the Notes to the Consolidated Financial Statements.

Subject to their respective rights as set forth in the Intercreditor and Subordination Agreement, dated as of June 25, 2002, by and between the Tranche A lenders, Tranche B lenders and certain other parties thereto (the Intercreditor Agreement), the Tranche A and Tranche B Lenders (collectively, the Lenders) would, upon notice within three days of the triggering event, have the right to declare all amounts outstanding under the New Credit Agreement to be immediately due and payable. The failure of PG&E Corporation to repay this accelerated indebtedness would entitle the Lenders, subject to the Intercreditor Agreement, to exercise certain remedies, including their rights as secured parties against their collateral, i.e., the pledged interests of PG&E Corporation in NEG, Inc., NEG LLC's pledged interests in NEG Inc., and a pledged interest in an interest reserve account with a current balance of approximately $65 million.

In the event that Moody's Investors Service also downgrades PG&E NEG to below investment grade, the dual downgrade would trigger an event of default under the New Credit Agreement. The occurrence of this default would also entitle the Lenders to exercise the remedies described in the foregoing paragraph.

Further, loss of PG&E NEG's investment grade credit ratings may prevent it from obtaining financing necessary for the funding of various project-related equity commitments. A failure to fund equity commitments in an aggregate amount of $100 million or more would also cause a cross default to the PG&E Corporation New Credit Agreement.

With respect to the $280 million aggregate principal amount of 7.5% Convertible Subordinated Notes issued by PG&E Corporation pursuant to an Indenture dated as of June 25, 2002 by and between PG&E Corporation and U.S. Bank, N.A., as trustee (the Notes), if PG&E Corporation fails to pay the accelerated obligations under the New Credit Agreement as described above and such failure continues for 30 days after receipt of written notice from the trustee or holders of at least 25% of the aggregate principal amount of outstanding Notes, the Notes would also be in default. Thereupon, and subject to the subordination provisions of the Indenture, the trustee or the Note holders would have the right to accelerate the Notes.

If PG&E Corporation's debt obligations become subject to acceleration as described above, PG&E Corporation would attempt to negotiate this situation with its Lenders and Note holders; however, PG&E Corporation cannot predict whether, or to what extent, it would be successful in such efforts. Current PG&E Corporation cash balances are insufficient to repay the full amount of its outstanding debt.

Letters of Credit -

Certain of PG&E NEG's commitments are supported by letters of credit. The following table lists the various letters of credit facilities that have the capacity to issue letters of credit (in millions):

Borrower	Maturity	Letter of Credit Capacity	Letters of Credit Outstanding June 30, 2002
PG&E NEG	8/02 & 8/03	$ 650	$ 184
USGenNE	9/03	25	3
PG&E Gen	12/04	10	7
PG&E ET	12/02	25	21
PG&E ET	-(1)	50	25
PG&E ET	11/03	35	31

- This letter of credit facility provides for up to $50 million of non-domestic letters of credit to be issued, available to PG&E Energy Trading, Canada Corporation, an indirect subsidiary of PG&E NEG, to use to post non-domestic letters of credit to support counterparty trading, for periods no longer than 364 days. There is no term for the facility, but the bank can review for termination each year.

Attala Lease

- On May 10, 2002, Attala Generating Company, an indirect subsidiary of PG&E NEG, completed a $340 million sale and leaseback transaction whereby it sold and leased back its facility to a third party special purpose entity. The related lease is being accounted for as an operating lease and will amortize a deferred gain of approximately $5 million from the sale over the lease period, which is 37 years. The payment obligations under this agreement are as follows (in millions):

2002	$	49
2003		38
2004		28
2005		29
2006		27
Thereafter		631

	$	802
	=========	

Attala Generating Company entered into a tolling agreement with Attala Energy Company, another wholly owned subsidiary of PG&E NEG. Attala Energy Company's obligations under this tolling agreement are guaranteed by a $300 million PG&E NEG guarantee.

Contingencies

PG&E Corporation Guarantees

At June 30, 2002, PG&E Corporation has a $16 million guarantee for an office lease relating to PG&E NEG's San Francisco office, a guarantee related to PG&E NEG's indemnification obligations to the purchaser of PG&E NEG's gas transmission assets in Texas, and a guarantee related to PG&E NEG's indemnification obligations to the purchaser of PG&E Energy Services. PG&E Corporation also has a $.9 million guarantee supporting the Utility's investment in low-income housing projects at June 30, 2002.

Utility

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 $26 million (property damage) and $9 million (business interruption), in each case per policy period, in the event losses exceed the resources of NEIL. The maximum $26 million retrospective assessment can arise if any NEIL member nuclear generating facility suffers a loss.

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 the Price-Andersen Act. Under the Price-Andersen Act, secondary financial protection is required for all nuclear reactors having a rated capacity of 100 MW licensed to operate and designed for production of electrical energy. It provides for loss sharing among utilities owning nuclear generating facilities if a costly incident occurs. If a nuclear incident results in claims in excess of $200 million, then the Utility may be assessed up to $176 million per incident, with payments in each year limited to a maximum of $20 million per incident.

Workers' Compensation Security -

The Utility must deposit collateral with the State Department of Industrial Relations (DIR) to maintain its status as a self-insurer for workers' compensation claims made against the Utility. Acceptable forms of collateral include surety bonds, letters of credit, cash, or securities. The Utility currently provides collateral in the form of approximately $365 million in surety bonds.

In February 2001, several surety companies provided cancellation notices, citing concerns about the Utility's financial situation. The DIR has not agreed to release the canceling sureties from their obligations for claims occurring prior to the cancellation and has continued to apply the cancelled bond amounts, totaling $185 million, towards the $365 million amount of collateral. The Utility was able to supplement the difference through three additional active surety bonds totaling $180 million. The cancelled bonds have not, to date, impacted the Utility's self-insured status under California law. PG&E Corporation has guaranteed the Utility's reimbursement obligation associated with these surety bonds and the Utility's underlying obligation to pay workers' compensation claims.

Environmental Matters

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 the Utility for the storage or disposal of potentially hazardous materials. Under Federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site.

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

The Utility had an environmental remediation liability of $312 million and $295 million (undiscounted) at June 30, 2002, and December 31, 2001, respectively. The $312 million accrued at June 30, 2002, includes (1) $139 million related to the pre-closing remediation liability associated with divested generation facilities, and (2) $173 million related to remediation costs for those generation facilities that the Utility still owns, manufactured gas plant sites, gas gathering sites, and compressor stations. Of the $312 million environmental remediation liability, the Utility has recovered $190 million through rates, and expects to recover the balance in future rates. The Utility also is recovering its costs from insurance carriers and from other third parties as appropriate.

The cost of the hazardous substance remediation ultimately undertaken by the Utility is difficult to estimate. A change in the estimate may occur in the near term due to uncertainty concerning the Utility's responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives. If other potentially responsible parties are not financially able to contribute to these costs or further investigation indicates that the extent of contamination or necessary remediation is greater than anticipated, the Utility's future cost could increase by as much as $449 million. 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.

On June 28, 2001, the Bankruptcy Court authorized the Utility to continue its hazardous waste remediation program and to expend:

- Up to $22 million in each calendar year in which the Chapter 11 case is pending to continue its hazardous substance remediation programs and procedures; and
- Any additional amounts necessary in emergency situations involving post-petition releases or threatened releases of hazardous substances subject to the Bankruptcy Court's specific approval.

The California Attorney General, on behalf of various state environmental agencies, filed claims in the Utility's bankruptcy proceeding for environmental remediation at numerous sites aggregating approximately $770 million. For most if not all of these sites, the Utility is in the process of remediation in cooperation with the relevant agencies and other parties responsible for contributing to the clean-up or would be doing so in the future in the normal course of business. In addition, for the majority of the remediation claims, the State would not be entitled to recover these costs unless it accepts responsibility to clean up the sites, which is unlikely. Since the Utility's proposed plan provides that the Utility intends to respond to these types of claims in the regular course of business, and since the Utility has not argued that the bankruptcy proceeding relieves the Utility of its obligations to respond to valid environmental remediation orders, the Utility believes the claims seeking specific cash recoveries are invalid.

Moss Landing -

In December 1999, the Utility was notified by the purchaser of its former Moss Landing power plant that the Utility had violated the plant's National Pollutant Discharge Elimination System (NPDES) permit issued by the Central Coast Regional Water Quality Control Board (Central Coast Board). A tentative settlement has been reached with the Central Coast Board. Under the settlement, the Utility will fund approximately $5 million in environmental projects related to coastal resources. The parties are negotiating the documentation of the settlement. The final agreement will be subject to public comment and will be incorporated in a consent decree to be entered in the California Superior Court. A claim has been filed by the California Attorney General in the Utility's bankruptcy proceeding on behalf of the Central Coast Board seeking unspecified penalties.

Diablo Canyon

- In October 2000, the Utility reached a tentative settlement with the Central Coast Board concerning alleged violations under the Utility's NPDES permit. Under the settlement, the Utility will take measures to preserve certain acreage north of the plant and will fund approximately $5 million in environmental projects related to coastal resources. The parties are negotiating the documentation of the settlement. The final agreement will be subject to public comment and will be incorporated in a consent decree to be entered in the California Superior Court. A claim has been filed by the California Attorney General in the Utility's bankruptcy proceeding on behalf of the Central Coast Board seeking unspecified penalties and other relief in connection with Diablo Canyon's operation of its cooling water system.

Additionally, on April 9, 2002, the U.S. Environmental Protection Agency (EPA), proposed regulations under Section 316(b) of the Clean Water Act for cooling water intake structures. The regulations would affect existing power generation facilities using over 50 million gallons per day (mgd), typically including some form of "once-through" cooling. The Utility's Diablo Canyon, Hunters Point, and Humboldt Bay power plants are among an estimated 539 plans nationwide that would be affected by this rulemaking. The proposed regulations call for a set of performance standards that vary with the type of water body and that are intended to reduce impacts to aquatic organisms. Significant capital investment may be required to achieve the standards if the regulations are adopted as proposed. The final regulations are scheduled to be promulgated in August 2003.

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

PG&E NEG

Environmental Matters

In May 2000, USGen New England (USGenNE), an indirect subsidiary of PG&E NEG, received an Information Request from the EPA, pursuant to Section 114 of the Federal Clean Air Act (CAA). The Information Request asked USGenNE to provide certain information relative to the compliance of its Brayton Point and Salem Harbor plants with the CAA. No enforcement action has been brought by the EPA to date. USGenNE has had preliminary discussions with the EPA to explore a potential settlement of this matter. Management believes that it is not possible to predict at this point whether any such settlement will occur, or in the absence of a settlement, the likelihood of whether the EPA will bring an enforcement action.

As a result of this and related regulatory initiatives by the Commonwealth of Massachusetts, USGenNE is exploring ways to achieve significant reductions of sulfur dioxide and, nitrogen oxide emissions. Additional requirements for the control of mercury and carbon dioxide emissions will also be forthcoming as part of these regulatory initiatives. Management believes that USGenNE would meet these requirements through installation of controls at the Brayton Point and Salem Harbor plants and estimates that capital expenditures on these environmental projects could approximate $332 million over the next five years. These estimates are currently under review and it is possible that actual expenditures may be higher. Based on an emission control plan filed for Brayton Point under the regulations implementing these initiatives, the Massachussetts Department of Environmental Protection (DEP) ruled that Brayton Point is required to meet the newer, more stringent emission limitations for sulfur dioxide and nitrogen oxide by 2006. However, on June 7, 2002, the DEP ruled that Salem Harbor must satisfy these limitations by 2004. USGenNE will not be able to operate Salem Harbor unless it is in compliance with these emission limitations. USGenNE believes it may not be feasible to comply by 2004, and that in any event DEP improperly applied the 2004 deadline to the Salem Harbor emission control plan. USGenNE filed with DEP a revised plan for Salem Harbor in April that it believes meets the DEP requirements for the 2006 compliance date. USGenNE has also filed an administrative appeal of DEP's ruling that Salem Harbor meet the 2004 compliance date.

Various aspects of DEP's regulations allow for public participation in the process through which DEP determines whether the 2004 or 2006 deadline applies and approves the specific activities that USGenNE will undertake to meet the new regulations. A local environmental group has made various filings with DEP requesting such participation.

The EPA is required under the CAA to establish new regulations for controlling hazardous air pollutants from combustion turbines and reciprocating internal combustion engines. Although the EPA has yet to propose the regulations, the CAA required that they be promulgated by November 2000. Another provision in the CAA requires companies to submit case-by-case Maximum Achievable Control Technology (MACT) determinations for individual plants, if the EPA fails to finalize regulations within 18 months past the deadline. On April 5, 2002, the EPA promulgated a regulation that extends this deadline for the case-by-case permits until May 2004. The EPA intends to finalize the MACT regulations before this date, thus eliminating the need for the plant-specific permits. PG&E NEG will not be able to accurately quantify the economic impact of the future regulations until more details are available through the rulemaking process.

PG&E NEG's existing power plants 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 (Salem Harbor, Manchester Street, and Brayton Point) are operating pursuant to NPDES permits that have expired. For the facilities whose NPDES permits have expired, permit renewal applications are pending, and all three facilities are continuing to operate under existing terms and conditions until new permits are issued. On July 22, 2002, the EPA and the DEP issued a draft NPDES permit for Brayton Point that, among other things, substantially limits the discharge of heat by Brayton Point into Mount Hope Bay. Based on its initial review of the draft permit, USGenNE believes that the draft permit is excessively stringent. It is estimated that USGenNE's cost to comply with the new permit conditions could be as much as $248 million through 2005, but this is a preliminary estimate. There are various administrative and judicial proceedings that must be completed before the draft NPDES permit for Brayton Point becomes final and these proceedings are not expected to be completed during 2002. In addition, it is possible that the new permits for Salem Harbor and Manchester Street may also contain more stringent limitations than prior permits, and that the cost to comply with the new permit conditions could be greater than the current estimate of $4 million. In addition, the issuance of any final NPDES permits may be affected by the EPA's proposed regulations under Section 316(b) of the Clean Water Act, which are discussed below.

On March 27, 2002, Rhode Island Attorney General, Sheldon Whitehouse, notified USGenNE of his belief that 'Brayton Point "is in violation of applicable statutory and regulatory provisions governing its operations...," including "protections accorded by common law" respecting discharges from the facility into Mt. Hope Bay. He stated that he intended to seek judicial relief "to abate these environmental law violations and to recover damages..." within the next 30 days. The notice purportedly was provided pursuant to section 7A of chapter 214 of Massachusetts General Laws. PG&E NEG believes that Brayton Point Station is in full compliance with all applicable permits, laws, and regulations. The complaint has not yet been filed or served. In early May 2002, the Rhode Island Attorney General stated that he did not plan to file the action until the EPA issues a draft Clean Water Act NPDES permit for Brayton Point. The EPA issued its draft permit on July 22, 2002, and the Rhode Island Attorney General has since stated that he has no intention of pursuing this matter until he reviews USGenNE's response to the draft permit. Management is unable to predict whether he will pursue this matter and, if he does, the extent to which it will have a material adverse effect on PG&E NEG's financial condition or results of operations.

On April 9, 2002, the EPA proposed regulations under Section 316(b) of the Clean Water Act for cooling water intake structures. The regulations would affect existing power generation facilities using more than 50 mgd typically including some form of "once-through" cooling. Brayton Point, Salem Harbor, and Manchester Street generating facilities are among an estimated 539 plants nationwide that would be affected by this rulemaking. The proposed regulations call for a set of performance standards that vary with the type of water body and that are intended to reduce impacts to aquatic organisms. The final regulations are scheduled to be promulgated in August 2003. The extent to which they may require additional capital investment will depend on the timing of the NPDES permit proceedings for the affected facilities. It is possible that the regulations may allow greater flexibility in achieving specified permit limits and thereby reduce the cost of compliance.

During April 2000, an environmental group served USGenNE and other PG&E NEG's subsidiaries with a notice of its intent to file a citizen's suit under the Resource Conservation and Recovery Act (RCRA). In September 2000, PG&E NEG signed a series of agreements with the DEP and the environmental group to resolve these matters that require PG&E NEG to alter its existing wastewater treatment facilities at its Brayton Point and Salem Harbor generating facilities.

PG&E NEG began the activities during 2000, and is expected to complete them in 2002. PG&E NEG incurred expenditures related to these agreements of approximately $5.8 million in 2000, $2.4 million in 2001, and $2.0 million through June 2002. In addition to the costs previously incurred in 2000 and 2001, PG&E NEG maintains a reserve in the amount of $8 million relating to its estimate of the remaining environmental expenditures to fulfill its obligations under these agreements. PG&E NEG has deferred costs associated with capital expenditures and has set up a receivable for amounts it believes are probable of recovery from insurance proceeds.

PG&E NEG believes that it may be required to spend up to approximately $592 million, excluding insurance proceeds, through 2008 for environmental compliance to continue operating these facilities. This amount may change, however, and the timing of any necessary capital expenditures could be accelerated in the event of a change in environmental regulations or the commencement of any enforcement proceeding against PG&E NEG. In the event PG&E NEG does not spend required amounts as of each facility's compliance deadline to maintain environmental compliance, PG&E NEG may not be able to continue to operate one or all of these facilities.

Legal Matters

In the normal course of business, PG&E Corporation, the Utility, and PG&E NEG are named as parties in a number of claims and lawsuits. The most significant of these are discussed below. The Utility's Chapter 11 bankruptcy filing on April 6, 2001, discussed in Note 2 of the Notes to the Consolidated Financial Statements, automatically stayed the litigation described below against the Utility, except as otherwise noted.

Chromium Litigation

- There are 15 civil suits pending against the Utility in several California state courts. One of these suits also name PG&E Corporation as a defendant. One additional civil suit filed against the Utility and PG&E Corporation after the Utility's bankruptcy filing was dismissed without prejudice while the plaintiffs seek the right to file and pursue late claims in the Bankruptcy 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 Hinkley, Kettleman, and Topock, California. Currently, there are claims pending on behalf of approximately 1,290 individuals.

The Utility is responding to the suits in which it has been served and is asserting affirmative defenses. The Utility will pursue appropriate legal defenses, including statute of limitations, exclusivity of workers' compensation laws, and factual defenses, including lack of exposure to chromium and the inability of chromium to cause certain of the illnesses alleged.

There have been approximately 1,260 claims filed with the Bankruptcy Court (by most of the plaintiffs in the 15 cases and other individuals) alleging that exposure to chromium in soil, air, or water near the Utility's compressor stations at Hinkley, Kettleman, or Topock, California, caused personal injuries, wrongful death, or other injuries. Approximately 1,035 of these claimants have filed proofs of claim requesting an approximate aggregate amount of $580 million and approximately another 225 claimants have filed claims for an "unknown amount." On November 14, 2001, the Utility filed objections to these claims and requested the Bankruptcy Court to transfer the chromium claims to the federal District Court. On January 8, 2002, the Bankruptcy Court denied the Utility's request to transfer the chromium claims and granted certain claimants' motion for relief from stay so that the state court lawsuits pending before the Utility filed its bankruptcy petition can proceed.

The Utility has recorded a 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 at June 30, 2002, 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.

Natural Gas Royalties Litigation

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

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

The complaints allege that the various defendants (most of which are pipeline companies or their affiliates) incorrectly measured the volume and heat content of natural gas produced from federal or Indian leases. As a result, it is alleged that the defendants underpaid, or caused others to underpay, the royalties that were due to the United States for the production of natural gas from those leases. The complaints do not seek a specific dollar amount or quantify the royalties claim. The complaints seek unspecified treble damages, civil penalties, and expenses associated with the litigation.

The relator has filed a claim in the Utility's bankruptcy case for $2.5 billion, $2 billion of which is based upon the plaintiff's calculation of penalties sought against the Utility.

PG&E Corporation and the Utility believe the allegations to be without merit and intend to present a vigorous defense. PG&E Corporation and the Utility believe that the ultimate outcome of the litigation will not have a material adverse effect on their financial condition or results of operations.

Federal Securities Lawsuit

- A complaint, *Gillam, et al. v. PG&E Corporation, et al*., is pending in the U.S. District Court for the Northern District of California. An executive officer of PG&E Corporation has also been named as a defendant. The first amended complaint, purportedly brought on behalf of all persons who purchased PG&E Corporation common stock or certain shares of the Utility's preferred stock between July 20, 2000, and April 9, 2001, claimed that the defendants caused PG&E Corporation's Consolidated Financial Statements for the second and third quarters of 2000 to be materially misleading in violation of federal securities laws as a result of recording as a deferred cost and capitalizing as a regulatory asset the under-collections that resulted when escalating wholesale energy prices caused the Utility to pay far more to purchase electricity than it was permitted to collect from customers. On January 14, 2002, the District Court granted the defendants' motion to dismiss the plaintiffs' first amended complaint, finding that the complaint failed to state a claim in light of the public disclosures by PG&E Corporation, the Utility, and others regarding the under-collections, the risk that they might not be recoverable, the financial consequences of non-recovery, and other information from which analysts and investors could assess for themselves the probability of recovery.

On February 4, 2002, the plaintiffs filed a second amended complaint that, in addition to containing many of the same allegations as appeared in the first amended complaint, contains many of the same allegations that appear in the California Attorney General's complaint discussed below. The plaintiffs seek an unspecified amount of compensatory damages, plus costs and attorneys' fees. On March 11, 2002, the defendants filed a motion to dismiss the second amended complaint. After a hearing held on June 24, 2002, the District Court issued an order on June 25, 2002, dismissing the second amended complaint with prejudice. Plaintiffs have filed a notice of appeal of the District Court's order with the appellate court.

PG&E Corporation believes the allegations to be without merit and intends to present a vigorous defense. PG&E Corporation believes that the ultimate outcome of the litigation will not have a material adverse effect on its financial condition or results of operations.

Order Instituting Investigation (OII) into Holding Company Activities and Related Litigation

- On April 3, 2001, the CPUC issued an OII into whether the California investor-owned utilities, including the Utility, have complied with past CPUC decisions, rules, or orders authorizing their holding company formations and/or governing affiliate transactions, as well as applicable statutes. The order states that the CPUC will investigate (1) the utilities' transfer of money to their holding companies since deregulation of the electric industry commenced, including during times when their utility subsidiaries were experiencing financial difficulties, (2) the failure of the holding companies to financially assist the utilities when needed, (3) the transfer by the holding companies of assets to unregulated subsidiaries, and (4) the holding companies' action to "ringfence" their unregulated subsidiaries. The CPUC will also determine whether additional rules, conditions, or changes are needed to adequately protect ratepayers and the public from dangers of abuse stemming from the holding company structure. The CPUC will investigate whether it should modify, change, or add conditions to the holding company decisions, make further changes to the holding company structure, alter the standards under which the CPUC determines whether to authorize the formation of holding companies, otherwise modify the decisions, or recommend statutory changes to the California Legislature. As a result of the investigation, the CPUC may impose remedies, prospective rules, or conditions, as appropriate.

On January 9, 2002, the CPUC issued an interim decision and order interpreting the "first priority condition" adopted in the CPUC's holding company decision. This condition requires that the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner, be given first priority by the board of directors of the holding company. In the interim order, the

CPUC stated, "the first priority condition does not preclude the requirement that the holding company infuse all types of 'capital' into their respective utility subsidiaries where necessary to fulfill the Utility's obligation to serve." The three major California investor-owned energy utilities and their parent holding companies had opposed the broader interpretation, first contained in a proposed decision released for comment on December 26, 2001, as being inconsistent with the prior 15 years' understanding of that condition as applying more narrowly to a priority on capital needed for investment purposes. The CPUC also interpreted the first priority condition as prohibiting a holding company from: (1) acquiring assets of its utility subsidiary for inadequate consideration, and (2) acquiring assets of its utility subsidiary at any price, if such acquisition would impair the utility's ability to fulfill its obligation to serve or to operate in a prudent and efficient manner. The utilities' applications for rehearing were denied on July 17, 2002.

In a related decision, the CPUC denied the motions filed by the California utility holding companies to dismiss the holding companies from the pending investigation on the basis that the CPUC lacks jurisdiction over the holding companies. However, in the interim decision interpreting the first priority condition discussed above, the CPUC separately dismissed PG&E Corporation (but no other utility holding company) as a respondent to the proceeding. In its written decision adopted on January 9, 2002, the CPUC stated that PG&E Corporation was being dismissed so that an appropriate legal forum could decide expeditiously whether adoption of the Utility's proposed Plan of Reorganization would violate the first priority condition. The utilities' applications for rehearing were denied on July 17, 2002.

On January 10, 2002, the California Attorney General filed a complaint in the San Francisco Superior Court against PG&E Corporation and its directors, as well as against the directors of the Utility, alleging PG&E Corporation violated various conditions established by the CPUC in decisions approving the holding company formation among other allegations. The Attorney General also alleges that the December 2000 and January and February 2001 ringfencing transactions by which PG&E Corporation subsidiaries complied with credit rating agency criteria to establish independent credit ratings violated the holding company conditions.

Among other allegations, the Attorney General alleges that, through the Utility's bankruptcy proceedings, PG&E Corporation and the Utility engaged in unlawful, unfair, and fraudulent business practices in alleged violation of California Business and Professions Code Section 17200 by seeking to implement the transactions contemplated in the proposed Plan of Reorganization filed in the Utility's bankruptcy proceeding. The complaint also seeks restitution of assets allegedly wrongfully transferred to PG&E Corporation from the Utility. On February 8, 2002, PG&E Corporation filed a notice of removal in the Bankruptcy Court to transfer the Attorney General's complaint to the Bankruptcy Court. On February 15, 2002, a motion to dismiss the lawsuit or in the alternative to stay the suit, was filed. Subsequently, the Attorney General filed a motion to remand the action to state court. The Bankruptcy Court held a hearing on April 24, 2002, to consider the remand motion. On June 14, 2002, the court issued a memorandum decision rejecting the Attorney General's claim of sovereign immunity, and ordered the Attorney General to amend its complaint to drop or at least separate its plan of reorganization-related claims from its other claims by July 14, 2002. The court indicated that it would then remand to state court the Attorney General's Section 17200 claims that did not relate to the plan of reorganization. The Attorney General dropped the plan of reorganization claims in the amended complaint filed with the Bankruptcy Court on July 22, 2002.

On February 11, 2002, a complaint entitled *City and County of San Francisco; People of the State of California v. PG&E Corporation, and Does 1-150* was filed in San Francisco Superior Court. The complaint contains some of the same allegations contained in the Attorney General's complaint, including allegations of unfair competition. In addition, the complaint alleges causes of action for conversion, claiming that PG&E Corporation "took at least $5.2 billion from the Utility," and for unjust enrichment. The City seeks injunctive relief, the appointment of a receiver, payment to ratepayers, disgorgement, the imposition of a constructive trust, civil penalties, and costs of suit.

On March 4, 2002, PG&E Corporation filed a notice of removal in the Bankruptcy Court to transfer the City's complaint to the Bankruptcy Court. Subsequently, the City filed a motion to remand the action to state court. The Bankruptcy Court held a hearing on April 24, 2002, to consider the remand motion. On June 14, 2002, the court rejected the City's claim of sovereign immunity and its request for remand as to the unjust enrichment and conversion claims. In the same ruling, the court remanded to the state court the City's Section 17200 claims. PG&E Corporation filed a notice of appeal regarding the remand decision in the City's case, the only one of the three Section 17200 cases that is ripe for appeal at this time.

In addition, a third case, entitled *Cynthia Behr v. PG&E Corporation, et al.*, has been filed by a private plaintiff (who has also filed a claim in bankruptcy) in Santa Clara Superior Court also alleging a violation of California Business and Professions Code Section 17200. The Behr complaint also names the directors of the Utility as defendants. The allegations of the complaint are similar to the allegations contained in the Attorney General's complaint but adds allegations of fraudulent transfer and violation of the California bulk sales laws. Plaintiff requests the same remedies as the Attorney General's case and in addition requests damages, attachment, and restraints upon the transfer of defendants' property. On March 8, 2002, PG&E Corporation filed a notice of removal in the Bankruptcy Court to transfer the complaint to the Bankruptcy Court. Subsequently, the plaintiff filed a motion to remand the action to state court. The Bankruptcy Court held a hearing on April 24, 2002, to consider the remand motion. In its June 14, 2002 ruling mentioned above as to the Attorney General's and the City's cases, the court rejected Behr's claim for remand on her fraudulent conveyances and bulk sales claims but remanded to state court the Section 17200 claims. By amended complaint, Behr has dropped her fraudulent conveyance and bulk sales claims.

PG&E Corporation and the Utility believe that they have complied with applicable statutes, CPUC decisions, rules, and orders. Neither the Utility nor PG&E Corporation, however, can predict what the outcome of the CPUC's investigation will be or whether the outcome will have a material adverse effect on their results of operations or financial condition. PG&E Corporation will vigorously respond to and defend the litigation. PG&E Corporation cannot predict whether the outcome of the litigation will have a material adverse effect on its results of operations or financial condition.

William Ahern, et al. v. Pacific Gas and Electric Company

- On February 27, 2002, a group of 25 ratepayers filed a complaint against the Utility at the CPUC demanding an immediate reduction of approximately $0.035 per kilowatt-hour (kWh) in allegedly excessive electric rates and a refund of alleged recent overcollections in electric revenue since June 1, 2001. The complaint claims that electric rate surcharges adopted in the first quarter of 2001 due to the high cost of wholesale power, surcharges that increased the average electric rate by $0.04 per kWh, became excessive later in 2001. (In January 2001, the CPUC authorized a $0.01 per kWh increase to pay for energy procurement costs. In March 2001, the CPUC authorized an additional $0.03 per kWh electric rate increase as of March 27, 2001, to pay for energy procurement costs, which the Utility began to collect in June 2001.) The only alleged over-collection amount calculated in the complaint is approximately $400 million during the last quarter of 2001. On April 2, 2002, the Utility filed an answer, arguing that the complaint should be denied and dismissed immediately as an impermissible collateral action and on the basis that the alleged facts, even if assumed to be true, do not establish that currently authorized electric rates are not reasonable. On May 10, 2002, the Utility filed a motion to dismiss the complaint. The CPUC has not yet issued a decision. PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material adverse effect on their financial condition or results of operation.

Recorded Liability for Legal Contingencies

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

(in millions)	2002
Beginning balance, January 1,	$ 209
Provision for liabilities	17
Adjustments	(5)
Ending balance, June 30,	$ 221

NOTE 7: SEGMENT INFORMATION

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

Segment information for the three and six months ended June 30, 2002 and 2001 was as follows:

		PG&E National Energy Group					
(in millions)	Utility	Total PG&E NEG	Integrated Energy & Marketing	Interstate Pipeline Operations	PG&E NEG Eliminations	PG&E Corporation & Other Eliminations[2]	Total
Three months ended June 30, 2002							
Operating revenues	$ 2,711	$ 3,041	$ 3,002	$ 44	$ (5)	$ -	$ 5,752
Intersegment revenues [1]	3	19	9	10	-	(22)	-
Total operating revenues	2,714	3,060	3,011	54	(5)	(22)	5,752

Income (loss) from continuing operations	463	(180)	(190)	17	(7)	(4)	279
Net income (loss)	463	(241)	(251)	17	(7)	(4)	218
Three months ended June 30, 2001							
Operating revenues	2,305	2,705	2,637	55	13	-	5,010
Intersegment revenues (1)	4	48	39	9	-	(52)	-
Total operating revenues	2,309	2,753	2,676	64	13	(52)	5,010
Income (loss) from continuing operations	696	71	53	19	(1)	(17)	750
Net income (loss)	696	71	53	19	(1)	(17)	750
Six months ended June 30, 2002							
Operating revenues	5,161	5,358	5,276	91	(9)	-	10,519
Intersegment revenues (1)	6	50	28	22	-	(56)	-
Total operating revenues	5,167	5,408	5,304	113	(9)	(56)	10,519
Income (loss) from continuing operations	1,053	(143)	(164)	35	(14)	-	910
Net income (loss)	1,053	(204)	(225)	35	(14)	-	849
Six months ended June 30, 2001							
Operating revenues	4,865	6,818	6,703	111	4	-	11,683
Intersegment revenues (1)	6	141	123	18	-	(147)	-
Total operating revenues	4,871	6,959	6,826	129	4	(147)	11,683
Income (loss) from continuing operations	(304)	125	88	38	(1)	(22)	(201)
Net income (loss)	(304)	125	88	38	(1)	(22)	(201)
Total assets at June 30, 2002 (3)	24,648	11,422	9,953	1,355	114	709	36,779
Total assets at June 30, 2001 (3)	23,216	12,990	11,343	1,172	475	223	36,429

(1) Intersegment electric and gas revenues are recorded at market prices, which for the Utility and PG&E NEG's Interstate Pipeline Operations business segment are tariffed rates prescribed by the CPUC and the FERC, respectively.

(2) Includes PG&E Corporation, PG&E Ventures LLC, and elimination entries.

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

NOTE 8: IMPAIRMENT OF PROJECT DEVELOPMENT, TURBINES, AND OTHER RELATED EQUIPMENT COSTS

PG&E NEG has reviewed its growth plans for its electric generating business in light of the recent changes in the energy and equity markets as well as the slowdown of the U.S. economy. Further, energy prices, electric generating industry fundamentals and financial market's support for competitive energy companies have significantly declined, thereby constraining access to funds at acceptable terms to PG&E NEG. Over supply of electric generation in the current and near future has significantly decreased the value of planned future development projects. In response to these market changes and considering the expected level of future electric generating supply, PG&E NEG has reconsidered the extent of and reduced its planned investment activities in electric generating development projects. PG&E NEG has analyzed the potential cash flow from those projects that it no longer anticipates pursuing and has recognized an impairment of the asset value it is carrying for those development projects. The aggregate pre-tax impairment charge recorded by PG&E NEG for its development assets (excluding associated equipment costs discussed below) is $19 million. The remaining asset value (recorded in Other Non Current Assets) that PG&E NEG has retained as of June 30, 2002 for its portfolio of development projects is $48 million. PG&E NEG anticipates continuing to develop these projects to completion or for future disposal and believes that their unique characteristics provide value that will enable recovery of the capitalized costs over the useful lives of the projects. PG&E NEG has no material commitments (excluding equipment costs discussed below) for the projects under continuing development.

To support PG&E NEG's electric generating development program, PG&E NEG had contractual commitments and options to purchase a significant number of combustion turbines and related equipment. PG&E NEG's commitment to purchase combustion turbines and related equipment exceeds the new planned development activities discussed above. The current electric generating market is faced with an over supply of facilities in operation and in construction. The current and future market for combustion turbines and related equipment has also seen an over supply and large cancellation of turbine orders. The net realizability of PG&E NEG's investment in and future committed payments for its excess combustion turbine and related equipment portfolio, in light of current development plans, is doubtful. Based upon PG&E NEG's current development plans and analysis of future market prices for combustion turbines and related equipment, PG&E NEG has recognized a charge of $246 million. The charge consists of the impairment of previously capitalized costs associated with prior payments made under the terms of the turbine and equipment contracts in the amount of $188 million and the accrual of $58 million for future termination payments required under the turbine and related equipment contracts. Although PG&E NEG has impaired the value of these turbines and related equipment, it has not terminated its commitments or options with respect to this equipment. The remaining asset value (recorded in Other Non Current Assets) that PG&E NEG has retained as of June 30, 2002, for its investment in turbines and related equipment is approximately $33 million. These turbine and equipment commitments have been retained to support the equipment needs for PG&E NEG's current portfolio of advanced development projects discussed above. PG&E NEG and its equipment vendors have agreed to suspend any PG&E NEG payment obligations, except for $19 million, for at least the next twelve months. Thereafter, PG&E NEG must either restart equipment payments or terminate such commitments and pay the associated termination costs.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

PG&E Corporation is an energy-based holding company headquartered in San Francisco, California. PG&E Corporation's energy utility subsidiary, Pacific Gas and Electric Company (the Utility), delivers electric service to approximately 4.8 million customers and natural gas service to approximately 4.0 million customers. On April 6, 2001, the Utility filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code (Bankruptcy Code) in the United States Bankruptcy Court for the Northern District of California (Bankruptcy Court). Under Chapter 11, the Utility retains control of its assets and is authorized to operate its business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court. The factors causing the Utility to take this action are discussed in this Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) and in Note 2 of the Notes to the Consolidated Financial Statements.

PG&E Corporation's other significant subsidiary is PG&E National Energy Group, Inc. (PG&E NEG), headquartered in Bethesda, Maryland. PG&E NEG is an integrated energy company with a strategic focus on power generation, power plant development, natural gas transmission, and wholesale energy marketing and trading in North America. PG&E NEG and its subsidiaries have integrated their generation, development, and energy marketing and trading activities in an effort to create energy products in response to customer needs, increase the returns from their operations, and identify and capitalize on opportunities to increase their generating and pipeline capacity. PG&E NEG was incorporated on December 18, 1998, as a wholly owned subsidiary of PG&E Corporation. Shortly thereafter, PG&E Corporation contributed various subsidiaries to PG&E NEG. PG&E NEG's principal subsidiaries include: PG&E Generating Company, LLC and its subsidiaries (collectively, PG&E Gen), PG&E Energy Trading Holdings Corporation and its subsidiaries (collectively, PG&E Energy Trading or PG&E ET), PG&E Gas Transmission Corporation and its subsidiaries (collectively, PG&E GTC), which include PG&E Gas Transmission, Northwest Corporation and its subsidiaries (collectively, PG&E GTN) and North Baja Pipeline, LLC (NBP). PG&E NEG also has other less significant subsidiaries.

PG&E Corporation has identified three reportable operating segments, which were determined based on similarities in economic characteristics, products and services, types of customers, methods of distribution, the regulatory environment, and how information is reported to PG&E Corporation's key decision makers. The Utility is one reportable operating segment. The other two reportable operating segments are the Integrated Energy and Marketing (PG&E Energy) and the Interstate Pipeline Operations (PG&E Pipeline) segments of PG&E Corporation's subsidiary, PG&E NEG. These three reportable operating segments provide different products and services and are subject to different forms of regulation or jurisdictions. Financial information about each reportable operating segment is provided in this MD&A and in Note 7 of the Notes to the Consolidated Financial Statements.

This Quarterly Report on Form 10-Q/A is a combined report of PG&E Corporation and the Utility. It includes separate Consolidated Financial Statements for each entity. The Consolidated Financial Statements of PG&E Corporation reflect the accounts of PG&E Corporation, the Utility, and PG&E Corporation's wholly owned and controlled subsidiaries. This MD&A should be read in conjunction with the Consolidated Financial Statements and Notes to the Consolidated Financial Statements included herein. Further, this combined Quarterly Report on Form 10-Q/A should be read in conjunction with PG&E Corporation's and the Utility's Consolidated Financial Statements and Notes to the Consolidated Financial Statements incorporated by reference in their combined 2001 Annual Report on Form 10-K.

This combined Quarterly Report on Form 10-Q/A, including this MD&A, contains forward-looking statements, including statements regarding management's guidance regarding 2002 earnings per share, that are necessarily subject to various risks and uncertainties. These statements are based on current expectations and assumptions which management believes are reasonable and on information currently available to management. These forward-looking statements are identified by words such as "estimates," "expects," "anticipates," "plans," "believes," and other similar expressions. Actual results could differ materially from those contemplated by the forward-looking statements.

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

- the quarterly amount of "headroom" (the current recovery in the Utility's existing electric rates of prior uncollected costs previously written off according to accounting principles generally accepted in the United States) recognized by the Utility, which can fluctuate materially due to many factors, including the outcome of regulatory proceedings and other regulatory actions, sales volatility, the impact of the end of the rate freeze period and post-rate freeze ratemaking, and changes in the application of the surcharge revenues accrued by the Utility under rate increases approved by the California Public Utilities Commission (CPUC) in January and March 2001, and the impact of the proceedings to determine the level of revenue requirements for the California Department of Water Resources' (DWR) power procurement costs

  ♦ the pace and outcome of the Utility's bankruptcy case, which will be affected by:

  ♦ whether the Bankruptcy Court confirms the Utility's proposed plan of reorganization (Utility Plan) or the CPUC's competing alternative proposed plan of reorganization (Alternative Plan);

  ♦ whether regulatory or governmental approvals required to implement either plan are obtained and the timing of such approvals;

    - the impact of any delays in implementation of a plan due to litigation related to regulatory, governmental, or Bankruptcy Court orders;

    - future equity or debt market conditions, future interest rates, future credit ratings, and other factors that may affect the ability to implement either plan or affect the amount and value of the securities proposed to be issued under either plan;

    - whether the Official Committee of Unsecured Creditors (OCC) submits a proposed alternative plan of reorganization and the terms and conditions of any such plan;

  ♦ whether the Utility is required to re-assume the obligation to purchase power for its retail customers under circumstances that threaten to undermine the Utility's creditworthiness, financial condition, or results of operation;

  ♦ whether the Utility is required to accept assignment or operational responsibility of the DWR's power purchase contracts and any ratemaking associated with that obligation;

  ♦ the outcome of the CPUC's pending investigation into whether the California investor-owned utilities, including the Utility, have complied with past CPUC decisions, rules, or orders authorizing their holding company formations, the outcomes of the lawsuits brought by the California Attorney General and the City and County of San Francisco (City) against PG&E Corporation alleging unfair or fraudulent business acts or practices based on alleged violations of conditions established in the CPUC's holding company decisions, and the outcome of the California Attorney General's petition requesting revocation of PG&E Corporation's exemption from the Public Utility Holding Company Act of 1935, and the effect of such outcomes, if any, on PG&E Corporation, the Utility, and PG&E NEG;

  ♦ the outcome of the Utility's various regulatory proceedings pending at the CPUC and at the Federal Energy Regulatory Commission (FERC);

- whether the Utility will be successful in its filed rate doctrine litigation and other claims against the CPUC and the State of California for recovery of costs that were not collected from retail ratepayers;

- the CPUC's determination of the end of the rate freeze and the amount of under-collected power procurement and transition costs the Utility is allowed to collect from its customers after the end of the rate freeze;

- legislative or regulatory changes affecting the electric and natural gas industries in the United States, including the pace and extent of efforts to restructure the electric and natural gas industries and changes to rules and tariffs applicable to energy marketing and trading transactions, the market in which PG&E NEG operates, and changes in the accounting treatment of such transactions;

- the volatility of commodity fuel and electricity prices and the spread between them (which may result from a variety of factors, including: weather; the supply and demand for energy commodities; the availability of competitively priced alternative energy sources; the level of production and availability of natural gas, crude oil, and coal; transmission or transportation constraints; federal and state energy and environmental regulation and legislation; the degree of market liquidity; and natural disasters, wars, embargoes, and other catastrophic events); any resulting increases in the cost of producing power and decreases in prices of power sold; and whether the Utility's and PG&E NEG's strategies to manage and respond to such volatility are successful;

- the extent to which the ability of PG&E Corporation to obtain financing or capital on reasonable terms is affected by conditions in the general economy, the energy or capital markets, by restrictions imposed on PG&E Corporation under its credit agreement, by changes in PG&E NEG's credit ratings, and by the interpretation of the CPUC's holding company conditions;

- PG&E NEG's ability to obtain financing from third parties or from PG&E Corporation while preserving PG&E NEG's credit quality, which ability could be negatively affected by conditions in the general economy, the energy markets, or the capital markets; and the market's perceptions of the energy industry;

- the extent to which PG&E NEG's current or planned construction of generation, pipeline, and storage facilities are completed and the pace and cost of that completion, including the extent to which commercial operations of these construction projects are delayed or prevented because of various development and construction risks such as PG&E NEG's failure to obtain necessary permits or equipment, the failure of third-party contractors to perform their contractual obligations, or the failure of necessary equipment to perform as anticipated and the potential loss of permits or other rights in connection with PG&E NEG's decision to delay or defer construction;

- the extent to which PG&E NEG's development plans and strategies are affected by changes in the national energy markets and by the timing of generating, pipeline, and storage capacity expansion and retirements by others;

- whether market conditions will require further impairment or write-off of PG&E NEG assets, which may cause PG&E NEG to fail to comply with the net worth requirements of its loan agreements or which may cause PG&E Corporation to fail to comply with the debt covenant in its term loan agreement requiring PG&E NEG to maintain a certain loan to value ratio;

- restrictions imposed upon PG&E Corporation and PG&E NEG under certain term loans of PG&E Corporation, including requirements for PG&E Corporation to comply with debt covenants regarding cash reserves, loan to value ratios, and investment grade credit ratings, among others;

- ♦ future sales levels which are affected by general economic and financial market conditions, changes in interest rates, weather, conservation efforts, outages, and in the case of the Utility, the level of exit fees that may be imposed on direct access customers;
- ♦ volatility in income resulting from mark-to-market accounting, changes in mark-to-market methodologies, and the extent to which the assumptions underlying PG&E NEG's and the Utility's mark-to-market accounting and risk management programs are not realized;
- ♦ the effectiveness of PG&E NEG's and the Utility's risk management policies and procedures;
- ♦ the ability of PG&E NEG's and the Utility's counterparties to satisfy their financial commitments to PG&E NEG and the Utility, respectively, and the impact of counterparties' nonperformance on PG&E NEG's and the Utility's liquidity position;
- ♦ the effect of compliance with existing and future environmental laws, regulations, and policies, the cost of which could be significant;
- ♦ the impact of the recent or future downgrades in credit ratings of PG&E NEG and other subsidiaries on PG&E NEG's and PG&E Corporation's financial condition which will be affected by the extent to which PG&E NEG and its subsidiaries can meet liquidity calls which may be made in connection with trading activities, meet obligations to fund various equity commitments, provide other collateral to replace PG&E NEG guarantees, or obtain financing for planned development projects, whether PG&E NEG is able to renew a substantial portion of its revolving credit lines otherwise due to expire on August 22, 2002; and whether a default occurs under PG&E Corporation's credit agreement;
- ♦ the extent to which counterparties seek damages based upon credit downgrades and their ability to recover such damages;
- ♦ the effect of new accounting pronouncements; and
- ♦ the outcome of pending litigation and environmental matters.

As the ultimate impact of these and other factors is uncertain, these and other factors may cause future earnings to differ materially from results or outcomes currently sought or expected.

In this MD&A, we first discuss our earnings guidance, we then discuss the impact of the California energy crisis and the Utility's bankruptcy on our liquidity, and then PG&E NEG's liquidity. We then discuss statements of cash flows and financial resources, and our results of operations for the six months ended June 30, 2002, and 2001. Finally, we discuss our competitive and regulatory environment, our risk management activities, and various uncertainties that could affect future earnings. Our MD&A applies to both PG&E Corporation and the Utility.

2002 Guidance

PG&E Corporation expects 2002 corporate earnings from operations, excluding headroom, to be in the range of $2.25 to $2.35 per share on a fully diluted basis. Earnings from operations, including headroom, are expected to exceed $4.75 per share for 2002. Earnings from operations with and without headroom exclude items impacting comparability, and should not be considered an alternative to net income as prescribed by accounting principles generally accepted in the United States.

STATE OF INDUSTRY

Utility

The California energy crisis described in Note 2 of the Notes to the Consolidated Financial Statements has had a significant negative impact on the liquidity and capital resources of the Utility. Beginning in June 2000, the wholesale price of electric power in California steadily increased to an average cost of $0.182 per kilowatt-hour (kWh) for the seven-month period June 2000 through December 2000, as compared to an average cost of $0.042 per kWh for the same period in 1999. During this period, retail electric rates were frozen. The Utility was only permitted to collect approximately $0.054 per kWh in frozen retail rates from its customers to pay for the Utility's generation-related costs. While seeking rate relief from the CPUC, the Utility financed the difference between its wholesale electricity costs and the amount collected through frozen retail rates. By December 31, 2000, the Utility had borrowed more than $3 billion. At December 31, 2000, the Utility had accumulated a total of approximately $6.9 billion in under-collected purchased power costs and generation-related transition costs. This amount was charged to earnings at December 31, 2000, because the Utility could no longer conclude that such costs were probable of collection through regulated rates.

In January 2001, the CPUC granted an interim rate increase of $0.010 per kWh. This increase, which could not be used to recover past procurement costs, was not sufficient to cover the ongoing high wholesale electricity costs then being experienced. As a result of the higher energy prices and the insufficient rate increase, PG&E Corporation's and the Utility's credit ratings deteriorated to below investment grade. These credit downgrades, which occurred on January 16 and 17, 2001, were events of default under one of the Utility's revolving credit facilities and precluded PG&E Corporation's and the Utility's access to the capital markets. Accordingly, the banks stopped funding under the Utility's revolving credit facility. On January 17, 2001, the Utility began to default on maturing commercial paper obligations. In addition, the Utility was no longer able to meet its obligations to generators, qualifying facilities (QF), the Independent System Operator (ISO), and the Power Exchange (PX), and began making partial payments of amounts owed.

As of January 19, 2001, the Utility had no credit under which it could purchase power for its customers, and generators were only selling to the Utility under emergency actions taken by the U.S. Secretary of Energy. As a result, the State of California authorized the DWR to purchase electricity for the Utility's customers. California Assembly Bill (AB) 1X was passed on February 1, 2001, authorizing the DWR to enter into contracts for the supply of electricity and to issue revenue bonds to finance electricity purchases, although the DWR indicated that it intended to buy power only at reasonable prices to meet the Utility's net open position, leaving the ISO to purchase the remainder in order to avoid blackouts. (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 Utility).

Throughout the energy crisis, the Utility sought relief through various regulatory proceedings and through efforts to reach a negotiated solution with the State of California (State). In late March and early April 2001, the CPUC issued a series of decisions that increased the Utility's inability to recover past debts and increased its exposure to significant additional costs. On March 27, 2001, the CPUC ruled on the Utility's November 20, 2000, request for rate relief. This decision made permanent the $0.010 per kWh interim increase authorized in January 2001 and granted an additional $0.030 per kWh (on average) energy surcharge that would be effective immediately, but that would not be included in customer bills until June 2001. The revenue generated by the rate increase was to be used only for electric power procurement costs incurred after March 27, 2001. This decision ordered the Utility to pay the DWR the full generation-related portion of retail rates for every kWh of electricity sold by the DWR without regard to whether overall retail rates were adequate to recover the remainder of the Utility's cost of service. In the same decision, the CPUC adopted an accounting proposal by The Utility Reform Network (TURN), which retroactively restates the way in which transition costs are recovered. This retroactive change had the effect of extending the rate freeze and reducing the amount of past wholesale power costs that could be eligible for recovery from customers. The CPUC denied the Utility's application for rehearing of this retroactive accounting change. The Utility also filed a petition for a writ of review with the California Court of Appeal, which also was denied. The Utility has filed a petition with the

California Supreme Court to review the appellate court action. The Utility's request filed with the Bankruptcy Court for an order enjoining the CPUC from enforcing its order was denied by the Bankruptcy Court. The Utility has appealed the Bankruptcy Court's denial of injunctive relief to the U.S. District Court for the Northern District of California.

On July 1, 2002, a CPUC Commissioner issued an Assigned Commissioner's Ruling seeking comments on whether the restrictions of applying the $0.010 per kWh and $0.030 per kWh surcharge revenues only to "ongoing procurement costs" and "future power purchases" should be modified to allow the surcharge amount to be applied to improve the financial health of the Utility. See further discussion in the Regulatory Matters section of this MD&A.

Also on March 27, 2001, the CPUC issued a ruling that required the Utility to begin paying the QFs in full and within 15 days of the end of the QF's billing cycle. On April 3, 2001, the CPUC issued a ruling which adopted a methodology for the Utility to reimburse the DWR for power purchases made to meet the Utility's net open position. The Utility believes that these actions taken by the CPUC were illegal and the Utility filed for rehearings and appeals with the CPUC, in federal court, and with the Bankruptcy Court. The status of these proceedings is discussed later in this MD&A.

As a result of (1) the failure of the DWR to assume the full procurement responsibility for the Utility's net open position, (2) the negative impact of a CPUC decision 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 of California to provide a solution for the energy crisis, and (4) the adoption by the CPUC of an illegal and retroactive accounting change that would appear to eliminate the Utility's true under-collected purchased power costs, the Utility filed a voluntary petition for relief under Chapter 11 of the Bankruptcy Code on April 6, 2001. See Note 2 of the Notes to the Consolidated Financial Statements for further discussion of the energy crisis, the Utility's voluntary petition for relief under Chapter 11 of the Bankruptcy Code, and the status of the proceedings.

Under AB 1X, the DWR is prohibited from entering into new agreements after January 1, 2003, to purchase power to meet the net open position of the California investor-owned utilities (IOUs). The CPUC has initiated a proceeding to address the regulatory obligations and standards under which the IOUs may be required to resume procurement for the net open after January 1, 2003, including whether the IOUs can be required to procure power even if they are not investment grade; the allocation of power and operating responsibility for DWR's existing power contracts among the IOUs; and the reasonableness standards applicable to the IOUs' procurement. This proceeding is further discussed below under the Regulatory Matters sections of this MD&A.

PG&E NEG

The national markets in which PG&E NEG participates are experiencing the first sustained downturn in the electric power commodity business cycle since electric deregulation began in the mid 1990's. Price spikes beginning in 1997 and 1998 culminated in peak prices in 2000 and early 2001. New supply additions begun during the high-price period combined with a softening economy and reduced load growth have resulted in excess energy supply in many regions. The excess supply conditions have put downward pressure on the price of electricity minus the cost of fuel, or spark spread, available in most regional wholesale energy markets. Furthermore, the economic slowdown and a number of regulatory events, many of which were consequences of the California energy crisis and the Enron bankruptcy, have increased uncertainty in the energy sector.

Conditions in the national energy markets will constrain PG&E NEG's near-term profitability and growth. The excess supply conditions reduce operating margins for electric generators and lower price volatility for energy products, potentially reducing profits from energy trading activities. In response to these market changes, PG&E NEG has reconsidered the extent of and reduced its planned investment activities in electric generating development projects. PG&E NEG has analyzed the potential cash flow from those projects that no longer anticipates pursuing and has recognized an impairment of the carrying value of those development projects and the associated turbine and equipment assets. This impairment, described under "Investing Activities" below, reflects PG&E NEG's judgment that the market viability of these development projects is uncertain. PG&E NEG is continuing to seek purchasers or partners for these development projects and the equipment associated with them. PG&E NEG also initiated a program to reduce administrative, general and other operating costs, with a targeted annual reduction of a minimum of $40 million.

In addition, a series of events and disclosures have created a more difficult financial and regulatory climate for the energy industry and its participants, including PG&E NEG. S&P announced that it has changed its methodology to review energy industry participants, and has recently issued several downgrades. On July 31, 2002, S&P downgraded PG&E NEG to BB+ from BBB. See "Credit Ratings and Liquidity Uses" below.

In addition, investigations are underway by state and federal authorities into energy trading matters. In response to a data request order from FERC, PG&E NEG conducted an investigation into certain activities of its subsidiaries in the U.S. portion of the Western Systems Coordinating Council ("WSCC") during the years 2000 and 2001. FERC requested information regarding transactions in which energy traders simultaneously engaged in any purchase and sale of the same product at the same price with the same counterparty in the WSCC during the years 2000 and 2001. As a result of its investigation, PG&E NEG identified 12 such instances. In addition, PG&E NEG has reviewed its activities including those in other regions during the period January 2000 through May 2002 using the FERC criteria and has identified 32 additional instances. These instances had no material effect on PG&E NEG's reported revenues or financial results. Revenues associated with these instances represent approximately 0.14 percent of PG&E NEG's revenues during the same period. PG&E Corporation has adopted a policy prohibiting participation in this type of transaction.

PG&E NEG maintains an insurance program including coverage for power plant construction and operating risks. Recent events have adversely affected the insurance industry generally and the machinery and equipment segment in particular. This effect is especially acute for insurance covering advanced gas turbine technology; including many of those PG&E NEG has in construction. As a result, PG&E NEG expects that its insurance coverages will be at lower levels than PG&E NEG has historically procured, certain coverages (for example, terrorism insurance) may no longer be available on commercially reasonable terms, deductibles will increase in size and premiums will be significantly higher. Therefore, PG&E NEG will likely carry a greater percentage of self-insurance at potential risk of greater losses than in prior periods.

LIQUIDITY AND FINANCIAL RESOURCES

In November 2001 and March 2002, PG&E Corporation amended its March 1, 2001, Credit Agreement (Old Credit Agreement) with General Electric Capital Corporation (GECC) and Lehman Commercial Paper Inc. (LCPI) and their assignees (Existing Lenders). The amendments provided PG&E Corporation the option to extend the original $1 billion aggregate term loan credit facility for two one-year periods so that the maturity date could be extended until as late as March 2, 2006, contingent upon PG&E Corporation making a principal repayment of $308 million by June 3, 2002. On June 3, 2002, PG&E Corporation made the principal repayment of $308 million, utilizing current working capital and reducing the principal balance outstanding under the Old Credit Agreement to $692 million.

On June 25, 2002, PG&E Corporation entered into an Amended and Restated Credit Agreement (New Credit Agreement) with GECC (Tranche A Lender) and LCPI and others (collectively, the Tranche B Lenders) which amended and restated the Old Credit Agreement. The New Credit Agreement provides for loans in two tranches. The Tranche A has a principal amount of $600 million (Tranche A Loan), representing the $692 million outstanding under the Old Credit Agreement less $92 million that has been converted to a Tranche B Loan. The Tranche B consists of the $92 million converted loan plus $328 million of new borrowings, for a total of $420 million (Tranche B Loan). The Tranche A Loan will continue to have the same maturity date and extension provisions as the Old Credit

Agreement. The Tranche B Loan will mature on the earlier of (1) September 2, 2006, or (2) the date of any spin-off of the shares of PG&E NEG by its indirect parent, PG&E Corporation. The interest rate for the Tranche A Loan is the Eurodollar Rate plus 2.5 percent for the period through August 31, 2002, and will increase to the Eurodollar Rate plus 4.0 percent beginning September 1, 2002. The Tranche B Loan has an interest rate of the Eurodollar Rate plus 4.0 percent. In addition, the Tranche B Loan has a 4.0 percent payment-in-kind interest compounded annually and added to the principal of the note at maturity. The Tranche A Loan and the Tranche B Loan are collectively referred to as the "Loans."

The Tranche A Loan continues to be secured by a first priority lien on (1) PG&E Corporation's equity interest in PG&E National Energy Group, LLC, a Delaware limited liability company (NEG LLC, and together with its direct and indirect subsidiaries, the NEG Group), and (2) NEG LLC's equity interest in PG&E NEG. The Tranche A Loan is also secured by the first priority lien on certain cash interest reserves. The Tranche B Loan is secured by a second priority lien on the equity interests in NEG LLC and PG&E NEG and by a first priority lien on certain other cash interest reserves. In addition, the Tranche B Loan is subordinated to the Tranche A Loan.

PG&E Corporation issued to the Tranche B Lenders warrants to purchase approximately 2.4 million shares of common stock of PG&E Corporation for an exercise price of $0.01 per share (Warrants). The Warrants are recorded at their fair value as an unamortized discount to long-term debt, and as additional paid-in capital on the PG&E Corporation Consolidated Balance Sheets at June 30, 2002.

In connection with the Old Credit Agreement, affiliates of the Existing Lenders received an option to purchase 3 percent of the shares of PG&E NEG, determined on a fully diluted basis, at an exercise price of $1.00. The option may be exercised at any time until 45 days after the full repayment of the Tranche A Loan. In addition, under the Old Credit Agreement, PG&E Corporation's exercise of each of its one-year extensions of the loan was conditioned upon NEG LLC granting affiliates of the Existing Lenders an additional option to purchase 1 percent of the common stock of PG&E NEG, determined on a fully diluted basis, at an exercise price of $1.00. As a result of the reduction in the principal amount of the Tranche A Loan to $600 million from the $692 million in loans outstanding under the Old Credit Agreement, the 1 percent has been reduced to approximately 0.87 percent of the common stock of PG&E NEG. The option may be exercised at any time from the relevant extension date until 45 days after full repayment or maturity of the Tranche A Loan. The fair value of the options granted are recorded as a debt issuance cost and amortized over the expected life of the loans. After the initial recording, the options are marked to market through an increase or decrease in earnings.

NEG LLC has the right to call the option after repayment of the Tranche A Loan in full at a cash purchase price equal to the fair market value of the underlying shares or, at the election of NEG LLC if an initial public offering of the shares of PG&E NEG (IPO) has occurred, by delivering the underlying shares. If an IPO has not occurred prior to repayment of the Tranche A Loan in full, 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 (Put Price), which right is exercisable at any time after the earlier of full repayment of the Tranche A Loan or 45 days before expiration of the option. In addition to the grant of the additional option, PG&E Corporation must pay a fee of 3 percent of the then outstanding balance of the Tranche A Loan as a condition of PG&E Corporation's exercise of each of the one-year extensions.

The New Credit Agreement contains certain limitations on the ability of PG&E Corporation and certain of its subsidiaries to grant liens, consolidate, merge, purchase or sell assets, declare or pay dividends, incur indebtedness, or make advances, loans and investments. However, the New Credit Agreement does not limit (1) PG&E Corporation's ability to spin-off its subsidiary, the Utility, substantially in accordance with the Utility's proposed plan of reorganization, and (2) the ability of the members of the PG&E NEG Group to grant liens, purchase or sell assets, make investments, and incur indebtedness in accordance with PG&E NEG's business plan, or (3) PG&E Corporation's ability to make investments in the Utility to the extent required by law or regulatory requirements.

The New Credit Agreement also generally requires mandatory prepayments of the Loans with the net cash proceeds from incurrence of indebtedness, issuance or sale of equity and sales of assets, the receipt of condemnation or insurance proceeds, and distributions or dividends paid to PG&E Corporation; provided however, that (1) PG&E Corporation may make investments in the Utility with cash proceeds from equity sales or issuances to the extent required by law or regulatory requirements, (2) the PG&E NEG Group may use such proceeds, or hold such proceeds in cash, to purchase assets or make investments in accordance with PG&E NEG's business plan, except that proceeds from an IPO must be used to the extent required to repay the Tranche A Loan, plus $20 million of the Tranche B Loan. Any mandatory prepayments of the Loans will be applied first to the principal amount of the Tranche A Loan and, after the Tranche A Loan is paid in full, to the principal amount of the Tranche B Loan.

The New Credit Agreement also requires PG&E Corporation to maintain an interest reserve account for each of the Tranche A Loan and the Tranche B Loan in an amount equal to one year's estimated interest. At June 30, 2002, the Tranche A Loan and the Tranche B Loan interest reserve balances, included in restricted cash, were $38 million and $27 million, respectively.

A breach of any covenants would entitle the Lenders to declare the Loans to be due and payable. The covenants include requirements that (1) PG&E NEG's unsecured long-term debt have a credit rating of at least BBB - by Standard & Poor's (S&P) or Baa3 by Moody's Investors Service, Inc. (Moody's), (2) the ratio of fair market value of PG&E NEG to the aggregate amount of principal then outstanding under the Loans be not less than 2 to 1, and (3) PG&E Corporation maintain cash or cash equivalents (including amounts held in the interest reserves) of either 15 percent or 10 percent (depending upon when applicable) of the total principal amount of the Loans outstanding plus the principal amount of the Notes (as described below).

Concurrent with the refinancing described above, on June 25, 2002, PG&E Corporation issued $280 million aggregate principal amount of 7.50% Convertible Subordinated Notes (Notes) due June 30, 2007, in a private offering. The Notes are unsecured and are subordinate to the Loans. PG&E Corporation will pay interest on the Notes semi-annually at a rate of 7.50 percent per year. PG&E Corporation has the right, subject to certain limitations, to pay interest by issuing additional Notes in lieu of paying cash. The New Credit Agreement prohibits PG&E Corporation from paying cash interest on the Notes (1) for 240 days after receipt by the Note trustee of notice delivered by the administrative agent or the Tranche A Lender stating that a default that would permit acceleration has occurred under the New Credit Agreement, or (2) if, after such interest payment, PG&E Corporation's cash and cash equivalents are less than 20 percent of the total principal amount of the Loans outstanding plus the principal amount of the Notes, or 15 percent of such amount upon any extension of the Loans. PG&E Corporation would nevertheless retain its right to issue new Notes in lieu of paying cash interest.

In addition to interest, if PG&E Corporation pays cash dividends to holders of its common stock, Note holders are entitled to receive cash equal to the dividends that would have been paid with respect to the number of shares that the holder would be entitled to receive if the Notes had been converted on the dividend record date. The Notes may be converted by the holders into shares of PG&E Corporation's common stock at a conversion price equal to 119 percent of the volume-weighted average price of the common stock of PG&E Corporation for each of 43 trading days beginning June 28, 2002. The conversion price is subject to adjustment under certain circumstances, including upon consummation of any spin-off transaction of the Utility as proposed in its plan of reorganization or a spin-off of the shares of PG&E NEG. Depending on the value of PG&E Corporation common stock used in the adjustment calculation, such adjustment could have a material adverse impact on PG&E Corporation's results of operation or financial condition.

Credit Ratings

As discussed below, the California energy crisis has impacted the credit ratings of various debt and equity instruments. The credit ratings at July 31, 2002, of the various debt and equity instruments of PG&E Corporation, the Utility, and PG&E NEG are summarized in the table below:

	Credit Rating	
	Standard & Poor's	Moody's Investors Service
PG&E Corporation		
GECC/LCPI Loans	Not Rated	B2
Convertible Subordinated Notes	Not Rated	Not Rated
Utility		
Mortgage Bonds	CCC	B3
Pollution Control Bonds-Bond Insurance	AAA	Aaa
Pollution Control Bonds-Letters of Credit	AA to AA-/A-1+	Not Rated
Medium-Term Notes	D	Caa2
San Joaquin Valley Power Authority Bond	Not Rated	Rating Withdrawn
DWR Loan	Not Rated	Not Rated
Senior 5-Year Note	D	Caa2
Revolving Credit Line	Not Rated	Not Rated
Floating Rate Notes	D	Not Rated
Matured Commercial Paper	D	Not Prime
Redeemed Pollution Control Bonds-Bank Loans	Not Rated	Not Rated
Deferrable Interest Subordinated Debentures (QUIDS)	Rating Pending	Caa3
Preferred Stock	D	Ca
PG&E NEG		
Senior Unsecured Notes due 2011 (PG&E NEG)	BB+	Baa2
Senior Unsecured Notes due 2005 (PG&E GTN)	BBB+	Baa1
Senior Unsecured Debentures due 2025 (PG&E GTN)	BBB+	Baa1
Medium-Term Notes (nonrecourse) (PG&E GTN)	BBB+	Baa1
Outstanding Credit Facilities	Various	Various
Term Loans-Gen Holdings I LLC	BBB-	Baa3
Mortgage Loans and Others	Not Rated	Not Rated

PG&E NEG

The PG&E Energy and PG&E Pipeline business segments require substantial amounts of liquidity and capital resources to support construction, working capital, and counterparty credit requirements. PG&E NEG's strategy has been to finance PG&E NEG operations using a combination of funds from operations, equity, long-term debt (secured directly by those assets without recourse to other entities), long-term corporate borrowings in the capital markets, and short and medium term bank facilities that provide working capital, letters of credit and other liquidity needs. PG&E NEG's credit ratings have been important to PG&E NEG's ability to provide counterparty guarantees and to obtain capital.

On July 31, 2002, S&P downgraded PG&E NEG to BB+ from BBB. On the same date S&P downgraded PG&E ET to BB+ from BBB+, PG&E GTN to BBB+ from A-, PG&E Gen to BB+ from BBB, and USGenNE to BB+ from BBB-. All of the rated companies have also been placed on CreditWatch with negative implications. In April 2002, Moody's affirmed PG&E NEG's Baa2 rating, but changed the outlook for PG&E NEG to negative from stable. The downgrade of PG&E NEG's credit ratings impacts certain guarantees and financial arrangements that require PG&E NEG to maintain certain credit ratings from S&P and/or Moody's. These provisions are referred to as "ratings triggers." Generally, the ratings triggers are linked to one or more investment grade ratings. PG&E NEG's counterparties generally hold guarantees from PG&E NEG or a rated subsidiary of PG&E NEG, usually PG&E ET or PG&E GTN.

In addition to agreements containing ratings triggers, other agreements allow counterparties to seek additional security for performance whenever such counterparty becomes concerned about PG&E NEG's or its subsidiaries' creditworthiness. The downgrades could give rise to such concerns. As a result of the rating triggers or other demand for security, PG&E NEG may be required to provide additional collateral in the form of cash, letters of credit or replacement guarantees or to fund obligations in advance of their expected schedules. The amount of this additional security or funding varies depending upon PG&E NEG's current exposure under its agreements and the reactions to the downgrades of counterparties holding PG&E NEG's guarantees. This funding or provision of additional collateral may significantly deplete or exceed PG&E NEG's liquidity resources.

Ratings triggers and additional security obligations are generally a feature of five categories of PG&E NEG agreements: (1) trading and non-trading hedging agreements and related guarantees, (2) tolling agreement guarantees, (3) debt repayment or equity commitments in connection with asset-specific debt arrangements, (4) guarantees related to other obligations by PG&E NEG companies to counterparties for goods or services, and (5) other contractual commitments to third parties.

Trading and non-trading hedging guarantees-

PG&E NEG and its rated subsidiaries have provided $2.9 billion of guarantees to approximately 250 counterparties in support of its energy trading and non-trading hedging operations. Typically, the overall exposure under these guarantees is only a fraction of the face value of these guarantees, since not all counterparty credit limits are fully utilized at any time. As of July 31, 2002, PG&E NEG and its rated subsidiaries' aggregate exposure under these guarantees was approximately $360 million. Of this exposure, the amounts subject to securitization requirements as a result of a downgrade to below investment grade of PG&E NEG by S&P are $115 million; of PG&E ET are $16 million; and of USGenNE are $1 million. In addition, $37 million of this exposure is under guarantees that have been issued by PG&E GTN with a ratings trigger. However, the ratings trigger for PG&E GTN is not affected by S&P's actions on July 31, 2002. The remaining $191 million could be subject to securitization requirements due to a counterparty's concern with PG&E NEG's or its subsidiary's creditworthiness. As of July 31, 2002, PG&E ET had sufficient cash to cover these obligations.

Equity Commitments and Debt Repayment Guarantees-

PG&E NEG has guaranteed debt or equity commitments in connection with the following (in millions):

Lake Road	$	230
La Paloma		379
Equipment Revolving Credit Facility		230

GenHoldings I	505

PG&E NEG has replaced the ratings triggers in these facilities with financial covenants that are consistent with those contained in PG&E NEG's revolving credit and other loan facilities. These covenants include requirements to exceed a specified cash flow to fixed charges ratio and a specified net worth as well as maintain less than a specified total debt to total capitalization ratio and are set forth in PG&E NEG's revolving credit agreement filed as Exhibit 10.21 to PG&E NEG's Annual Report on Form 10-K filed with the SEC on March 5, 2002. PG&E NEG is in compliance with these covenants.

Not withstanding the above, if PG&E NEG is also downgraded to below investment grade by Moody's, PG&E NEG would be required to fund construction draws under the GenHoldings I financing entirely with equity until the equity commitment is fulfilled. This would result in PG&E NEG being obligated to fund approximately $270 million of additional equity through December 2002 that would have otherwise been funded through June 2003. After December 2002, the lenders would fund the construction draws pursuant to the credit agreement. Failure by PG&E NEG to fund any required equity would result in a default under the GenHoldings I credit facility as well as a default under PG&E NEG's revolving credit facility.

Tolling arrangement -

PG&E NEG has entered into five long-term tolling transactions with third parties. Each tolling agreement is supported by a separate guarantee backing the payment obligations of the PG&E NEG affiliate over the term of these long-term contracts (9-25 years). PG&E NEG or its rated subsidiaries has extended approximately $620 million of such guarantees. Of these guarantees, $575 million have been issued by PG&E NEG and contain a ratings trigger that requires PG&E NEG to replace the guarantee or provide alternative collateral as a result of its credit rating dropping below BBB or Baa2. This amount increases by an additional $20 million if PG&E NEG's credit rating is also downgraded to below investment grade by Moody's. In addition, $24 million of these guarantees have been issued by PG&E GTN with a ratings trigger. However, the ratings trigger for PG&E GTN is not affected by S&P's actions on July 31, 2002. The ratings downgrade by S&P on July 31, 2002, has triggered the need for additional guarantees, alternative collateral or other acceptable arrangements under these agreements within a ten to 30 day cure period. In the event that PG&E NEG does not replace the guarantee, provide alternative collateral or agree on other acceptable arrangements as required, the counterparty has the right to terminate the related tolling agreement and seek recovery of damages to be determined in arbitration. It is not known whether the counterparties to the tolling agreement would exercise their rights to terminate the agreements. If a party did exercise its right to terminate a tolling agreement, the agreements generally provide that any damages are to be awarded based upon the difference in the contract price for the power under the agreement and the market price for the power, estimated by PG&E NEG to be $20 million under current conditions. In the event of a dispute over the amount of any termination payment that the parties are unable to resolve by negotiation, the tolling agreements provide for mandatory arbitration, which could take as long as six months to more than a year to complete, depending on the specific procedures detailed in the tolling agreements.

Other Guarantees -

PG&E NEG has provided approximately $1.3 billion of guarantees related to other obligations by PG&E NEG companies to counterparties for goods or services. Of this $1.3 billion, the amount subject to securitization requirements as a result of a downgrade to below investment grade of PG&E NEG is $770 million and PG&E Gen is $9 million. The most significant of these guarantees relate to performance under certain construction and equipment procurement contracts. In the event PG&E NEG is unable to provide the additional or replacement security required in the event of such a downgrade, the counterparty providing the goods or services could suspend performance or terminate the underlying agreement and seek recovery of damages.

These guarantees represent guarantees of subsidiary obligations for transactions entered into in the ordinary course of business. The first is for guarantees related to the construction or development of PG&E NEG's power plants and pipelines. Specifically, these include guarantees for the performance of the contractor building the Harquahala and Covert power projects amounting to $545 million. Any exposure under the guarantees for construction completion is mitigated by guarantees in favor of PG&E NEG from the constructor and equipment vendors related to performance, schedule and cost. Since the constructor and various equipment vendors are performing under their underlying contracts, PG&E NEG does not believe that it has significant exposure under these guarantees. Further, although these guarantees contain ratings triggers, the same lenders who are the beneficiaries of these guarantees are the funding banks for GenHoldings I.

PG&E NEG has provided $343 million in guarantees in favor of the various contractors and equipment vendors for the payment of any cancellation penalties in the event that projects or equipment contracts are cancelled and there remain unpaid amounts. Of this amount, approximately $58 million will be paid to these vendors for cancellation of equipment contracts. In the event that these vendors seek to terminate the contracts sooner, this amount would also represent PG&E NEG's maximum exposure. Included in the above amount is $100 million of guarantees to the constructor of the Harquahala and Covert projects to cover certain separate cost-sharing arrangements. Failure to fund a demand for collateralization would permit the constructor to terminate those separate cost sharing arrangements. This would not have an impact on the constructors' obligations to complete the Harquahala and Covert projects pursuant to the contracts. Therefore, this would not have a financial impact on PG&E NEG or its subsidiaries.

PG&E NEG has provided a $300 million guarantee to support a tolling agreement that a wholly owned subsidiary, Attala Energy Company, has entered into with Attala Generating Company. Attala Generating Company entered into a $340 million sale-lease back transaction. The tolling payments provide the lessee with sufficient cash flows to pay rent under the lease. So long as Attala Energy Company continues to perform under the tolling agreement PG&E NEG does not believe it has any incremental liability or exposure under this guarantee.

The balance of the guarantees are for commitments undertaken by PG&E NEG or subsidiaries in the ordinary course of business for services such as facility and equipment leases, pipe capacity, ash disposal rights, and surety bonds.

Other Commitments-

There is a total of $149 million in potential additional liquidity requirements related to other commitments.

In addition to the $360 million in trading exposure that is covered by guarantees and addressed above, there is an additional $73 million of current exposure under trading agreements at July 31, 2002. Some portion of this exposure is related to agreements that contain subjective language requiring additional securitization.

The remaining commitments included in the $149 million, are up to $16 million of surety bonds outstanding on behalf of the PG&E NEG that may need to be replaced; transportation and storage agreement tariff provisions that may require an additional $38 million in security; incremental security to power pools that could be as much as $11 million, and; miscellaneous guarantees for land options and other contracts of $11 million.

Liquidity Resources

The summary above identifies the potential demands on PG&E NEG's liquidity as a result of S&P's actions taken on July 31, 2002. As noted above, only the GenHoldings I equity commitment and one additional tolling agreement guarantee will be further impacted if Moody's reduces PG&E NEG's credit rating to below investment grade. The actual calls on PG&E NEG's liquidity will depend largely upon counterparties' reactions to the downgrade, the continued performance of PG&E NEG companies under the underlying agreements and the counterparties' other commercial considerations. PG&E NEG has reviewed its anticipated sources and uses of liquidity in light of the impact of the S&P downgrade and current market conditions. The following table provides an estimate of PG&E NEG's potential sources and uses of cash for the next twelve months and is based upon the assumptions regarding exposure and negotiations with and payments to counterparties and calls on PG&E NEG's liquidity set forth above (in millions):

Potential sources of cash		
Cash on hand, July 31, 2002	$	728
Estimated operating cash flow [(1)]		500

Financings	
Available capacity under two-year $500 million revolver	310
Available capacity under one-year $750 million revolver to be renewed August 22, 2002(2)	319
Available capacity under USGenNE $100 million credit facility	22
Available capacity under PG&E GTN $125 million facility (3)	125
Available capacity under other facilities with $120 million capacity	20
Facility financing on GenHoldings I for construction costs(4)	266
Refinancing of Lake Road/La Paloma required by March 31, 2003	609
Other non-recourse financings in progress (5)	125
Other sources of cash	65

Total potential sources of cash	3,089

Potential uses of cash	
Operating and debt service cost	314
Capital requirements for current construction program	974
Payment for equipment termination and repayment of equipment revolver	126
Potential collateral requirements for asset business (6)	76
Maximum cash collateral requirements on trading (7)	323
Lake Road/La Paloma loan maturity	609

Total potential uses of cash	2,422

Net potential surplus liquidity	$ 667
	======

(1) Distributions and dividends from PG&E NEG subsidiaries.

(2) One year revolver facility due for renewal on August 22, 2002: $431 million outstanding at July 31, 2002.

(3) PG&E GTN debt capacity is only available for affiliated entities to the extent PG&E NEG can meet certain

ringfencing restrictions.

(4) Five year facility, net of letters of credit and working capital to support underlying projects.

(5) Non-recourse financing for operating projects with cash to be available to PG&E NEG under current conditions.

(6) Covers pipeline transport, gas storage, and power pool collateral requirements.

(7) Exposure for all trading agreements having financial covenants for subinvestment grade entities.

PG&E NEG cannot predict with certainty the actual calls on PG&E NEG's liquidity. In the past, PG&E NEG has been able to negotiate acceptable arrangements and reduce its overall exposure to counterparties when PG&E NEG or its counterparties have faced similar situations. However, there can be no assurance that PG&E NEG could negotiate acceptable arrangements in the current circumstances.

As the table above indicates, as of July 31, 2002, PG&E NEG had $728 million in unrestricted cash and $796 million of unused credit lines and letter of credit facilities. Certain of PG&E NEG's financing instruments are due to mature in the near future. PG&E NEG is currently seeking bank commitments to renew $750 million of revolving credit that expires on August 22, 2002. As of July 31, 2002, PG&E NEG had $431 million outstanding under this facility. PG&E NEG is seeking to replace this short-term facility with a $750 million credit facility containing a $500 million two-year tranche and a $250 million 364-day tranche. In addition, PG&E NEG is seeking to refinance $609 million of debt guaranteed by PG&E NEG in connection with the Lake Road and La Paloma facilities that matures on March 31, 2003. PG&E NEG may be unable to obtain commitments for substantial portions of these financings. If PG&E NEG is unable to do so or otherwise effect acceptable arrangements, PG&E NEG's liquidity position will be materially and adversely impacted, and PG&E NEG may be unable to satisfy demands on its liquidity.

As described above, the downgrade of PG&E NEG's credit ratings impacts certain PG&E NEG's guarantees and financial arrangements that require PG&E NEG to maintain certain credit ratings from S&P and/or Moody's. With respect to certain guarantees issued by PG&E NEG and its affiliates to project lenders and tolling counterparties, the downgrade of PG&E NEG's credit rating to below investment grade by S&P triggers a requirement that PG&E NEG replace the guarantees or provide alternative collateral within a 10 to 30 day cure period. The failure of PG&E NEG to do so would entitle the holders of the guarantees to demand payment of the guaranteed amounts, or, in the case of tolling counterparties, to terminate the tolling agreements and seek damage payments to be determined by arbitration. To the extent that PG&E NEG's lenders or counterparties have the right to make such demands on PG&E NEG in an aggregate amount of $100 million or more, this would constitute an event of default under PG&E Corporation's New Credit Agreement with respect to the aggregate $1.02 billion in Tranche A and Tranche B loans outstanding thereunder, as discussed in Note 4 of the Notes to the Consolidated Financial Statements.

Subject to their respective rights as set forth in the Intercreditor and Subordination Agreement, dated as of June 25, 2002, by and between the Tranche A lenders, Tranche B lenders and certain other parties thereto (the Intercreditor Agreement), the Tranche A and Tranche B Lenders (collectively, the Lenders) would, upon notice within three days of the triggering event, have the right to declare all amounts outstanding under the New Credit Agreement to be immediately due and payable. The failure of PG&E Corporation to repay this accelerated indebtedness would entitle the Lenders, subject to the Intercreditor Agreement, to exercise certain remedies, including their rights as secured parties against their collateral, i.e., the pledged interests of PG&E Corporation in NEG, Inc., NEG LLC's pledged interests in NEG Inc., and a pledged interest in an interest reserve account with a current balance of approximately $65 million.

In the event that Moody's also downgrades PG&E NEG to below investment grade, the dual downgrade would trigger an event of default under the New Credit Agreement. The occurrence of this default would also entitle the Lenders to exercise the remedies described in the foregoing paragraph.

Further, loss of PG&E NEG's investment grade credit ratings may prevent it from obtaining financing necessary for the funding of various project-related equity commitments. A failure to fund equity commitments in an aggregate amount of $100 million or more would also cause a cross default to the PG&E Corporation New Credit Agreement.

With respect to the $280 million aggregate principal amount of 7.5% Convertible Subordinated Notes issued by PG&E Corporation pursuant to an Indenture dated as of June 25, 2002 by and between PG&E Corporation and U.S. Bank, N.A., as trustee (the Notes), if PG&E Corporation fails to pay the accelerated obligations under the New Credit Agreement as described above and such failure continues for 30 days after receipt of written notice from the trustee or holders of at least 25 percent of the aggregate principal amount of outstanding Notes, the Notes would also be in default. Thereupon, and subject to the subordination provisions of the Indenture, the trustee or the Note holders would have the right to accelerate the Notes.

If PG&E Corporation's debt obligations become subject to acceleration as described above, PG&E Corporation would attempt to negotiate this situation with its Lenders and Note holders; however, PG&E Corporation cannot predict whether, or to what extent, it would be successful in such efforts. Current PG&E Corporation cash balances are insufficient to repay the full amount of its outstanding debt.

PG&E Corporation

Operating Activities

Net cash provided by operating activities totaled $394 million and $2,852 million for the six months ended June 30, 2002, and 2001, respectively. The decrease of $2,458 million between 2002 and 2001 was partially due to the $1.1 billion income tax refund received in the six months ended June 30, 2001, with no such refund received in 2002. In 2002, PG&E NEG recorded a loss on impairment of assets of $265 million. In addition, the Utility made payments in satisfaction of certain obligations classified as liabilities subject to compromise in the six months ended June 30, 2002.

Investing Activities

Net cash used in investing activities was $1.3 billion and $1.2 billion for the six months ended June 30, 2002, and 2001, respectively. The increase of approximately $.1 billion between 2002 and 2001 was primarily due to increased capital expenditures in 2002 for improvement of the Utility's electric and gas transmission and distribution networks, along with construction on PG&E NEG's generation facilities and pipelines. Offsetting this increase in capital expenditures were proceeds of $340 million received from a sales/leaseback and a decrease in PG&E NEG's development costs and turbine prepayments in 2002.

Financing Activities

Cash generated through financing activities was $540 million and $289 million for the six months ended June 30, 2002, and 2001, respectively. Activity for 2002 resulted from the Utility's repayment of long-term debt, offset by PG&E NEG's increased borrowings under new and existing credit facilities and the proceeds that PG&E Corporation received from the refinancing of its Old Credit Agreement. See Note 4 of the Notes to the Consolidated Financial Statements for more information on PG&E NEG's new credit facilities and PG&E Corporation's refinancing of its Old Credit Agreement. A loan by PG&E Corporation in 2001 netted $906 million in proceeds, which was used with cash on hand to repay defaulted commercial paper, other loans, and dividends. In addition, the Utility and PG&E NEG paid down long-term balances in 2001.

Utility

The Utility is currently operating as a debtor-in-possession under Chapter 11 of the Bankruptcy Code. While certain pre-petition debts are stayed, the Utility does not have access to external funding from the capital markets.

Additionally, the Utility is in default under its credit facilities, commercial paper, floating rate notes, senior notes, pollution control reimbursement agreements, and medium-term notes resulting from its failure to pay certain of its obligations. The event of default under each security has been stayed in accordance with the bankruptcy proceedings. The Utility has been making the capital investment in its infrastructure out of cash on hand under supervision of the Bankruptcy Court. It is uncertain whether the Utility will be able to continue to make such necessary capital investment in the future. See Note 2 of the Notes to the Consolidated Financial Statements for a discussion of the Chapter 11 bankruptcy filing.

On March 27, 2002, the Bankruptcy Court issued an order authorizing the Utility to pay pre- and post-petition interest to holders of certain undisputed claims, including commercial paper, senior notes, floating rate notes, medium-term notes, Cumulative Quarterly Income Preferred Securities (QUIPS), prior bond claims, revolving line of credit claims, trade creditors, and certain other general unsecured creditors. Pursuant to the court's order, the Utility was required to make an initial payment of pre- and post-petition interest to holders of financial debt (excluding trade creditors and certain other general unsecured creditors) within 10 business days after the Bankruptcy Court approval of the disclosure statement related to the Utility's proposed Plan of Reorganization. The Bankruptcy Court approved the disclosure statement on April 24, 2002.

In the second quarter of 2002, the Utility paid approximately $460 million in pre- and post-petition interest related to these claims. An interest payment of $102 million also was made to holders of financial debt on July 1, 2002, for interest accrued through June 30, 2002. Interest payments will be made on a quarterly basis in the future, on October 1, January 1, April 1, and July 1, of each year. The Utility also repaid advances and interest on advances of $21 million to banks providing letters of credit backing pollution control bonds, which repayment was separately authorized by the Bankruptcy Court.

The Utility estimates that payments made to the creditors pursuant to the Bankruptcy Court's authorization could be as much as approximately $700 million through the third quarter of 2002 based on the claim amounts estimated in the Utility's disclosure statement; however, the Utility has withheld approximately $150 million of this amount because it disputes the underlying claims and will not pay interest on these disputed claims until the disputes are resolved. The actual amount of pre- and post-petition interest eventually paid may be different, depending on the amount of claims ultimately allowed by the Bankruptcy Court.

As the Utility has been accruing interest on its pre- and post-petition debt at the approved rates, the payment of such interest is not expected to have an adverse material impact on its financial condition or results of operation.

Additionally, since January 2002, the Utility has entered into agreements with additional QFs to assume their power purchase agreements, which also contained the same interest and payment terms contained in the supplemental agreements described above. At June 30, 2002, $474 million and $55 million in principal and interest, respectively, have been paid to the QFs.

As of June 30, 2002, the Utility had cash and short-term investments of $3.8 billion. The Utility believes that these funds will be adequate to maintain its continuing operations through 2002.

The following section discusses the Utility's significant cash flows from operating, investing, and financing activities for the six months ended June 30, 2002, and 2001.

Operating Activities

Net cash provided by operating activities decreased to $630 million for the six months ended June 30, 2002, from $2,664 million for the same period in the prior year. The decrease is primarily due to payments made in the six months ended June 30, 2002, pursuant to Bankruptcy Court orders, which primarily consisted of principal and interest payments to QFs and interest on financial debt and other general unsecured and secured debt. See discussion of payment of liabilities subject to compromise in Note 2 of the Notes to the Consolidated Financial Statements. Additionally, the 2000 income tax refund of $1.1 billion was received in the first quarter of 2001, with no comparable refund received in the six months ended June 30, 2002.

Investing Activities

The primary uses of cash from investing activities were additions to property, plant and equipment. While the Utility is in Chapter 11, these expenditures will be funded from cash provided by operating activities. Capital expenditures were $743 million and $575 million for the six months ended June 30, 2002, and 2001, respectively, and were primarily attributable to the improvement of the distribution and transmission networks for electric and gas operations. Planned expenditures for 2002 are $1.6 billion, and mainly include projects designed to upgrade and improve the Utility's gas and electric transmission and distribution system

Financing Activities

Net cash used by financing activities in the six months ended June 30, 2002, was $475 million, reflecting mainly the repayment of long-term debt. Repayment of matured long-term debt consisted of $333 million related to mortgage bonds, pursuant to a Bankruptcy Court order, and $141 million related to the Rate Reduction Bonds, which are held by PG&E Funding LLC, a wholly owned subsidiary of the Utility.

Except as discussed in Note 2 of the Notes to the Consolidated Financial Statements, the Utility has no plans to seek external financing alternatives as a source of funding. In addition, until its financial condition is restored, the Utility is precluded from paying dividends to its shareholders. Dividends on preferred stock are cumulative. Until cumulative dividends on preferred stock are paid, the Utility may not pay any dividends on its common stock.

Net cash used by financing activities in the six months ended June 30, 2001, was $281 million, reflecting mainly the net repayment under credit facilities and short-term borrowings of $28 million and repayment of long-term debt of $252 million. Repayment of long-term debt consisted of payments of $93 million and $18 million made prior to the filing for Chapter 11 related to maturities of mortgage bonds and medium-term notes, respectively, and payments totaling $141 million related to the Utility's Rate Reduction Bonds.

Other Commitments and Contingencies

The Utility has substantial financial commitments and contingencies in connection with its operating, investing, and financing activities. See Note 6 of the Notes to the Consolidated Financial Statements for further discussion of commitments and contingencies.

PG&E NEG

Operating Activities

PG&E NEG's funds from operations come from distributions from PG&E NEG's subsidiary companies. Cash flow distributions from subsidiaries are subject to various debt covenants, organizational by-laws, and partner approvals that can restrict these entities from distributing cash to PG&E NEG unless, among other things, debt service, lease obligations, and any applicable preferred payments are current, the applicable subsidiary or project affiliate meets certain debt service coverage ratios, a majority of the participants approve the distribution, and there are no events of default. In addition, PG&E GTN and the subsidiaries that own PG&E NEG's energy trading businesses cannot pay dividends unless the subsidiary's board of directors or board of control, including its independent director, unanimously approves the dividend payment and the subsidiary has either a specified investment grade credit rating or meets a consolidated interest coverage ratio of greater than or equal to 2.25 to 1.00 and a consolidated leverage ratio of less than or equal to 0.70 to 1.00.

During the six months ended June 30, 2002, PG&E NEG generated net cash from operations of $18 million compared to net cash from operations of $34 million for the same period in 2001, or decrease of $16 million. Increases in net income including adjustments to reconcile net income to net cash provided in operations activities, improved operating cash flow by $69 million period to period. The increase from period to period was primarily due to net price risk management activities. Offsetting this increase in cash flow from operations was a decrease due to the net effect of changes in operating assets and liabilities of $85 million period to period. Included in investing activities is a cash flow of $42 million related to the long-term receivable from New England Power Company associated with the assumption of power purchase agreements. These cash flows offset cash payments made to New England Power Company, which are reflected in operating activities.

Investing Activities

PG&E NEG's cash outflows from investing activities are primarily attributable to capital expenditures on generating and pipeline assets in construction and advanced development and turbine prepayments. During the six months ended June 30, 2002, PG&E NEG used net cash of $530 million in investing activities compared to $673 million for the same period in 2001, or a decrease of $143 million. The decrease in investing activities from period to period was primarily due to proceeds from the Attala Generating Company sale/leaseback transaction providing $340 million in the second quarter of 2002. Offsetting the sale/leaseback proceeds were increased construction expenditures of $900 million for the six months ended June 30, 2002, versus $473 million for the six months ended June 30, 2001. Advanced development and turbine prepayments were $6 million and $173 million for the six months ended June 30, 2002, and 2001, respectively. Other net expenditures were $39 million and $27 million for the six months ended June 30, 2002, and 2001, respectively. To date, PG&E NEG has made a number of commitments associated with the planned growth of owned and controlled generating facilities and pipelines. These include commitments for projects under construction, commitments for the acquisition and maintenance of equipment needed for the projects under development, payment commitments for tolling arrangements, and forward sale and purchase commitments associated with PG&E NEG's energy marketing and trading activities.

Generating Projects in Construction

PG&E NEG currently owns five generating facilities under construction. The table below outlines the expected dates that these projects will be completed.

Projects	Location	Percentage Completion	Projected In-Service Date
Athens	New York	53 %	3rd Quarter 2003
Covert	Michigan	41	3rd Quarter 2003
Harquahala	Arizona	45	3rd Quarter 2003
La Paloma	California	98	4th Quarter 2002
Mantua Creek	New Jersey	18	Undetermined

A local intervenor group has contested in federal court the issuance of a U.S. Army Corps of Engineers (ACOE) permit for the Athens facility alleging, among other things, that the ACOE violated the National Environmental Policy Act. The intervenor group sought preliminary and permanent injunctive relief. The court denied the preliminary relief and the intervenor group has appealed.

PG&E NEG has entered into a construction contract for the Mantua Creek project and released the contractor to perform early construction activities; however, full mobilization of the construction contractor has not taken place and unrestricted construction has been delayed. As of June 30, 2002, PG&E NEG had recorded assets of $244 million for Mantua Creek, representing equipment payments, construction activities, and development costs. The interconnection arrangements for the Mantua Creek project currently require that Mantua Creek achieve commercial operation by June 2004. PG&E NEG is seeking an extension of this deadline. If PG&E NEG is unable to obtain such an extension, PG&E NEG may be required to accelerate current construction activities and increase expenditures accordingly in order to preserve its investment in Mantua Creek. This acceleration of costs could put additional pressure on PG&E NEG's liquidity position. PG&E NEG continues to explore its options to find a partner for, or to finance or sell, the project.

PG&E NEG has executed construction contracts, excluded from above, for its Smithland and Cannelton projects for up to 163 megawatts (MW) at two hydroelectric facilities on the Ohio River in Kentucky. PG&E NEG had commenced construction of the first 16 MW of turbines for the Smithland project, but has suspended construction because recently stated seismic requirements caused a re-evaluation of the project's design in connection with the ACOE permit. PG&E NEG believes that satisfying the new seismic criteria will not require any design changes and the ACOE will concur. Pending such concurrence, PG&E NEG has not restarted construction.

Generating Projects in Development

- PG&E NEG has reviewed its growth plans for its electric generating business in light of the recent changes in the energy and equity markets as well as the slowdown of the U.S. economy. Further, energy prices, electric generating industry fundamentals, and financial market's support for competitive energy companies have significantly declined, thereby constraining access to funds at acceptable terms to PG&E NEG. Over supply of electric generation in the current and near future has significantly decreased the value of planned future development projects. In response to these market changes and considering the expected level of future electric generating supply, PG&E NEG has reconsidered the extent of and reduced its planned investment activities in electric generating development projects. PG&E NEG has analyzed the potential cash flow from those projects that it no longer anticipates pursuing and has recognized an impairment of the asset value it is carrying for those development projects. The aggregate pre-tax impairment charge recorded by PG&E NEG for its development assets (excluding associated equipment costs discussed below) is $19 million. The remaining asset value (recorded in Other Non Current Assets) that PG&E NEG has retained as of June 30, 2002, for its portfolio of development projects is $48 million. PG&E NEG anticipates continuing to develop these projects to completion or for future disposal and believes that their unique characteristics provide value that will enable recovery of the capitalized costs over the useful lives of the projects. PG&E NEG has no material commitments (excluding equipment costs discussed below) for the projects under continuing development.

Turbine Purchase Commitments -

To support its electric generating development program, PG&E NEG had contractual commitments and options to purchase a significant number of combustion turbines and related equipment. PG&E NEG's commitment to purchase combustion turbines and related equipment exceeds the new planned development activities discussed above. The current electric generating market is faced with an over supply of facilities in operation and in construction. The current and future market for combustion turbines and related equipment has also seen an over supply and large cancellation of turbine orders. The net realizability of PG&E NEG's investment in and future committed payments for its excess combustion turbine and related equipment portfolio, in light of current development plans, is doubtful. Based upon PG&E NEG's current development plans and analysis of future market prices for combustion turbines and related equipment, PG&E NEG has recognized a charge of $246 million. The charge consists of the impairment of previously capitalized costs associated with prior payments made under the terms of the turbine and equipment contracts in the amount of $188 million and the accrual of $58 million for future termination payments required under the turbines and related equipment contracts. Although PG&E NEG has impaired the value of these turbines and related equipment, it has not terminated its commitments or options with respect to this equipment. The remaining asset value (recorded in Other Non Current Assets) that PG&E NEG has retained as of June 30, 2002, for its investment in turbines and related equipment is approximately $33 million. These turbine and equipment commitments have been retained to support the equipment needs for PG&E NEG's current portfolio of advanced development projects discussed above. PG&E NEG and its equipment vendors have agreed to suspend any PG&E NEG payment obligations, except for $19 million, for at least the next 12 months. Thereafter, PG&E NEG must either restart equipment payments or terminate such commitments and pay the associated termination costs, if any. PG&E NEG's recorded liability reflects these termination costs.

PG&E GTN Pipeline Expansion

- PG&E GTN is in the process of completing its 2002 Expansion Project, which when completed will expand its system by approximately 217 million cubic feet (MMcf) per day. Approximately 40 MMcf per day of that expansion capacity was placed in service in November 2001 and the remaining capacity is scheduled to be placed in service by the end of 2002. The total cost of the expansion is estimated to be $122 million of which $118 million has been spent through June 30, 2002. FERC has issued a preliminary determination on non-environmental matters authorizing PG&E GTN to complete a second expansion of approximately 150 MMcf per day of additional capacity, at a cost of approximately $111 million. PG&E GTN is evaluating plans for the timing of the second expansion and may defer its construction. PG&E GTN expects to fund these expansions from cash provided by operations, external financing, and capital contributions from PG&E NEG.

PG&E GTN regularly solicits expressions of interest for the acquisition or development of additional pipeline capacity and may develop additional firm transportation capacity as sufficient demand is demonstrated. PG&E GTN has also initiated a preliminary assessment of a Washington lateral pipeline that would originate at the PG&E GTN mainline system and extend to metropolitan areas in the Pacific Northwest.

North Baja Pipeline -

PG&E NEG has begun construction of a new 500 MMcf per day gas pipeline, North Baja, to deliver natural gas to Northern Mexico and Southern California. The North Baja project is expected to be completed by the end of 2002. At June 30, 2002, PG&E NEG had spent approximately $100 million on this project. PG&E NEG owns all of the United States section of this cross-border project. PG&E NEG's share of the costs to develop this project will be approximately $140 million.

The California State Lands Commission is a defendant and, along with North Baja, is a real party in interest in an action brought by the County of Imperial and the City of El Centro alleging that the environmental impact report prepared for the North Baja pipeline in California failed to address environmental justice and other issues as required by the California Environmental Quality Act (CEQA). The claim seeks an injunction restraining construction of the pipeline, but no request for a temporary restraining order was filed. Therefore, construction of the project is underway. PG&E NEG intends to vigorously participate in the lawsuit. A hearing on the merits of the case is scheduled for August 30, 2002.

Financing Activities

PG&E NEG's cash outflows from financing activities were primarily attributable to increases in borrowings under PG&E NEG's credit facilities relating to the continuing completion of PG&E NEG's construction facilities and borrowings under construction financing. For the six months ended June 30, 2002, and 2001, PG&E NEG provided net cash flows from financing activities of $553 million and $702 million, respectively. This decrease is primarily related to the timing of construction funding needed for the Athens, La Paloma, Covert, and Harquahala projects.

RISK MANAGEMENT ACTIVITIES

PG&E Corporation and the Utility have established risk management policies that allow the use of energy, financial, and weather derivative instruments (a derivative is a contract whose value is dependent on or derived from the value of some underlying asset) and other instruments and agreements to be used to manage its exposure to market, credit, volumetric, regulatory, and operational risks. Such derivatives include forward contracts, futures, swaps, options, and other contracts.

- ♦ Forward contracts are commitments to purchase or sell energy commodities in the future.
- ♦ Futures contracts are standardized commitments to purchase or sell an energy commodity or financial instrument at a specific price and future date.
- ♦ Swap agreements require payments to or from counterparties for a quantity based upon the difference between agreed upon prices, at least one of which is an index.

- ♦ Option contracts provide the right to buy or sell energy or a financial instrument at a price.

PG&E Corporation uses derivatives for both trading (for profit) and non-trading purposes. Trading activities may be done for purposes of generating profit, gathering market intelligence, creating liquidity, maintaining a market presence, and taking a market view. Non-trading activities may be done for purposes of hedging the risks associated with an asset, liability, committed transaction, or probable forecasted transaction.

The activities affecting the estimated fair value of trading activities and the non-trading activities balance, included in net price risk management assets and liabilities, are presented below:

(in millions)	Three Months Ended June 30, 2002 (1)	Six Months Ended June 30, 2002 (1)
Fair values of trading contracts at beginning of period	$ 31	$ 33
Net gain on contracts settled during the period	34	78
Changes in fair values attributable to changes in valuation techniques and assumptions	-	-
Other changes in fair values	(66)	(112)
Fair values of trading contracts outstanding at end of period	(1)	(1)
Fair value of non-trading contracts at the end of the period	(216)	(216)
Net Price Risk Management Asset at end of period	$ (217)	$ (217)

(1)

For the three and six months ended June 30, 2002, the fair value of all new contracts when entered into was zero.

PG&E Corporation estimated the fair value of its trading contracts at June 30, 2002, using the midpoint of quoted bid and ask prices, where available, and other valuation techniques when market data was not available (e.g., illiquid markets or products). When market data is not available, PG&E Corporation utilizes alternative pricing methodologies, including, but not limited to, third-party pricing curves, the extrapolation of forward pricing curves using historically reported data, or interpolating between existing data points. Most of PG&E Corporation's risk management models are reviewed by or purchased from third-party experts with extensive experience in specific derivative applications. The fair value of trading contracts also includes deductions for time value, credit, model, and other reserves necessary to determine fair value.

The weighted average maturity of the entire portfolio of trading contracts was approximately one year as of June 30, 2002. The following table shows the fair value of PG&E Corporation's trading contracts by maturity at June 30, 2002.

	Fair Value of Trading Contracts [2]				
Source of Prices Used in Estimating Fair Value	Maturity Less than One Year	Maturity One-Three Years	Maturity Four-Five Years	Maturity in Excess of Five Years	Total Fair Value
(in millions)					
Actively quoted markets	$ 59	$ (38)	$ (7)	$ (4)	$ 10
Provided by other external sources	-	-	(43)	66	23
Based on models and other valuation methods (1)	(21)	(29)	1	15	(34)
Total Mark-to-Market	$ 38	$ (67)	$ (49)	$ 77	$ (1)

(1) In many cases, these prices are an input into option models that calculate a gross mark-to-market value from which fair value is derived.

(2)

Excludes all non-trading contracts including non-trading contracts that receive mark-to-market accounting treatment.

The amounts disclosed above are not indicative of likely future cash flows, as these positions may be impacted by changes in underlying valuations, new transactions in the trading portfolio in response to changing market conditions, market liquidity, and PG&E Corporation's risk management portfolio needs and strategies.

Market Risk

Market risk is the risk that changes in market conditions will adversely affect earnings or cash flow. Such risks include price risk, credit risk, interest rate risk, and foreign currency risk and may impact PG&E Corporation and its subsidiaries' assets and trading portfolios.

Commodity Price Risk

Commodity price risk is the risk that changes in market prices of a commodity for physical delivery will adversely affect earnings and cash flows.

Utility Electric Commodity Price Risk

In compliance with regulatory requirements, the Utility manages commodity price risk independently from the activities in PG&E Corporation's unregulated businesses. The Utility reports its commodity price risk separately for its electricity and natural gas businesses. Since January 2001, the DWR has been responsible for purchasing wholesale power for the Utility's retail electric customers on behalf of the State of California. The Utility is currently passing through revenues to the DWR based on the amount of power supplied by the DWR to cover the Utility's net open position and the per kWh rate established by the CPUC's March 21, 2002, revenue requirement decision. Future revisions to the DWR's revenue requirement as a result of, among other things, changes in the market price of electric energy, may impact the amount of revenues allocated from the Utility to the DWR. Because the Utility's electric rates are frozen, the Utility is exposed to commodity price risk as changes in the amount of revenues allocated to the DWR as pass through revenues impact the amount of remaining revenues the Utility has available to recover its generation, transmission, and distribution costs.

Under AB 1X, the DWR is prohibited from entering into new power purchase contracts and from purchasing power on the spot market after January 1, 2003. The CPUC has opened a rulemaking proceeding to consider the ratemaking mechanisms that will apply to the California IOUs' power procurement costs incurred to meet their net open position after January 1, 2003. See discussion of the Generation Procurement OIR in the Regulatory Matters section of this MD&A.

Utility Natural Gas Commodity Price Risk

Under a ratemaking method called the Core Procurement Incentive Mechanism (CPIM), the Utility recovers in retail rates the cost of procuring natural gas for its customers as long as the costs are within 99 percent to 102 percent "dead-band" of a benchmark price. The CPIM benchmark price reflects a weighting of prescribed daily and monthly gas price indices that are representative of Utility gas purchases. Ratepayers and shareholders share costs or savings outside the "dead-band" equally. In addition, the Utility has contracts for capacity on various gas pipelines. Although the Utility recovers most of the cost of the capacity contracts in retail rates, there is price risk related to the unused portions of the pipeline capacity to the extent that it is brokered at floating rates, which are reset monthly to reflect changes in commodity prices.

Under a ratemaking pact called the Gas Accord, currently scheduled to be in effect through December 2002, shareholders are at risk for any revenues from the sale of capacity on the Utility's pipelines and gas storage fields. According to the terms of the Gas Accord, a portion of the pipeline and storage capacity is sold at competitive market-based rates. The Utility is generally exposed to reduced revenues when the price spreads between two delivery points narrow. In addition, the Utility is generally exposed to reduced revenues when throughput volumes are lower than expected, primarily caused by temperature and precipitation effects or by economy-driven impacts. On October 9, 2001, the Utility filed another Gas Accord application with the CPUC requesting a two-year extension without modification to existing terms and conditions of the existing Gas Accord. In return, the Utility will maintain gas transmission and storage rates at year 2002 levels during the two-year period.

On February 26, 2002, the CPUC issued a ruling that set an expedited schedule of hearings. On May 20, 2002, on behalf of itself and a wide cross-section of parties, the Utility filed a joint motion for approval of a "Gas Accord II Settlement Agreement." If approved, the Settlement Agreement would extend terms and conditions of the existing Gas Accord for one year. The Settlement Agreement also would provide an open season for any new or relinquished Utility transmission and storage capacity for the first year of the Gas Accord II period. The Settlement Agreement would postpone until 2004 any changes that might result from litigation of issues raised by individual parties in response to the Utility's October 2001 application. On July 23, 2002, the ALJ issued a draft decision that would approve the Settlement Agreement. A decision is expected in late August 2002. The Utility cannot predict what the outcome of the final decision in this proceeding will be, or whether the outcome will have a material adverse effect on its results of operations or financial condition.

PG&E NEG Commodity Price Risk

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

Value-at-Risk

PG&E Corporation and the Utility measure commodity price risk exposure using value-at-risk and other methodologies that simulate future price movements in the energy markets to estimate the size and probability of future potential losses. Market risk is quantified using a variance/co-variance value-at-risk model that provides a consistent measure of risk across diverse energy markets and products. The use of this methodology requires a number of important assumptions, including the selection of a confidence level for losses, volatility of prices, market liquidity, and a holding period.

PG&E Corporation uses historical data for calculating the price volatility of its contractual positions and how likely the prices of those positions will move together. The model includes all derivatives and commodity instruments over the entire length of the terms of the transaction in the trading and non-trading portfolios. PG&E Corporation and the Utility express value-at-risk as a dollar amount of the potential loss in the fair value of their portfolios based on a 95 percent confidence level using a one-day holding period. Therefore, there is a 5 percent probability that PG&E Corporation and its subsidiaries' portfolios will incur a loss in one day greater than their value-at-risk. For example, if the value-at-risk is calculated at $5 million, there is a 95 percent confidence level that if prices moved against current positions, the reduction in the value of the portfolio resulting from such one-day price movements would not exceed $5 million.

The following table illustrates the daily value-at-risk exposure for commodity price risk at June 30, 2002.

(in millions)	
Utility	
Non-Trading Activities [1]	$ 3.5
PG&E NEG	
Trading Activities	3.8
Non-Trading Activities:	
Non-Trading Contracts that Receive Mark-to-Market Accounting Treatment [2]	3.9
Non-Trading Contracts Accounted for as Hedges [3]	13.9

(1)

Includes the Utility's gas portfolio only.

(2)

Includes derivative power and fuels contracts that do not qualify to be accounted for as cash flow hedges, due to certain pricing provisions, or exempted from SFAS No. 133 as normal purchases and sales.

(3)

Includes only the risk related to the financial instruments that serve as hedges and does not include the related underlying hedged item.

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

Interest Rate Risk

Interest rate risk is the risk that changes in interest rates could adversely affect earnings and cash flows. Specific interest rate risks for PG&E Corporation and the Utility include the risk of increasing interest rates on short-term and long-term debt, the risk of decreasing rates on floating rate assets which have been financed with fixed rate debt, the risk of increasing interest rates for planned new fixed long-term financings, and the risk of increasing interest rates for planned refinancing using long-term fixed rate debt. In addition, the Utility is exposed to changes in interest rates on interest accruing on loan payments and trade payables currently in default.

PG&E Corporation uses the following interest rate instruments to manage its interest rate exposure: interest rate swaps, interest rate caps, floors, or collars, swaptions, or interest rate forward and futures contracts. Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At June 30, 2002, if interest rates change by 1 percent for all variable rate debt at PG&E Corporation and the Utility, the change would affect net income by approximately $30 million and $29 million, respectively, based on variable rate debt and derivatives and other interest rate sensitive instruments outstanding.

Foreign Currency Risk

Foreign currency risk is the risk of changes in value of pending financial obligations in foreign currencies that could occur prior to the settlement of the obligation due to a change in the value of that foreign currency in relation to the U.S. dollar. The Utility and PG&E Corporation are exposed to foreign currency risk associated with foreign currency exchange variations related to Canadian denominated purchase and swap agreements. However, for the Utility changes in gas purchase costs due to fluctuations in the value of the Canadian dollar would be passed through to customers in rates. In addition, PG&E Corporation has translation exposure resulting from the need to translate Canadian-denominated financial statements of its affiliate PG&E Energy Trading Canada Corporation into U.S. dollars for PG&E NEG's Consolidated Financial Statements. PG&E Corporation and the Utility use forwards, swaps, and options to hedge foreign currency exposure.

PG&E Corporation and the Utility use sensitivity analysis to measure their foreign currency exchange rate exposure to the Canadian dollar. Based on a sensitivity analysis at June 30, 2002, a 10 percent devaluation of the Canadian dollar would be immaterial to PG&E Corporation's and the Utility's Consolidated Financial Statements.

Credit Risk

Credit risk is the risk of loss that PG&E Corporation and the Utility would incur if counterparties fail to perform their contractual obligations (accounts receivable, notes receivable and price risk management assets reflected on the balance sheet). PG&E Corporation and the Utility conduct business primarily with customers in the energy industry, and this concentration of counterparties may impact the overall exposure to credit risk in that its counterparties may be similarly affected by changes in economic, regulatory, or other conditions. PG&E Corporation and the Utility manage credit risk pursuant to their Risk Management Policies, which provide processes by which counterparties are assigned credit limits in advance of entering into significant exposure. These procedures include an evaluation of a potential counterparty's financial condition, net worth, credit rating, and other credit criteria as deemed appropriate, and are performed at least annually. Credit exposure is calculated daily and, in the event that exposure exceeds the established limits, PG&E Corporation and the Utility take immediate action to reduce exposure and/or obtain additional collateral. Further, PG&E Corporation and the Utility rely heavily on master agreements that allow for the netting of positive and negative exposures associated with a counterparty, under certain circumstances.

At June 30, 2002, PG&E Corporation had no single counterparty that represented greater than 10 percent of PG&E Corporation's net credit exposure. At June 30, 2002, the Utility had two investment grade counterparties and one below investment grade counterparty that each represented greater than 10 percent of the Utility's net credit exposure.

The schedule below summarizes the exposure to counterparties that are in a net asset position, with the exception of exchange-traded futures (the exchange provides for contract settlement on a daily basis), at June 30, 2002:

(in millions)	Gross Exposure (1)	Credit Collateral (2)	Net Exposure (2)

PG&E Corporation	$ 1,084	$ 183	$ 901
Utility (3)	143	101	42

(1)

Gross credit exposure equals fair value (adjusted for appropriate credit reserves), notes receivable, and net receivables (payables) where netting is allowed.

(2)

Net exposure is the gross exposure minus credit collateral (cash deposits and letters of credit).

(3)

The Utility's gross exposure includes wholesale activity only. Retail activity and payables prior to the Utility's bankruptcy filing are not included. Retail activity at the Utility consists of the accounts receivable from the sale of gas and electricity to residential and small commercial customers. Reserves for uncollectible accounts receivable from these customers exist and are based on their historical experience of nonpayment.

At June 30, 2002, approximately $121 million or 13 percent of PG&E Corporation's net credit exposure is to entities that have credit ratings below investment grade. Approximately $17 million or 41 percent of the Utility's net credit exposure is to below investment grade entities. Investment grade is determined using publicly available information, including S&P's rating of at least BBB-. Approximately $206 million or 23 percent of PG&E Corporation's net credit exposure at PG&E NEG is not rated. Subsequent to June 30, 2002, the credit ratings of two large counterparties (Williams Companies, Inc. and Dynegy Holdings, Inc.) were reduced to below investment grade. At June 30, 2002, PG&E Corporation's and the Utility's net exposure to these companies was $36 million and $2 million, respectively. By July 29, 2002, the net exposure to these companies was reduced to less than $1 million for both PG&E Corporation and the Utility. PG&E Corporation has regional concentrations of credit exposure to counterparties that conduct business primarily in the western United States and also to counterparties that conduct business primarily throughout North America. In addition to the Utility's concentration of credit risk due to receivables from residential and small commercial customers in northern California, the Utility has a net regional concentration of credit exposure totaling $42 million to counterparties that conduct business primarily throughout North America.

RESULTS OF OPERATIONS

The following table shows for the three months and six months ended June 30, 2002 and 2001, certain items from the accompanying Consolidated Statements of Operations detailed by Utility and PG&E NEG operations of PG&E Corporation. (In the "Total" column, the table shows the combined results of operations for those items.) The information for PG&E Corporation (the "Total" column) includes the appropriate intercompany elimination. Results of operations are discussed following this table.

PG&E National Energy Group

(in millions)	Utility	Total PG&E NEG	Integrated Energy & Marketing	Interstate Pipeline Operations	PG&E NEG Elimi-nations	PG&E Corpora-tion & Other Elimi-nations[1]	Total
Three months ended June 30, 2002							
Operating revenues	$ 2,714	$ 3,060	$ 3,011	$ 54	$ (5)	$ (22)	$ 5,752
Operating expenses	1,655	3,340	3,320	25	(5)	(17)	4,978
Operating income (loss)	1,059	(280)	(309)	29	-	(5)	774
Interest income							43
Interest expense							(361)
Other income (expenses), net							(21)
Income taxes							156
Income from continuing operations							279
Net income							218
Net cash used by operating activities							(837)
Net cash used by investing activities							(518)
Net cash provided by financing activities							668
EBITDA [2]	1,346	(245)	(285)	44	(4)	(12)	1,089
Three months ended June 30, 2001							
Operating revenues	2,309	2,753	2,676	64	13	(52)	5,010
Operating expenses	973	2,628	2,595	25	8	(38)	3,563
Operating income (loss)	1,336	125	81	39	5	(14)	1,447
Interest income							74
Interest expense							(312)
Other income (expenses), net							4
Income taxes							463
Income from continuing operations							750
Net income							750

Net cash provided by operating activities							900
Net cash used by investing activities							(532)
Net cash provided by financing activities							522
EBITDA (2)	1,550	163	108	49	6	(3)	1,710
Six months ended June 30, 2002							
Operating revenues	5,167	5,408	5,304	113	(9)	(56)	10,519
Operating expenses	2,860	5,627	5,576	51	-	(48)	8,439
Operating income (loss)	2,307	(219)	(272)	62	(9)	(8)	2,080
Interest income							85
Interest expense							(695)
Other income (expenses), net							(3)
Income taxes							557
Income from continuing operations							910
Net income							849
Net cash provided by operating activities							394
Net cash used by investing activities							(1,255)
Net cash provided by financing activities							540
EBITDA (2)	2,854	(133)	(214)	90	(9)	12	2,733
Six months ended June 30, 2001							
Operating revenues	4,871	6,959	6,826	129	4	(147)	11,683
Operating expenses	4,955	6,749	6,692	50	7	(128)	11,576
Operating income (loss)	(84)	210	134	79	(3)	(19)	107
Interest income							109
Interest expense							(559)
Other income (expenses), net							(5)
Income taxes (benefits)							(147)
Loss from continuing operations							(201)
Net loss							(201)
Net cash provided by operating activities							2,852

Net cash used by investing activities							(1,217)
Net cash provided by financing activities							289
EBITDA (2)	$ 337	$ 291	$ 192	$ 99	$ -	$ (12)	$ 616

(1) All inter-segment transactions are eliminated.

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

PG&E Corporation - Consolidated

Overall Results

PG&E Corporation's consolidated results of operations continue to be impacted by California's electric industry and the Utility's Chapter 11 filing. See the "Liquidity and Financial Resources" section of this MD&A and Note 2 of the Notes to the Consolidated Financial Statements for more information. In addition, results of operations for the Utility and PG&E NEG are discussed below.

PG&E Corporation's net income for the three months ended June 30, 2002, was $218 million, compared to net income of $750 million for the same period in 2001, representing a decrease of $532 million. The Utility and PG&E NEG accounted for $233 million and $312 million, respectively, of this decrease.

PG&E Corporation's net income for the six months ended June 30, 2002, was $849 million, compared to a net loss of $201 million for the same period in 2001. Substantially all of this change was attributable to the Utility.

PG&E Corporation and the Utility expect future earnings to continue to reflect increased volatility as a result of no longer being able to reflect the impact of generation-related regulatory balancing accounts in their financial statements, since these amounts cannot be deemed probable of recovery. As such, these amounts are accounted for as expenses and now directly impact net income.

The changes in performance for the three and six months ended June 30, 2002, and 2001, are generally attributable to the following factors:

- The Utility's electric operating revenues increased $696 million and $1.2 billion for the three and six months ended June 30, 2002, respectively, mainly due to an increase in CPUC-authorized generation-related surcharges and a decrease in the amount of pass-through revenues for electricity procured by the DWR. The amount of revenue passed through to the DWR decreased due to the overall reduction in the Utility's net short position offset by additional revenues available to pass through provided by the surcharges. Revenues collected on behalf of the DWR and the related costs are not reflected in the financial statements, as the Utility is a collection agent for the DWR.

- The Utility's cost of electric energy increased $867 million for the three months ended June 30, 2002, compared to the same period in 2001, primarily due to a 2001 reduction in previously accrued ISO related purchased power costs, and an offset in 2001 against previously expensed purchased power costs related to the market value of terminated bilateral contracts.

- The Utility's cost of electric energy decreased by $1.6 billion for the six months ended June 30, 2002, compared to the same period in the prior year, primarily due to a lower average cost of electric energy purchased, along with the first quarter 2002 net reversal of previously expensed ISO electricity costs.

- The Utility's depreciation, amortization and decommissioning increased $72 million and $126 million for the three and six months ended June 30, 2002, compared to the same periods in 2001, primarily due to the amortization of the rate reduction bond regulatory asset.

- PG&E NEG's net loss for the three and six months ended June 30, 2002, was $241 million and $204 million, respectively. Net income decreased $312 million and $329 million for the three and six months ended June 30, 2002, respectively, compared to the same periods in 2001. The 2002 results included a net loss for the cumulative effect of a change in accounting principle of $61 million, impairments and write-offs of long-term turbine prepayments and related capitalized development costs of approximately $265 million, and lower gross margins and higher operating and maintenance costs due to the timing of major overhauls on generating facilities. In addition, higher depreciation expenses were incurred, due to plants that were either acquired or began operations in 2001.

Dividends

On January 10, 2001, the Board of Directors of PG&E Corporation suspended the payment of its fourth quarter 2000 common stock dividend of $0.30 per share declared by the Board of Directors on October 18, 2000, and payable on January 15, 2001, to shareholders of record as of December 15, 2000. These defaulted dividends were later paid on March 2, 2001, in conjunction with the refinancing of PG&E Corporation obligations, discussed above under the Liquidity and Financial Resources section. No dividends were declared in 2001. The New Credit Agreement described under "Liquidity and Financial Resources" above prohibits PG&E Corporation from declaring or paying dividends until the term loans have been repaid.

Utility

Overall Results

The Utility's income available for common stock was $463 million for the three months ended June 30, 2002, compared to $696 million for the three months ended June 30, 2001. The decrease in net income was primarily due to an increase in the recorded cost of electric energy partially offset by an increase in electric revenues. Also contributing to the decrease in net income was an increase in depreciation, amortization, and decommissioning expenses.

The Utility's income available for common stock was $1,053 million for the six months ended June 30, 2002, compared to a loss of $304 million for the six months ended June 30, 2001. The increase in net income was primarily due to an increase in electric revenues and a decrease in the cost of electric energy. Other factors affecting net income between the periods were increases in operating and maintenance, depreciation, amortization, and decommissioning, and interest expenses.

Electric Operations

Electric Revenues

The following table shows the components of the Utility's electric revenue by customer class:

(in millions)	Three months ended June 30, 2002	Three months ended June 30, 2001	Six months ended June 30, 2002	Six months ended June 30, 2001
Residential	$ 814	$ 738	$ 1,759	$ 1,542
Commercial	1,115	889	1,996	1,567
Industrial	370	333	627	631
Agricultural	155	134	221	180
Total electric revenue	2,454	2,094	4,603	3,920
Direct access credits	(82)	(31)	(112)	(354)
DWR pass-through revenue	(363)	(862)	(743)	(1,153)
Miscellaneous	184	296	223	343
Total electric operating revenues	$ 2,193	$ 1,497	$ 3,971	$ 2,756

Electric revenues for the three months ended June 30, 2002, increased by $696 million, or 46 percent, from the three months ended June 30, 2001. Likewise, electric revenues for the six months ended June 30, 2002, increased by $1.2 billion, or 44 percent, from the six months ended June 30, 2001. The variances in electric revenues over both periods were significantly affected by four factors.

First, the amount of CPUC-authorized generation-related surcharges increased by $396 million and $863 million for the three and six months ended June 30, 2002, respectively, compared to the same periods in the prior year. The increases were both attributable to the fact that a three-cent surcharge, effective June 2001, was collected over the entire three and six months ended June 30, 2002, whereas it was only in effect for one month during the three and six months ended June 30, 2001.

Second, conservation efforts by the Utility's customers in response to the California energy crisis, mild weather, and higher prices from the three-cent surcharge implemented in June 2001 reduced electric sales volumes by 2.1 and 2.6 percent for the three and six months ended June 30, 2002, respectively, compared to the same periods in the prior year.

Third, the amount of pass-through revenues for electricity procured by the DWR decreased by $499 million and $410 million for the three and six months ended June 30, 2002, respectively, compared to the same periods in the prior year. Revenues collected on behalf of the DWR and the related costs are not reflected in the Utility's Consolidated Statements of Operations, as the Utility is a collection agent for the DWR. See "Electricity Purchases" under Note 2 of the Notes to the Consolidated Financial Statements. DWR pass-through revenues declined in 2002 in comparison to 2001 due to the overall reduction in the Utility's net short position covered by the DWR, slightly offset by the additional revenues available to pass through to the DWR provided by the generation-related surcharges. The Utility's net short position has been reduced in 2002 in comparison to 2001 due to (1) an increase in power supplied by Energy

Service Providers (ESP) to direct access customers; (2) an increase in the power purchased from QFs due to renegotiated payment terms through the Utility's bankruptcy proceeding; (3) an increase in the amount of power supplied by the Utility's hydro facilities and irrigation districts which were lower in 2001 due to abnormally dry conditions; and (4) a decrease in overall consumption by the Utility's customers.

Finally, there were $51 million more direct access credits for the three months ended June 30, 2002, in comparison to the same period in 2001, and $242 million less direct access credits for the six months ended June 30, 2002, in comparison to the same period in 2001. In accordance with CPUC regulations, the Utility provides an energy credit to those customers (known as direct access customers) who have chosen to buy their electric generation energy from an ESP, other than the Utility. (See discussion of Direct Access Credits in the "Regulatory Matters" section of this MD&A.) The Utility bills direct access customers based upon fully bundled rates (generation, distribution, transmission, public purpose programs, and a competition transition charge). However, direct access customers receive an energy credit equal to the per kWh average generation price multiplied by customer energy usage for the period.

The increase in direct access credits for the three months ended June 30, 2002, in comparison to the same period in the prior year was due to a significant increase in the total GWh provided to direct access customers by ESPs offset by a decrease in the average per kWh generation price. During the three months ended June 30, 2002, ESPs provided approximately 2,322 GWh to the Utility's direct access customers compared to 222 GWh provided in the three months ended June 30, 2001. Because of lower market prices for electric energy, the average, direct access credit in the three months ended June 30, 2002, was $0.035 per kWh compared to an average credit of $0.140 per kWh for the three months ended June 30, 2001.

The decrease in direct access credits for the six months ended June 30, 2002, in comparison to the same period in the prior year, was due to an increase in the total GWh provided to direct access customers by ESPs offset by a significant decrease in the average per kWh generation price. During the six months ended June 30, 2002, ESPs provided approximately 3,805 GWh to the Utility's direct access customers compared to 1,643 GWh provided in the six months ended June 30, 2001. Because of lower market prices for electric energy, the average direct access credit issued in the six months ended June 30, 2002, was $0.029 per kWh compared to an average credit of $0.215 per kWh in the six months ended June 30, 2001.

Cost of Electric Energy

The following table shows the components of the Utility's cost of electric energy:

	Three months ended June 30,		Six months ended June 30,	
(in millions)	2002	2001	2002	2001
Cost of electric energy purchased	$ 481	$ 440	$ 886	$ 2,727
Fuel used in own-generation	24	11	48	41
Adjustment to purchased power accruals	-	(261)	(595)	(261)
Market value of terminated bilateral contracts	-	(552)	-	(552)
Total cost of electric energy	$ 505	$ (362)	$ 339	$ 1,955

Average cost of electric energy purchased per kWh	$ 0.077	$ 0.093	$ 0.073	$ 0.230
Total electric energy purchased (GWh)	6,232	4,720	12,116	11,881

The cost of electric energy for the three months ended June 30, 2002, increased by $867 million, as compared to the three months ended June 30, 2001. This increase was primarily due to amounts recorded in the three months ended June 30, 2001, that (1) reduced the Utility's previously accrued ISO related purchased power costs, and (2) were recognized as an offset against previously expensed purchased power costs related to the market value of terminated bilateral contracts.

The cost of electric energy for the six months ended June 30, 2002, decreased by $1.6 billion, as compared to the six months ended June 30, 2001. The significant variance between the two periods is attributable to several factors.

First, the Utility's average cost of electric energy purchased per kWh decreased to $0.073 per kWh over the six months ended June 30, 2002, from $0.230 for the same period in 2001. The more favorable price was primarily due to the stabilization of the energy market in the second half of 2001. Also reducing the average cost of electric energy in 2002 was the impact of the Utility purchasing more electricity from QFs, bilaterals and irrigation districts and less purchases of imbalance energy (energy obtained from the market) through the PX as these amounts were purchased by the DWR.

Second, in March 2002, the CPUC approved a decision adopting a revenue requirement for the DWR for electricity costs for the two-year period ending December 31, 2002, and the FERC upheld its previous decisions requiring the DWR to pay for ISO electricity costs previously invoiced by the ISO to the Utility. As a result of the FERC and CPUC decisions, the Utility recorded a reduction to cost of electric energy of $595 million. See Note 2 of the Notes to the Consolidated Financial Statements for further discussion of the FERC and CPUC decisions.

Finally, offsetting these impacts were amounts recorded during the six months ended June 30, 2001, that (1) reduced the Utility's previously accrued ISO related purchased power costs, and (2) an offset against previously expensed purchased power costs related to the market value of terminated bilateral contracts.

Gas Operations

Gas Revenues

For the three and six months ended June 30, 2002, gas revenues decreased by $291 million and $919 million, respectively, due to a lower average price of gas, which was passed on to customers and refunded in gas revenues. The average bundled price of gas sold for the three and six months ended June 30, 2002, was $9.14 and $6.95 per thousand cubic feet (Mcf), respectively, compared to $15.61 and $12.66 per Mcf for the same periods in 2001, respectively.

Cost of Gas

For the three and six months ended June 30, 2002, the Utility's cost of gas decreased by $231 million and $832 million, respectively, principally due to the decrease in the unit cost of gas to an average of $3.41 and $2.93 per Mcf during the three and six months ended June 30, 2002, respectively, from $7.91 and $8.09 per Mcf for the same periods in 2001, respectively.

Other Operating Expenses

Operating and Maintenance

For the three months ended June 30, 2002, the Utility's operating and maintenance expenses decreased by $36 million compared to the same period in the prior year. For the six months ended June 30, 2002, the Utility's operating and maintenance expenses increased by $201 million compared to the same period in the prior year primarily due to increased spending in public purpose programs and customer related costs of $64 million, increased expense for environmental and legal related costs of $37 million, and increased administrative and general costs of $55 million. In addition, there was a general increase in incurred costs for the six months ended June 30, 2002, compared to the same period in 2001 because of cash conservation efforts that were in effect in 2001.

Depreciation, Amortization, and Decommissioning

Depreciation, amortization, and decommissioning increased by $72 million and $126 million for the three and six months ended June 30, 2002, respectively, from the same periods in 2001. The increase was mainly due to amortization of the rate reduction bond regulatory asset, which began in January 2002, and totaled $71 million and $113 million in the three and six months ended June 30, 2002. The rate reduction bond regulatory asset is discussed further in the Regulatory Matters section of this MD&A.

Interest Income

In accordance with the American Institute of Certified Public Accountants' SOP 90-7, the Utility has reported reorganization interest income separately on the Condensed Consolidated Statements of Operations. Interest income decreased by $30 million and $15 million for the three and six months ended June 30, 2002, respectively, compared to the same periods in 2001. The decrease in interest income in 2002 was due to a lower average interest rate and the liquidation of short-term investments held by the Utility during the six months ended June 30, 2002, in order to make payments for settlement of certain obligations classified as Liabilities Subject to Compromise. See discussion of Liabilities Subject to Compromise in Note 2 of the Notes to the Consolidated Financial Statements.

Interest Expense

For the three and six months ended June 30, 2002, the Utility's interest expense increased by $26 million and $88 million, respectively, compared to the same period in 2001. The increases over both periods were due to the Utility's bankruptcy proceeding which has resulted in higher negotiated interest rates and an increased level of unpaid debts accruing interest beginning in the second quarter of 2001. See discussion of interest rates in Note 2 of the Notes to the Consolidated Financial Statements.

Reorganization Fees and Expenses

In accordance with SOP 90-7, the Utility has reported reorganization fees and expenses separately on the Consolidated Statements of Operations. Such costs primarily include professional fees for services in connection with the Chapter 11 proceedings totaling $18 million and $34 million for the three and six months ended June 30, 2002.

PG&E NEG

Overall Results

PG&E NEG's net loss (after cumulative effect of a change in accounting principle) was $241 million for the three months ended June 30, 2002, a decrease of $312 million from the three months ended June 30, 2001.

PG&E NEG's pre-tax operating income decreased $405 million mainly due to impairments and write-offs of long-term turbine pre-payments and related capitalized development costs of approximately $265 million. Also contributing to the decline in pre-tax operating income were lower gross margins principally related to operations in New England and PG&E ET, higher operations and maintenance costs and higher depreciation due to the start-up of new plants. Interest expense was higher primarily due to the PG&E NEG $1 billion Senior Notes which were issued late in the second quarter of 2001.

The three and six months ended June 30, 2002, included a net loss for the cumulative effect of a change in accounting principle of $61 million. The cumulative effect was based on PG&E NEG's adoption as of April 1, 2002, of interpretations issued by the Derivatives Implementation Group (DIG), DIG C15 and DIG C16, reflecting the mark-to-market value of certain contracts that had previously been accounted for under the accrual method as normal purchases and sales.

PG&E NEG's pre-tax operating income for the six months ended June 30, 2002, compared to the same period in the prior year decreased $429 million mainly due to impairments and write-offs of long-term turbine prepayments and related capitalized development cost of approximately $265 million. Also contributing to the decline in pre-tax operating income were lower gross margins principally related to operations in New England and PG&E ET; higher operations and maintenance costs and higher depreciation due to the start-up of new plants. Offsetting these declines in pre-tax operating income was a decline in administrative and general costs primarily related to lower employee related expenses in the first quarter of 2002. Interest expense was higher due to the PG&E NEG $1 billion Senior Notes which were issued late in the second quarter of 2001.

Operating Revenues

PG&E NEG's operating revenues were $3.060 billion in the three months ended June 30, 2002, an increase of $307 million from the three months ended June 30, 2001. This increase occurred in the Integrated Energy and Marketing Activities segment with a slight decline in revenue from Interstate Pipeline Operations. PG&E NEG's wholesale energy trading revenues, included in the Integrated Energy and Marketing Activities segment, increased as a result of settled volume increases compared to the prior year. Settled volume increases were somewhat offset by declines in commodity prices and continued compressed spark spreads through the second quarter of 2002 as compared to the same period last year. Interstate Pipeline Operations operating revenues declined $10 million due to weak pricing fundamentals on gas transportation to the California and Pacific Northwest gas markets compared to the same period last year.

PG&E NEG's operating revenues were $5.408 billion in the six months ended June 30, 2002, a decrease of $1.551 billion from the six months ended June 30, 2001. These declines occurred primarily in the Integrated Energy and Marketing Activities segment. The principal driver in this decrease was in PG&E NEG's wholesale energy trading business, primarily due to a decline in commodity prices and significantly compressed spark spreads in 2002 as compared to the same period last year. Interstate Pipeline Operations operating revenues declined $16 million due to weak pricing fundamentals on gas transportation to the California and Pacific Northwest gas markets compared to the same period last year.

Operating Expenses

PG&E NEG's operating expenses were $3.340 billion in the three months ended June 30, 2002, an increase of $712 million from the same period in the prior year. These increases occurred primarily in the Integrated Energy and Marketing segment. The cost of commodity sales and fuel increased $458 million in line with, but greater than, the increases in operating revenues within the wholesale energy trading business discussed above. During the second quarter of 2002, PG&E NEG recognized an impairment charge of approximately $265 million of previously capitalized turbine prepayments and related capitalized development costs. In addition, operations, maintenance and management costs increased $20 million in the second quarter of 2002 as compared to the same period last year principally due to the operations of new plants coming on line. In addition, depreciation and amortization costs increased $4 million in the period also mainly due to the new plants coming on line. Offsetting these increases in operating costs was a decline in other operating expenses.

PG&E NEG's operating expenses were $5.627 billion in the six months ended June 30, 2002, a decrease of $1.122 billion from the same period in the prior year. These declines occurred primarily in the Integrated Energy and Marketing segment. The cost of commodity sales and fuel declined $1.389 billion in line with the declines in operating revenues within the wholesale energy trading business. Included in operating expenses is approximately $265 million of impairment charges related to previously capitalized turbine prepayments and related capitalized development cost. In addition, operations, maintenance, and management costs increased $35 million in 2002 as compared to the same period last year principally due to the operations of new plants coming on line. In addition, depreciation and amortization costs increased $14 million in the period also mainly due to new plants coming on line. Offsetting these increases in operating costs was a decline in administrative and general operating costs principally associated with lower employee related expense in the first quarter of 2002 and reduced other operating expenses in the second quarter of 2002.

REGULATORY MATTERS

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

Utility

The Utility is the only subsidiary with significant regulatory proceedings or issues at this time. The Utility's significant regulatory proceedings and issues are discussed below. Regulatory proceedings associated with electric industry restructuring are discussed further in Note 2 of the Notes to the Consolidated Financial Statements.

DWR Rate Agreement and Revenue Requirement

In January 2001, the California Legislature and the Governor of California authorized the DWR to begin purchasing wholesale electric energy on behalf of the Utility's retail customers. On February 1, 2001, the Governor signed into law California AB 1X authorizing the DWR to purchase power to meet the Utility's net open position (the amount of power needed by retail electric customers that cannot be met by utility-owned generation or power under contract to the Utility). The DWR initially purchased energy on the spot market until it was able to enter into contracts for the supply of electricity.

On February 21, 2002, the CPUC approved a decision adopting rates for the DWR that will allow the DWR to collect power charges and financing charges from ratepayers to recover the $19 billion in funds needed by the DWR to procure electricity for the California investor-owned utilities (IOUs) for the two-year period ending December 31, 2002. These funds needed by the DWR will be financed partially through a DWR bond issuance (see "DWR Bond Charges Allocation Proceeding" below) and partially through the DWR's total statewide revenue requirement that is allocated among the Utility and other California IOUs. Accordingly, the CPUC established a total statewide revenue requirement for power charges of the DWR for the two-year period ending December 31, 2002, of $9.0 billion and allocated $4.5 billion to the Utility's customers. The February 21, 2002, CPUC order noted that the DWR had been found by the FERC to be responsible for ISO imbalance energy purchases for 2001, and authorized the DWR to collect revenues from the Utility's customers sufficient to reimburse the DWR for these costs. On March 21, 2002, the

CPUC modified its February 21, 2002, revenue requirement decision, effectively lowering the amount allocated to the Utility's customers to $4.4 billion (approximately $0.092 per kWh) for the two-year period ending December 31, 2002. Based on the March 21, 2002, CPUC decision, the Utility estimates that its total DWR revenue requirement allocation for 2002 is $1.8 billion.

On May 10, 2002, the Sacramento Superior Court ruled that the DWR must hold a public hearing before determining that its power purchases are "just and reasonable" under the law that gave it authority to buy electricity. The court also ruled that the result is subject to judicial review, and that the hearings must occur before the CPUC agrees to add the DWR's power expenses to rates. However, the court stated that the revenue requirements covering the DWR's power costs for 2001-2002 approved by the CPUC would not be revoked pending completion of required public proceedings.

The February 21, 2002, DWR revenue requirement decision, as modified by the March 21, 2002, decision, requires the DWR to submit true-ups of differences between forecasted and actual data contained in its 2001-2002 revenue requirement when it submits its 2003 revenue requirement. On June 14, 2002, the DWR released its proposed 2003 revenue requirement. The proposed revenue requirement will allow the DWR to collect power charges and bond charges from ratepayers to recover the estimated $5.5 billion in revenues needed by the DWR to procure electricity for the California IOUs in 2003. In addition to its proposed 2003 revenue requirement, the DWR requested an increase in its revenue requirement for the period from January 17, 2001, through December 31, 2002, to $9.1 billion, a slight increase from the $9.0 billion originally forecast. This revenue requirement reflects actual costs through April 2002, and projected costs for the remainder of 2002.

The DWR identified a number of uncertainties that may require material changes to its 2003 revenue requirement. These uncertainties include assumptions regarding direct access participation, its role in the procurement of the California IOUs net short (including residual net short), developments with its bond financing, and potential changes in California's electricity market design proposed by the ISO.

DWR Bond Charges Allocation Proceeding

The February 21, 2002, rate agreement decision provided for future recovery by the DWR of just and reasonable bond-related costs. The decision deferred the allocation among service territories or customer classes to future CPUC decisions. On June 6, 2002, a CPUC Commissioner issued a ruling scheduling a proceeding to determine how the DWR will recover bond-related costs through bond charges imposed on the California IOUs' customers. Based on the anticipated bond sale schedule, the collection of the bond charges must commence before January 1, 2003. The proceeding will consider the amount of bond charges, how the bond charges will be allocated among the service territories and/or customer classes of the IOUs, rate design and other issues necessary to levy bond charges in an amount sufficient to provide for the timely repayment of the DWR's bond-related costs. The ruling stated that the bond charge would be imposed based on the aggregate amount of electric power sold to customers in the IOUs' service territories, regardless of whether the power is sold by the DWR, the IOUs, or ESPs. Hearings began July 30, 2002, and a final decision is expected to be issued in mid-October 2002.

On June 14, 2002, the DWR notified the CPUC of its projected $840 million in bond related charges for 2003. Bond related charges include debt service, credit enhancement and liquidity facilities charges, and costs relating to other financial instruments and servicing arrangements entered into in connection with the bonds.

Retained Generation Revenue Requirement

On April 4, 2002, the CPUC issued a decision establishing the Utility's utility retained generation (URG) revenue requirement for 2002. The decision adopted a cost-based 2002 generation revenue requirement for the Utility of $2.9 billion subject to adjustment to reflect actual recorded regulatory costs (based on recorded December 31, 2000, net regulatory value). In accordance with the decision, on April 24, 2002, the Utility filed an advice letter with the CPUC updating the adopted revenue requirement to reflect the net regulatory value of generation assets as of December 31,

2000. The CPUC approved the advice letter, effective June 3, 2002. As a result of this update, the Utility's 2002 generation revenue requirement increased by $106 million, to a total of $3 billion.

The April 4, 2002, decision allows the Utility to recover reasonable costs for retained generation incurred in 2002, subject to reasonableness review in the Utility's 2003 General Rate Case (GRC) proceeding. The decision does not change retail electric rates and the Utility does not expect it to have a current earnings impact. Instead, the decision defers consideration of future rate changes until such time as the CPUC addresses the status of the retail rate freeze. The CPUC also noted in its decision that recovery of the Utility's past unrecovered generation-related costs will not be addressed in this phase of the rate stabilization proceeding. In addition, the April 4, 2002, decision stated that the Utility's 2003 URG revenue requirement will be considered in the Utility's 2003 GRC proceeding. On June 3, 2002, the Utility filed additional testimony requesting the CPUC to authorize a $3.3 billion 2003 revenue requirement for its generation business. (See "2003 GRC" below.)

Divestiture of Retained Generation Facilities

In response to the energy crisis, in January 2001, the California Legislature passed AB 6X, which amended Public Utilities Code (PUC) Section 377 to prohibit utilities from divesting their retained generating plants before January 1, 2006. AB 6X did not amend PUC Section 367, which requires the CPUC to market value the generating assets of each utility by no later than December 31, 2001, based on appraisal, sale, or other divestiture. However, on December 21, 2001, a CPUC Commissioner issued a ruling requesting comments on the impact of AB 6X on the valuation obligation and indicating that in her opinion AB 6X supersedes PUC Section 367 to delete any requirement of market valuation for utility generation assets. On January 15, 2002, the Utility filed comments reiterating the reasons contained in previous pleadings as to why the enactment of AB 6X did not supersede or repeal the CPUC's statutory obligation to market value the Utility's generation assets by December 31, 2001. The CPUC has not yet issued a decision on this matter.

On January 17, 2002, the Utility filed an administrative claim with the State of California Victim Compensation and Government Claims Board (Board) alleging that the January 2001 enactment of AB 6X violates the Utility's contractual rights under AB 1890. The Utility's claim seeks compensation for the denial of the Utility's right to at least $4.1 billion market value of its retained generating facilities in FERC-regulated interstate power markets. On March 7, 2002, the Board formally denied the Utility's claim. The Utility has six months from the date of the denial to file suit on this claim in the California Superior Court.

The Utility cannot predict what the outcome of any of these proceedings will be or whether they will have a material adverse effect on its results of operations or financial condition.

Direct Access Suspension OIR

Until September 20, 2001, California's restructured electricity market gave customers the option of subscribing either to "bundled service" from the Utility or "direct access" service from an ESP. Customers receiving bundled services receive distribution, transmission, and generation services from the Utility. Direct access customers receive distribution and transmission service from the Utility, but purchase electricity (generation) from their ESP. On September 20, 2001, the CPUC, pursuant to AB 1X, suspended the right of retail end-use customers to acquire direct access service, thereby preventing additional customers from entering into contracts to purchase electricity from ESPs. The decision did not address agreements entered into before September 20, 2001, including renewals of such contracts or agreements, and stated that such issues would be addressed in a subsequent decision.

In the subsequent decision issued on March 21, 2002, the CPUC decided to allow all customers with direct access contracts entered into on or before September 20, 2001, to remain on direct access. However, the CPUC proposed to assess an exit fee, or non-bypassable charge, on those direct access customers to avoid a shift of costs from direct access customers to bundled service customers. On March 29, 2002, an administrative law judge (ALJ) issued a ruling finding that, in addition to the DWR's costs, the Utility's energy procurement and generation costs would be considered in determining the exit fees.

On June 6, 2002, the Utility filed testimony proposing that two non-bypassable charges (NBCs) be imposed on certain customers to recover an estimated $346 million in ongoing portfolio costs of the DWR and $409 million in ongoing Competition Transition Charges (ongoing CTC). Both NBCs would be adjusted annually and begin on January 1, 2003. First, a DWR NBC would be imposed on direct access and departing load customers to ensure that bundled service customers are indifferent to the level of direct access participation after July 1, 2001. The Utility's illustrative estimate of this charge for 2003 is 3.277 cents per kWh in 2003, declining to 1.878 cents per kWh by 2007. The Utility proposed that the actual 2003 DWR NBC be set in the 2003 DWR Annual Revenue Requirement Proceeding. The Utility proposed to collect this NBC and pass it through directly to the DWR.

Second, an ongoing CTC NBC would be imposed on all customers to recover the uneconomic costs associated with QF and other power purchase agreement contracts entered into before December 20, 1995, and employee transition costs. The Utility estimated this charge to be a half-cent per kWh and proposed that the rate for this NBC be established in this proceeding.

Finally, the Utility proposed that larger electric customers be allowed to return to bundled service at any time. However, once returned, these customers would remain on bundled service for a minimum of one year. These customers comprise approximately 95 percent of current direct access load. These larger customers would be placed on a transitional tariff for one year. Under the transitional tariff, the customer would pay the higher of the generation charge applicable to bundled service customers or the charge for energy based on the spot market price. Rules for smaller customers would need to be revisited in the event they come to represent a significant portion of direct access load in the future.

The Utility cannot predict what the outcome of any of these proceedings will be or whether they will have a material adverse effect on its results of operations or financial condition.

Hearings on this matter ended in July 2002. The outcome of this proceeding will not be known until the CPUC issues its decision, expected later this year.

Direct Access Credits

When the direct access credit was established, direct access customers paid the full bundled rate less a credit based on the Schedule PX price. Under this methodology, when the Schedule PX price exceeded the bundled rates, the direct access customer received a bill credit. As a result, during the energy crisis, direct access customers did not contribute to the Utility's transition cost recovery nor did they pay for transmission and distribution services. Under the interim direct access credit methodology in place since the PX ceased operations in January 2001, the Utility has calculated the Schedule PX price using an estimate of its cost of service for its retained generation and the Utility's generation component of the frozen rate for energy provided by the DWR. Additionally, direct access customers pay the one-cent surcharge but are exempt from the three-cent surcharge.

On May 31, 2002, the Utility filed its proposal for calculating the post-PX direct access credit that would continue allowing direct access customers to receive a credit for generation-related costs avoided as a result of their self-procurement. Specifically, the Utility proposes that the credit be based on avoided procurement costs. The Utility proposes to use the Dow Jones Daily Index as a proxy for the short-term market price paid by the DWR. On a going forward basis, the credit would be limited to the generation charge component of the Utility's total bundled rate, including surcharges, less any non-bypassable direct access charges. Consequently, direct access customers would pay at least the same non-procurement charges that are applicable to bundled customers. This prospective methodology for calculating the direct access credit would end when the CPUC ends the rate freeze and establishes rates to recover specific revenue requirements.

The Utility proposes to adjust the direct access credit retroactively to December 28, 2000, using the Dow Jones Index after January 18, 2001. The Utility proposes to limit the amount of the credit at the price cap established by the FERC.

Generation Procurement OIR

Under AB 1X, the DWR is prohibited from entering into new power purchase contracts and from purchasing power on the spot market after January 1, 2003. Under current FERC tariffs, in order to purchase power through the ISO, the IOUs must meet the ISO's creditworthiness standards for third party transactions, which require that the IOUs have an investment grade credit rating or meet certain collateral or prepayment requirements. The CPUC has initiated a proceeding which is expected to result in decisions in the second half of 2002 which will address the regulatory obligations and standards under which the IOUs may be required to resume procurement for the net open after January 1, 2003, including whether the IOUs can be required to procure power even if they are not investment grade; the allocation of power and operating responsibility for DWR's existing power contracts among the IOUs; and the reasonableness standards applicable to the IOUs procurement. In addition, it is possible that the CPUC may seek to compel each IOU to accept assignment of legal and financial responsibility for existing DWR power contracts once the IOU's investment grade credit rating is restored. The Utility believes any such compelled assignment of the DWR contracts would be unlawful, and intends to challenge vigorously any such attempt by the CPUC. If an IOU is unable to achieve investment grade credit ratings, the IOU may be required to post significant collateral or make significant cash prepayments to meet its net open position. It is possible that the Utility will be required to post collateral or make prepayments in order to resume procurement for the net open prior to regaining its investment grade credit rating, and procurement under such conditions could materially affect the Utility's earnings and the amount of cash projected to be available to pay creditors' bankruptcy claims under the Utility Plan or the Alternative Plan.

On May 1, 2002, the Utility filed testimony proposing a framework for generation procurement for 2003 and beyond. While the Utility's customer demand forecast indicates the need for substantial dispatchable capacity during the peak hours of the day, the Utility indicated that it cannot provide a definitive procurement plan and forecast of its net open position until the DWR's contractual commitments to purchase power are allocated operationally to the IOUs and a suitable exit fee as well as conditions for customers' return to bundled service are established. The Utility's filing was made subject to any limitations which might exist by virtue of its Chapter 11 debtor-in-possession status.

The Utility also stated that as to any power procurement by the Utility, the CPUC must adopt prospective standards that would be used to determine whether a reasonableness review is necessary. Only deviations from the approved purchases or procurement methodologies outlined in the procurement plan would be subject to reasonableness review. The Utility also proposed a ratemaking mechanism that provides for monthly rate changes in response to changing procurement costs.

On May 15, 2002, the CPUC issued a ruling directing the California IOUs to file supplemental testimony on Southern California Edison's (SCE's) May 6, 2002, motion requesting the CPUC issue an interim decision approving contracts to purchase electricity for 2003 and beyond. In supplemental testimony filed on May 24, 2002, the Utility indicated that SCE's request to enter into dispatchable capacity contracts through the DWR was worth exploring as an option for each of the IOUs, provided that other conditions are met. These conditions include having the DWR serve as the initial contract counterparty until the IOUs achieve investment grade status and the prompt recovery of the contract costs without after-the-fact reasonableness reviews.

On May 31, 2002, the Utility filed additional supplemental testimony further clarifying that the Utility would be willing to enter into capacity contracts, if:

- ♦ all three California IOUs received authorization at the same time;
- ♦ the Utility receives approval from the Bankruptcy Court for its resumption of procurement;

- ♦ while the DWR is the buyer under the contracts until the IOUs achieve investment grade credit status, these costs must be recovered through the DWR's revenue requirement; and
- ♦ the Utility receives authorization to engage in gas hedging transactions.

On July 19, 2002, and July 26, 2002, the Utility filed comments regarding the allocation of DWR contract power. The Utility stated that power should be allocated on a prorata basis to all customers of the IOUs, consistent with the genesis and original purpose for DWR's contracting activities.

The Utility cannot predict what the outcome of this proceeding will be or whether it will have a material adverse effect on its results of operations or financial condition.

One-Cent and Three-Cent Surcharge Revenues

On January 4, 2001, the CPUC allowed the Utility to establish an interim energy procurement surcharge of $0.010 per kWh, to remain in effect for 90 days from the effective date of the decision. On March 27, 2001, the CPUC authorized the Utility to add an average of $0.030 per kWh surcharge to its current rates and made the January $0.010 per kWh surcharge permanent. The March 27, 2001, order directed the Utility to apply these new rates solely to power costs incurred after the decision date and to reflect the new surcharges in customers' bills beginning in June 2001. For each month that the revenues from the surcharge exceed procurement costs, the Utility records a reserve for such excess. At June 30, 2002, the total amount of the reserve was approximately $75 million.

In May 2001, the CPUC authorized an "incremental system average surcharge of $0.52 per kWh" for a 12-month period beginning June 1, 2001, to recover revenues not collected between March 27, 2001, when the three-cent surcharge was approved, and June 1, 2001, when the Utility began collecting the three-cent surcharge. This "half-cent surcharge" had been projected to end May 31, 2002.

In an advice letter dated April 15, 2002, the Utility proposed to eliminate the half-cent surcharge in accordance with the May 2001 decision, and to calculate new surcharges for each rate schedule by reducing each surcharge on an equal percentage basis. On June 6, 2002, the CPUC instead issued a resolution that the Utility and SCE should continue collecting the half-cent surcharge until a later unspecified date. The CPUC ordered the Utility to record the surcharge in a balancing account beginning June 1, 2002, until further consideration by the CPUC. The Utility has recorded a reserve for the surcharge of approximately $34 million at June 30, 2002. The Utility will continue to reserve for these surcharges until further CPUC action.

On July 1, 2002, a CPUC Commissioner issued a ruling seeking comments on whether the restrictions on applying the one-cent and three-cent surcharge revenues to "ongoing procurement costs," and "future power purchases" should be modified to allow the surcharge amount to be applied to improve the financial health of the Utility. The ruling suggests that one potentially just and reasonable use of surcharge revenues would be any purpose necessary to restore financial health to the Utility. The Utility has filed comments in support of this suggestion. However, other parties have filed comments arguing that under applicable California law the surcharges may not be used in this fashion and requesting that the CPUC reduce the Utility's retail electric rates, terminate the surcharges, or change the application of the surcharge revenues in a manner which would reduce the Utility's headroom revenues. It is possible that at some future date the CPUC may change the surcharges or the application of the surcharges, either prospectively or retroactively, and any such change could materially affect the Utility's earnings. The CPUC has not set a schedule for deciding these issues, and the Utility cannot predict the outcome of these matters.

1999 General Rate Case

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

The 1999 GRC Decision, issued on February 17, 2000, ordered the CPUC's Energy Division to contract with a consultant to assess the contribution of the Utility's 1999 electric and gas distribution capital additions to system reliability, capacity, and adequacy of service. The CPUC's consultants began the engineering audit in February 2002 and are expected to issue a draft report on or before October 1, 2002. This report may recommend adjustments to the Utility's distribution rate base.

The CPUC issued a rehearing decision in October 2001 that, among other matters, orders the record in the 1999 GRC to be reopened to receive evidence of the actual level of 1998 electric distribution capital spending in relation to the forecast used to determine 1999 rates. This could possibly result in an adjustment of the adopted 1998 capital spending forecast level to conform to the 1998-recorded level.

On November 15, 2001, the Utility filed a petition for a review of the October 2001 rehearing decision with the California Court of Appeal, as well as an application for rehearing decision with the CPUC. On January 9, 2002, the CPUC denied the Utility's application for rehearing of the rehearing decision. The Court of Appeal summarily denied the Utility's petition for rehearing on May 22, 2002.

Following the 1998 capital spending rehearing and resolution of all other outstanding matters, a final result of operations analysis will be performed, and a final revenue requirement will be determined. The rehearing decision apparently intends that the revised revenue requirement would be made retroactive to January 1, 1999. The Utility does not expect a material impact on its financial position or results of operations from the remaining proceedings.

2003 GRC

On April 15, 2002, the Utility tendered its Notice of Intent (NOI) to file its 2003 GRC application. 'The NOI was submitted pursuant to the Utility's proposal, accepted by the CPUC, to resolve the CPUC's order to show cause issued on December 11, 2001, relating to the Utility's failure to submit a NOI by November 14, 2001. Pursuant to the accepted proposal, the Utility paid a voluntary fine of $48,000.

In the 2003 GRC, the CPUC will determine the amount of authorized base revenues to be collected from ratepayers to recover the Utility's basic business and operational costs for its gas and electric distribution operations for the period 2003 through 2005. These revenue requirements are determined based on a forecast of costs for 2003 (the "test year"). The NOI indicates that the Utility's GRC application will request an increase in electric and gas distribution revenue requirements of $407 million and $71 million, respectively, over the current authorized amounts to maintain current service levels to existing customers, and to adjust for wages and inflation. The Utility also has indicated that it will seek an attrition rate adjustment (ARA) increase for 2004 and 2005. The ARA mechanism is designed to avoid a reduction in earnings in years between GRCs to reflect increases in rate base and expenses.

The Utility's requested 2003 electric distribution revenue requirement increase would not increase overall bundled electric rates over their current authorized level. The Utility is seeking an increase in a typical residential customer's total gas bill of approximately 2.6 percent or $0.99 per month.

On June 3, 2002, the Utility submitted additional testimony, as directed by the CPUC in its 2002 URG proceeding, addressing the costs of operating the Utility's generation facilities and related costs. The Utility requested an increase of approximately $301 million or 10 percent over the interim 2002 URG revenue requirement authorized by the CPUC. The revenue requirement increase results from reflecting the Utility's estimated market valuation of $4.6 billion for its non-nuclear generation assets, and results in the end of the Utility's rate freeze as of August 1, 1999. (See "Divestiture of Retained Generation Facilities" above for a related discussion of the Utility's market valuation claim.)

After addressing any deficiencies that may be identified and after acceptance for filing by the Executive Director of the CPUC, the Utility must wait 60 days to file the actual GRC application with the CPUC. Hearings will then be held and a decision issued setting the 2003 revenue requirement and addressing other issues. On June 6, 2002, the CPUC issued a decision, adopting a goal of having the Utility's 2003 GRC processed by June 1, 2003. The decision does not preclude the Utility from requesting an interim relief mechanism for its 2003 GRC. The Utility intends to request that any revenue requirement change be effective January 1, 2003.

The Utility cannot predict what amount of revenue requirements, if any, the CPUC will authorize for the 2003 through 2005 period, nor when such decision will be made.

2002 ARA Request

In light of the postponement of a 2002 GRC, on November 9, 2001, the Utility informed the CPUC of its need for a 2002 Attrition Revenue Adjustment (ARA) to allow for recovery of escalating costs of providing electric and gas distribution services. On January 17, 2002, the Utility requested an interim decision to ensure that whatever ARA adjustment was ultimately approved would be effective as early in 2002 as possible.

On April 22, 2002, the CPUC issued a decision authorizing the Utility's request for interim relief. The decision sets the effective date of interim relief at either the effective date of the interim decision, or such later date as may be determined by the CPUC. The decision provides the Utility the opportunity to present arguments regarding which interim relief date should be adopted when it submits substantive arguments for adoption to its 2002 ARA request. On June 11, 2002, the Utility filed its 2002 ARA application. In its application, the Utility requests an increase of $76.7 million to its electric distribution revenue requirement, and an increase of $19.5 million to its gas distribution revenue requirement. A prehearing conference will be held on August 26, 2002, and a final decision is not expected before the last quarter of 2002.

FERC Prospective Price Mitigation Relief

The FERC issued a series of significant orders in the spring and summer of 2001 that prescribed prospective price mitigation relief for the extreme wholesale energy prices which were in evidence in 2000 and 2001. On April 26, 2001, the FERC issued an order that prescribed price mitigation for those hours in which the ISO declared an emergency. The order also imposed a requirement that effectively all generators in California offer available generation for sale to the ISO's real-time energy market during all hours. While the Utility recognized the importance of the FERC's action, it sought rehearing of the April 26, 2001, order on the premise that the price mitigation methodology could be made more comprehensive, both in terms of the hours in which it was to be applied and the types of transactions that it covered. The Utility also has sought rehearing of the FERC orders on price mitigation on grounds that recent disclosure of Enron trading strategies and similar activities by others should be considered by the FERC to increase the amount of refunds owed or the time period for which refunds are due.

In July 2002, the FERC modified the maximum market-price methodology for spot market sales in all hours from a variable formula based cap to a fixed price cap of $91.87 per megawatt-hour (MWh). This market clearing price limit and other FERC ordered mitigation measures are scheduled to expire on September 30, 2002.

On July 17, 2002, the FERC further ordered prospective price mitigation for the wholesale spot markets throughout both California and the Western Electricity Coordinating Council (WECC, formerly known as Western Systems Coordinating Council) that established the current mitigation methodology going forward. Features of this current methodology, effective October 1, 2002, include:

1. a bid cap of $250 per MWh;
2. the reaffirmation of FERC's requirement that effectively all generators in California offer available generation for sale to the ISO's real-time energy market; and

3. adoption of the ISO's Automatic Mitigation Procedures (AMP) using conduct, price and impact screens that will, when triggered, reduce bids to a reference price for each generator in California to be determined by an independent organization. The AMP will apply only to bids above the cap of $91.87 per MWh.

The FERC also directed the ISO to use Reliability Must Run (RMR) units to alleviate intra-zonal congestion, and then apply AMP procedures if local market power still exists. The FERC also ordered the ISO to file its integrated day-ahead market proposal, ancillary service reforms, and hour-ahead and real-time reforms by October 21, 2002, for implementation by January 1, 2003. The FERC also placed a bid cap of $30 per MWh on negative decremental bids.

In June and July 2001, the FERC's chief ALJ conducted settlement negotiations among power sellers, the State of California, and the California investor-owned utilities in an attempt to resolve disputes regarding past power sales. The negotiations did not result in a settlement, but the judge recommended that the FERC conduct further hearings to determine possible refunds and what the power sellers and buyers are each owed. These hearings, in which the State of California is seeking up to $8.9 billion in refunds for electricity overcharges on behalf of buyers included in investor-owned utilities, are currently scheduled to start in August 2002. The Utility does not believe these matters will be resolved until late 2002 or early 2003, nor can it predict whether a refund will be ordered or the amount the Utility might receive. In connection with this proceeding, on August 17, 2001, the ISO submitted data indicating that a PG&E NEG affiliate, PG&E Energy Trading-Power, L.P. (ET Power) may be required to refund approximately $26 million. However, the FERC has indicated that unpaid amounts owed by the ISO and the PX may be used as offsets to any refund obligations. Potential offsets would significantly reduce any potential refund required to be made by ET Power. Finalization of any refunds and offsets are subject to the ongoing FERC proceeding.

Cost of Capital Proceedings

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

On May 8, 2002, the Utility filed an application with the CPUC to establish its authorized ROR for electric and gas distribution operations for 2003. The application requests a ROE of 12.5 percent and 12.25 percent for electric and gas distribution operations, respectively. The application also requests an authorized ROR of 9.88 percent and 9.76 percent for electric and gas distribution operations, respectively. If granted, the requested ROR would increase 2003 electric and gas distribution revenues by approximately $111.2 million and $22.3 million, respectively. Hearings are set for mid-August 2002.

FERC Transmission Rate Cases

Electric transmission revenues and both wholesale and retail transmission rates are subject to authorization by the FERC. The FERC has not yet acted upon a settlement filed by the Utility that, if approved, would allow the Utility to recover $391 million in electric transmission rates for the 14-month period of April 1, 1998, through May 31, 1999. During this period, somewhat higher rates have been collected, subject to refund. A FERC order approving this settlement is expected by the end of 2002. The Utility has accrued $29 million for potential refunds related to the 14-month period ended May 31, 1999.

In July 2001, the FERC approved a settlement that permits the Utility to collect $262 million annually (net of the 2002 Transmission Revenue Balancing Account) in electric transmission rates beginning on May 6, 2001. The level of transmission rates relative to previous time periods is due to unusually large balances paid to the Utility by the ISO for congestion management charges and other transmission-related services billed by the ISO that are booked in the Transmission Revenue Balancing Account. These balances paid by the ISO are offset against the Utility's transmission revenue requirement. The Utility does not expect the outcome of these settlements to have a material adverse effect on its results of operations or financial condition.

In March 2001, the Utility filed at the FERC to increase its power and transmission-related rates charged to the Western Area Power Administration (WAPA). The majority of the requested increase is related to passing through market power prices billed to the Utility by the ISO and others for services, which apply to WAPA under a pre-existing contract between the Utility and WAPA. On September 21, 2001, the FERC ALJ issued an Initial Decision denying the Utility the ability to increase the rates as requested. On October 24, 2001, the FERC confirmed the ALJ's Initial Decision in its entirety. The FERC denied the Utility's November 21, 2001, request for rehearing, and that decision has been appealed to the U.S. Court of Appeals for the D.C. Circuit. Pending a decision from the Court, until December 31, 2004, the date the WAPA contract expires, WAPA's rates will continue to be calculated on a yearly basis pursuant to the formula specified in WAPA's contract. Any revenue shortfall or benefit resulting from this contract is included in rates through the end of the contract period as a purchased power cost. The difference between the Utility's cost to meet its obligations to WAPA and revenues it receives from WAPA cannot be accurately estimated since both the purchase price and the amount of energy that WAPA will need from the Utility through the end of the contract are uncertain.

Scheduling Coordinator Costs

In connection with electric industry restructuring, the ISO was established to provide operational control over most of the state's electric transmission facilities and to provide comparable open access for electric transmission service. The Utility serves as the scheduling coordinator to schedule transmission with the ISO to facilitate continuing service under existing wholesale transmission contracts that the Utility entered into before the ISO was established. The ISO bills the Utility for providing certain services associated with these contracts. These ISO charges are referred to as the "scheduling coordinator (SC) costs."

As part of the Utility's Transmission Owner rate case filed at the FERC, the Utility established the Transmission Revenue Balancing Account (TRBA) to record these SC costs in order to recover these costs through transmission rates. Certain transmission-related revenues collected by the ISO and paid to the Utility are also recorded in the TRBA. Through June 30, 2002, the Utility had recorded approximately $102 million of these SC costs in the TRBA. The Utility has also disputed approximately $27 million of these costs as incorrectly billed by the ISO. Any refunds that ultimately may be made by the ISO would be credited to the TRBA.

In September 1999, an ALJ of the FERC issued a proposed decision denying recovery of these SC costs from retail and new wholesale customers in the TRBA. The ALJ indicated that the Utility should try to recover these costs from existing wholesale customers. The proposed decision is subject to change by the FERC in its final decision. The FERC is expected to issue a final decision in 2002. In January 2000, the FERC accepted a proposal by the Utility to establish the Scheduling Coordinator Services (SCS) Tariff. The SCS Tariff would serve as a back-up mechanism for recovery of the SC costs from existing wholesale customers if the FERC ultimately decides that these costs may not be recovered in the TRBA. The FERC also conditionally granted the Utility's request that the SCS Tariff be effective retroactive to March 31, 1998. However, the FERC suspended the procedural schedule until the final decision is issued regarding the inclusion of SC costs in the TRBA. The Utility has accrued a $64 million reserve in connection with the potential unrecoverable costs.

The Utility does not expect the outcome of this proceeding to have a material adverse effect on its results of operations or financial condition.

Gas Accord II Application

Under a ratemaking pact called the Gas Accord, implemented in March 1998, the Utility's gas transmission and storage services were separated or unbundled from its distribution services, and the terms of service and rate structure for gas transportation were changed. The Gas Accord also allows core customers to purchase gas from competing suppliers, establishes an incentive mechanism whereby the Utility recovers its core procurement costs, and establishes gas transmission rates through 2002 and gas storage rates through March 2003. On October 9, 2001, the Utility filed an application with the CPUC, known as Gas Accord II, requesting a two-year extension, without modification to the terms and conditions of the existing Gas Accord. As part of this application requesting the two-year extension, the Utility proposed to maintain gas transmission and storage rates at current levels during the two-year extension period.

On February 26, 2002, the CPUC issued a ruling that set an expedited schedule of hearings. On May 20, 2002, on behalf of itself and a wide cross-section of parties, the Utility filed a joint motion for approval of a "Gas Accord II Settlement Agreement (Settlement Agreement)." If approved, the Settlement Agreement would extend terms and conditions of the existing Gas Accord for one year. The Settlement Agreement also would provide an open season for any new or relinquished Utility transmission and storage capacity for the first year of the Gas Accord II period. The Settlement Agreement would postpone until 2004 any changes that might result from litigation of issues raised by individual parties in response to the Utility's October 2001 application. On July 9, 2002, the ALJ issued a ruling modifying the procedural schedule, delaying hearings until after the CPUC rules on the Settlement Agreement. On July 23, 2002, the ALJ issued a draft decision approving in large part the Settlement Agreement. A final decision is expected in late August 2002. The Utility does not expect the outcome of the final decision in this proceeding will have a material adverse effect on its results of operations or financial condition.

El Paso Capacity Decision

In May 2002, a FERC order directed El Paso Natural Gas Company (El Paso) to change the way it allocates space on its pipeline. The order required El Paso's East of California customers to convert their capacity rights from unlimited "full requirement" to a limited contract demand amount of firm capacity. These customers must decide by July 31, 2002, how much El Paso capacity rights they will need in contract demand contracts and how much capacity they will relinquish.

In response, on July 17, 2002, the CPUC issued a decision that requires California IOUs to sign up for El Paso pipeline capacity relinquished by the shippers and not subscribed to by replacement shippers serving California, and pre-approves such costs as just and reasonable. The utilities are required to purchase a proportionate amount of the released capacity. The decision stated that this requirement would spread El Paso reservation charges over as many ratepayers as possible to minimize the impact on any particular IOU's customers. The decision also addressed current capacity issues. The decision ordered that current capacity held by the utilities on any interstate pipeline cannot be turned back and must be retained for the benefit of California ratepayers. Any capacity in excess of the IOU's need should be released under short-term capacity release arrangements. The IOUs' short-term capacity releases ensure that the capacity is not withheld from the California market. The decision also finds that to the extent the IOUs comply with the decision, they shall also receive full cost recovery for their costs associated with existing capacity contracts.

In a future proceeding, the CPUC will address other issues that relate to these proposed rules. Issues to be resolved include cost allocation of turned back capacity among the California IOUs' customers for recovery, capacity releases, and details concerning the guaranteed recovery in rates of the IOUs' costs for subscription to interstate pipeline capacity.

In 1995, the CPUC issued a decision concluding that it was unreasonable for the Utility to commit to purchase gas pipeline capacity from Transwestern Pipeline Company (Transwestern). The decision ordered that costs for the capacity commitments in subsequent years of the contract be disallowed unless the Utility can demonstrate that the benefits of the capacity commitment outweigh the costs. Under the Gas Accord, the Utility could not recover any costs paid to Transwestern through 1997 and would have limited recovery during the period 1998 through 2002. In view of the El Paso decision, which allows for recovery of existing capacity contracts, the Utility expects to fully recover its future purchases of gas pipeline capacity, resulting in additional revenues of approximately $90 million over the remaining contract period that ends in March of 2007.

Rate Reduction Bonds

AB 1890 mandated a rate freeze and a 10 percent rate reduction for residential and small commercial customers. Under the original mandate, the Utility expected the 10 percent rate reduction to end the earlier of March 31, 2002, or when its transition costs were fully recovered.

To pay for the 10 percent rate reduction, the Utility financed $2.9 billion of its transition costs with the proceeds 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 these transition costs until after the transition period. The transition costs financed by the bonds were deferred to the Rate Reduction Bond regulatory asset and are to be recovered in the future through separate NBCs mandated by AB 1890 called Fixed Transition Amount (FTA) charges. The Utility stopped deferring transition costs to the Rate Reduction Bond regulatory asset in the first quarter of 2002, when the financed transition costs in the regulatory asset equaled the remaining principal balance of the Rate Reduction Bonds. At this time, the Utility started amortizing the regulatory asset concurrent with the amortization of the Rate Reduction Bond principal. At June 30, 2002, the Rate Reduction Bond regulatory asset amounted to $1,523 million. The Utility recorded net amortization expense of $71 million for the three months ended June 30, 2002.

Annual Earnings Assessment Proceeding (AEAP)

The Utility administers general and low-income energy efficiency programs funded through a public goods component in customers' rates. The Utility has been authorized to receive incentives for successful past programs, including incentives based on a portion of the net present value of the savings achieved by the programs, incentives based on accomplishing certain tasks, and incentives based on expenditures. Annually, the Utility files an earnings claim in the AEAP, a forum for stakeholders to comment on and for the CPUC to verify the Utility's claim. On March 21, 2002, the CPUC issued a decision that prospectively eliminated the opportunity for shareholder incentives in connection with the California IOUs' 2002 energy efficiency programs.

In May 2000 and 2001, the Utility filed its annual AEAP applications, which establish incentives to be collected during 2001 and 2002, respectively. The CPUC has combined the two proceedings and delayed action on them. The Utility's outstanding claim for shareholder incentives in this combined proceeding is approximately $80 million. The Utility has not included any earnings associated with incentives in the Utility's Consolidated Statements of Operations.

On May 1, 2002, the Utility filed its 2002 AEAP application requesting $25.6 million in shareholder earnings. In its filing, the Utility proposed to increase its electric and gas distribution revenue requirements by $15.8 million and $3.3 million, respectively, and to recover $6.5 million from electric Public Goods Charge funds. The electric distribution increase would be incorporated into rates established in the next Revenue Adjustment Proceeding (RAP). The gas distribution amount would be incorporated into rates established in the next gas transportation rate change, such as the Biennial Cost Allocation Proceeding.

On March 13, 2002, an ALJ for the CPUC requested comments on whether incentives adopted for pre-1998 energy efficiency programs should be reduced or eliminated. The CPUC has not yet ruled on the comments.

The Utility cannot predict what the outcome of these proceedings will be, or whether the outcome will have a material adverse effect on its results of operations or financial condition.

Baseline Allowance Increase

On April 9, 2002, the CPUC issued a decision that required the Utility to increase baseline allowances for certain residential customers by May 1, 2002. An increase to a customer's baseline allotment increases the amount of their monthly usage that will be covered under the lowest possible rate and that is exempt from surcharges. The decision deferred consideration of corresponding rate changes until Phase 2 of the proceeding and ordered the utilities to track the under-collections associated with their respective baseline quantity changes in an interest-bearing balancing account. The Utility estimates the annual revenue shortfall to be approximately $96 million for electric, and $6 million for gas. The Utility cannot predict what the outcome of Phase 2 will be, nor can it conclude that recovery of the electric related balancing account is probable. Therefore, the revenue shortfall will be charged to earnings and reduce revenue available to recover previously written-off under-collected purchase power costs and transition costs.

Nuclear Decommissioning Cost Triennial Proceeding Application

On March 15, 2002, the Utility filed its 2002 Nuclear Decommissioning Cost Triennial Proceeding (NDCTP) application, seeking to increase its nuclear decommissioning revenue requirements for the years 2003 through 2005. The Utility seeks recovery of $24 million in revenue requirements relating to the Diablo Canyon Nuclear Decommissioning Trusts and $17.5 million in revenue requirements relating to the Humboldt Bay Power Plant Decommissioning Trusts. The Utility also seeks recovery of $7.3 million in CPUC-jurisdictional revenue requirements for Humboldt Bay Unit 3 SAFSTOR operating and maintenance costs, and escalation associated with that amount in 2004 and 2005. The Utility proposes continuing to collect the revenue requirement through an NBC in electric rates, and to record the revenue requirement and the associated revenues in the Nuclear Decommissioning Adjustment Mechanism Balancing Account. Until post-freeze ratemaking is implemented, the increase in revenue requirements would reduce the amount of revenues available to offset electric generation costs. The CPUC held a prehearing conference on the application and established a schedule that should result in hearings in September 2002 and a final decision during April 2003.

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

In August 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 143, "Accounting for Asset Retirement Obligations." This Statement is effective for fiscal years beginning after June 15, 2002. SFAS No. 143 provides accounting requirements for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. Under the Statement, the asset retirement obligation is recorded at fair value in the period in which it is incurred by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value in each subsequent period and the capitalized cost is depreciated over the useful life of the related asset. PG&E Corporation is currently evaluating the impact of SFAS No. 143 on its Consolidated Financial Statements.

In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections." This Statement eliminates the current requirement that gains and losses on debt extinguishment must be classified as extraordinary items in the income statement. Instead, such gains and losses will be classified as extraordinary items only if they are deemed to be unusual and infrequent, in accordance with the current GAAP criteria for extraordinary classification. In addition, SFAS No. 145 eliminates an inconsistency in lease accounting by requiring that modifications of capital leases that result in reclassification as operating leases be accounted for consistent with sale-leaseback accounting rules. This Statement also contains other nonsubstantive corrections to authoritative accounting literature. The changes related to debt extinguishment will be effective for fiscal years beginning after May 15, 2002, and the changes related to lease accounting will be effective for transactions occurring after May 15, 2002. Adoption of this statement will not have any immediate effect on the Consolidated Financial Statements of PG&E Corporation or the Utility. PG&E Corporation will apply this guidance prospectively.

On June 20, 2002, the FASB's Emerging Issues Task Force (EITF) reached a partial consensus on Issue No. 02-03, "Recognition and Reporting of Gains and Losses on Energy Trading Contracts under EITF Issues No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," and No. 00-17, "Measuring the Fair Value of Energy-Related Contracts in Applying Issue No. 98-10." The EITF concluded that, effective for periods ending after July 15, 2002, mark-to-market gains and losses on energy trading contracts (including those to be physically settled) must be retroactively presented on a net basis in earnings. Also, companies must disclose volumes of physically settled energy trading contracts. PG&E Corporation is evaluating the impact of this new consensus on the presentation of its Consolidated Statement of Operations, but believes it will have a material impact on total revenues and expenses. The consensus will have no impact on net income.

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities," which addresses accounting for restructuring and similar costs. SFAS No. 146 supersedes previous accounting guidance, principally Emerging Issues Task Force Issue (EITF) No. 94-3. PG&E Corporation will adopt the provisions of SFAS No. 146 for restructuring activities initiated after December 31, 2002. SFAS No. 146 requires that the liability for costs associated with an exit or disposal activity be recognized when the liability is incurred. Under EITF No. 94-3, a liability for an exit cost was recognized at the date of the Company's commitment to an exit plan. SFAS No. 146 also establishes that the liability should initially be measured and recorded at fair value. Accordingly, SFAS No. 146 may affect the timing of recognizing future restructuring costs as well as the amounts recognized.

NEW ACCOUNTING POLICIES

On April 1, 2002, PG&E Corporation implemented two interpretations issued by the FASB's DIG. DIG Issues C15 and C16 changed the definition of normal purchases and sales included in 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" (collectively, SFAS No. 133). Previously, certain derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business were exempt from the requirements of SFAS No. 133 under the normal purchases and sales exception, and thus were not marked to market and reflected on the balance sheet like other derivatives. Instead, these contracts were recorded on an accrual basis.

DIG C15 changed the definition of normal purchases and sales for certain power contracts. DIG C16 disallowed normal purchases and sales treatment for commodity contracts (other than power contracts) that contain volumetric variability or optionality. PG&E NEG determined that five of its derivative commodity contracts for the physical delivery of power and purchase of fuel no longer qualified for normal purchases and sales treatment under these interpretations. Beginning April 1, 2002, these five contracts were required to be recorded on the balance sheet at fair value and marked to market through earnings. Three of the contracts had positive market values and resulted in pre-tax income of $125 million. The remaining two contracts had negative market values that resulted in a pre-tax charge of $127 million. The cumulative effects of implementation of these accounting changes at April 1, 2002, resulted in PG&E Corporation recording price risk management assets of $37 million, price risk management liabilities of $255 million, and a reduction of out-of-market obligations of $129 million reclassified to net price risk management liabilities.

One of the contracts with a positive market value included above is for a power sales contract at a partnership in which PG&E NEG has a 50% ownership interest. PG&E NEG reflects its investment in this partnership on an equity basis (Investments in Unconsolidated Affiliates). Upon adoption of C15 and C16, PG&E NEG recognized its equity share of the gain from the cumulative change in accounting method and correspondingly increased the book value of its equity investment in the partnership. However, the future net cash flows from the partnership do not support the increased equity investment balance. Therefore, PG&E NEG has recognized an impairment charge of $101 million to reduce its equity-method investment to fair value. The cumulative effect of the change in accounting principle for DIG C15 and C16 was a net charge of $61 million, after-tax, and included the recognition of the fair market value of the five contracts impacted by C15 and C16 and the resulting impairment charge. The Utility was not impacted by these accounting changes.

Implementation of these accounting changes will not impact the timing and amount of cash flows associated with the affected contracts; however, it will impact the timing and magnitude of future earnings. Future earnings will reflect the gradual reversal of the assets and liabilities recorded upon adoption over the contracts' lives, as well as any prospective changes in the market value of the contracts. The net reversal of these assets and liabilities (using the April 1, 2002, implementation amounts and assuming no market price changes) would provide approximately $44 million of pre-tax net income over the next five years, and a total of $45 million of pre-tax net income thereafter, with no offsetting expenses. However, any prospective changes in the market value of these contracts could result in significant volatility in earnings. Value-at-risk provides a measure of PG&E NEG's exposure to volatility in future earnings related to the market risk associated with these contracts. PG&E NEG estimates a combined value-at-risk for these contracts of $3.9 million, based on a 95 percent confidence level using a one-day liquidation period. Over the total lives of the contracts, there will be no net impact to total operating results after netting the cumulative effect of adoption against the subsequent years' impacts (assuming that the affected contracts are held to their expiration).

CRITICAL ACCOUNTING POLICIES

Effective 2001, PG&E Corporation and the Utility adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Hedging Activities" (collectively, SFAS No. 133), which required all financial instruments to be recognized in the financial statements at market value. See further discussion in "Quantitative and Qualitative Disclosure about Market Risk" above, and Notes 1 and 3 of the Notes to the Consolidated Financial Statements. PG&E NEG accounts for its energy trading activities in accordance with EITF 98-10 and SFAS No. 133, which require certain energy trading contracts to be accounted for at fair values using mark-to-market accounting. EITF 98-10 also allows two methods of recognizing energy trading contracts in the income statement. The "gross" method provides that the contracts are recorded at their full value in revenues and expenses. The other method is the "net" method in which revenues and expenses are netted and only the trading margin (or when realized sometimes trading loss) is reflected in revenues. PG&E NEG uses the gross method for those energy trading contracts for which PG&E NEG has a choice. However, as discussed above, beginning in the third quarter of 2002, PG&E NEG will be required under EITF 00-17, to use the net method of presentation.

PG&E Corporation also has derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business. These derivatives are exempt from the requirements of SFAS No. 133, under the normal purchases and sales exception, and are not reflected on the balance sheet at fair value. See further discussion in "New Accounting Policies" above.

PG&E Corporation and the Utility apply SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," to their regulated operations. This standard allows capitalizing of a cost that otherwise would be charged to expense if it is probable that the cost is recoverable through regulated rates. This standard also allows amounts to be recorded as liabilities for rate actions of a regulator that will result in amounts that are to be credited to customers through the ratemaking process. At June 30, 2002, the Utility reported regulatory assets of $2.2 billion and regulatory liabilities of $1.1 billion.

PG&E Corporation's commodities and service revenues derived from power generation are recognized upon output, product delivery, or satisfaction of specific targets. Regulated gas and electric revenues are recorded as services are provided based upon applicable tariffs and include amounts for services rendered but not yet billed. Unbilled revenues amounted to $512 million at June 30, 2002.

The Utility's 2001 financial statements are presented in accordance with SOP 90-7, which is used for entities in reorganization under the Bankruptcy Code. As of June 30, 2002, the Utility reported liabilities subject to compromise of $9.2 billion. See Note 2 of the Notes to the Consolidated Financial Statements for further discussion.

PG&E Corporation and the Utility have recorded an environmental remediation liability associated with both owned and divested generation facilities, gas sites, and compressor stations. At June 30, 2002, this liability amounted to $312 million. See Note 6 of the Notes to the Consolidated Financial Statements for further discussion.

The amount of headroom recognized by the Utility can fluctuate materially due to many factors, including the outcome of regulatory proceedings and other regulatory actions, sales volatility, and the impact of the end of the rate freeze period and post-rate freeze ratemaking, and the impact of the proceedings to determine the level of revenue requirements for the DWR's power procurement costs. For the six months ended June 30, 2002, total headroom recorded was $542 million. See Note 2 of the Notes to the Consolidated Financial Statements.

See Note 1 of the Notes to the Consolidated Financial Statements for further discussion of accounting polices and new accounting developments.

TAXATION MATTERS

The Internal Revenue Service (IRS) has completed its audit of PG&E Corporation's 1997 and 1998 consolidated U.S. federal income tax returns and has assessed additional federal income taxes of $66.5 million. PG&E Corporation has filed protests contesting certain adjustments made by the IRS in that audit and is currently discussing those adjustments with the IRS' Appeals Office. The IRS is also auditing PG&E Corporation's 1999 and 2000 consolidated U.S. federal income tax returns, but has not issued its final report. In addition, PG&E Corporation is utilizing the IRS pre-filing agreement process to seek advance determinations of a 2001 tax return position with respect to energy tax credits. The resolution of these matters with the IRS is not expected to have a material adverse effect on PG&E Corporation's earnings. All of PG&E Corporation's federal income tax returns prior to 1997 have been closed.

In addition, California and certain other state tax authorities are currently auditing various state tax returns. The results of these audits are not expected to have a material adverse effect on PG&E Corporation's earnings.

ENVIRONMENTAL AND LEGAL MATTERS

PG&E Corporation and the Utility are subject to laws and regulations established to both maintain and improve the quality of the environment. Where PG&E Corporation's and the Utility's properties contain hazardous substances, these laws and regulations require PG&E Corporation and the Utility to remove those substances or remedy effects on the environment. Also, in the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits. See Note 6 of the Notes to the Consolidated Financial Statements for further discussion of environmental matters and significant pending legal matters.

ITEM 3: QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

PART II. OTHER INFORMATION

ITEM 1 - LEGAL PROCEEDINGS

Pacific Gas and Electric Company Bankruptcy

As previously disclosed in PG&E Corporation's and the Utility's Annual Report on Form 10-K for the year ended December 31, 2001, and Quarterly Report on Form 10-Q for the quarter ended March 31, 2002, on April 6, 2001, Pacific Gas and Electric Company (Utility) filed a voluntary petition for relief under the provisions of Chapter 11 of the United States Bankruptcy Code (Bankruptcy Code) in the United States Bankruptcy Court for the Northern District of California (Bankruptcy Court). On June 17, 2002, the disclosure statements relating to the proposed plan of reorganization sponsored by PG&E Corporation and the Utility (Utility Plan) and an alternative proposed plan of reorganization sponsored by the California Public Utilities Commission (CPUC) were sent to creditors entitled to vote on the plans. All ballots must be received by August 12, 2002. Neither plan will become effective unless it is confirmed by the Bankruptcy Court.

On May 7, 2002, the CPUC, the City and County of San Francisco (City), and the California Attorney General (AG) filed a motion to dismiss PG&E Corporation's and the Utility's appeal of the Bankruptcy Court's March 18, 2002 order to the U. S. District Court for the Northern District of California. The Bankruptcy Court's March 18, 2002 order disapproved PG&E Corporation's and the Utility's December 19, 2001 disclosure statement for the reasons set forth in the Bankruptcy Court's February 7, 2002 memorandum decision and entered final judgment thereon. In the February 7, 2002 decision, the Bankruptcy Court rejected the proponents' contentions that bankruptcy law permits express preemption of state law in connection with the implementation of a plan of reorganization. The Bankruptcy Court nonetheless held that "the Plan could be confirmed if Proponents are able to establish with particularity the requisite elements of implied preemption." The Bankruptcy Court stated that proponents must show facts that would lead the Bankruptcy Court to find that the "application of those laws to the facts of [the Debtor's] proposed reorganization are economic in nature rather than directed at protecting public safety or other non-economic concerns, and that those particular laws stand as an obstacle to the accomplishment and execution of the purposes and objectives of Congress and the Bankruptcy Code."

In the motion to dismiss the appeal, the CPUC, the City, and the California AG argued, among other matters, that the District Court lacked appellate jurisdiction because the Bankruptcy Court erred in certifying its March 18, 2002 order as immediately appealable. On June 24, 2002, the District Court issued a ruling finding that the Bankruptcy Court's certification of its preemption order was proper and, on two different grounds, that the District Court had appellate jurisdiction. The District Court has set a hearing for August 16, 2002 to hear arguments regarding the appeal.

On June 7, 2002, PG&E Corporation and the Utility filed a motion with the Bankruptcy Court to extend, until December 31, 2002, the period during which no third parties, other than the CPUC, may submit an alternative proposed plan of reorganization. The exclusivity period was scheduled to end on June 30, 2002, unless extended. On June 24, 2002, the Official Committee of Unsecured Creditors (OCC) filed a response in the Bankruptcy Court requesting that the exclusivity period be modified to enable the OCC to formulate and be in a position to file an alternative plan of reorganization if the proponents of the Utility's proposed plan of reorganization and the CPUC's alternative proposed plan of reorganization fail to come to terms on a consensual plan and it appears that neither plan as currently proposed is likely to be confirmed by the court or implemented in an expeditious fashion. As previously disclosed, in May 2002, the OCC conducted a review of both plans and issued a report for inclusion in the solicitation package mailed to creditors recommending that creditors vote in favor of both plans but declining to state a position on a preference vote for either plan. On July 9, 2002, the Bankruptcy Court issued an order granting the OCC's request and extending the exclusivity period until December 31, 2002, except as to the CPUC (which the court previously excepted) and the OCC. Neither the Utility nor PG&E Corporation can predict whether the OCC will submit an alternative plan nor what the terms of such plan would be.

Objections to the competing plans were required to be filed with the Bankruptcy Court by July 17, 2002. On July 17, 2002, PG&E Corporation and the Utility submitted a summary of their principal objections to confirmation of the CPUC plan with the Bankruptcy Court, identifying elements of the CPUC plan that PG&E Corporation and the Utility believe render the CPUC plan not feasible. Among other elements, the CPUC plan proposes to require the Utility to sell $1.75 billion of Utility common stock. PG&E Corporation and the Utility believe that the proposed stock sale would violate the Bankruptcy Code's requirement that a plan of reorganization be fair and equitable in its treatment of equity holders. PG&E Corporation and the Utility believe that the proposed stock sale would significantly dilute shareholder equity constituting an illegal confiscation of property. Further, PG&E Corporation and the Utility believe that the CPUC plan's proposed Utility debt offering is not feasible, given, among other concerns, the size of the proposed offering and the likelihood that the debt would be rated below investment grade because of the failure of the CPUC plan to contain provisions ensuring that the Utility would become an investment grade rated company.

The CPUC filed objections to the Utility Plan and other parties filed objections to both plans. The CPUC and the State of California filed objections to the Utility Plan, arguing, among other things, that the Utility Plan should not be confirmed because it is based on an impermissible federal preemption of state environmental and public health laws, necessitates a rate change without authorization from the CPUC, improperly impinges on the State's sovereign immunity by seeking declaratory and injunctive relief against the State and constitutes an improper attempt by PG&E Corporation and the Utility to manipulate the bankruptcy process to effect a change in regulation. The CPUC also contends in its objection that PG&E Corporation and the Utility have engaged in improper solicitation of votes for the Utility Plan and that the Utility Plan is not feasible because it is dependent on contingent and speculative approvals from federal regulatory bodies and there is no assurance that PG&E Corporation and the Utility will be able to consummate the financings required by the Utility Plan or that the Long Term Notes to be issued to certain creditors under the Utility Plan will trade at par. Other creditors have filed objections to the Utility Plan based on, among other things, the particular treatment of their individual claims under the Utility Plan, which PG&E Corporation and the Utility anticipate will be resolved through negotiations with the holders of such claims.

On July 22, 2002, the Bankruptcy Court denied the CPUC's request to require the Utility to pay the fees of the CPUC's financial advisor in connection with the CPUC's proposed plan.

With respect to the application filed with the Nuclear Regulatory Commission (NRC) for permission to transfer the NRC operating licenses held by the Utility for its Diablo Canyon nuclear power plant to Electric Generation, LLC (Gen) (which will become a subsidiary of PG&E Corporation after consummation of the Utility Plan) as contemplated by the Utility Plan, on June 25, 2002, the NRC issued a Memorandum and Order denying various petitions to intervene and requests for hearing that had been filed by the CPUC, the County of San Luis Obispo, and the OCC, among others. In particular, with respect to the CPUC, the NRC found that the CPUC did not have standing to participate at the NRC with respect to public health and safety matters, as opposed to economic regulatory matters. In addition, the NRC found that the CPUC did not raise any litigable issues within the NRC's jurisdiction and that the CPUC's issues were being more properly addressed in other forums, such as the Bankruptcy Court and the Federal

Energy Regulatory Commission (FERC).

Several other parties also had filed petitions to intervene expressing concerns solely with regard to how the antitrust conditions in the current licenses will be addressed in the proposed license transfers. These parties supported the Utility's proposal to make the reorganized Utility, Gen, and Electric Transmission LLC (ETrans) (the new limited liability company formed to operate the electric transmission business of the Utility as contemplated in the Utility's Plan) jointly and severally responsible to comply with the antitrust conditions. These parties seek intervention only if the NRC decides not to adopt the Utility's proposal. The NRC indicated that it will reserve its ruling as to these petitions. If the NRC orders a hearing, the NRC stated that it would allow the CPUC and San Luis Obispo County to participate, but that their participation will be limited specifically to the antitrust matters.

With respect to the application filed with the FERC for approval of the bilateral power sales agreement to be entered into between the reorganized Utility and Gen as contemplated in the Utility Plan, the FERC must find that the power sales agreement is just and reasonable before the agreement could become effective. In order to demonstrate that the pricing, terms and conditions of the proposed power sales agreement are just and reasonable, Gen submitted benchmark evidence of contemporaneous sales made by non-affiliated parties for similar services in the California electric market. On June 12, 2002, the FERC ordered that an expedited hearing be held on the narrow issues of (1) whether the power sales agreement is comparable to the selected benchmark contracts, and (2) whether Gen used an appropriate set of contracts for the benchmark analysis. The FERC ordered that the administrative law judge (ALJ) hold a hearing and issue an initial decision for consideration by the FERC within 120 days of the order. At a prehearing conference held on June 18, 2002, the ALJ set a procedural schedule that calls for discovery to be concluded by August 19, 2002, for the parties' proposed findings of fact and conclusions of law to be filed by August 20, 2002, for hearings to begin August 26, 2002, and for the ALJ's initial decision to be issued by October 10, 2002.

The confirmation hearings are scheduled to begin August 1, 2002 with a status conference. The Utility and the CPUC each filed a proposed form of protocol for the parties to follow in conducting discovery in preparation for the confirmation hearings and they have each requested that the Bankruptcy Court begin the confirmation trial on November 12, 2002. It is expected that the Bankruptcy Court will consider the discovery protocols and scheduling matters at the status conference to be held on August 1, 2002.

Neither PG&E Corporation nor the Utility can predict what the outcome of the Utility's bankruptcy proceeding will be.

Pacific Gas and Electric Company vs. California Public Utilities Commissioners

As previously disclosed in PG&E Corporation's and the Utility's Annual Report on Form 10-K for the year ended December 31, 2001, and Quarterly Report on Form 10-Q for the quarter ended March 31, 2002, the Utility filed a lawsuit in the U.S. District Court for the Northern District of California against the CPUC Commissioners, asking the court to declare that the federally approved wholesale power costs that the Utility has incurred to serve its customers are recoverable in retail rates (Filed Rate Case). The Filed Rate Case has been deemed a related case to the Utility's pending appeal of the Bankruptcy Court's denial of the Utility's request for injunctive and declaratory relief against the retroactive accounting order adopted by the CPUC in March 2001. Both matters are pending before the same District Court judge.

On April 18, 2002, the Utility filed a motion for summary judgment requesting the court to order the relief sought in the Filed Rate Case. Also, on April 18, 2002, the CPUC Commissioners and The Utility Reform Network (TURN), a ratepayer advocacy group which filed a request to intervene in the Filed Rate Case, filed motions to dismiss the Utility's claim as well as motions for summary judgment asking the court to rule against the Utility on its federal preemption claim as a matter of law. The principal ground for the CPUC's and TURN's motions is that, by adopting the retroactive change in the accounting mechanisms for recovery of transition and power procurement costs in March

2001, the CPUC has already allowed the Utility to recover its wholesale procurement costs. (The retroactive accounting change, adopted by the CPUC in March 2001, appeared to eliminate the Utility's true under-collected wholesale electricity costs by applying amounts that were previously applied first to transition cost recovery to under-collected procurement costs, effectively transforming under-collected procurement costs to under-collected transition costs. The Utility requested the Bankruptcy Court to enjoin the CPUC from enforcing the accounting order but the Bankruptcy Court denied the Utility's request. The Utility's appeal of the Bankruptcy Court's order has been deemed a related case to the Filed Rate Case and has been transferred to Judge Walker of the District Court.

On July 25, 2002, the District Court issued an order denying the CPUC's and TURN's motions to dismiss the Filed Rate Case, as well as motions for summary judgment that had been filed by the CPUC, the Utility, and TURN. TURN's request to intervene in the Filed Rate Case was also granted.) However, much of the District Court's order is a discussion of the merits of the Utility's federal preemption claims. The court rejected every argument advanced by the CPUC and TURN against the application of the filed rate doctrine, stating: "in most instances today a utility must purchase the power delivered to consumers pursuant to the rate filed with the appropriate federal agency."

After concluding that the Utility's federal preemption claims as pleaded are meritorious, the motions to dismiss were denied without substantial discussion. The court stated that despite the unique features of the regulatory context underlying the Filed Rate Case, and the lack of precedent specifically on point, "the filed rate doctrine applies in this case in much the same way as it does under a cost-of-service regime." The rule adopted by the court was stated: "Costs of wholesale energy, incurred pursuant to rate tariffs filed with FERC, whether these rates are market-based or cost-based, must be recognized as recoverable costs by state regulators and may not be trapped by excessively low retail rates or other limitations imposed at the state level." The court recognized that under the dual system of utility regulation, adherence to the filed rate requirement, in conjunction with the requirement that utilities provide electricity to end users, prohibits state regulators from trapping the costs prudently incurred pursuant to FERC-filed tariffs. The court also noted that "allowing a utility to pass through these costs to consumers– if that is what is required– would not provide a windfall to the utility, but would merely properly allocate the burden of responsibility for the expense of providing a mandated service to the public."

The court found, however, that the Utility's preemption claims could not be decided on summary judgment because two factual issues remain in dispute: (1) the appropriate period for considering whether a net under-collection has occurred, and (2) the determination of which revenue sources, within constitutional bounds, may be applied against the Utility's operating costs.

As to the first issue, the court concluded that the reasonable period for measuring the existence of an under-collection may involve considering such factual issues as the understanding of the parties at the beginning of the four-year electric industry restructuring transition period, the parties' reasonable expectations, the reasonableness of the Utility's use of surplus revenues during the first years of the transition period, and the availability of these and other revenues during the California energy crisis.

Regarding the determination of appropriate revenue sources for the Utility to apply against operating costs, the court suggested that the proper standard to be applied is the "overall impact of ratemaking orders." The court will need to consider factors such as the availability of certain revenues to the Utility during the relevant period. For example, the revenue from rate reduction bonds or from sales from the Utility's power plants may be available to offset the costs of purchased power. The court stated that if revenue was "simply not available to sustain PG&E's operations, and if this unavailability was reasonable and not due to financial mismanagement, the CPUC's reliance upon the existence of that revenue 'on the books' is insufficient to meet its obligations under the filed rate doctrine."

The court set a case management conference for August 16, 2002. The court had previously set a trial date in the Filed Rate Case for March 31, 2003.

Neither PG&E Corporation nor the Utility can predict what the outcome of the Filed Rate Case litigation will be.

Federal Securities Lawsuit

As previously disclosed in PG&E Corporation's and the Utility's Annual Report on Form 10-K for the year ended December 31, 2001, and Quarterly Report on Form 10-Q for the quarter ended March 31, 2002, the plaintiffs filed a second amended complaint in the case entitled *Gillam, et al. v. PG&E Corporation, and Robert D. Glynn, Jr*., pending in the U.S. District Court for the Northern District of California. In addition to containing many of the same allegations as were contained in the first amended complaint which the court dismissed, the second amended complaint contained allegations similar to the allegations made in the AG's complaint against PG&E Corporation discussed below. After a hearing on June 24, 2002, the court issued an order granting the defendants' motion to dismiss the second amended complaint. The dismissal is with prejudice, prohibiting the plaintiffs from filing a further amended complaint. The plaintiffs filed a notice of appeal on July 16, 2002.

PG&E Corporation believes the case is without merit and intends to present a vigorous defense. PG&E Corporation believes that the ultimate outcome of this litigation will not have a material adverse effect on PG&E Corporation's financial condition or results of operations.

In re: Natural Gas Royalties Qui Tam Litigation

For information regarding this matter, see PG&E Corporation's and the Utility's Annual Report on Form 10-K for the year ended December 31, 2001.

Baldwin Associates

As previously disclosed in PG&E Corporation's and the Utility's Annual Report on Form 10-K for the year ended December 31, 2001, Baldwin Associates, Inc. (Baldwin) filed a notice of appeal in the U.S. District Court for the Northern District of California. Baldwin sought to appeal the Bankruptcy Court's decision sustaining PG&E's objection to Baldwin's bankruptcy claim. In a written order dated May 6, 2002, the District Court granted the Utility's motion to dismiss Baldwin's appeal. On May 29, 2002, the court entered an amended order holding Baldwin and its counsel of record jointly and severally liable for the attorneys' fees and costs related to the appeal.

PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material adverse effect on PG&E Corporation's or the Utility's financial condition or results of operations.

Wayne Roberts

For information regarding this matter, see PG&E Corporation's and the Utility's Annual Report on Form 10-K for the year ended December 31, 2001.

Moss Landing Power Plant

For more information regarding this matter, see PG&E Corporation's and the Utility's Annual Report on Form 10-K for the year ended December 31, 2001, and the Quarterly Report on Form 10-Q filed by PG&E Corporation and the Utility for the quarter ended March 31, 2002.

Diablo Canyon Power Plant

On June 13, 2002, the Utility received a draft Enforcement Order from the California Department of Toxic Substances Control (DTSC) alleging that the Diablo Canyon Power Plant failed to maintain an adequate financial assurance mechanism to cover closure costs for its hazardous waste storage facility for several months during 2001. Under the California Health and Safety Code, operators of hazardous waste facilities must demonstrate to the DTSC (using a limited number of alternative methods specified by regulation) that the operator can close and clean up the facility at the end of its useful life. The Utility has used a "balance sheet" method in the past, but was unable to do so after the Utility's financial condition deteriorated in early 2001. Nevertheless, the Utility was able to secure an endorsement to its existing insurance policy that met the DTSC's requirements. The draft order seeks $340,000 in civil penalties for the period during which the Utility was unable to comply with the DTSC's requirements. The draft order also directs the Utility to maintain appropriate financial assurance on a going forward basis.

PG&E Corporation believes that the ultimate outcome of this matter will not have a material adverse impact on its financial condition or results of operations.

Compressor Station Chromium Litigation

As previously disclosed in PG&E Corporation's and the Utility's Annual Report on Form 10-K for the year ended December 31, 2001, the Utility has been named in several civil lawsuits relating to alleged chromium contamination. There are currently 15 of such civil actions pending in California courts against the Utility.

The case entitled *Kearney v. Pacific Gas and Electric Company*, pending in Los Angeles County Superior Court, was filed November 15, 2001, after the Utility's April 6, 2001bankruptcy filing. On March 26, 2002, the case was dismissed without prejudice as to the Utility and to PG&E Corporation. Currently, the plaintiffs are seeking the right to file and pursue late claims in the Bankruptcy Court.

PG&E Corporation and the Utility believe that, in light of the reserves that have already been accrued with respect to this matter, 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 results of operations. See Note 6 of the "Notes to Consolidated Financial Statements."

California Energy Trading Litigation

PG&E Energy Trading Holdings Corporation and various of its affiliates (collectively ET-Power) have been named as defendants, along with other generators and market participants in the California electricity market, in connection with a variety of claims arising out of the California energy crisis. ET-Power has been served with complaints in the following cases. It is possible that it will be served with additional complaints and that all of these cases will be consolidated with other cases in which similar allegations have been raised respecting other market participants. These proceedings are administrative and judicial in nature.

As previously disclosed in PG&E Corporation's and the Utility's Annual Report on Form 10-K for the year ended December 31, 2001, ET-Power has been named, along with multiple other defendants, in four class action lawsuits against marketers and other unnamed sellers of electricity in California markets. These cases are pending in the U.S. District Court for the Southern District of California. Plaintiffs have a filed motion to remand the proceedings to state court. In addition, the judge has established September 19, 2003 as the deadline for filing motions to dismiss the plaintiffs' complaint. The hearing on the motion to remand is also set for September 19, 2003.

On May 13, 2002, ET-Power was named, along with multiple other defendants, in a complaint filed by James A. Millar, individually and on behalf of the general public and as a representative taxpayer against energy suppliers and other unnamed sellers of electricity in the California market, in San Francisco Superior Court. In his complaint, plaintiff asserts the defendants violated state laws against unfair and fraudulent business practices by entering into certain long-term energy contracts with the DWR. The plaintiff claims that the contracts were made under circumstances that resulted in excessively high and unfair prices and, as a result, refunds should be made to the extent that the prices in the contracts were excessive. In addition, plaintiff seeks, among other remedies, an order enjoining enforcement of the allegedly unfair terms and conditions of the long-term contracts, declaratory relief, and attorneys' fees. The FERC is currently addressing the DWR contracts in the administrative actions before the FERC brought by the CPUC and California Electricity Oversight Board on February 25, 2002. On June 13, 2002, the defendants removed the case to the U.S. District Court for the Northern District of California based on federal preemption. Plaintiffs filed a motion to remand the case to state court. On July 12, 2002 the Judicial Panel on Multidistrict Litigation entered a conditional order transferring this case to the Southern District of California. The panel determined that the Millar case, as well as seven other pending lawsuits, involved common questions of law and fact. ET-Power is currently not a defendant in any of these other lawsuits.

On July 15, 2002, ET-Power was named among other sellers of power in an action filed by the Public Utility District No. 1 of Snohomish County, *Public Utility District No. 1 of Snohomish County v. Dynegy Power Marketing, et al.*, in the U.S. District Court for the Central District of California. Plaintiff alleges various theories of manipulation of the deregulated California electricity market by the defendants in violation of state antitrust laws and state laws against unlawful and fraudulent business practices. Plaintiff claims that the defendants manipulated the energy market, resulting in higher electricity prices and seeks, among other remedies, disgorgement, restitution, injunctive relief, treble damages. Plaintiff also claims that defendants failed to file their rates in advance with the FERC, which failure plaintiff asserts was a violation of the Federal Power Act.

By letter dated May 7, 2002, ET-Power was advised by the AG of California that it believes ET-Power (along with numerous other generators and market participants) violated state laws governing unfair and fraudulent business practices and that unless ET-Power settled the matter the AG would by June 1, 2002 file suit against ET-Power. The AG stated that he will claim that ET-Power failed to have its rates on file with FERC and that accordingly any sales made under such rates violated the Federal Power Act (a claim that the AG has made before FERC and which FERC has rejected) and that ET-Power exercised market-power in charging unjust and unreasonable prices. ET-Power has not yet been served with a complaint in this matter.

In addition to these judicial proceedings, on March 20, 2002 the California AG filed a complaint at the FERC against ET-Power and other named and unnamed public utility sellers of energy and ancillary services. The AG alleges that wholesale sellers of energy to the California ISO, PX and the DWR failed to file their rates in accordance with the requirements of Section 205 of the Federal Power Act. Specifically, the California AG claims that the FERC has not been able to determine whether the rates charged by such sellers are just and reasonable; that the FERC's reporting requirements are insufficient to provide the FERC the information necessary to make this determination and that even if the FERC's policies and procedures did comply with Section 205 of the Federal Power Act, the wholesale sellers failed to comply with its quarterly reporting requirements. As a result, the California AG requests that: (1) sellers should be directed to comply, on a prospective basis, with the requirements of Section 205 of the Federal Power Act; (2) sellers should be required to provide transaction-specific information regarding their short-terms sales to the ISO, PX and the DWR for the years 2000 and 2001 to the FERC; (3) if rates were charged that were not just and reasonable, refunds should be ordered; (4) the FERC should declare that market-based rates are not subject to the filed rate doctrine; and (5) the FERC should institute proceedings to determine whether any further relief would be appropriate. On May 31, 2002, the FERC issued a decision denying most of the relief requested and on July 1, 2002 the AG filed a petition with the FERC seeking rehearing of its order, which petition is now pending.

PG&E Corporation believes that the outcome of these matters will not have a material adverse affect on PG&E Corporation's financial condition or results of operations.

California Attorney General Complaint

As previously disclosed in PG&E Corporation's and the Utility's Annual Report on Form 10-K for the year ended December 31, 2001, and the Quarterly Report on Form 10-Q for the quarter ended March 31, 2002, the California AG filed a complaint against PG&E Corporation alleging violations of California's unfair business practices statute (California Business and Professions Code Section 17200), in state court. After removing the AG's complaint to the Bankruptcy Court, on February 15, 2002, PG&E Corporation filed a motion to dismiss, or in the alternative, to stay, the AG's complaint with the Bankruptcy Court. Subsequently, the AG filed a motion to remand the action to state court. The Bankruptcy Court held a hearing on April 24, 2002, to consider the remand motion. On June 14, 2002, the Bankruptcy Court issued a memorandum decision rejecting the AG's claim that sovereign immunity barred the removal of the case from state court to federal court. The Bankruptcy Court also found that what the court called the "Plan Claims" - those alleging that PG&E Corporation had manipulated the bankruptcy process in a manner constituting an unlawful or unfair business practice - are exclusively bankruptcy issues to be heard in bankruptcy court and cannot be heard by the state court.

With respect to the claims related to the transfers of money from the Utility to PG&E Corporation (for example, by way of dividends and stock repurchases), ring-fencing transactions, and related issues (what the court referred to collectively as the "First Priority Claims"), the court found that these claims should be returned to the state court. The court reasoned that the AG's First Priority Claims, based on alleged violation of California Business and Professions Code Section 17200, was a civil actions brought by a governmental unit to enforce such governmental unit's police or regulatory power. Under the Bankruptcy Code, the court found, such an action may not be removed to the Bankruptcy Court. The Bankruptcy Court ordered the AG to amend its complaint to delete or at least separate its Plan Claims and its First Priority Claims into distinct causes of action by July 14, 2002. The AG dropped the Plan Claims in the amended complaint the AG filed with the Bankruptcy Court on July 22, 2002.

PG&E Corporation believes that the allegations of the complaint are without merit and will vigorously respond to and defend the litigation. PG&E Corporation is unable to predict whether the outcome of this litigation will have a material adverse affect on its financial condition or results of operations.

Complaint filed by the City and County of San Francisco, and the People of the State of California

As previously disclosed in the Quarterly Report on Form 10-Q filed by PG&E Corporation and the Utility for the quarter ended March 31, 2002, on March 4, 2002, the City filed a complaint in state court against PG&E Corporation alleging violations of California's unfair business practices statute (California Business and Professions Code Section 17200), and for unjust enrichment and conversion. After removing the City's action to the Bankruptcy Court PG&E Corporation thereafter filed a motion to dismiss the complaint. Subsequently, the City filed a motion to remand the action to state court. The Bankruptcy Court held a hearing on April 24, 2002 to consider the remand motion. On June 14, 2002, the Bankruptcy Court rejected the City's claim that sovereign immunity barred the removal of the case from state court to federal court. The Bankruptcy Court also rejected the City's request for remand as to the City's unjust enrichment and conversion claims. Nevertheless, the court remanded the City's Section 17200 claims to state court finding that the action was brought by a governmental unit to enforce such governmental unit's police or regulatory power. Under the Bankruptcy Code, the court found, such an action may not be removed to the Bankruptcy Court. PG&E Corporation filed a notice of appeal regarding the remand decision in the City's case.

PG&E Corporation believes that the allegations of the complaint are without merit and will vigorously respond to and defend the litigation. PG&E Corporation is unable to predict whether the outcome of this litigation will have a material adverse affect on its financial condition or results of operations.

Sierra Pacific Industries v. Pacific Gas and Electric Company

As previously disclosed in PG&E Corporation's and the Utility's Annual Report on Form 10-K for the year ended December 31, 2001, Sierra Pacific Industries, Inc. (SPI), a qualifying facility (QF) generator, filed a complaint in Sacramento County Superior Court on April 2, 2001, against the Utility and the ISO alleging various contract, tort, unfair business practice, and antitrust claims against the defendants. SPI claimed the Utility breached four power purchase agreements (PPAs) with SPI by making only partial payments for SPI's December 2000 through March 2001 energy deliveries. In addition, SPI claimed the Utility and the ISO conspired to prevent SPI from terminating the PPAs and selling its power into the California wholesale energy markets. SPI's claims for tortuous interference, unfair business practices, and antitrust claims are based on this alleged conspiracy. SPI filed a $1.1 billion proof of claim in the Utility's bankruptcy proceeding, seeking, among other things, $1 billion in punitive damages under its tort theory.

On June 4, 2002, PG&E reached a settlement agreement with SPI that calls for reinstatement of SPI's four PPA's with certain modifications to increase SPI's flexibility in meeting contractual commitments. The Utility has agreed to pay SPI a fixed price of 5.37 cents per kWh for energy delivered for four years. In addition, the Utility has agreed to pay for the energy and capacity SPI delivered but for which the Utility had not paid when its bankruptcy petition was filed on April 6, 2001. SPI has agreed to dismiss its $1.1 billion complaint claim and to withdraw its bankruptcy claim. The settlement is subject to receiving CPUC and Bankruptcy Court approval within five months after June 4, 2002. This date can be extended if both parties agree to the extension. In the meantime, the parties have placed their pending litigation on hold.

PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material adverse impact on their financial condition or results of operations.

William Ahern, et al v. Pacific Gas and Electric Company

As previously disclosed in PG&E Corporation's and the Utility's Annual Report on Form 10-K for the year ended December 31, 2001, and the Quarterly Report on Form 10-Q filed by PG&E Corporation and the Utility for the quarter ended March 31, 2002, a group of 25 ratepayers filed a complaint against the Utility at the CPUC demanding an immediate reduction of approximately 3.5 cents per kWh in allegedly excessive electric rates and a refund of alleged recent over-collections in electric revenue since June 1, 2001.

On April 2, 2002, the Utility filed an answer, arguing that the complaint should be denied and dismissed immediately as an impermissible collateral action and on the basis that the alleged facts, even if assumed to be true, do not establish that currently authorized electric rates are not reasonable. On May 10, 2002 the Utility filed a motion to dismiss the complaint. The CPUC has not yet issued a decision.

PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material adverse impact on their financial condition or results of operations.

PG&E NEG's Brayton Point Generating Station

As previously disclosed in the Quarterly Report on Form 10-Q filed by PG&E Corporation and the Utility for the quarter ended March 31, 2002, on March 27, 2002, the Attorney General of the State of Rhode Island notified

USGenNE of his belief that Brayton Point is operating in violation of applicability statutory and regulatory provisions, including what he characterized as "protections afforded by common law." The Attorney General purported to provide notice under the Massachusetts General Laws of his intention to seek judicial relief within the following thirty days to abate the alleged violations and to recover damages and to obtain other unexplained statutory and equitable remedies. PG&E NEG believes that Brayton Point Station is in full compliance with all applicable permits, laws and regulations. The complaint has not yet been filed or served. In late May 2002, the Attorney General stated that he did not plan to file the action until the EPA issues a draft Clean Water Act National Pollutant Discharge Elimination System (NPDES) permit for Brayton Point. On July 22, 2002, the EPA and the Massachusetts Department of Environment (DEP) issued a draft NPDES permit for Brayton Point that, among other things, substantially limits the discharge of heat by Brayton Point into Mt. Hope Bay. Based on its initial review of the draft permit, USGenNE believes that the draft permit is excessively stringent. It is estimated that USGenNE's cost to comply with the new permit conditions could be as much as $267 million through 2005, an increase of $200 million from previous estimates, but this is a preliminary estimate. For more information, see Note 6 of the "Notes to Consolidated Financial Statements."

PG&E Corporation is unable to predict whether the ultimate outcome of this matter will have a material adverse affect on its financial condition or results of operations.

ITEM 2. CHANGES IN SECURITIES AND USE OF PROCEEDS

As disclosed in a Current Report on Form 8-K filed by PG&E Corporation with the Securities and Exchange Commission (SEC) on June 26, 2002, PG&E Corporation obtained term loans from General Electric Capital Corporation (GECC), Lehman Commercial Paper Inc. (LCPI) and their assignees (collectively the "Existing Lenders") on March 1, 2001 under a credit agreement (the "Old Credit Agreement"). On June 25, 2002, PG&E Corporation entered into an Amended and Restated Credit Agreement with the Existing Lenders and additional lenders that amended and restated the Old Credit Agreement (the "New Credit Agreement").

The New Credit Agreement provides for loans in two tranches. The Tranche A has a principal amount of $600 million (the "Tranche A Loan"), representing the $692 million outstanding under the Old Credit Agreement less $92 million that has been converted to a Tranche B Loan. The Tranche B consists of the $92 million converted loan plus $328 million of new borrowings, for a total of $420 million (the "Tranche B Loan").

In connection with these loans, PG&E Corporation issued to the Tranche B lenders warrants to purchase approximately 2.4 million shares of common stock of PG&E Corporation at an exercise price of $0.01 per share (Warrants). The issuance of the Warrants by PG&E Corporation was not registered under the Securities Act of 1933 in reliance on the exemption afforded by Section 4(2)

As previously disclosed, in connection with the Old Credit Agreement, affiliates of the Existing Lenders received an option to purchase 3 percent of the shares of NEG, Inc., determined on a fully diluted basis

, at an exercise price of $1.00. The option may be exercised at any time until 45 days after the full repayment of the Tranche A Loan. In addition, under the Old Credit Agreement, PG&E Corporation's exercise of each of its one-year extensions of the loan was conditioned upon PG&E National Energy Group, LLC, a Delaware limited liability company, (NEG LLC) granting affiliates of the Existing Lenders an additional option to purchase one percent of the common stock of NEG, Inc., determined on a fully-diluted basis, at an exercise price of $1.00. As a result of the New Credit Agreement, the one percent has been reduced to approximately .87 percent of the common stock of NEG, Inc. (reflecting the reduction in the principal amount of the Tranche A Loan to $600 million from the $692 million in loans outstanding under the Old Credit Agreement). The option may be exercised at any time from the relevant extension date until 45 days after full repayment or maturity of the Tranche A Loan.

NEG LLC has the right to call the option after repayment of the Tranche A Loan in full at a cash purchase price equal to the fair market value of the underlying shares, or, at the election of NEG LLC if an initial public offering of the shares of NEG, Inc. (IPO) has occurred, by delivering the underlying shares. If an IPO has not occurred prior to repayment of the Tranche A Loan in full, 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 (the "Put Price"), which right is exercisable at any time after the earlier of full repayment of the Tranche A Loan or 45 days before expiration of the option. The issuance of the put option by PG&E Corporation was not registered under the Securities Act of 1933 in reliance on the exemption afforded by Section 4(2).

Under the terms of the New Credit Agreement, PG&E Corporation may not declare or pay any dividends until both the Tranche A and Tranche B loans have been repaid in full.

Concurrent with the refinancing described above, on June 25, 2002, PG&E Corporation issued $280 million aggregate principal amount of 7.50% Convertible Subordinated Notes due June 30, 2007 (Notes), in a private offering. The Notes are unsecured and are subordinate to the Loans. PG&E Corporation will pay cash interest on the Notes semi-annually at a rate of 7.50 percent per year. PG&E Corporation has the right, subject to certain limitations, to pay interest by issuing additional Notes in lieu of paying cash. In addition to interest, if PG&E Corporation pays cash dividends to holders of its common stock, Note holders are entitled to receive cash equal to the dividends that would have been paid with respect to the number of shares that the holder would be entitled to receive if the Notes had been converted on the dividend record date. The Notes may be converted by the holders into shares of PG&E Corporation's common stock at a conversion price equal to 119 percent of the volume-weighted average price of the common stock of PG&E Corporation for each of 43 trading days beginning three days after the closing of the transaction**.** The conversion price is subject to adjustment under certain circumstances, including upon consummation of any spin-off transaction of the Utility as proposed in its plan of reorganization or a spin-off of the shares of NEG, Inc.

PG&E Corporation has agreed to provide, following consummation of a plan of reorganization of the Utility, registration rights in connection with the shares issuable upon conversion of the Notes and exercise of the Warrants.

The net proceeds of the Loans and the Note issuance will be used to fund corporate working capital, repay certain indebtedness, and fund two interest reserve accounts.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

The Utility has authorized 75 million shares of First Preferred Stock ($25 par value) and 10 million shares of $100 First Preferred Stock ($100 par value), which may be issued as redeemable or non-redeemable preferred stock. (The Utility has not issued any $100 First Preferred Stock.) At June 30, 2002, the Utility had issued and outstanding 5,784,825 shares of non-redeemable preferred stock and 5,973,456 shares of redeemable preferred stock. The Utility's redeemable preferred stock is subject to redemption at the Utility's option, in whole or in part, if the Utility pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. The Utility's redeemable preferred stock with mandatory redemption provisions consists of 3 million shares of the 6.57 percent series and 2.5 million shares of the 6.30 percent series at June 30, 2002. The 6.57 percent series and 6.30 percent series may be redeemed at the Utility's option beginning in 2002 and 2004, respectively, at par value plus accumulated and unpaid dividends through the redemption date. These series of preferred stock are subject to mandatory redemption provisions entitling them to sinking funds providing for the retirement of stock outstanding. At June 30, 2002, the redemption requirements for the Utility's redeemable preferred stock with mandatory redemption provisions are $4 million for 2002 and 2003 and $3 million per year beginning 2004, for the series 6.57 percent and 6.30 percent, respectively.

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

Due to the California energy crisis and the Utility's pending bankruptcy, the Utility's Board of Directors has not declared the regular preferred stock dividends since the dividend paid with respect to the three-month period ended October 31, 2001.

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and equal preference in dividend and liquidation rights. Accumulated and unpaid dividends through June 30, 2002, amounted to $37.9 million. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series. Until cumulative dividends on its preferred stock are paid, the Utility may not pay any dividends on its common stock, nor may the Utility repurchase any of its common stock.

The Utility's total defaulted commercial paper outstanding at June 30, 2002, was $873 million. At June 30, 2002, the Utility had drawn and had outstanding $938 million under the bank credit facility, which was also in default. Per the terms of the Amended and Restated Settlement and Support Agreement, the Utility made interest payments totaling $179.7 million on May 6, 2002, May 31, 2002, and July 1, 2002 for the periods starting April 1, 2001, for the commercial paper and March 31, 2001, for the bank credit facility up to and including June 30, 2002.

With regard to certain pollution control bond-related debt of the Utility, the Utility has been in default under the credit agreements with the banks that provide letters of credit as credit and liquidity support for the underlying pollution control bonds. These defaults included the Utility's non-payment of other debt in excess of $100 million, the Utility's filing of a petition for reorganization under Chapter 11 of the Bankruptcy Code, and non-payment of interest. As a result of these defaults, several of the letter of credit banks caused the acceleration and redemption of four series of pollution control bonds. All of these redemptions were funded by the letter of credit banks, resulting in loans from the banks to the Utility, which have not been paid. At June 30, 2002, the total principal of the bonds (and related loans) accelerated and redeemed was $454 million. Per the Amended and Restated Settlement and Support Agreement, the Utility made interest payments on these loans totaling $43.0 million on May 6, 2002, May 31, 2002, and July 1, 2002.

On June 18, 2002 and July 1, 2002, the Utility paid advances and interest on advances of $20.5 million to banks providing letters of credit on pollution control bonds series 96C, 96E, 96F, and 97B. The Utility also made interest payments on pollution control bond series 96A backed by bond insurance. Per the Amended and Restated Settlement and Support Agreement, unpaid interest advances totaling $13.7 million for the period from June 1, 2001, through June 30, 2002, was paid on May 6, 2002, May 31, 2002, and July 1, 2002. With regard to certain pollution control bond-related debt of the Utility backed by the Utility's mortgage bonds, an event of default has occurred under the relevant loan agreements with the California Pollution Control Financing Authority due to the Utility's bankruptcy filing.

The Utility's filing of a petition for reorganization under Chapter 11 of the Bankruptcy Code also constitutes a default under the indenture that governs its medium-term notes ($287 million aggregate amount outstanding), five-year 7.375% senior notes ($680 million aggregate amount outstanding), and floating rate notes ($1.24 billion aggregate amount outstanding). Per the Amended and Restated Settlement and Support Agreement, on May 6, 2002, the Utility made interest payments on its medium-term notes, its 7.375% senior notes, and its $1.24 billion floating rate notes totaling $281.2 million through the period June 30, 2002.

From the date of the filing of the bankruptcy petition (April 6, 2001) to June 30, 2002, the Utility has not made principal payments on unsecured long-term debt of $131 million.

With regard to the 7.90% Quarterly Income Preferred Securities (QUIPS) and the related 7.90% Deferrable Interest Debentures (debentures), the Utility's filing of a petition for reorganization under Chapter 11 of the Bankruptcy Code is an event of default under the applicable indenture. Pursuant to the related trust agreement, the trustee was required to take steps to liquidate the trust and distribute the debentures to the QUIPS holders. Pursuant to the trustee's notice dated April 24, 2002, the trust was liquidated on May 24, 2002. Upon liquidation of the trust, the former holders of

QUIPS received a like amount of Subordinated Debentures, or QUIDS. See Note 5 of the "Notes to Consolidated Financial Statements" regarding current interest payments on the QUIDS.

ITEM 5. OTHER INFORMATION

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

Pacific Gas and Electric Company's earnings to fixed charges ratio for the six months ended June 30, 2002, was 4.16. Pacific Gas and Electric Company's earnings to combined fixed charges and preferred stock dividends ratio for the six months ended June 30, 2002, was 4.02. The statement of the foregoing ratios, together with the statements of the computation of the foregoing ratios filed as Exhibits 12.1 and 12.2 hereto, are included herein for the purpose of incorporating such information and exhibits into Registration Statement Nos. 33-62488, 33-64136, 33-50707, and 33-61959, relating to Pacific Gas and Electric Company's various classes of debt and first preferred stock outstanding.

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) Exhibits:

Exhibit 4.1	Indenture related to PG&E Corporation's 7.50% Convertible Subordinated Notes due June 2007, dated as of June 25, 2002, between PG&E Corporation and U.S. Bank, N.A., as Trustee (incorporated by reference to PG&E Corporation's Current Report on Form 8-K filed June 26, 2002, Exhibit 99.1).
Exhibit 4.2	Warrant Agreement, dated as of June 25, 2002, by and among PG&E Corporation, LB I Group Inc. and each other entity named on the signature pages thereto (incorporated by reference to PG&E Corporation's Current Report on Form 8-K filed June 26, 2002, Exhibit 99.9).
Exhibit 10.1	Amended and Restated Credit Agreement, dated as of June 25, 2002, among PG&E Corporation, as Borrower, the Lenders party thereto, Lehman Commercial Paper Inc., as Administrative Agent and Lehman Brothers Inc., as Lead Arranger and Book Manager (incorporated by reference to PG&E Corporation's Current Report on Form 8-K filed June 26, 2002, Exhibit 99.4).
Exhibit 11	Computation of Earnings Per Common Share
Exhibit 12.1	Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company
Exhibit 12.2	Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company

Exhibit 99.1	Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002
Exhibit 99.2	Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002

(b) The following Current Reports on Form 8-K were filed during the second quarter of 2002 and through the date hereof:

1. April 2, 2002 Item 5. Pacific Gas and Electric Company Bankruptcy
   - A. Amended and Restated Settlement and Support Agreement, Payment of Interest and Claims
   - B. Appeal of Rejection of Express Preemption Theory to Implement Proposed Plan of Reorganization
   - C. Schedule
   - D. Monthly Operating Report

   Item 7. Financial Statements, Pro Forma, Financial Information, and Exhibits

   Exhibit 99 - Pacific Gas and Electric Company Income Statement for the month ended February 28, 2002, and Balance Sheet dated February 28, 2002

2. April 19, 2002 Item 5. Other Events
   - A. Pacific Gas and Electric Company Bankruptcy
   - B. Utility Retained Generation Ratemaking Proceeding
   - C. California Independent System Operator (ISO) Charges
   - D. 2003 General Rate Case Proceeding
   - E. 2002 Attrition Rate Adjustment (ARA) Case
   - F. PG&E National Energy Group, Inc. - Credit Rating Outlook

3. May 21, 2002 Item 5. Pacific Gas and Electric Company Bankruptcy
   - A. Payment of Interest
   - B. Schedule

4. June 4, 2002 Item 5. Pacific Gas and Electric Company Bankruptcy
   - A. Monthly Operating Report
   - B. Official Committee of Unsecured Creditors

	Item 7.	Financial Statements, Pro Forma, Financial Information, and Exhibits	
			Exhibit 99 - Pacific Gas and Electric Company Income Statement for the month ended April 30, 2002, and Balance Sheet dated April 30, 2002
5. June 20, 2002	Item 5.	Other Events	
		A. B.	Pacific Gas and Electric Company Bankruptcy Legal Proceedings
6. June 26, 2002-PG&E Corporation only	Item 5.	Other Events	
		A.	Amended and Restated Credit Agreement; Issuance of Related Notes, Option and Warrants
	Item 7.	Financial Statements, Pro Forma, Financial Information, and Exhibits	
			Exhibit 99.1 - Indenture, dated as of June 25, 2002, between PG&E Corporation and U.S. Bank, N.A., as Trustee
			Exhibit 99.2 - Purchase Agreement, dated as of June 25, 2002, between PG&E Corporation and Lehman Brothers Inc., Jackson Investment Fund Ltd., Citadel Distressed and Credit Opportunity Fund, Ltd. And Citadel Equity Fund Ltd., as the Purchasers
			Exhibit 99.3 - Equity Registration Rights Agreement, dated as of June 25, 2002, between PG&E Corporation, as Issuer, and LB I Group Inc. and each other entity named as the signature pages thereto, as Initial Holders
			Exhibit 99.4 - Amended and Restated Credit Agreement, dated as of June 25, 2002, among PG&E Corporation, as Borrower, the Lenders party thereto, Lehman Commercial Paper Inc. as Administrative Agent and Lehman Brothers Inc., as Lead Arranger and Book Manager
			Exhibit 99.5 - Amended and Restated LLC Pledge Agreement, dated as of June 25, 2002, by and among PG&E Corporation, as Pledgor, PG&E National Energy Group, LLC, as Issuer, Lehman Commercial Paper Inc. as Administrative Agent and Deutsche Bank Trust Company Americas, as Collateral Agent for the benefit of the Lenders as Pledgee

			Exhibit 99.6 - Amended and Restated Stock Pledge Agreement, dated as of June 25, 2002 by and among PG&E National Energy Group, LLC, as Pledgor, PG&E National Energy Group, Inc., as Issuer and Lehman Commercial Paper Inc. as Administrative Agent and Deutsche Bank Trust Company Americas, as Collateral Agent for the benefit of the Lenders as Pledgee
			Exhibit 99.7 - Amended and Restated Option Agreement, dated as of June 25, 2002 by and among PG&E National Energy Group, Inc., PG&E Corporation, as Borrower, PG&E National Energy Group LLC and GPSF-F Inc. and LB I Group Inc., as the Initial Holders and each entity named on the signature pages thereto as the Subsequent Holders
			Exhibit 99.8 - Intercreditor and Subordination Agreement, dated as of June 25, 2002
			Exhibit 99.9 - Warrant Agreement, dated as of June 25, 2002, by and among PG&E Corporation, LB I Group Inc. and each other entity named on the signature pages thereto
			Exhibit 99.10 - Resale Registration Rights Agreement, dated as of June 25, 2002, between PG&E Corporation as Issuer and the Purchasers identified on the signature pages thereto
7. July 2, 2002	Item 5.	Other Events	
		A.	Pacific Gas and Electric Company Bankruptcy: Monthly Operating Report
		B.	Dismissal of Federal Securities Lawsuit
		C.	Motion to Extend Exclusivity Period
		D.	Nuclear Regulatory Commission Ruling
	Item 7.	Financial Statements, Pro Forma, Financial Information, and Exhibits	
			Exhibit 99 - Pacific Gas and Electric Company Income Statement for the month ended May 31, 2002, and Balance Sheet dated May 31, 2002
8. July 29, 2002	Item 5.	Other Events	
		A.	Recovery of Wholesale Power Purchase Costs

SIGNATURE

Pursuant to the requirements of the Securities Exchange act of 1934, the registrants have duly caused this Quarterly Report on Form 10-Q/A to be signed on their behalf by the undersigned thereunto duly authorized.

PG&E CORPORATION

BY: CHRISTOPHER P. JOHNS

CHRISTOPHER P. JOHNS

Senior Vice President and Controller

(duly authorized officer and principal accounting officer)

PACIFIC GAS AND ELECTRIC COMPANY

BY: DINYAR B. MISTRY

DINYAR B. MISTRY

Vice President and Controller

(duly authorized officer and principal accounting officer)

Dated: August 2, 2002

Exhibit Index

Exhibit No.	Description of Exhibit
10.1	Amended and Restated Agreement, dated as of June 25, 2002, among PG&E Corporation, as Borrower, the Lenders party thereto, Lehman Commercial Paper Inc., as Administrative Agent and Lehman Brothers Inc., as Lead Arranger and Book Manager (incorporated by reference to PG&E Corporation's Current Report on Form 8-K filed June 26, 2002, Exhibit 99.4).
10.2	Indenture related to PG&E Corporation's 7.5 percent Convertible Subordinated Notes due June 2007, dated as of June 25, 2002, between PG&E Corporation and U.S. Bank, N.A., as Trustee (incorporated by reference to PG&E Corporation's Current Report on Form 8-K filed June 26, 2002, Exhibit 99.1).
10.3	Warrant Agreement, dated as of June 25, 2002, by and among PG&E Corporation, LB I Group Inc., and each other entity named on the signature pages thereto (incorporated by reference to PG&E Corporation's Current Report on Form 8-K filed June 26, 2002, Exhibit 99.9).
11	Computation of Earnings Per Common Share
12.1	Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company
12.2	Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company
99.1	Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002
99.2	Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002