(Mark One)

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C., 20549
FORM 10-Q

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

For the quarterly period ended March 31, 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, April 26, 2002:

PG&E Corporation	389,405,450 shares
Pacific Gas and Electric Company	Wholly-owned by PG&E Corporation

PG&E CORPORATION AND
PACIFIC GAS AND ELECTRIC COMPANY,
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED March 31, 2002
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ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

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

	Three months ended March 31, 2002	Three months ended March 31, 2001
Operating Revenues		
Utility	$ 2,453	$ 2,562
Energy commodities and services	2,314	4,111
Total operating revenues	4,767	6,673
Operating Expenses		
Cost of energy for utility	149	3,233
Cost of energy commodities and services	2,053	3,839
Operating and maintenance	923	686
Depreciation, amortization, and decommissioning	320	255
Reorganization professional fees and expenses	16	-
Total operating expenses	3,461	8,013
Operating Income (Loss)	1,306	(1,340)
Reorganization interest income	22	-
Interest income	20	35
Interest expense	(334)	(247)
Other income (expense), net	18	(9)
Income (Loss) Before Income Taxes	1,032	(1,561)
Income taxes provision (benefit)	401	(610)
Net Income (Loss)	$ 631	$ (951)
Weighted Average Common Shares Outstanding	364	363
Earnings (Loss) Per Common Share, Basic		
Net Earnings (Loss)	$ 1.73	$ (2.62)
Earnings (Loss) Per Common Share, Diluted		
Net Earnings (Loss)	$ 1.71	$ (2.62)

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	
	March 31, 2002	**December 31, 2001**
ASSETS		
Current Assets		
Cash and cash equivalents	$ 5,787	$ 5,421
Restricted cash	202	195
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $88 million and $89 million, respectively)	2,588	3,016
Regulatory balancing accounts	72	75
Price risk management	457	381
Inventories	342	462
Prepaid expenses and other	331	223
Total current assets	9,779	9,773
Property, Plant and Equipment		
Utility	26,263	25,963
Non-utility:		
Electric generation	3,169	2,848
Gas transmission	1,520	1,514
Construction work in progress	2,500	2,426
Other	200	195
Total property, plant and equipment (at original cost)	33,652	32,946
Accumulated depreciation and decommissioning	(14,077)	(13,831)
Net property, plant and equipment	19,575	19,115
Other Noncurrent Assets		
Regulatory assets	2,260	2,319
Nuclear decommissioning funds	1,340	1,337
Price risk management	473	426
Other	2,871	2,892
Total other noncurrent assets	6,944	6,974
TOTAL ASSETS	$ 36,298	$ 35,862

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

	Balance at	
	March 31, 2002	**December 31, 2001**
LIABILITIES AND STOCKHOLDERS' EQUITY		
Liabilities Not Subject to Compromise		
Current Liabilities		
Short-term borrowings	$ 406	$ 330
Long-term debt, classified as current	48	381
Current portion of rate reduction bonds	290	290
Accounts payable:		
Trade creditors	1,598	1,289
Regulatory balancing accounts	350	228
Other	649	530
Income taxes payable	1,089	610
Price risk management	445	277
Other	836	931
Total current liabilities	5,711	4,866
Noncurrent Liabilities		
Long-term debt	7,502	7,297
Rate reduction bonds	1,376	1,450
Deferred income taxes	1,628	1,666
Deferred tax credits	151	153
Price risk management	481	434
Other	3,701	3,688
Total noncurrent liabilities	14,839	14,688
Liabilities Subject to Compromise		
Financing debt	5,748	5,651
Trade creditors	4,315	5,555
Total liabilities subject to compromise	10,063	11,206
Commitments and Contingencies (Notes 1, 2 and 5)	-	-
Preferred Stock of Subsidiaries	480	480
Utility Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures	300	300
Common Stockholders' Equity		
Common stock, no par value, authorized 800,000,000 shares, issued 388,899,379 and 387,898,848 shares, respectively	6,007	5,986
Common stock held by subsidiary, at cost, 23,815,500 shares	(690)	(690)
Accumulated deficit	(373)	(1,004)
Accumulated other comprehensive income (loss)	(39)	30
Total common stockholders' equity	4,905	4,322
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 36,298	$ 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)

	Three months ended March 31, 2002	2001
Cash Flows From Operating Activities		
Net income (loss)	$ 631	$ (951)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	320	255
Deferred income taxes and tax credits, net	(82)	(527)
Price risk management assets and liabilities, net	23	25
Other deferred charges and noncurrent liabilities	116	(149)
Net changes in liabilities subject to compromise	(1,143)	-
Net changes in operating assets and liabilities:		
Accounts receivable	428	1,310
Accounts payable	428	515
Inventories	120	22
Income taxes receivable	-	1,241
Income taxes payable	479	-
Regulatory balancing accounts, net	125	571
Other working capital	(203)	(217)
Other, net	(11)	(143)
Net cash provided by operating activities	1,231	1,952
Cash Flows From Investing Activities		
Capital expenditures	(731)	(538)
Other, net	(6)	(147)
Net cash used by investing activities	(737)	(685)
Cash Flows From Financing Activities		
Net borrowings (repayments) under credit facilities	76	(993)
Long-term debt issued	190	1,105
Long-term debt matured, redeemed, or repurchased	(415)	(236)
Common stock issued	21	-
Dividends paid	-	(109)
Net cash used by financing activities	(128)	(233)
Net change in cash and cash equivalents	366	1,034
Cash and cash equivalents at January 1	5,421	2,430
Cash and cash equivalents at March 31	$ 5,787	$ 3,464
Supplemental disclosures of cash flow information		
Cash paid for:		
Interest (net of amount capitalized)	$ 108	$ 235
Income taxes paid (refunded) - net	8	(1,241)

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 March 31,	
	2002	**2001**
Operating Revenues		
Electric	$ 1,778	$ 1,259
Gas	675	1,303
Total operating revenues	2,453	2,562
Operating Expenses		
Cost of electric energy	(166)	2,317
Cost of gas	315	916
Operating and maintenance	769	532
Depreciation, amortization, and decommissioning	271	217
Reorganization professional fees and expenses	16	-
Total operating expenses	1,205	3,982
Operating Income (Loss)	1,248	(1,420)
Reorganization interest income	22	-
Interest income	-	7
Interest expense (contractual interest of $198 million and $201 million, respectively)	(263)	(201)
Other income (expense), net	(5)	(4)
Income (Loss) Before Income Taxes	1,002	(1,618)
Income tax provision (benefit)	406	(624)
Net Income (Loss)	596	(994)
Preferred dividend requirement	6	6
Income (Loss) Available for (Allocated to) Common Stock	$ 590	$ (1,000)

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	
	March 31, 2002	**December 31, 2001**
ASSETS		
Current Assets		
Cash and cash equivalents	$ 4,732	$ 4,341
Restricted cash	48	53
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $46 million and $48 million, respectively)	1,726	1,931
Related parties	15	18
Regulatory balancing accounts	72	75
Inventories:		
Gas stored underground and fuel oil	109	218
Materials and supplies	117	119
Deferred income taxes	33	-
Prepaid expenses and other	61	80
Total current assets	6,913	6,835
Property, Plant and Equipment		
Electric	18,378	18,153
Gas	7,885	7,810
Construction work in progress	351	323
Total property, plant and equipment (at original cost)	26,614	26,286
Accumulated depreciation and decommissioning	(13,134)	(12,929)
Net property, plant and equipment	13,480	13,357
Other Noncurrent Assets		
Regulatory assets	2,231	2,283
Nuclear decommissioning funds	1,340	1,337
Other	1,315	1,325
Total noncurrent assets	4,886	4,945
TOTAL ASSETS	$ 25,279	$ 25,137

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

	Balance at	
	March 31, 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	767	333
Related parties	86	86
Regulatory balancing accounts	350	228
Other	392	289
Income taxes payable	814	295
Deferred income taxes	-	65
Other	575	625
Total current liabilities	3,274	2,544
Noncurrent Liabilities		
Long-term debt	3,019	3,019
Rate reduction bonds	1,376	1,450
Deferred income taxes	1,015	1,028
Deferred tax credits	151	153
Other	2,755	2,724
Total noncurrent liabilities	8,316	8,374
Liabilities Subject to Compromise		
Financing debt	5,748	5,651
Trade creditors	4,516	5,733
Total liabilities subject to compromise	10,264	11,384
Commitments and Contingencies (Notes 1, 2 and 5)	-	-
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	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
Accumulated deficit	(399)	(989)
Accumulated other comprehensive loss	(2)	(2)
Total stockholders' equity	2,988	2,398
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 25,279	$ 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)

	Three months ended March 31, 2002	Three months ended March 31, 2001
Cash Flows From Operating Activities		
Net income (loss)	$ 596	$ (994)
Adjustments to reconcile net income (loss) to		
net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	271	217
Deferred income taxes and tax credits, net	(113)	(170)
Other deferred charges and noncurrent liabilities	79	(110)
Net changes in liabilities subject to compromise	(1,120)	-
Net changes in operating assets and liabilities:		
Accounts receivable	208	138
Income taxes receivable	-	1,120
Inventories	111	(4)
Accounts payable	537	1,579
Income taxes payable	519	45
Regulatory balancing accounts payable, net	125	571
Other working capital	(68)	(579)
Other, net	14	4
Net cash provided by operating activities	1,159	1,817
Cash Flows From Investing Activities		
Capital expenditures	(353)	(284)
Other, net	(7)	22
Net cash used by investing activities	(360)	(262)
Cash Flows From Financing Activities		
Net repayment under credit facilities		
and short-term borrowings	-	(28)
Long-term debt matured, redeemed, or repurchased	(408)	(187)
Net cash used by financing activities	(408)	(215)
Net change in cash and cash equivalents	391	1,340
Cash and cash equivalents at January 1	4,341	1,344
Cash and cash equivalents at March 31	$ 4,732	$ 2,684
Supplemental disclosures of cash flow information		
Cash received for:		
Reorganization interest income	$ 22	$ -
Cash paid for:		
Interest (net of amount capitalized)	65	109
Income taxes paid (refunded) - net	-	(1,120)
Reorganization professional fees and expenses	2	-

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 4.7 million customers and natural gas service to approximately 3.9 million customers in Northern and Central California. Both PG&E Corporation and the Utility are headquartered in San Francisco. PG&E Corporation's other significant subsidiary is PG&E National Energy Group, Inc. and its subsidiaries (PG&E NEG), headquartered in Bethesda, Maryland. 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 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 the following: PG&E Generating Company, LLC, and its subsidiaries (collectively, PG&E GenLLC); PG&E Energy Trading Holdings Corporation and its subsidiaries (collectively, PG&E ET); 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). PG&E NEG also has other less significant subsidiaries.

This Quarterly Report on Form 10-Q 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. 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.

Earnings (Loss) Per Share

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

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

	Three months ended March 31,	
(in millions, except per share amounts)	**2002**	**2001**
Net Income (Loss)	$ 631	$ (951)
Weighted average common shares outstanding	364	363
Add: Outstanding options reduced by the number of shares that could be repurchased with the proceeds from such purchase	4	-
Shares outstanding for diluted calculations	368	363
Earnings (Loss) Per Common Share, Basic		
Net earnings (loss)	$ 1.73	$ (2.62)
Earnings (Loss) Per Common Share, Diluted		
Net earnings (loss)	$ 1.71	$ (2.62)

PG&E Corporation reflects the preferred dividends of subsidiaries as other expense for computation of both basic and diluted earnings per share.

Comprehensive Income (Loss)

Comprehensive income (loss) reports a measure for changes in income of an enterprise that result from transactions and other economic events other than transactions with shareholders. PG&E Corporation's and the Utility's comprehensive income (loss) consists principally of changes in the market value of certain cash flow hedges with the implementation of SFAS No. 133 on January 1, 2001.

	PG&E Corporation		Utility	
	Three months ended March 31,		Three months ended March 31,	
(in millions)	**2002**	**2001**	**2002**	**2001**
Net income	$ 631	$ (951)	$ 596	$ (994)
Cumulative effect of adoption of SFAS No. 133		(243)		90
Net Gain (Loss) from current period hedging transactions and price changes in accordance with SFAS No. 133	(75)	(29)	-	1
Net reclassification to earnings	5	(43)	-	(143)
Comprehensive income (loss)	$ 561	$ (1,266)	$ 596	$ (1,046)

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 have not adopted or changed any accounting principles.

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. Implementation of this Statement did not have any impact on PG&E Corporation's and the Utility's statement of position or results of operation. The amount of goodwill amortization expense for the three months ended March 31, 2001, was $1 million. Prospective elimination of goodwill amortization will not have a significant impact on the financial statements.

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			
	March 31, 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	44	8	44	8
Other Agreements	28	6	27	5
Utility:				
Hydro Licenses and other Agreements	66	15	66	14
PG&E Corporation-Consolidated	$ 171	$ 35	$ 170	$ 33

The schedule below shows the aggregate amortization expense for the periods.

	Three months ended March 31,	
(in millions)	2002	2001
Amortization expense:		
PG&E NEG	$ 1	$ 1
Utility	1	1

The following schedule shows the estimated amortization expenses of intangible assets for the next five years.

(in millions)	2002	2003	2004	2005	2006
PG&E NEG	$ 6	$ 6	$ 6	$ 6	$ 6
Utility	3	3	3	5	6

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 the fundamental provisions for recognizing and measuring impairment of long-lived assets to be held and used or disposed of by sale. The Statement also supersedes the accounting and reporting provisions for the disposal of a segment of a business. SFAS No. 144 eliminates the conflict between accounting models for treating the disposition of long-lived assets that existed between SFAS No. 121 and the guidance for a segment of a business accounted for as a discontinued operation by adopting the methodology established in SFAS No. 121, and also resolves implementation issues related to SFAS No. 121. The adoption of the statement did not have an impact on the Consolidated Financial Statements of PG&E Corporation or the Utility.

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 March 31,	
(in millions)	**2002**	**2001**
Utility revenues from:		
Administrative services provided to PG&E Corporation	$ 1	$ 2
Gas reservation services provided to PG&E ET	3	3
Utility expenses from:		
Administrative services received from PG&E Corporation	$ 27	$ 25
Gas commodity and transmission services received from PG&E ET	19	77
Transmission services received from PG&E GT	12	11

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 rate freeze prohibited the Utility from passing on the increases in power costs to its customers. The Utility continued to finance 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 a total of approximately $6.9 billion in under-collected power costs and generation-related transition costs as of December 31, 2000. The under-collected purchased power costs generally 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 earnings for its under-collected purchased power costs and its remaining unamortized transition costs at December 31, 2000.

During 2001, the CPUC increased electric rates, and the price of wholesale electricity stabilized. As a result, in 2001, the Utility's generation-related electric revenues were greater than its generation-related costs, resulting in earnings of $458 million, 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.

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, 2001, 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, 2001, in a court proceeding involving a settlement between Southern California Edison Company (SCE) and the CPUC authorizing SCE to maintain its existing retail electric rates at the same levels as the AB 1890 rate freeze in order to recover SCE's unrecovered transition and purchased power costs, the CPUC represented to the court that it has the authority to allow the Utility and SCE to recover their under-collected transition costs beyond the end of the AB 1890 rate freeze. 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. 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, 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.

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 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 utilities for the two-year period ending December 31, 2002. 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 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, the February 21, 2002, CPUC order, and the March 21, 2002, CPUC order, the Utility has reversed the excess of the ISO accrual for the period from January 17, 2001, through April 6, 2001, 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.

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 in the Bankruptcy Court a voluntary petition for relief under Chapter 11 of the Bankruptcy Code. 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 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 March 31, 2002 Consolidated Balance Sheets as $10.3 billion of Liabilities Subject to Compromise and as $3.0 billion of Long-Term Debt. 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 holders of such claims have received authorization from the Bankruptcy Court for relief from the stay for 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 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 interest on certain claims prior to the effectiveness of the Utility's Plan.

Through March 31, 2002, $44.8 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 financial institutions (which the Utility believes contain significant duplication). This 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.

Approximately $12.4 billion of claims have been disallowed by the Bankruptcy Court or withdrawn.

The claims resolution process in bankruptcy involves establishment of the validity of the claim and determination of specifically how the claim is to be discharged. 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 (Disclosure Statement). The Utility and PG&E Corporation filed or lodged 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 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 April 15, 2002, the CPUC filed a competing plan and disclosure statement with the Bankruptcy Court, as discussed below. Hearings are scheduled to occur in May 2002 to address any objections that may be filed with respect to the CPUC's plan and disclosure statement.

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 valid claims, with interest.

The Utility's Plan proposes that all valid 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%

PG&E Corporation and the Utility, through a settlement with a group of senior debtholders, have 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:

(in millions)	**Amount Owed**	**Agreed Upon Rate**
Commercial Paper Claims	$ 873	7.466% per annum
Floating Rate Notes	1,240	7.583% per annum
Senior Notes	680	9.625%
Medium Term Notes	287	5.81% to 8.45%
Revolving Line of Credit Claims	938	8.000% per annum

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 of the Plan 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 of the Plan does not occur on or before March 15, 2004, the agreed rates will be increased by an additional 37.5 basis points.

In December 2001 and January, February, and March 2002, the Bankruptcy Court approved supplemental agreements entered into between the Utility and several QFs to resolve the issue of the applicable interest rate to be applied to the pre-petition payables. 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) provide for an accelerated payment of the principal amount of the pre-petition payables (and interest thereon) in 12 equal monthly payments of principal (and interest thereon) commencing on the last business day of the month during which Bankruptcy Court approval is granted, and continuing for 11 subsequent months, or, 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. At March 31, 2002, $246 million and $46 million in principal and interest, respectively, have been paid to the QFs. Through March 31, 2002, 166 of 313 active QFs have signed supplemental agreements. The Utility believes that most remaining QFs will also wish to enter into similar supplemental agreements.

On March 27, 2002, the Bankruptcy Court authorized payment of pre- and post-petition interest to holders of certain undisputed claims, including creditors holding certain financial instruments issued by the Utility, 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). The Utility expects that payments pursuant to this authorization will be approximately $700 million by July 30, 2002, based on the claim amounts estimated in the Disclosure Statement and the Plan. The actual amount ultimately payable may be different, depending on the amount of claims allowed by the Bankruptcy Court.

On March 25, 2002, the Bankruptcy Court authorized the Utility to pay the principal amount of all undisputed creditor claims that are $5,000 or less and undisputed mechanics' lien and reclamation claims, for an aggregate amount of approximately $22 million. These amounts will be paid on or before July 30, 2002.

The Utility's Plan, which has been endorsed by the Official Committee of Unsecured Creditors (Committee) and another group of senior debtholders, 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 investment 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 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, the unit would have approximately 7,100 megawatts (MW) of generation. The facilities would be operated in accordance with all current FERC and NRC licenses. The generating business would sell its power back to the Reorganized Utility under a 12-year contract at a stable, market-based rate.

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 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;

- 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.

If the Bankruptcy Court determines that the CPUC and the State have not waived their sovereign immunity with respect to the Plan, the proponents intend to amend the conditions to 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 Utility's currently outstanding preferred stock would remain preferred stock of the Reorganized Utility. It is contemplated that holders of preferred stock would receive on the Effective Date, and in cash, 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 pursuant to the Securities Exchange Act of 1934, and would be freely tradeable 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 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 $50.00 per megawatt-hour (MWh), and (3) the assumption by the Reorganized Utility of responsibility for the net open position only after 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 Debtor 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.

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 the various service agreements to be entered into between the Reorganized Utility and one or more of the disaggregated entities. Additionally, the SEC must approve the Plan as administrator of the Public Utility Holding Company Act (PUHCA). 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 & Poors (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.

On March 18, 2002, the Bankruptcy Court entered an order disapproving the First Amended Disclosure Statement, concluding that bankruptcy law does not expressly preempt state law in connection with the implementation of a plan of reorganization. Instead, the Bankruptcy Court interpreted the applicable bankruptcy law to impliedly preempt state law where it has been shown that enforcing the state law at issue would be an obstacle to the accomplishment and execution of the full purposes of the bankruptcy laws. On March 22, 2002, PG&E Corporation and the Utility filed a Notice of Appeal of the Bankruptcy Court's March 18, 2002, order and elected to have the appeal heard by the United States District Court.

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 provided by the Bankruptcy Court, on April 15, 2002, the CPUC filed its Alternative Plan which, although similar to the plan described in its term sheet, contained significant differences. 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 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 during 2001, 2002, and January 2003;

- Proposes to raise $3.9 billion through the issuance of new debt;

- Proposes to raise $1.75 billion through the sale of Utility stock;

- Assumes the Utility will satisfy FERC's creditworthiness requirements and will resume purchasing the net open position no later than January 31, 2003;

- Require 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 $5.8 billion);

- Become 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 which may be needed to pay collateral for post-petition worker's compensation liabilities.

The CPUC's proposed timeline for its alternate plan provides for a confirmation order to be issued on or before October 31, 2002, and for the 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 and no more practical or confirmable than its first plan. PG&E Corporation and the Utility also do not believe the CPUC's plan will restore the Utility to investment grade status when the plan becomes effective. Additionally, PG&E Corporation and the Utility believe the CPUC's plan to eliminate any return on equity violates federal and state law and would prompt substantial litigation. Objections to the CPUC's Alternative Plan and related disclosure statement are due on May 3, 2002, and a hearing to consider the filed objections is set for May 9, 2002.

Further, on April 22, 2002, the CPUC, in responding to a legal challenge by the Foundation for Taxpayers and Consumer Rights (FTCR) that the CPUC did not have the authority to propose an alternative plan, voted to initiate a regulatory proceeding to consider the rate impacts of its Alternative Plan in order to give interested parties an opportunity to comment.

The Bankruptcy Court has set June 17, 2002, as the target date to begin solicitations of creditor approval of the competing plans. PG&E Corporation and the Utility anticipate that the 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. Once the voting period has ended the Bankruptcy Court will select a plan to confirm, taking into consideration creditor preference, plan feasibility, distributions to creditors, and the financial viability of the reorganized entity.

PG&E Corporation and the Utility are unable to predict which plan the creditors will approve, or which plan, if any, the Bankruptcy Court will confirm. The Utility's current exclusivity period for proposing a Plan, which is applicable to all parties other than the CPUC, is scheduled to terminate on June 30, 2002. PG&E Corporation and the Utility cannot predict whether the Bankruptcy Court would issue an order, upon the request of the Utility, approving further extensions of this exclusivity period. Consideration of alternative plans could cause delays in the current schedule contemplated under the Utility's Plan. Whichever plan is confirmed, implementation of the confirmed plan may be delayed due to appeals, CPUC actions or proceedings (including the recently opened investigative proceedings to consider the rate impacts of CPUC's Alternative Plan), the FERC or other regulatory hearings that could be required in connection with the regulatory approvals necessary to implement the plan and other events. The tendency 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. The Utility is not able at this time to predict the outcome of its 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 March 31, 2002, of $4.7 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's net gain (loss) on trading activities, recognized on a fair value basis, were as follows:

(in millions)	Three months ended March 31, 2002	Three months ended March 31, 2001
Trading activities[(1)]:		
Unrealized losses, net	$ (3)	$ (46)
Realized gains, net	45	74
Total	$ 42	$ 28

[(1)] The Utility did not engage in trading activities for the periods presented.

PG&E Corporation's and the Utility's ineffective portion of changes in fair values of cash flow hedges were immaterial for the three months ended March 31, 2002. PG&E Corporation's and the Utility's estimated net derivative gains or losses included in accumulated other comprehensive income (loss) at March 31, 2002, that are expected to be reclassified into earnings within the next 12 months are net losses of $31 million and $0, respectively. The actual amounts reclassified from accumulated other comprehensive loss to earnings can differ as a result of market price changes. At March 31, 2002, the maximum length of time over which PG&E Corporation had hedged its exposure to the variability in future cash flows associated with commodity price risk is through December 2010. The maximum length of time over which PG&E Corporation has hedged its exposure to the variability in future cash flows associated with interest rate risk is through March 2014.

The schedule below summarizes the activities affecting accumulated other comprehensive loss net of tax, from derivative instruments for the three months ended March 31, 2002:

(in millions)	PG&E Corporation	Utility
Derivative gains (losses) included in accumulated other comprehensive income (loss) at January 1	$ 36	$ -
Net loss of current period hedging transactions and price changes	(75)	-
Net reclassification to earnings	5	-
Derivative losses included in accumulated other comprehensive loss at March 31	(34)	-
Foreign currency translation adjustment	(5)	(2)
Other	(1)	-
Accumulated other comprehensive loss at March 31	$ (40)	$ (2)

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. 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 its 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 a master agreement containing 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 mark-to-market 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 March 31, 2002, PG&E Corporation and the Utility customers that represent greater than 10 percent of their respective total credit exposures include the DWR, which represents 12 percent of PG&E Corporation's credit exposure. In addition, two investment grade counterparties account for 18 percent and 14 percent, respectively, of the Utility's credit exposure.

The schedule below summarizes the exposure to counterparties that are in a net asset position, with the exception of written options and exchange-traded futures (the exchange provides for contract settlement on a daily basis) at March 31, 2002:

(in millions)	**Gross Exposure** (1)	**Credit Collateral** (2)	**Net Exposure** (2)
PG&E Corporation	$ 965	$ 183	$ 782
Utility	216	104	112

(1) Gross credit exposure equals mark-to-market value plus net (payables) receivables where netting is allowed. The Utility's gross exposure includes wholesale activity only. Retail activity and payables prior to the Utility's bankruptcy filing are not included.

(2) Net exposure is the gross exposure minus credit collateral (cash deposits and letters of credit). Amounts are not adjusted for probability of default.

The majority of counterparties to which PG&E Corporation and the Utility are exposed are considered to be investment grade, determined using publicly available information including an S&P rating of at least BBB-. At March 31, 2002, PG&E Corporation's net credit exposure to below investment grade entities, consisting principally of DWR and Southern California Edison, aggregates to approximately $266 million or 34 percent. Approximately $34 million or 30 percent of the Utility's net credit exposure is below investment grade. PG&E Corporation's regional concentration of credit exposure is to counterparties that conduct business primarily in the western United States and also to counterparties that conduct business primarily throughout North America. The Utility has a regional concentration of credit exposure to counterparties that conduct business primarily throughout the entire United States.

NOTE 4: DEBT FINANCING

PG&E NEG

On April 5, 2002, GenHoldings I, LLC increased its committed financing from $1.075 billion to $1.460 billion. 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.

In April 2002, PG&E GTN received commitments from several financial institutions for a new three-year revolving credit agreement of up to $125 million to replace the existing revolving credit agreement. PG&E GTN expects to complete such financing in May 2002. PG&E GTN also plans to obtain additional long-term financing in the near future and has obtained a commitment from a financial institution for a backup 364-day bank facility if PG&E GTN decides to postpone such long-term financing.

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 issuance of the common stock securities to purchase 7.90 percent Deferrable Interest Subordinated Debentures (Debentures), due 2025, issued by the Utility with a face value of $309 million.

On March 16, 2001, the Utility deferred quarterly interest payments on the Utility's Debentures 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, have been similarly deferred.

Distributions may be deferred up to 20 consecutive quarters under the terms of the indenture. Per 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 these QUIPS would be entitled to the liquidation preference of $25 per share plus all accrued and unpaid dividends thereon to the date of payment.

On April 12, 2001, Bank One, N.A., as successor-in-interest to The First National Bank of Chicago (Property Trustee), gave notice that an event of default exists under the Trust Agreement due to the Utility's filing for Chapter 11 on April 6, 2001 (see Note 2). As a result of the Chapter 11 filing, the Trust Agreement requires the Trust to be liquidated by the Trustees by distributing, after satisfaction of liabilities to creditors of the Trust, the Debentures to the holders of the QUIPS. The liquidation date of the Trust is May 24, 2002.

On December 13, 2001, the Utility received permission from the Bankruptcy Court to distribute the Debentures of the Utility, and register the Debentures under the Securities Exchange Act of 1934. However, the Debentures will not be distributed to QUIPS holders until such time as the Trustee notifies the holders of the QUIPS of the Trust's liquidation. The Trustee has notified the QUIPS holders that the Trust will be liquidated as of May 24, 2002, and that on such date the Debentures will be distributed to the former holders of QUIPS. The QUIPS are reflected as "Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures" on the Utility's Consolidated Balance Sheets. The terms and interest payments on the Debentures correspond to the terms and dividend payments of the QUIPS. The Utility has the right to redeem all or part of the Debentures.

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 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 April 2003, and total $466 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 or Reorganization; or
- the dismissal or conversion of the Utility's bankruptcy proceeding.

At March 31, 2002, total gas accounts receivable pledged amounted to $453 million.

At March 31, 2002, the Utility's obligations related to natural gas transportation and supply commitments held pursuant to long-term contracts are as follows:

(in millions)	
2002	$ 474
2003	201
2004	88
2005	77
2006	21
Thereafter	5
Total	$ 866

PG&E NEG

Letters of Credit - Certain of PG&E NEG's commitments in connection with agreements entered into supporting its construction and development activities are supported by letters of credit. The following table provides the various letters of credit facilities which have the capacity to issue letters of credit (in millions):

Borrower	**Maturity**	**Letter of Credit Capacity**	**Letters of Credit Outstanding March 31, 2002**
PG&E NEG	8/02 & 8/03	$ 650	$ 197
USGenNE	9/03	50	9
PG&E GenLLC	12/04	10	7
PG&E ET	12/02	25	19
PG&E ET	-[1]	50	22
PG&E ET	11/03	35	32

[1] This letter of credit facility provides for up to $50 million of 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.

Contingencies

PG&E Corporation Guarantees

At March 31, 2002, PG&E Corporation had issued a $16 million guarantee for an office lease relating to PG&E NEG's San Francisco office. PG&E Corporation also has a $0.9 million guarantee supporting the Utility's investment in low-income housing projects at March 31, 2002. See below for additional PG&E Corporation guarantees.

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 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 provide collateral to maintain its status as a self-insurer for workers' compensation. Acceptable forms of collateral include surety bonds, letters of credit, cash, or securities. On May 9, 2001, the State Department of Industrial Relations (DIR) approved the Utility's security deposit of approximately $401 million in surety bonds. The Utility's reimbursement obligations under these bonds and the underlying workers' compensation obligations are guaranteed by PG&E Corporation.

In February 2001, several surety companies provided cancellation notices, citing concerns about the Utility's financial situation. However, the state 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 required $401 million amount of collateral. The Utility was able to supplement the difference through three additional active surety bonds totaling $216 million. The cancelled bonds have not, to date, impacted the Utility's self-insured status under California law, or its ability to meet current plan obligations.

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 $303 million and $295 million (undiscounted) at March 31, 2002, and December 31, 2001, respectively. The $303 million accrued at March 31, 2002, includes (1) $139 million related to the pre-closing remediation liability associated with divested generation facilities, and (2) $164 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 $303 million environmental remediation liability, the Utility has recovered $191 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 $452 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 to 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 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 they accept responsibility to clean up the sites, which is unlikely. Since the 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 it 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 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 - The Utility's Diablo Canyon employs a “once-through” cooling water system, which is regulated under a NPDES Permit issued by the Central Coast Board. This permit allows Diablo Canyon to discharge the cooling water at a temperature no more than 22 degrees above ambient receiving water and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, marine and wildlife habitat, shellfish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft Cease and Desist Order alleging that, although the temperature limit has never been exceeded, Diablo Canyon's discharge was not protective of beneficial uses. In October 2000, the Central Coast Board and the Utility reached a tentative settlement of this matter pursuant to which the Central Coast Board has agreed to find that the Utility's discharge of cooling water from the Diablo Canyon plant protects beneficial uses and that the intake technology reflects the “best technology available” under Section 316(b) of the Federal Clean Water Act. As part of the settlement, the Utility will take measures to preserve certain acreage north of the plant and will fund approximately $5 million in environmental projects related to coastal resources. The parties are negotiating the documentation of the settlement. The final agreement will be subject to public comment and will be incorporated in a consent decree to be entered in California Superior Court. 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.

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

PG&E NEG

Guarantees Supporting Tolling Agreements - A subsidiary of the PG&E NEG has entered into five long-term tolling transactions with third parties. Each tolling agreement is supported by a separate guarantee backing PG&E NEG affiliate’s payment obligations over the term of these long-term contracts (9-25 years). PG&E NEG has extended approximately $620 million of such guarantees with the initial face values varying from $20 million to $250 million declining over time as the future obligation declines. Each of these guarantees contains a trigger event provision that requires the guarantor to replace the guarantee or provide alternative collateral in the event that PG&E NEG’s credit rating drops (as measured by one or two major agencies as identified in the agreement) below the prescribed grade (generally BBB or Baa2). At March 31, 2002, the net exposure under guarantees supporting tolling agreements was approximately 3% or $20 million.

Guarantees Supporting Trading Related Agreements - PG&E NEG's energy marketing, trading, hedging, and risk management operations are conducted with counterparties under various master agreements. These agreements typically provide for reciprocal extension of credit lines based on creditworthiness standards. Net open positions under these agreements are marked-to-market on a routine basis and if the net exposed position including receivables and payables falls outside of the established credit limits, then additional collateral must be provided. Therefore, key components of a successful energy business consist of creditworthiness, liquidity resources, risk management systems that provide current mark-to-market of all open positions, and a strong credit department to evaluate and manage counterparty credit risk.

In addition to issuing guarantees supporting tolling agreements, at March 31, 2002, PG&E NEG and its subsidiaries provided $2.7 billion of guarantees to counterparties in support of its energy trading operations. This includes provision of fuel and pipeline capacity to, and sale of energy products from, its power plants. These guarantees were provided in favor of approximately 230 counterparties to permit and facilitate physical and financial transactions in gas, pipeline capacity, power, coal, and related commodities and services with these entities. Typically, the overall exposure under these guarantees is only a fraction of the face value of the guarantees, since not all counterparty credit limits are fully utilized at any time and there may be no outstanding transactions or financial exposure underlying an outstanding guarantee. PG&E NEG receives similar deposits, letters of credit, and guarantees as collateral for credit extended by PG&E NEG to these, in many cases, same counterparties. These offsetting exposures can often be netted in lieu of posting alternative collateral. At March 31, 2002, PG&E NEG's net exposure under its guarantees was approximately 9 percent or approximately $260 million. This exposure is a contingent obligation that could be called only if PG&E NEG or one of its subsidiaries fails to meet and then fails to cure a payment obligation.

The continued acceptability of many of these guarantees is dependent on PG&E NEG's maintaining various standards of creditworthiness. As a result, maintenance of investment grade ratings by one or more rating agencies is an important criterion for PG&E NEG and its subsidiaries. If PG&E NEG or its subsidiaries are downgraded by one or more of the rating agencies, PG&E NEG may be required to provide alternative collateral to replace guarantees that no longer meet the creditworthiness standards of the agreements. Therefore, PG&E NEG and its trading subsidiaries maintain substantial cash balances and credit capacity to provide liquidity to its businesses in the event that open credit limits are exceeded through volatility, or in the event of a credit downgrade.

The amount of exposure under master agreements subject to securitization requirements in the event of a credit downgrade of PG&E NEG or its subsidiaries to below investment grade by one or more rating agencies was approximately 5 percent of the outstanding guarantees or approximately $144 million at March 31, 2002. PG&E NEG manages this risk through maintenance of investment grade credit ratings at several principal operating subsidiaries so that guarantees of one entity could be substituted for another in the event of a credit downgrade of one entity.

Guarantees Supporting Other Agreements with Third Parties - PG&E NEG and its subsidiaries have issued in excess of $720 million of guarantees in support of various performance and payment obligations under agreements with third parties. Of these guarantees supporting other agreements with third parties, $486 million have investment grade rating maintenance requirements. In addition, a number of other agreements have specific security provisions requiring maintenance of investment grade ratings. In the event of a downgrade below the trigger level and exhaustion of any cure period, some of these agreements would allow the counterparty to demand payment for any outstanding obligations or contract termination penalties, if any. Others simply provide the counterparty with a right to terminate the contract.

Environmental Matters

In May 2000, USGen New England (USGenNE), an indirect subsidiary of PG&E NEG, received an Information Request from the U.S. Environmental Protection Agency (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 Generating Stations with the CAA. No enforcement action has been brought by the EPA to date. USGenNE has had very 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 initiatives that would assist USGenNE to achieve significant reductions of sulfur dioxide and nitrogen oxide and thermal emissions by 2006. 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 approximate $266 million over the next five years. The Massachusetts Department of Environmental Protection (DEP) may require earlier compliance, which USGenNE believes may not be feasible and would require the use of credit allowances it currently owns or the purchase of additional credit allowances.

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 are operating pursuant to NPDES permits that have expired. For the facilities whose NPDES permits have expired, permit renewal applications are pending, and it is anticipated that all three facilities will be able to continue to operate under existing terms and conditions until new permits are issued. Those three facilities are Salem Harbor, Manchester Street, and Brayton Point. It is estimated that USGenNE's cost to comply with the new permit conditions could be as much as $67 million through 2005. It is possible that the new permits may contain more stringent limitations than prior permits, and that the cost to comply with the new permit conditions could be substantially greater than that amount.

On March 27, 2002, Rhode Island Attorney General Sheldon Whitehouse notified USGenNE, of his belief that PG&E NEG's Brayton Point Station "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 intends 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. PG&E NEG is currently awaiting the issuance of a draft Clean Water Act NPDES permit renewal from the EPA. Management is unable to predict whether the outcome of this matter will have a material adverse effect on PG&E Corporation's financial condition or results of operation.

Additionally, 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 over 50 million gallons per day (mgd), typically including some form of "once-through" cooling. PG&E NEG's Brayton Point, Salem Harbor, and Manchester Street Stations are among an estimated 539 plants nationwide that would be affected by this rulemaking. The proposed rule calls for a set of performance standards that vary with the type of water body and which are intended to reduce impacts to aquatic organisms. Significant capital investment will likely be required to achieve the standards if the regulations are finalized as proposed. The final rules are scheduled for promulgation in August 2003.

During April 2000, an environmental group served USGenNE and other of PG&E NEG's subsidiaries with a notice of its intent to file a citizen's suit under 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 and $2.4 million in 2001. In addition to the costs incurred in 2000 and 2001, at December 31, 2001, PG&E NEG maintains a reserve in the amount of $10 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.

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 Act required that they be promulgated by November 2000. Another provision in the Act requires companies to submit case-by-case 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 Maximum Achievable Control Technology (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 anticipates spending up to approximately $363 million, net of insurance proceeds, through 2008 for environmental compliance at currently operating facilities. PG&E NEG believes that a substantial portion of this amount will be funded from PG&E NEG's operating cash flow. 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.

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 this are discussed below. The Utility's Chapter 11 bankruptcy filing on April 6, 2001, discussed in Note 2, automatically stayed the litigation described below against the Utility.

***Chromium Litigation* -** There are 16 civil suits pending against the Utility in several California state courts. Two of these suits also name PG&E Corporation as a defendant. 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 16 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 the 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 March 31, 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 United States 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 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 discuss 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 compensating damages, plus costs and attorneys' fees. 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 PG&E Corporation's financial condition or results of operations. On March 11, 2002, the defendants filed a motion to dismiss the second amended complaint. The court has set a hearing on the motion to dismiss for June 24, 2002.

***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.

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 mailed on January 11, 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 would violate the first priority condition.

On January 10, 2002, the 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 by seeking to implement the transactions proposed in the proposed Plan filed in the Utility's bankruptcy proceeding. The complaint also seeks restitution of assets allegedly wrongfully transferred to PG&E Corporation from the Utility. The Bankruptcy Court has original and exclusive jurisdiction of these claims. Therefore, 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 and a decision is pending.

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 PG&E," 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 and County of San Francisco's (City) 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 and a decision is pending.

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 alleging a violation of California Business and Professions Code Section 17200 which prohibits unfair business practices. 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 in 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 and a decision is pending.

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 April 10, 2002, the CPUC set a prehearing conference for May 8, 2002. 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
Provisions for liabilities	17
Payments	-
Ending balance, March 31,	$ 226

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 generally accepted accounting principles, prior year segment information has been restated to conform to the current segment presentation. The Utility is one reportable operating segment and the other two are part of PG&E NEG. These three reportable operating segments provide products and services and are subject to different forms of regulation or jurisdictions. PG&E Corporation's reportable segments are described below.

Segment information for the three months ended March 31, 2002 and 2001 was as follows:

(in millions)	Utility	Total PG&E NEG (PG&E National Energy Group)	Integrated Energy & Marketing (PG&E National Energy Group)	Interstate Pipeline Operations (PG&E National Energy Group)	PG&E NEG Eliminations (PG&E National Energy Group)	PG&E Corporation & Other Eliminations[2]	Total
Three months ended March 31, 2002							
Operating revenues	$ 2,450	$ 2,317	$ 2,274	$ 47	$ (4)	$ -	$ 4,767
Intersegment revenues [1]	3	31	19	12	-	(34)	-
Total operating revenues	2,453	2,348	2,293	59	(4)	(34)	4,767
Net income (loss)	590	37	26	18	(7)	4	631
Total assets at March 31, 2002 [3]	25,279	10,669	9,212	1,290	167	350	36,298
Three months ended March 31, 2001							
Operating revenues	2,560	4,113	4,066	56	(9)	-	6,673
Intersegment revenues [1]	2	93	84	9	-	(95)	-
Total operating revenues	2,562	4,206	4,150	65	(9)	(95)	6,673
Net income (loss)	(1,000)	54	35	20	(1)	(5)	(951)
Total assets at March 31, 2001 [3]	$ 22,455	$ 13,252	$ 11,833	$ 1,188	$ 231	$ 358	$ 36,065

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

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

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

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 4.7 million customers and natural gas service to approximately 3.9 million customers. PG&E Corporation's other significant subsidiary is PG&E National Energy Group, Inc. (PG&E NEG), headquartered in Bethesda, Maryland. 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 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 its generation, development and energy marketing, and trading activities in an effort to create energy products in response to customer needs, increase the returns from its operations, and identify and capitalize on opportunities to increase its 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 LLC); 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 includes PG&E Gas Transmission, Northwest Corporation and its subsidiaries (collectively, PG&E GTN), and PG&E North Baja Pipeline, LLC (PG&E 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 is a combined Quarterly Report on Form 10-Q 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 included herein. Further, this quarterly report should be read in conjunction with PG&E Corporation's and the Utility's Consolidated Financial Statements and Notes to the Consolidated Financial Statements incorporated by reference in their combined 2001 Annual Report on Form 10-K.

This combined Quarterly Report on Form 10-Q, 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 for 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, and the impact of the end of the rate freeze period;

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

    - The timing of the approval of the disclosure statement relating to the alternative plan of reorganization (Alternative Plan) of the Utility sponsored by the California Public Utilities Commission (CPUC) which may be delayed due to challenges made by consumer groups as to the CPUC's authority to propose the Alternative Plan and the recently opened investigative proceeding to consider the rate impacts of the Alternative Plan, or other events;

    - whether the Utility's creditors approve PG&E Corporation's and the Utility's proposed plan of reorganization (Plan) or the Alternative Plan;

    - whether the Bankruptcy Court will confirm either plan and the timing of such confirmation;

    - whether the CPUC or the State of California take action that would negatively affect the feasibility of PG&E Corporation's and the Utility's proposed Plan;

    - whether the Bankruptcy Court will permit other parties to submit alternative plans of reorganization after June 30, 2002, when the period during which (except for the CPUC), only the Utility may submit a plan expires, or whether the Bankruptcy Court will extend such exclusivity period;

    - assuming the Utility's Plan is confirmed, the pace of implementation of the Plan, which may be delayed to beyond the Utility's Plan's target date of January 1, 2003, due to delays in obtaining various regulatory or governmental approvals in connection with the transactions contemplated under the Plan, or by appeals or litigation relating to the confirmation order or the regulatory or governmental approvals, and the effect any delay could have on creditor support of the Utility's Plan and the continued feasibility of the Utility's Plan;

    - whether in connection with the confirmed plan, the Utility is required to re-assume the obligation to purchase power for its customers from the California Department of Water Resources (DWR) under circumstances that threaten to undermine the Utility's creditworthiness, financial condition, or results of operation;

    - whether in connection with the confirmed plan, the Utility is required to accept assignment of the DWR's power purchase contracts;

- whether, even if confirmed, the Plan is implemented, which may be affected by, among other factors:

- risks relating to the issuance of new debt securities by each of the disaggregated entities, including higher interest rates than are assumed in the financial projections which could affect the amount of cash that could be raised to satisfy allowed claims, and the inability to successfully market the debt securities due to, among other reasons, an adverse change in market conditions or in the condition of the disaggregated entities before completion of the offerings;

- the failure to obtain a favorable tax ruling or opinion regarding the tax-free nature of the transactions contemplated in the Plan; and

- the failure to obtain approval from the various federal regulatory agencies to implement the transactions contemplated in the Plan;

- whether the Utility will be able to successfully disaggregate its businesses, if the Utility's Plan is confirmed and becomes effective;

- the effect of the Utility's bankruptcy proceedings on PG&E Corporation and PG&E NEG, and in particular, the impact a protracted delay in the Utility's bankruptcy proceedings could have on PG&E Corporation's liquidity and access to capital markets;

- 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, the City and County of San Francisco, and the People of the State of California, 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 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, and by the interpretation of the CPUC's holding company conditions;

- the outcome of the Utility's various regulatory proceedings pending at the CPUC, including the 2002 attrition rate adjustment application, the 2003 General Rate Case (GRC), and any future retail rate changes that may be implemented by the CPUC to reflect the adopted revenue requirements for the Utility's retained generation and DWR purchases made on behalf of the Utility's retail customers;

- whether the CPUC's March 27, 2001, accounting decision regarding the Utility's under-collected wholesale power purchase costs is upheld and whether the Utility's lawsuit against the CPUC for recovery of those costs is successful;

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

- whether the Utility's hydroelectric and non-nuclear generating assets are valued for regulatory and ratemaking purposes and if so, the amount and timing of such regulatory valuation;

- 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;

- the volatility of commodity fuel and electricity prices (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;

- PG&E NEG's ability to obtain financing from third parties, or from PG&E Corporation for PG&E NEG's planned development projects and related equipment purchases and to refinance PG&E NEG's and its subsidiaries' existing indebtedness as it matures, in each case, on reasonable terms, while preserving PG&E NEG's credit quality, which could be negatively affected by conditions in the general economy, the energy markets, or the capital markets; and the extent to which the CPUC's holding company conditions may be interpreted to restrict PG&E Corporation's ability to provide financial support to PG&E NEG;

- the extent to which the CPUC's holding company conditions may be interpreted to restrict PG&E Corporation's ability to provide financial support to PG&E NEG;

- the extent to which PG&E NEG's current or planned development 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 development 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;

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

- the performance of PG&E NEG's projects and the success of PG&E NEG's efforts to invest in and develop new opportunities;

- restrictions imposed upon PG&E Corporation and PG&E NEG under certain term loans of PG&E Corporation, including maintenance of minimum segregated cash balances by PG&E Corporation and prohibitions on payment of dividends by both PG&E Corporation and PG&E NEG, and the extent to which the debt covenants can be maintained;

- future sales levels, which, in the case of the Utility, will be affected by the level of exit fees that may be imposed on direct access customers; general economic and financial market conditions; and changes in interest rates;

- volatility resulting from mark-to-market accounting 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 effect of compliance with existing and future environmental laws, regulations, and policies, the cost of which could be significant;

- heightened rating agency criteria and the impact of changes in credit ratings on PG&E NEG's future financial condition, particularly a downgrade to below investment grade which would impair PG&E NEG's ability to meet liquidity calls in connection with its trading activities and obtain financing for its planned development projects;

- 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 first quarter 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 $2.50 to $2.55 per share on a fully diluted basis. Earnings from operations exclude headroom and 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 wholesale electricity 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 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. On April 15, 2002, the Utility filed a proposal with the CPUC to reduce rates by approximately $0.05 per kWh to eliminate that portion of the surchage that was to compensate the Utility for the period from March 27, 2001 (the date of the decision) until implementation on June 1, 2001.

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 this ruling, along with other rulings, illegally compels the Utility to make payments to the DWR and QFs without providing adequate revenues for such payments.

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 discussed further in Note 2 of the Notes to the Consolidated Financial Statements, 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 wholesale electricity 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.

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 under the high-price period combined with a softening economy have resulted in projected excess energy supply. The price of electricity minus the cost of fuel, or spark spread, available in most regional wholesale energy markets has declined recently, and prices and spark spreads in the forward markets in which PG&E NEG transacts much of its business for its generating portfolio have declined as well. Furthermore, the economic slowdown and a number of regulatory events, many of which were consequences of the California energy crisis and the Enron Corp. Bankruptcy, have increased uncertainty in the energy sector.

Conditions in the national energy markets will constrain PG&E NEG’s near-term growth. The U.S. economy has slowed significantly in the last year, and the timing for a recovery is uncertain. A lower level of economic activity may result in a decline in energy consumption and new electric supply additions begun during more robust economic conditions are beginning to commence operation. The combination of decreased consumption and increased supply may result in excess supply and declining operating margins for electric generators. Furthermore, these same factors may result in lower price volatility for energy products, potentially reducing profits from energy trading activities. In response to these market changes, PG&E NEG may defer, cancel, sell, joint venture or otherwise dispose of some or all of PG&E NEG's projects in development and the equipment associated with those projects.

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 unproven new technology turbines, 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) will no longer be available on commercially reasonable terms, deductibles will increase in size, and premiums will be significantly higher.

LIQUIDITY AND FINANCIAL RESOURCES

In March 2002, PG&E Corporation signed an agreement to amend its current $1 billion aggregate term loan credit facility with General Electric Capital Corporation (GECC) and Lehman Commercial Paper Inc. (LCPI) and their assignees. The obligations under the credit agreement (originally entered into on March 1, 2001) are secured by a pledge of PG&E Corporation's interest in PG&E NEG. The credit agreement also provided the lenders an option to purchase for $1.00 up to a 3 percent ownership interest in PG&E NEG, depending upon how long the loans are outstanding. The original credit agreement permitted PG&E Corporation to extend the term of the credit facility, which would otherwise expire on March 2, 2003, by an additional year upon payment of a fee and a principal payment of $308 million. The March 2002 amendment provides for two additional one-year extensions so that the termination date could be extended to March 2, 2006, contingent upon PG&E Corporation making an accelerated principal payment of $308 million by June 3, 2002. If PG&E Corporation fails to make the principal payment by June 3, 2002, the loan would mature on March 2, 2003, unless PG&E Corporation pays a fee of up to 4 percent of the then outstanding balance of the loan for the one-year extension.

Assuming PG&E Corporation makes the accelerated payment by June 3, 2002, PG&E Corporation must pay a fee of 3 percent of the then-outstanding balance of the loan and also issue to the lenders additional options equal to approximately 1 percent of the common stock of PG&E NEG, as a condition for the exercise of each of the one-year extensions.

In addition, the credit agreement with GECC and LCPI provides that a failure to comply with financial covenants will constitute an event of default, after applicable grace periods. These covenants include, among other things, the requirement that PG&E NEG maintain an investment grade credit rating and a ratio of fair market value to the aggregate amount of principal outstanding under the loan of at least 2:1, and that PG&E Corporation maintain a cash reserve of at least 15 percent of the loan balance until March 2, 2004, and 10 percent thereafter, unless interest is prepaid. In addition, failure of PG&E NEG to maintain at least a 1.25:1 ratio of fair market value to loan balance would constitute an immediate event of default and result in acceleration of the loan.

PG&E Corporation, on an unconsolidated basis, had cash and short-term investments of approximately $350 million at March 31, 2002, and believes that the funds will be adequate to maintain PG&E Corporation's continuing operations through 2002.

Unless funded from internal sources, PG&E Corporation would be required to obtain additional debt or equity financing to meet its future liquidity needs. The ability of PG&E Corporation to obtain required debt or equity financing on reasonable terms may be affected by conditions in the general economy, the energy or capital markets, by restrictions imposed on PG&E Corporation under its credit agreement, and by the interpretation of the CPUC's holding company conditions. The structure and source of any such financing may be affected by regulatory considerations and the uncertainty surrounding the outcome of the Utility's bankruptcy proceeding. To the extent that PG&E Corporation issues additional equity, such issuance would dilute the equity interests of the holders of PG&E Corporation outstanding common stock.

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.

Credit Ratings

As discussed below, the California energy crisis has impacted the credit ratings of various debt and equity instruments. The credit ratings at March 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 and Poors	**Moody's Investors Service**
PG&E Corporation		
GECC/LCPI	Not Rated	B2
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 W/D
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
Quarterly Income Preferred Securities (QUIPS)	D	Caa3
Preferred Stock	D	Ca
PG&E NEG		
Senior Unsecured Notes due 2011 (PG&E NEG)	BBB	Baa2
Senior Unsecured Notes due 2005 (PG&E GTN)	A-	Baa1
Senior Unsecured Debentures due 2025 (PG&E GTN)	A-	Baa1
Medium-Term Notes (nonrecourse) (PG&E GTN)	A-	Baa1
Outstanding Credit Facilities	Various	Various
Term Loans-Gen Holdings	BBB-	Baa3
Mortgage Loans and Others	Not Rated	Not Rated

PG&E Corporation Consolidated

Operating Activities

Net cash provided by operating activities totaled $1.2 billion for the three months ended March 31, 2002, a decrease of $721 million from the same period in the prior year. The decrease is mainly attributed to the $1.1 billion income tax refund, received in the first quarter of 2001, somewhat offset by lower gas prices, and the net effect of changes in working capital at PG&E NEG, all occurring in the first quarter of 2002.

Investing Activities

Cash used in investing activities was $737 million for the three months ended March 31, 2002, an increase of $52 million over the same period in the prior year. The change is due to increased capital expenditures for the improvement of the Utility's electric and gas transmission and distribution networks, along with construction on PG&E NEG's generation facilities and pipelines. The increase in capital expenditures was somewhat offset by a decrease in PG&E NEG's development costs and turbine prepayments in the first quarter of 2002, as compared to the first quarter of 2001.

Financing Activities

Cash used in financing activities was $128 million for the three months ended March 31, 2002. The current quarter's activity resulted from the Utility's repayment of long-term debt, offset by PG&E NEG's increased borrowings under its existing credit facilities. Cash used on financing activities was $233 million for the three months ended March 31, 2001. This was the result of a loan to PG&E Corporation, which netted $906 million in proceeds, and was used with cash on hand to repay defaulted commercial paper, other loans, and dividends. In addition, the Utility and PG&E NEG also paid down long-term debt balances.

Utility

The Utility is currently operating as a debtor-in-possession under Chapter 11 of the Bankruptcy Code. Accordingly, the Utility's primary sources of liquidity are funds from operations. These funds are largely used to fund the ongoing operations and construction projects for its electric and gas distribution and transmission networks, along with its retained electric generation facilities. Under Chapter 11, the Utility is not restricted from capital investment, but is required to notify the Official Committee of Unsecured Creditors and Bankruptcy Court of all new capital projects greater than $10 million.

The following section discusses the Utility's significant cash flows from operating, investing, and financing activities for the three months ended March 31, 2002, and 2001.

Operating Activities

Net cash provided by operating activities decreased to $1.2 billion in the first quarter of 2002, from $1.8 billion for the same period in the prior year. The decrease is primarily due to receipt of the 2000 income tax refund of $1.1 billion in the first quarter of 2001, with no such refund received in the first quarter of 2002. In addition, payments for electricity purchase costs decreased in the first quarter of 2002 compared to the same period in 2001.

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 $353 million and $284 million for the three months ended March 31, 2002, and 2001, respectively, and 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 include significant ongoing capital projects totaling $223 million to upgrade its gas and electric transmission facilities. Total planned expenditures for 2002 to improve the distribution network for electric and gas operations are approximately $1.4 billion.

Financing Activities

Net cash used by financing activities in the first quarter of 2002 was $408 million, reflecting the repayment of long-term debt. On February 27, 2002, the Bankruptcy Court approved the payment of $333 million of mortgage bonds that matured in March 2002. In addition, the Utility paid $75 million of the Rate Reduction Bonds, which are held by PG&E Funding LLC, a wholly-owned subsidiary of the Utility.

Due to the bankruptcy and the lack of creditworthiness, 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 first quarter of 2001 was $215 million, reflecting the net repayment under credit facilities and short-term borrowings of $28 million and repayment of long-term debt of $187 million. Repayment of long-term debt consisted of $75 million related to the Utility's Rate Reduction Bonds, $93 million related to mortgage bonds maturing, and $19 million related to maturities of medium-term notes.

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

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 is 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. At March 31, 2002, PG&E NEG had $691 million in cash and approximately $700 million available in unused credit lines.

Operating Activities

During the three months ended March 31, 2002, PG&E NEG generated net cash from operations of $84 million compared to net cash used from operation of $192 million for the same period in 2001, or an increase of $314 million. Increases in net income, including adjustments to reconcile net income to net cash provided in operating activities, improved operating cash flow by $36 million period to period. The increase from period to period was primarily due to net price risk management activities, timing of deferred income tax, and increased non cash depreciation and amortization offsetting a lower net income. Cash flow from operations was also improved due to the net effect of changes in operating assets and liabilities of $240 million period to period. The net effect of changes in operating assets and liabilities were a use of operating cash for the three months ended March 31, 2001, of $189 million driven primarily by an increase in margin deposits relating to PG&E NEG's trading activities, whereas the net effect of working capital changes providing operating cash for the three months ended March 31, 2002, of $51 million was primarily due to reduced margin level requirements and increased option premiums.

PG&E NEG 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, the subsidiaries that own PG&E NEG's natural gas transmission facilities and 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 a 2.25 to 1.00 and a consolidated leverage ratio less than or equal to 0.70 to 1.00.

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 three months ended March 31, 2002, PG&E NEG used net cash of $377 million in investing activities compared to $265 million for the same period in 2001, or an increase of $112 million. Construction expenditures were $335 million and $123 million for the three months ended March 31, 2002, and 2001, respectively. Advanced development and turbine prepayments were $5 million and $90 million for the three months ended March 31, 2002, and 2001, respectively. Other net expenditures were $37 million and $52 million for the three months ended March 31, 2002, and March 31, 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, controls, or will own the output of ten generating facilities under construction. The following projects are consolidated by PG&E NEG: Lake Road, La Paloma, Athens, Plains End, Harquahala, and Covert. The table below outlines the expected dates that these projects will be completed.

Project	**Location**	**Percentage Completion**	**Projected In-Service Date**
Athens	New York	34%	3rd Quarter 2003
Covert	Michigan	25%	3rd Quarter 2003
Harquahala	Arizona	24%	2nd Quarter 2003
Lake Road	Connecticut	99%	2nd Quarter 2002
La Paloma	California	96%	4th Quarter 2002
Plains End	Colorado	95%	2nd Quarter 2002

Additionally, PG&E NEG will control the output of the following projects: Southaven, Caledonia, Liberty Elevtric and a portion of Otay Mesa. Calpine Corporation (Calpine), the owner of the Otay Mesa project, has informed PG&E NEG that Otay Mesa is under construction.

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 executed construction contracts 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. The ACOE has initially determined that the design of the first hydroelectric facility does not meet recently stated seismic requirements in light of the condition of the dam where the facility is to be located. PG&E NEG disagrees with these findings and believes that even if the ACOE maintains its position, certain engineering changes will remedy any deficiency. In the event that PG&E NEG is unable to proceed with this facility, PG&E NEG will be compelled to either relocate the facility to a different dam at a cost yet to be determined or terminate the contract for the procurement and construction of the facility resulting in a termination payment to the contractor of approximately $10.5 million to $12 million.

Generating Projects in Development

PG&E NEG has reviewed its growth plans for its electric generating business in light of circumstances presented by recent changes in energy and equity markets as well as the slowdown of the U.S. economy. Further, energy prices and price-earnings multiples for competitive energy companies have significantly declined, thereby constraining access to equity funds at acceptable terms to PG&E NEG. In response to these market changes, PG&E NEG continues to assess and modify its growth plans for ownership and control of electric generating facilities to manage its future capital and equity requirements. As a result, based on PG&E NEG's view of the regional energy markets, PG&E NEG expects to delay, swap or sell generation development projects that are currently not under construction and associated commitments to take delivery of turbines. Management expects that PG&E NEG's total owned and controlled generating capacity will be less than the 22,000 MW in 2004 that had been previously forecast. Since management's review of its growth plans for ownership and control of electric generating facilities is ongoing, it is not practical to provide new projections of the total capacity that PG&E NEG will own or control.

Turbine Purchase Commitments

To support PG&E NEG's development program, PG&E NEG has contractual commitments and options for combustion turbines and related equipment representing approximately 14,000 MW of net generating capacity. In connection with PG&E NEG's current revised development plans, PG&E NEG has restructured some of the equipment purchase and option commitments to provide additional flexibility in payment terms and delivery schedules to better accommodate the potential delay, swap, or sale of generation projects in development. If PG&E NEG determines to further defer or cancel a project, PG&E NEG may create a mismatch between equipment delivery schedules and its development plans. If equipment delivery schedules cannot be adjusted, PG&E NEG may be compelled to choose between paying for equipment which PG&E NEG would have to store for future use or terminating the commitments to purchase equipment. If PG&E NEG decides to terminate such commitments to purchase, PG&E NEG would incur costs to the equipment vendors consisting of amounts shown as assets on its balance sheet plus all additional cash payments, if any, due upon termination (Termination Costs). PG&E NEG's exposure for these Termination Costs gradually increases over time and currently approximates $250 million. PG&E NEG's cash exposure for Termination Costs would be offset by amounts expended for the equipment through the date of termination.

Generally, each of PG&E NEG's equipment supply contracts allows PG&E NEG to cancel any or all of its commitments to purchase the equipment for a predefined cost. To date, PG&E NEG has not cancelled any of its equipment commitments or options. PG&E NEG continues to work with its vendors to defer payments, delay increases of termination fees, and revise equipment delivery dates. PG&E NEG has good relationships with its vendors and has, to date, been largely successful in these efforts. However, PG&E NEG cannot assure that PG&E NEG will continue to be able to modify these agreements to minimize its Termination Costs and match equipment deliveries with its evolving development plans. PG&E NEG's estimates of its exposure for Termination Costs are, in part, based upon current contractual arrangements and amendments thereto.

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. For the three months ended March 31, 2002, and 2001, PG&E NEG provided net cash flow from financing activities of $259 million and $166 million, respectively. This was primarily related to the construction funding needed for the Athens, Lake Road, La Paloma, Covert, and Harquahala projects.

Other Commitments and Contingencies

PG&E NEG has substantial financial commitments and contingencies in connection with their operating, investing, and financing activities. See Note 6 of the Notes to the Consolidated Financial Statements for further discussion of commitments and contingencies.

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. PG&E Corporation and the Utility use derivatives for both trading (for profit) and non-trading (hedging) purposes. Such derivatives include forward contracts, futures, swaps, options, and other contracts. Trading activities may be done for purposes of gathering market intelligence, creating liquidity, maintaining a market presence, and taking a market view. Non-trading activities may be done for purposes of mitigating the risks associated with an asset, liability, committed transaction, or probable forecasted transaction.

The activities affecting the estimated fair value of trading activities are presented below:

(in millions)	
Fair values of trading contracts at January 1, 2002	$ 33
Net gain on contracts settled during the period	(45)
Fair value of new trading contracts when entered into	-
Changes in fair values attributable to changes in valuation techniques and assumptions	-
Other changes in fair values	43
Fair values of trading contracts outstanding at March 31, 2002	31
Fair value of non-trading contracts	(28)
Net price risk management assets at March 31, 2002	$ 3

PG&E Corporation estimated the gross mark-to-market value of its trading contracts at March 31, 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 following table shows the mark-to-market value of PG&E Corporation's trading contracts after deduction of time value, credit, model, and other reserves necessary to determine fair value.

	Fair Value of Trading Contracts				
Source of Prices [1] 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	$ 92	$ 14	$ (14)	$ 1	$ 93
Provided by other external sources	-	-	(11)	29	18
Based on models and other valuation methods	(43)	(42)	(1)	6	(80)
Total Mark-to-Market	$ 49	$ (28)	$ (26)	$ 36	$ 31

[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.

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

Market Risk

To the extent that PG&E Corporation and the Utility have an open position (an open position is a position that is either not hedged or only partially hedged), it is exposed to the risk that fluctuations in commodity, futures, and basis prices may impact financial results. Such risks include any and all changes in value whether caused by trading positions, asset ownership/availability, debt covenants, exposure concentration, currency, weather, and other factors regardless of accounting method. Market risk is also affected by changes in volatility, correlation, and liquidity. PG&E Corporation manages its exposure to market fluctuations within the risk limits provided for in the PG&E Corporation Risk Management Policy and minimizes forward value fluctuations through hedging (i.e., selling plant output, buying fuel, and utilizing transportation and transmission capacity) and portfolio management.

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. Because of different ratemaking methods, the Utility reports its commodity price risk separately for its electricity and natural gas businesses. In January 2001, the DWR has been responsible for purchasing wholesale power for electric customers on behalf of the State of California. The Utility is currently paying the DWR the amount of money it collects in retail generation rates for electricity purchased by the DWR for the net open position. The Utility believes that it is obligated to remit only these revenues to the DWR and, therefore, there is no price risk for electricity purchases to serve the net open position.

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 a 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. There is price risk related to the unused portions of the pipeline capacity to the extent that it is brokered at floating rates.

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. It is unclear when the CPUC will act upon the Utility's proposal or adopt it as requested.

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, in addition to various merchant plants currently in development. 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 their forecasted generation. PG&E NEG is also exposed to commodity price risk for net open positions within their 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 liquidation 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 its 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.

(in millions)	**March 31, 2002**
Utility	
Non-trading [1]	$ 3
PG&E NEG	
Trading	8
Non-Trading [2]	19

[1] Includes the Utility's gas portfolio only. The Utility believes that there is currently no commodity price risk associated with fluctuating electric power prices, because the Utility is not currently responsible for managing the net open position.

[2] 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 due to the Utility's bankruptcy proceedings and the current California energy crisis.

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 floating rate 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 price risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At March 31, 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 $59 million and $26 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. 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 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 March 31, 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. 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 its 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.

At March 31, 2002, PG&E Corporation and the Utility customers that represent greater than 10 percent of their respective total credit exposures include the DWR, which represents 12 percent of PG&E Corporation’s credit exposure. In addition, two investment grade counterparties accounted for 18 percent and 14 percent, respectively, of the Utility’s credit exposure.

The schedule below summarizes the exposure to counterparties that are in a net asset position, with the exception of written options and exchange-traded futures (the exchange provides for contract settlement on a daily basis), at March 31, 2002:

(in millions)	**Gross Exposure** [1]	**Credit Collateral** [2]	**Net Exposure** [2]
PG&E Corporation	$ 965	$ 183	$ 782
Utility	216	104	112

[1] Gross credit exposure equals mark-to-market value plus net (payables) receivables where netting is allowed. The Utility's gross exposure includes wholesale activity only. Retail activity and payables prior to the Utility's bankruptcy filing are not included.

[2] Net exposure is the gross exposure minus credit collateral (cash deposits and letters of credit). Amounts are not adjusted for probability of default.

The majority of counterparties to which PG&E Corporation and the Utility are exposed are considered to be investment grade, determined by using publicly available information including an S&P rating of at least BBB-. At March 31, 2002, PG&E Corporation's net credit exposure to below investment grade entities, consisting principally of DWR and Southern California Edison, aggregates to approximately $266 million or 34 percent. Approximately $34 million or 30 percent of the Utility's net credit exposure are below investment grade. 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. The Utility has a regional concentration of credit exposure to counterparties that conduct business primarily throughout North America.

RESULTS OF OPERATIONS

The table shows for the three months ended March 31, 2002 and 2001, certain items from the 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 this group.) 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 March 31, 2002							
Operating revenues	$ 2,453	$ 2,348	$ 2,293	$ 59	$ (4)	$ (34)	$ 4,767
Operating expenses	1,205	2,287	2,256	26	5	(31)	3,461
Operating income	1,248	61	37	33	(9)	(3)	1,306
Interest income							42
Interest expense							(334)
Other income (expenses), net							18
Income taxes							401
Net income							631
Net cash provided by operating activities							1,231
Net cash used by investing activities							(737)
Net cash used by financing activities							(128)
EBITDA [2]	1,508	112	71	46	(5)	24	1,644
Three months ended March 31, 2001							
Operating revenues	2,562	4,206	4,150	65	(9)	(95)	6,673
Operating expenses	3,982	4,121	4,097	25	(1)	(90)	8,013
Operating income	(1,420)	85	53	40	(8)	(5)	(1,340)
Interest income							35
Interest expense							(247)
Other income (expenses), net							(9)
Income taxes							(610)
Net income							(951)
Net cash provided by operating activities							1,952
Net cash used by investing activities							(685)
Net cash used by financing activities							(233)
EBITDA [2]	$ (1,213)	$ 128	$ 84	$ 51	$ (7)	$ (9)	$ (1,094)

[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 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 results of operations continue to be impacted by the California energy crisis and the Utility's bankruptcy filing. Please see the “Liquidity and Financial Resources” section and Note 2 of the Notes to the Consolidated Financial Statements for more information.

PG&E Corporation's net income for the three months ended March 31, 2002, was $631 million, compared to a net loss of $951 million for the same period in 2001, representing an increase of $1,582 million. 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. Financial reporting standards require that these amounts be accounted for as expenses unless they can be deemed probable of recovery. Due to the uncertainty created by the California energy crisis, the Utility cannot meet the accounting probability standard required to defer generation costs for future recovery. As such, costs and revenues historically deferred in regulatory balancing accounts now directly impact net income. The Utility's net income will be impacted by changes in electricity and gas costs, customer demand, weather, costs of operations, conservation, regulatory orders, and other items.

The changes in performance for the three months ended March 31, 2002, as compared to the same period in 2001, are generally attributable to the following factors:

- The Utility’s electric operating revenues increased by approximately $0.5 billion, mainly due to CPUC authorized energy procurement charges, along with fewer direct access credits paid to customers of energy service providers.

- The Utility’s cost of electric energy purchased decreased by approximately $1.9 billion, as the Utility is no longer purchasing electricity through the Power Exchange (PX) market, and the DWR is buying electricity on behalf of the Utility’s customers.

- The Utility reduced its accrual for 2001 electricity purchases by approximately $595 million.

- Interest expense has increased $88 million over amounts reflected in 2001 due to increased borrowings, interest on pre-petition bankruptcy claims and increased interest rates all as a result of the California Energy Crisis and the Utility’s bankruptcy.

- The Utility has incurred incremental financial and legal expenses associated with the California Energy Crisis, the bankruptcy proceedings and the development of a plan of reorganization. For the three months ended March 31, 2002, these expenses were approximately $13 million greater than the same period in 2001.

- PG&E NEG’s net earnings decreased by $17 million, mainly due to 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. PG&E Corporation's refinancing agreement prohibits dividends from being declared or paid until the term loans have been repaid.

Utility

Overall Results

The Utility's income available for common stock was $590 million for the first quarter of 2002, compared to a loss of $1.0 billion in 2001. The Utility had higher earnings primarily due to increased electric revenues, decreased electricity purchase costs, including the adjustment of the purchased power accruals, offset by increases in operating and maintenance, and depreciation, amortization, and decommissioning expenses.

Electric Operations

Electric Revenues

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

	Three months ended March 31,	
(in millions)	**2002**	**2001**
Residential	$ 945	$ 804
Commercial	881	677
Industrial	258	298
Agricultural	65	46
Total electric revenue	2,149	1,825
Direct access credits	(31)	(322)
DWR pass-through revenues	(380)	(291)
Miscellaneous	40	47
Total electric operating revenues	$ 1,778	$ 1,259

Electric revenues in the first quarter of 2002 increased by $519 million, or 41.22 percent, from 2001 and were significantly affected by three factors.

First, there were $291 million fewer direct access credits. In accordance with CPUC regulations, the Utility provides an energy credit to those customers (known as direct access customers) who have chosen to buy their electric generation energy from an energy service provider (ESP) other than the Utility. The Utility bills direct access customers based upon fully bundled rates (generation, distribution, transmission, public purpose programs, and a competition transition charge). However, the direct access customer receives an energy credit equal to the average generation price multiplied by customer energy usage for the period. The decrease in direct access credits is primarily due to the lower cost per kWh of electric energy in 2002 relative to 2001, and a reduction in the number of direct access customers.

Second, generation-related surcharges increased revenues but were offset by pass-through revenues collected on behalf of the DWR. Energy procurement surcharges authorized by the CPUC increased revenues by $467 million. The increase provided by the surcharges was offset by an increase of $89 million in the pass-through revenues for electricity that the DWR provided to the Utility's customers. 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.

Third, conservation efforts by the Utility's customers in response to the California energy crisis, mild weather, economic, and other factors reduced electricity usage by 3.2 percent in 2002 compared to 2001.

Cost of Electric Energy

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

	Three months ended March 31,	
(in millions)	**2002**	**2001**
Cost of electric energy purchased	$ 405	$ 2,287
Fuel used in own-generation	24	30
Adjustment to purchased power accruals	(595)	-
Total cost of electricity expenses	$ (166)	$ 2,317
Average cost of electric energy purchased per kWh	$ 0.069	$ 0.319
Total energy purchased (GWh)	5,906	7,161

The decrease in the total cost of electricity expenses in the first quarter of 2002 of $2.5 billion is primarily the result of three factors. First, the Utility's average cost of electric energy purchased per kWh significantly decreased to $0.069 per kWh in the first quarter of 2002 from $0.319 per kWh for the same period in the prior year, primarily due to the stabilization of the energy market in the second half of 2001. In addition, the DWR purchased 4,125 and 4,931 gigawatt-hours (GWh) of electricity on behalf of the Utility's customers to cover the Utility's net open position for the three months ended March 31, 2002, and 2001, respectively. The cost of the DWR's purchases is not reflected in the Utility's financial statements because the Utility is a collection agent on behalf of 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 ended December 31, 2002. Also in March 2002, 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 orders, 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.

Third, as discussed previously, electricity usage was approximately 3.2 percent less compared to 2001.

Gas Operations

Gas Revenues

In the first quarter of 2002, gas revenues decreased by $628 million due to a lower average price of gas, which was passed on to customers and reflected in gas revenues. The average bundled price of gas sold in the first quarter of 2002 was $5.97 per thousand cubic feet (Mcf) compared to $11.53 per Mcf for the same period in 2001.

Cost of Gas

In the first quarter of 2002, the Utility's cost of gas decreased by $601 million principally due the decrease in the unit cost of gas to $2.79 per Mcf in 2002 from $8.11 per Mcf in 2001.

Other Operating Expenses

Operating and Maintenance

In the first quarter of 2001, the Utility's operating and maintenance expenses increased by $237 million compared to the same period in the prior year primarily due to increased spending on public purpose programs and customer related costs of $64 million, increased expense for environmental and legal related costs of $42 million, and increased administrative costs of $31 million. In addition, there was a general increase in incurred costs in the first quarter of 2002 compared to 2001 because stringent cash conservation efforts were in effect in 2001, which deferred costs to later periods in 2001.

Depreciation, Amortization, and Decommissioning

Depreciation, amortization, and decommissioning increased $54 million in the first quarter of 2002 from 2001, primarily due to the amortization of the Rate Reduction Bond Regulatory asset of $42 million beginning in the first quarter of 2002.

Interest Income

In accordance with the American Institute of Certified Public Accountants' Statement of Position (SOP) 90-7, the Utility has reported reorganization interest income separately on the Consolidated Statements of Operations. Interest income increased by $15 million in the first quarter of 2002 compared to the same period in the prior year due to higher average cash and cash equivalents for the period as a result of the Utility's obligations being stayed under Chapter 11.

Interest Expense

In the first quarter of 2002, the Utility's interest expense increased by $62 million compared to the same period in 2001 due to higher market interest rates, and the effect of the California energy crisis on the level of borrowings and unpaid debts accruing interest.

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 $16 million.

PG&E NEG

Overall Results

PG&E NEG's net income was $37 million for the three months ended March 31, 2002, a decrease of $17 million from the three months ended March 31, 2001. PG&E NEG's pre-tax operating income decreased $24 million, mainly due to lower gross margins principally related to operations in PG&E NEG New England, higher operations and maintenance costs due to the timing of major overhauls, and higher depreciation due to the start-up and acquisitions of new plants in 2001. Offsetting these declines was an improvement in administrative and general costs, primarily related to lower incentive expense in the first quarter of 2002. Interest expense was higher due to PG&E NEG's $1 billion Senior Notes, which were issued in the second quarter of 2001. PG&E NEG's effective tax rate was lower for the three months ended March 31, 2002, as compared to the same period last year due to certain energy tax credits.

Operating Revenues

PG&E NEG's operating revenues were $2.3 billion for the three months ended March 31, 2002, a decrease of $1.9 billion from the same period in 2001. These declines occurred primarily in the Integrated Energy and Marketing segment. PG&E NEG's wholesale energy trading business declines are primarily due to a decline in natural gas prices and significantly compressed spark spreads in the first quarter of 2002 as compared to the same period last year. In addition, operating revenues declined in New England primarily due to, lower energy prices and a lower fuel adjustment provision, partially offset by hedges. Interstate Pipeline Operations operating revenues declined $6 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 $2.3 billion for the three months ended March 31, 2002, a decrease of $1.8 billion from the same period in 2001. These declines occurred primarily in the Integrated and Energy Marketing segment. The cost of commodity sales and fuel declined $1.8 billion in line with the declines in operating revenues within its wholesale energy trading business. Operations, maintenance, and management costs increased $15 million in the first quarter of 2002, as compared to the same period last year principally due to the timing of major overhauls at generation facilities. Depreciation and amortization costs also increased $10 million in the period mainly due to the increase of new projects and acquisitions in 2001. Offsetting these increases in operating costs was a decline in administrative and general operating costs principally associated with lower incentive expenses.

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 at this time. The Utility's significant regulatory proceedings 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. 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.

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 revenues needed by the DWR to procure electricity for the California investor-owned utilities for the two-year period ending December 31, 2002. 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 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 Southern California Edison Company (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 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 2001 is $2.5 billion.

Retained Generation Revenue Requirement

On April 4, 2002, the CPUC issued a decision establishing the Utility's retained generation revenue requirement for 2002. The decision adopts a cost-based 2002 generation revenue requirement for the Utility of $2.9 billion subject to adjustment to reflect actual 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 Utility's regulatory value for Diablo Canyon and its non-nuclear generation assets at December 31, 2000, is $845 million and $1 billion, respectively. As a result of this update, the Utility estimates an increase in its 2002 generation revenue requirement of $106 million, to a total of $3 billion. The decision allows the Utility to recover reasonable costs for retained generation incurred in 2002, subject to reasonableness review in the Utility's 2003 GRC proceeding. The CPUC also indicated that the Utility's 2003 GRC revenue requirement will be considered in the Utility's 2003 GRC proceeding. The decision does not change retail electric rates and does not have a current earnings impact. The decision defers consideration of future rate changes until such time as the CPUC addresses the status of the retail rate freeze. In addition, the CPUC noted in its April 4, 2002, decision that recovery of the Utility's past unrecovered generation-related costs will not be addressed in this phase of the rate stabilization proceeding.

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 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.

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 February 22, 2002, the Board voted to deny 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 Service

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. Direct access customers receive distribution and transmission service from the Utility, but purchase electricity (generation) from their ESP. Customers receiving bundled services receive distribution, transmission, and generation services from the Utility.

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.

On March 21, 2002, the CPUC issued the follow-up decision to the September 20, 2001, decision that retains the direct access suspension date of September 20, 2001. The decision allows all customers with direct access contracts entered into on or before September 20, 2001, to remain on direct access. However, the decision proposes to assess an exit fee on those direct access customers to avoid a shift of costs from direct access customers to bundled service customers. On March 29, 2002, an ALJ issued a ruling expanding the scope of direct access customers' responsibility for the DWR's costs to include energy procurement and generation costs of the Utility. The ruling establishes the scope of the proceeding to consider the components of such exit fees.

The Utility's ability to recover incurred generation costs is affected by the amount of generation-related revenues the Utility is able to collect. To the extent that the Utility's customers elect direct access service, they do not pay generation-related revenue to the Utility. Direct access credits to customers that elected to purchased wholesale electricity from ESPs totaled $461 million in 2001. See the ''Results of Operations—Electric Revenue'' section for a discussion of direct access credits.

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 distribution capital spending in 1999 to system reliability, capacity, and adequacy of service. The CPUC's consultants began the engineering audit in February 2002 and are expected to issue their report in mid-2002. This report may recommend adjustments to the Utility's distribution rate base.

In an October 2001 rehearing decision, the CPUC ordered the record 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 forecast level to conform to the 1998 recorded level.

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.

On November 15, 2001, the Utility filed a petition for a review of the rehearing decision with the California Court of Appeal, as well as an application for rehearing of the rehearing decision with the CPUC. On January 9, 2002, the CPUC denied the Utility's application for rehearing of the rehearing decision. The petition at the Court of Appeal is still pending.

2003 GRC

On April 15, 2002, the Utility tendered its Notice of Intent (NOI) to file its 2003 GRC application with the CPUC's Office of Ratepayer Advocates (ORA). 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 an 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 meet the needs of hundreds of thousands of new customers, 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 increase for 2004 and 2005. The Utility's requested electric distribution revenue requirement increase would not increase electric rates over their current authorized level. If granted, the amount available from revenues to pay generation related costs would be reduced by a like amount.

The ORA has 25 days to review the NOI and notify the Utility of any deficiencies. 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. 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. The Utility intends to request that any revenue requirement change be effective January 1, 2003.

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 Rate Adjustment (ARA) to allow for recovery of costs of providing electric and gas distribution services. To the extent the Utility's proposed 2002 ARA is similar to the proposed ARA for 2001, the requested increase will reflect similar annual cost growth as shown in the Utility's 2001 ARA. However, the revenue increase authorized for 2002 will depend on both the amount authorized by the CPUC, and the effective date for which the CPUC authorizes interim relief. When interim relief is effective for the 2002 ARA, the authorized amount would be prorated for the period extending from the date of the interim authorization to the end of 2002.

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. In its April 15, 2002, NOI to file its 2003 GRC, the Utility indicated that it would seek a 2002 ARA increase of approximately $90 million for electric and gas distribution.

Revenue Adjustment Proceeding

The CPUC established the Revenue Adjustment Proceeding (RAP) to verify amounts recorded in the Utility's Transition Revenue Account (TRA) and to verify authorized revenue requirements, including adjustments approved in other proceedings. The RAP also establishes revenue allocation and rate design, and identifies all electric balancing and memorandum accounts for continued retention or elimination.

In June 2001, the Utility filed its RAP application addressing revenues and costs recorded in the TRA from July 1, 1999, through April 30, 2001. A CPUC decision is still pending.

Annual Transition Cost Proceeding

The Annual Transition Cost Proceeding (ATCP) was established to verify the accounting and recording of costs and revenues in the Transition Cost Balancing Account (TCBA), and ensure that only eligible transition costs have been entered. The TCBA tracks the revenues available to offset transition costs, including the accelerated recovery of plant balances, and other generation-related assets and obligations. Transition costs will receive a limited "reasonableness" review.

In September 2000, the Utility filed its 2000 ATCP application seeking approval of amounts recorded in the TCBA and generation memorandum accounts for the period July 1, 1999, through June 30, 2000. The CPUC has not yet issued a proposed decision for that period. In September 2001, the Utility filed its 2001 ATCP application seeking approval of the recorded amounts for the period July 1, 2000, through June 30, 2001. The scope of the 2001 ATCP application has been expanded to include a reasonableness review of demand bidding practices, generation scheduling and dispatch practices, and fuel decisions at Humboldt Bay Power Plant. On January 11, 2002, the Utility filed additional testimony that addresses the reasonableness of its procurement and generation practices, and fuel use at the Humboldt Bay Power plant during July 1, 2000, through June 30, 2001. On March 22, 2002, the CPUC issued a ruling bifurcating the 2001 ATCP into two phases. Phase 1 addresses the issues in testimony filed with the Utility's application in September 2001. Phase 2 addresses the issues in testimony filed on January 11, 2002. These Phases will proceed on separate schedules, with the Phase 1 issues being considered first. On March 27, 2002, the ORA issued a report on Phase I challenging $43.6 million of costs included in the TCBA. These costs relate to the Utility's ability to recover hydroelectric asset divestiture costs, electric supply administration costs, shareholder incentives associated with 15 incremental energy agreements, and employee transition cost payments associated with displacement from a second power plant.

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

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. 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 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.

In June 2001, the FERC further ordered prospective price mitigation for the wholesale spot markets throughout both California and the Western Systems Coordinating Council (WSCC) that established the current mitigation methodology going forward. Features of this current methodology include:

1. Its extension to all hours of the day,
2. The reaffirmation of its requirement that all generators in California offer available generation for sale to the ISO's real-time energy market,
3. The establishment of a single market clearing price in the ISO's spot markets during emergency hours, and
4. The establishment of a maximum market clearing price for spot market sales in all hours.

The market clearing price limits set under the current mitigation methodology are scheduled to expire on September 30, 2002. However, California state officials and other Congressmen urged the extension of such price limits in a Congressional hearing on April 11, 2002.

In June and July 2001, the FERC's chief ALJ conducted settlement negotiations among power generators, 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 what the power sellers and buyers are each owed. These hearings, in which the State and the California investor owned utilities are seeking $1.5 billion for electricity overcharges by the generators, are currently scheduled to start in August 2002. The Utility does not believe these matters will be resolved until mid- to late 2002, 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.

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 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 under AB 1890. 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.

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 March 31, 2002, the Utility had recorded approximately $103 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 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 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 an order setting an expedited schedule of hearings. Hearings are set to begin in 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.

Rate Reduction Bonds

AB 1890 mandated a rate freeze and 10% rate reduction for residential and small commercial customers. Under the original mandate, the Utility expected the 10 percent rate reduction to end at 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. At March 31, 2002, and December 31, 2001, the Rate Reduction Bond regulatory asset amounted to $1,594 million and $1,636 million, respectively, and the Utility has recorded amortization expense of $42 million for the three months ended March 31, 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 receives incentives for this activity, 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 evaluate the Utility's claim verification.

In May 2000, the Utility filed its 2000 AEAP application, which establishes incentives to be collected during 2001. The CPUC has delayed action on the Utility's 2000 AEAP and combined the 2000 AEAP with the Utility's 2001 AEAP. The Utility's claim for shareholder incentives in this combined proceeding is approximately $80 million. The Utility has not reflected incentives in the Utility's Consolidated Statements of Operations.

On March 13, 2002, an ALJ for the CPUC issued a ruling requesting comments on whether incentives adopted for pre-1998 energy efficiency programs should be modified. On March 21, 2002, the CPUC approved an interim decision that reaffirmed a previous CPUC decision to eliminate shareholder incentives in connection with the California investor-owned utilities' 2002 programs and beyond.

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 requires 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 II of the proceeding and ordered the utilities to track the over- or under-collections associated with their respective baseline quantity changes in an interest bearing balancing account. The Utility estimates the annual revenue shortfall to be between $78 million and $85 million for electric, and $6 million for gas. The stated recovery of this shortfall will occur in Phase II. The Utility cannot predict what the outcome of Phase II will be or whether it will have a material adverse impact on its financial position or results of operations.

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. These amounts include costs for the Diablo Canyon Nuclear Decommissioning Trusts, Humboldt Bay Power Plant Decommissioning Trusts, and the Humboldt Bay Unit 3 SAFSTOR operating and maintenance costs. The Utility proposes continuing to collect the revenue requirement through a non-bypassable charge in electric rates, and to record the revenue requirement and the associated revenues in the Nuclear Decommissioning Adjustment Mechanism Balancing Account. Because the Utility has frozen electric rates, the increase in revenue requirements would reduce the amount of revenues available to offset electric generation costs until post-freeze ratemaking is implemented.

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 addition to its derivatives designed as cash flow hedges in accordance with 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), 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 thus are not reflected on the balance sheet at fair value. Another attribute that a contract must have to qualify for the normal purchases and sales exemption is that the pricing must be deemed to be clearly and closely related to the asset to be delivered under the contract. In June 2001 (as amended in October 2001 and December 2001), the FASB approved an interpretation issued by the Derivatives Implementation Group (DIG), DIG C15, that changed the definition of normal purchases and sales for certain power contracts. Implementation of this interpretation will result in several of PG&E NEG's contracts' failure to continue qualifying for the normal purchases and sales exemption under DIG C15, resulting in these contracts being marked-to-market through earnings. The FASB has also approved another DIG interpretation, DIG C16, that disallows normal purchases and sales treatment for commodity contracts (other than power contracts) that contain volumetric variability or optionality. PG&E NEG determined that certain of its fuel contracts no longer qualify for normal purchases and sales treatment under DIG C16, and must be marked-to-market through earnings. The Utility does not believe that these changes to DIG C15 and DIG C16 will have an impact on its earnings. PG&E Corporation must implement both of these interpretations beginning in April 2002. PG&E Corporation is in the process of completing its evaluation and valuation of those contracts that meet the mark-to-market criteria of DIG C15 and DIG C16. Based on its preliminary analysis, PG&E Corporation estimates that certain of the contracts have pre-tax mark-to-market losses totaling approximately $170 million and certain of the contracts have pre-tax mark-to-market gains totaling approximately $250 million. Upon concluding its final evaluation and valuation of the contracts impacted by DIG C15 and DIG C16, PG&E Corporation will record the net after-tax impact as a cumulative effect of a change in accounting principle.

Any cumulative impact from the accounting change reflected in the second quarter will not impact the timing and amount of cash flows associated with the affected contracts. The cumulative effect will, however, impact the timing and extent of future operating results. The cumulative effect will reflect the mark-to-market value of the contracts immediately. In addition, future earnings will primarily reflect prospective changes in the market value of these contracts.

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 Emerging Issues Task Force (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 used the gross method for those energy trading contracts for which PG&E NEG has a choice.

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 purchase and sales exception, and are not reflected on the balance sheet at fair value. See further discussion in "Accounting Pronouncements Issued But Not Yet Adopted" above.

PG&E Corporation and the Utility apply SFAS No. 71 to their regulated operations. This standard allows a cost to be capitalized, that otherwise would be charged to expense if it is probable that the cost is recoverable through regulated rates. This standard also allows a regulator to create a liability that is recognized in the financial statements.

PG&E Corporation 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.

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.

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

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 DISCLOSURE 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 and the Utility engage 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 Price 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, on April 6, 2001, Pacific Gas and Electric Company (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). On April 19, 2002, the Utility and PG&E Corporation jointly filed with the Bankruptcy Court their most recent form of their proposed plan of reorganization (Plan) and related disclosure statement.

On March 18, 2002 the Bankruptcy Court entered an order and judgment disapproving the First Amended Disclosure Statement relating to the Plan for the reasons set forth in its February 7, 2002, decision based upon the court's rejection of the proponents' express preemption theory. The Bankruptcy Court found that there was no just reason to delay appellate review of the court's ruling on express preemption, and directed the clerk to enter its order as a final judgment. The court stated that its order was not intended to address or finally adjudicate any issues or disputes other than express preemption, including but not limited to the implied preemption and sovereign immunity aspects of its February 7, 2002 decision, and reserved such issues for final rulings in connection with the plan confirmation process.

On March 22, 2002, PG&E Corporation and the Utility filed a notice of appeal from the Bankruptcy Court's March 18, 2002 order. PG&E Corporation and the Utility elected to have the appeal heard by the United States District Court for the Northern District of California, and at the same time filed a protective motion for leave to appeal the March 18, 2002 order on a discretionary basis, which has been opposed.

In addition, on or about March 29, 2002, the California Public Utilities Commission (CPUC) and the City and County of San Francisco (City) served a Notice of Cross-Appeal from the March 18, 2002, order (and related pleadings). In addition, on or about April 1, 2002, the California Attorney General's Office filed a separate Notice of Cross-Appeal from the March 18, 2002, order on behalf of a number of State entities. Generally stated, the two issues that these parties identified for cross-appeal are: (1) whether the Bankruptcy Court erred in entering a final judgment concerning its ruling on express preemption, and (2) whether it was an abuse of discretion for the Bankruptcy Court to determine that there was no just reason to delay the entry of judgment on its express preemption ruling.

On April 17, 2002, PG&E Corporation and the Utility filed their opening brief in the United States District Court in their appeal from the Bankruptcy Court's express preemption ruling.

On March 25, 2002, the Bankruptcy Court authorized the Utility to pay the principal amount of all undisputed creditor claims that are $5,000 or less, and undisputed mechanics' lien and reclamation claims, for an aggregate amount of approximately $22 million. These amounts will be paid on or before July 30, 2002.

On March 27, 2002, the Bankruptcy Court approved the Amended and Restated Settlement and Support Agreement (Amended Agreement) entered into among PG&E Corporation, the Utility, and certain of the Utility's senior debtholders (Senior Debtholders). The original agreement, entered into on February 12, 2002, was amended to (i) delete the voting restrictions with respect to alternative plans of reorganization, and (ii) allow the Senior Debtholders to meet and confer with other parties, discuss, negotiate, consider, and vote for and express a preference for alternative plans of reorganization, provided that the Senior Debtholders must vote for the Plan. In addition, the Amended Agreement no longer contains a condition to effectiveness that holders of at least $3 billion in Class 5 Claims (as such term is defined in the Plan) become parties to the Amended Agreement or a substantially similar agreement.

Under the Amended Agreement, interest rates will not be fixed as part of the Senior Debtholders' allowed claims. Rather, any payment of pre-petition interest and post-petition interest made to the Senior Debtholders at the rates agreed upon in the Amended Agreement generally can be re-characterized as a payment on principal under the following circumstances: (i) if the Utility is determined to be insolvent, pursuant to a final order of the Bankruptcy Court, and (ii) if the Plan is not confirmed and another plan of reorganization is confirmed, in which case any payments of interest made to Senior Debtholders before confirmation may be re-characterized by the proponent of such confirmed plan of reorganization as a partial payment of principal to the extent such pre-confirmation payments exceed the amount of interest otherwise required to be paid to such Senior Debtholders under the terms of the confirmed plan. In such event, the Senior Debtholders reserve their right to object to any such plan of reorganization and the treatment of their claims under such plan.

The Amended Agreement provides that the Senior Debtholders will be paid pre- and post-petition interest within 10 days after the Bankruptcy Court approves the disclosure statement related to the Plan.

Also, on March 27, 2002, the Bankruptcy Court also authorized payment of pre- and post-petition interest to holders of certain undisputed claims, including creditors holding certain financial instruments issued by the Utility, 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). The Utility expects that payments pursuant to this authorization will be approximately $700 million by July 30, 2002, based on the claim amounts estimated in the disclosure statement and Plan. The actual amount 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, the payment of such interest pursuant to the Amended Agreement and to the holders of undisputed claims is not expected to have an adverse material impact on its financial condition or results of operation.

On April 15, 2002, the CPUC filed its proposed alternative plan of reorganization (Alternative Plan) with the Bankruptcy Court. For a description of the Alternative Plan, see Note 2 of the Notes to Consolidated Financial Statements included in this report.

The CPUC has proposed that its Alternative Plan become effective on January 31, 2003. Objections to the Alternative Plan and the related disclosure statement are due on May 3, 2002, and a hearing to consider the filed objections is set for May 9, 2002.

On April 24, 2002, the Bankruptcy Court approved the disclosure statement relating to PG&E Corporation's and the Utility's Plan. The Bankruptcy Court's approval of the disclosure statement does not constitute approval of the Plan.

The Bankruptcy Court has set June 17, 2002, as the target date for the beginning of solicitation for the competing plans of reorganization.

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, 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 (the Filed Rate Case). The case has been transferred to District Court Judge Walker in the Northern District of California and 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 (Bankruptcy Appeal). At a joint case management conference held on March 7, 2002, in the two related actions, the court indicated that it would place priority on the Filed Rate Case and that it was necessary to clarify issues further in the Filed Rate Case before proceeding in the Bankruptcy Appeal. At the Utility's request, the court therefore set no dates for oral argument in the Bankruptcy Appeal, but indicated that the CPUC would be free at any time to attempt to establish that it was appropriate to reactivate the Bankruptcy Appeal in light of developments in the Filed Rate Case.

Pursuant to the schedule set at the joint case management conference, 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 on the basis that federal law requires the CPUC to permit the Utility to recover its wholesale procurement costs incurred in Federal Energy Regulatory Commission (FERC) tariffed markets. Also, on April 18, 2002, the CPUC Commissioners and The Utility Reform Network (TURN), a ratepayer advocacy group which intervened in the Filed Rate Case, also filed 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 the CPUC has already allowed the Utility to recover its wholesale procurement costs by means of the accounting changes ordered in one of its March 27, 2001, decisions. A hearing has been set for May 24, 2002, to consider the parties' motions.

The court has set a trial date in the Filed Rate Case for January 13, 2003.

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, the plaintiffs have 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 contains allegations similar to the allegations made in the Attorney General's (AG) complaint against PG&E Corporation discussed below. On March 11, 2002, the defendants filed a motion to dismiss the second amended complaint. The court has set a hearing on the motion to dismiss for June 24, 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

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.

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

In March 2002, the Utility and the Central Coast Regional Water Quality Control Board (Board) reached a tentative settlement of this matter under which the Utility would pay a total of $5 million to be used for environmental projects. No civil penalties would be paid under the settlement. The parties are negotiating the documentation of the settlement. The final agreement will be subject to public comment and final approval by the Board, and, once signed by the parties, will be incorporated into a consent decree to be entered in California Superior Court.

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.

Compressor Station Chromium 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.

California Energy Trading 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.

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, after removing the AG's complaint to 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 and a decision is pending.
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 operation.

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

On February 8, 2002, PG&E Corporation removed the City's action to the Bankruptcy Court 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 and a decision is pending. For more information about this mater, see PG&E Corporation's and the Utility's Annual Report on Form 10-K for the year ended December 31, 2001.

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 operation.

Sierra Pacific Industries v. Pacific Gas and Electric Company

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.

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, a group of 25 ratepayers has filed a complaint against the Utility at the CPUC demanding an immediate reduction of approximately 3.5 cents per kilowatt-hour (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 April 10, 2002, the CPUC set a prehearing conference for May 8, 2002.

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

In September 2000, PG&E NEG's subsidiary, USGenNE, received correspondence from the State of Rhode Island and an environmental advocacy group known as Save the Bay, both of which alleged that USGenNE's thermal discharge from its Brayton Point generating facility violated applicable federal and state environmental laws. No litigation was brought and the federal authorities with jurisdiction over the matter have not brought any enforcement actions. This letter is related to on-going efforts to obtain a new National Pollutant Discharge Elimination System Permit ("NPDES Permit") for the Brayton Point generating facility, which permit would govern thermal discharge from the facility.

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. PG&E NEG is currently awaiting the issuance of a draft Clean Water Act NPDES permit renewal from the Environmental Protection Agency (EPA).

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 operation.

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 March 31, 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 March 31, 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 March 31, 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 January 31, 2002, amounted to $31.6 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 March 31, 2002, was $873 million. At March 31, 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 will make interest payments totaling $132.1 million on May 6, 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 February 28, 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 March 31, 2002, the total principal of the bonds (and related loans) accelerated and redeemed was $454 million. At March 31, 2002, the Utility did not make interest payments of $16.4 million on pollution control bonds series 96C, 96E, 96F, and 97B. The Utility did not make interest payments on pollution control bond series 96A backed by bond insurance. Per the Settlement and Support Agreement, unpaid interest advances totaling $8.3 million for the period from June 1, 2001, through February 28, 2002, will be paid on May 6, 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 Settlement and Support Agreement, on May 6, 2002, the Utility will make interest payments on its medium-term notes, its 7.375% senior notes, and its $1.24 billion floating rate notes through the period February 28, 2002. The total arrearage of these interest payments is $219.1 million. Also at March 31, 2002, the Utility did not make principal payments on unsecured long-term debt of $131 million.

With regard to the 7.90% Quarterly Income Preferred Securities 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 is required to take steps to liquidate the trust and distribute the debentures to the QUIPS holders. On April 24, 2002, the trustee notified the Depository Trust Company that the trust would be liquidated as of May 24, 2002, and that on such date the former registered owners of QUIPS would become registered owners of debentures.

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

PG&E Corporation:

On April 17, 2002, PG&E Corporation held its annual meeting of shareholders. At that meeting, the shareholders voted as indicated below on the following matters:

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

	For	**Withheld**
David R. Andrews	248,913,345	8,039,086
David A. Coulter	250,099,590	6,852,841
C. Lee Cox	248,955,573	7,996,858
William S. Davila	249,049,141	7,903,290
Robert D. Glynn, Jr.	250,437,192	6,515,239
David M. Lawrence, MD	250,383,063	6,569,368
Mary S. Metz	249,010,480	7,941,951
Carl E. Reichardt	250,443,456	6,508,975

Barry Lawson Williams	248,991,827	7,960,604

2. Ratification of the appointment of Deloitte & Touche LLP as independent public accountants for 2002 (included as Item 2 in proxy statement):

For:	238,798,417
Against:	15,350,850
Abstain:	2,803,164

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

3. Management proposal regarding a proposed amendment to PG&E Corporation's Articles of Incorporation to implement enhancement of simple majority voting (included as Item 3 in proxy statement):

For:	191,591,222
Against:	15,982,892
Abstain:	3,506,688
Broker non-vote (1):	45,871,629

The proposal was approved by a majority of the outstanding shares.

4. Management proposal regarding proposed amendment to PG&E Corporation's Articles of Incorporation and Bylaws to reduce the authorized range of directors and delete from the Bylaws the provision that restates the authorized range of directors as set forth in the Articles of Incorporation (included as Item 4 in proxy statement):

For:	247,259,121
Against:	5,835,720
Abstain:	3,857,590
Broker non-vote (1):	0

The proposal was approved by a majority of the outstanding shares.

5. Consideration of a shareholder proposal regarding independent directors (included as Item 10 in proxy statement):

For:	63,085,072
Against:	140,397,397
Abstain:	7,598,333
Broker non-vote (1):	45,871,629

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

6. Consideration of a shareholder proposal regarding poison pills (Shareholder Rights Plan) (included as Item 11 in proxy statement):

For:	136,698,687
Against:	68,676,772
Abstain:	5,705,343
Broker non-vote (1):	45,871,629

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

7. Consideration of a shareholder proposal regarding auditor services (included as Item 12 in proxy statement):

For:	87,640,402
Against:	100,707,579
Abstain:	22,732,821
Broker non-vote (1):	45,871,629

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

8. Consideration of a shareholder proposal regarding the Board of Directors' role (included as Item 13 in proxy statement):

For:	28,820,978
Against:	174,507,038
Abstain:	7,752,786
Broker non-vote (1):	45,871,629

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

9. Consideration of a shareholder proposal regarding radioactive wastes (included as Item 14 in proxy statement):

For:	16,579,938
Against:	181,347,004
Abstain:	13,153,860
Broker non-vote (1):	45,871,629

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

10. Consideration of a shareholder proposal regarding confidential voting (included as Item 15 in proxy statement):

For:	62,374,367
Against:	141,389,907
Abstain:	7,316,528
Broker non-vote (1):	45,871,629

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

11. Consideration of a shareholder floor proposal introduced at the annual meeting regarding annual disclosure of philanthropic links between the company and its directors was duly and properly conducted by ballot.

For:	17,922
Against:	159,866
Abstain:	0
Broker non-vote (1):	0

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

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

Pacific Gas and Electric Company:

On April 17, 2002, Pacific Gas and Electric Company held its annual meeting of shareholders. Shares of capital stock of Pacific Gas and Electric Company consist of shares of common stock and shares of first preferred stock. As PG&E Corporation and a subsidiary own all of the outstanding shares of common stock, they hold approximately 95% of the combined voting power of the outstanding capital stock of Pacific Gas and Electric Company. PG&E Corporation and the subsidiary voted all of their respective shares of common stock for the nominees named in the 2002 joint proxy statement, for the ratification of the appointment of Deloitte & Touche LLP as independent public accountants for 2002, and for the five management proposals to amend Pacific Gas and Electric Company's Articles of Incorporation and Bylaws. The balance of the votes shown below were cast by holders of shares of first preferred stock. At the annual meeting, the shareholders voted as indicated below on the following matters:

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

	For	**Withheld**
David R. Andrews	339,609,614	302,968
David A. Coulter	339,614,326	298,256
C. Lee Cox	339,624,319	288,263
William S. Davila	339,623,099	289,483
Robert D. Glynn, Jr.	339,616,628	295,954
David M. Lawrence, MD	339,626,295	286,287
Mary S. Metz	339,617,986	294,596
Carl E. Reichardt	339,618,016	294,566
Gordon R. Smith	339,625,832	286,750
Barry Lawson Williams	339,624,009	288,573

2. Ratification of the appointment of Deloitte & Touche LLP as independent public accountants for 2002 (included as Item 2 in proxy statement):

For:	339,659,728
Against:	122,714
Abstain:	130,140

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

3. Management proposal regarding a proposed amendment to Pacific Gas and Electric Company's Articles of Incorporation to establish a classified board of directors (included as Item 5 in proxy statement):

For:	330,963,622
Against:	2,068,545
Abstain:	268,670
Broker non-vote (1):	0

The proposal was approved by a majority of the outstanding shares.

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

4. Management proposal regarding proposed amendments to Pacific Gas and Electric Company's Articles of Incorporation and Bylaws to reduce the authorized range of directors and transfer the provision that establishes the authorized range of directors from the Bylaws to the Articles of Incorporation (included as Item 6 in proxy statement):

For:	332,684,409
Against:	248,428
Abstain:	368,000
Broker non-vote:	0

The proposal was approved by a majority of the outstanding shares.

5. Management proposal regarding a proposed amendment to Pacific Gas and Electric Company's Articles of Incorporation and Bylaws to transfer the provision that prohibits cumulative voting in the election of directors from the Bylaws to the Articles of Incorporation (included as Item 7 in proxy statement):

For:	331,504,332
Against:	1,416,314
Abstain:	380,191
Broker non-vote:	0

The proposal was approved by a majority of the outstanding shares.

6. Management Proposal regarding a proposed amendment to Pacific Gas and Electric Company's Articles of Incorporation to include constituency provision (included as item 8 in proxy statement):

For:	331,403,941
Against:	1,408,975
Abstain:	487,821
Broker non-vote:	0

The proposal was approved by a majority of the outstanding shares.

7. Management proposal regarding a proposed amendment to Pacific Gas and Electric Company's Articles of Incorporation to require that shareholder action be taken at an annual or special meeting (included as item 9 in proxy statement):

For:	331,517,507
Against:	1,439,990
Abstain:	343,340
Broker non-vote:	0

The proposal was approved by a majority of the outstanding shares.

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 three months ended March 31, 2002, was 4.64. Pacific Gas and Electric Company's earnings to combined fixed charges and preferred stock dividends ratio for the three months ended March 31, 2002, was 4.5. The statement of the foregoing ratios, together with the statements of the computation of the foregoing ratios filed as Exhibits 12.1 and 12.2 hereto, are included herein for the purpose of incorporating such information and exhibits into Registration Statement Nos. 33-62488, 33-64136, 33-50707, and 33-61959, relating to Pacific Gas and Electric Company's various classes of debt and first preferred stock outstanding.

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits:

Exhibit 10.1	Second Amendment dated as of March 4, 2002, to Credit Agreement, dated as of March 1, 2001, among PG&E Corporation, General Electric Capital Corporation, and Lehman Commercial Paper, Inc.
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

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

1. January 11, 2002 — Item 5. Other Events
   Item 7. A. CPUC Order Instituting Investigation into Holding Company Activities
   B. California Attorney General Complaint
   C. Pacific Gas and Electric Company Bankruptcy – CPUC Opposition to Motion to Extend Exclusivity Period

2. January 15, 2002 — Item 5. Other Events
   Pacific Gas and Electric Company Bankruptcy -- Agreement with Ad Hoc Committee

3. January 18, 2002 — Item 5. Other Events
   Item 7. A. Pacific Gas and Electric Company Bankruptcy
   B. Pacific Gas and Electric Company's Filing of Claim with State of California Victim Compensation and Government Claims Board

4. February 13, 2002 — Item 5. Other Events
   Item 7. A. Pacific Gas and Electric Company Bankruptcy
   B. California Attorney General Complaint
   C. Complaint filed by the City and County of San Francisco, and the People of the State of California

5. February 28, 2002 — Item 5. Other Events

A. Pacific Gas and Electric Company Bankruptcy

B. 2001 Attrition Rate Adjustment

C. Allocation of California Department of Water Resources' Revenue Requirements

D. PG&E National Energy Group Synthetic Leases

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

Exhibit 99 - Pacific Gas and Electric Company Income Statement for the month ended December 31, 2001, and Balance Sheet dated December 31, 2001.

6. March 5, 2002

Item 5. Other Events

Pacific Gas and Electric Company Bankruptcy

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

Exhibit 99 - Pacific Gas and Electric Company Income Statement for the month ended January 31, 2002, and Balance Sheet dated January 31, 2002

7. 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

8. 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

SIGNATURE

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

PG&E CORPORATION

BY: 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: April 30, 2002

Exhibit Index

Exhibit No.	Description of Exhibit
Exhibit 10.1	Second Amendment dated as of March 4, 2002, to Credit Agreement, dated as of March 1, 2001, among PG&E Corporation, General Electric Capital Corporation, and Lehman Commercial Paper, Inc.
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
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