PG&E CORP
Form 10-Q/A
June 30, 2003

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C., 20549

FORM 10-Q/A

Amendment No. 1

(Mark One)

ý **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2003

OR

o **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 ý No o

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Yes ý No o

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

Common Stock Outstanding, May 9, 2003:

PG&E Corporation	409,191,299 shares
Pacific Gas and Electric Company	Wholly owned by PG&E Corporation

Explanatory Note

Subsequent to the issuance of PG&E Corporation's 1st quarter 2003 Consolidated Financial Statements, management discovered a misclassification of certain offsetting revenues and expenses within its continuing operations of PG&E National Energy Group (PG&E NEG). The reclassification resulted in a decrease in Operating Revenues from $2,607 million to $2,401 million and a similar decrease in Operating Expenses Cost of Commodity Sales and Fuel from $364 million to $158 million. This Amendment No. 1 to PG&E Corporation's and Pacific Gas and Electric Company's joint Form 10-Q for the quarter ended March 31, 2003, contains revised consolidated financial statements for PG&E Corporation for the quarter ended March 31, 2003. To reflect the revisions, this Amendment No. 1 hereby amends:

Part I, Item 1. Financial Statements. Corrections have been made to the Consolidated Statement of Operations for the three months ended March 31, 2003 and to Note 1 of the "Notes to the Consolidated Financial Statements."

Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations. Corrections have been made to the sections entitled "Results of Operations" and "Consolidated Statements of Operations."

Part I, Item 3. Quantitative and Qualitative Disclosures About Market Risk. References are made to the "Management's Discussion and Analysis of Financial Condition and Results of Operations" filed as part of this amended Form 10-Q/A.

Part II, Item 6. Exhibits and Reports on Form 8-K (amended to file herewith, Exhibit 99.1, Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002, and Exhibit 99.2, Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002.)

PART I. FINANCIAL INFORMATION

ITEM 1: CONSOLIDATED FINANCIAL STATEMENTS

PG&E CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per share amounts)

	Three months ended March 31,	
	2003	**2002**
	(as revised see Note 1)	
	(Unaudited)	
Operating Revenues		

	Three months ended March 31,	
Utility	$ 2,067	$ 2,453
Energy commodities and services	334	482
Total operating revenues	2,401	2,935
Operating Expenses		
Cost of electricity and natural gas for utility	1,027	149
Cost of energy commodities and services	158	306
Depreciation, amortization, and decommissioning	336	303
Operating and maintenance	774	860
Impairments, write-offs, and other charges	200	
Reorganization professional fees and expenses	35	16
Total operating expenses	2,530	1,634
Operating Income (Loss)	(129)	1,301
Reorganization interest income	10	22
Interest income	4	10
Interest expense	(375)	(334)
Other income (expense), net	3	20
Income (Loss) Before Income Taxes	(487)	1,019
Income tax provision (benefit)	(209)	396
Income (Loss) From Continuing Operations	(278)	623
Discontinued Operations		
Earnings (loss) from operations of USGenNE, Mountain View, and ET Canada (net of income tax expense (benefit) of $(35) million in 2003 and $5 million in 2002)	(65)	8
Net loss on disposal of USGenNE, Mountain View, and ET Canada (net of income tax (benefit) of $(2) million in 2003)	(5)	
Net Income (Loss) Before Cumulative Effect of Changes in Accounting Principles	(348)	631
Cumulative effect of changes in accounting principles (net of income tax (benefit) of $(4) million in 2003)	(6)	
Net Income (Loss)	$ (354)	$ 631
Weighted Average Common Shares Outstanding, Basic	382	364
Earnings (Loss) Per Common Share from Continuing Operations, Basic	$ (0.73)	$ 1.71
Net Earnings (Loss) Per Common Share, Basic	$ (0.93)	$ 1.73
Earnings (Loss) Per Common Share from Continuing Operations, Diluted	$ (0.73)	$ 1.69

Net Earnings (Loss) Per Common Share, Diluted	$ (0.93)	$ 1.71

See accompanying Notes to the Consolidated Financial Statements.

PG&E CORPORATION

CONSOLIDATED BALANCE SHEETS

(in millions)

	Balance at	
	March 31, 2003	**December 31, 2002**
	(Unaudited)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 4,568	$ 3,895
Restricted cash	567	708
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $109 million in 2003 and $113 million in 2002)	2,307	2,747
Regulatory balancing accounts	126	98
Price risk management	717	498
Inventories	240	347
Assets held for sale	266	707
Prepaid expenses and other	449	480
Total current assets	9,240	9,480
Property, Plant and Equipment		
Utility	27,811	27,045
Non-utility:		
Electric generation	997	636
Gas transmission	1,779	1,761
Construction work in progress	1,315	1,560
Other	187	177
Total property, plant and equipment	32,089	31,179
Accumulated depreciation and decommissioning	(13,223)	(14,251)
Net property, plant and equipment	18,866	16,928
Other Noncurrent Assets		
Regulatory assets	1,984	2,053

	Balance at	
Nuclear decommissioning funds	1,314	1,335
Price risk management	264	398
Deferred income taxes	958	657
Assets held for sale	810	916
Other	1,857	1,929
Total other noncurrent assets	7,187	7,288
TOTAL ASSETS	$ 35,293	$ 33,696

See accompanying Notes to the Consolidated Financial Statements.

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PG&E CORPORATION

CONSOLIDATED BALANCE SHEETS

(in millions)

	Balance at	
	March 31, 2003	December 31, 2002
	(Unaudited)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
Liabilities Not Subject to Compromise		
Current Liabilities		
Debt in default	$ 4,373	$ 4,230
Long-term debt, classified as current	601	298
Current portion of rate reduction bonds	290	290
Accounts payable:		
Trade creditors	1,327	1,273
Regulatory balancing accounts	337	360
Other	721	660
Interest payable	219	139
Income taxes payable		129
Price risk management	642	506
Liabilities of operations held for sale	353	699
Other	660	685
Total current liabilities	9,523	9,269
Noncurrent Liabilities		
Long-term debt	4,279	4,345
Rate reduction bonds	1,086	1,160

	Balance at	
Asset retirement obligations	1,374	
Deferred income taxes	1,605	1,439
Deferred tax credits	139	144
Price risk management	259	305
Liabilities of operations held for sale	758	793
Other	3,286	2,963
Total noncurrent liabilities	12,786	11,149
Liabilities Subject to Compromise		
Financing debt	5,605	5,605
Trade creditors	3,611	3,580
Total liabilities subject to compromise	9,216	9,185
Commitments and Contingencies (Notes 1, 2, 3, and 6)		
Preferred Stock of Subsidiaries	480	480
Common Stockholders' Equity		
Common stock, no par value, authorized 800,000,000 shares, issued 408,610,591 common and 1,569,260 restricted shares in 2003 and 405,486,015 common shares in 2002	6,318	6,274
Common stock held by subsidiary, at cost, 23,815,500 shares	(690)	(690)
Unearned compensation	(21)	
Accumulated deficit	(2,233)	(1,878)
Accumulated other comprehensive loss	(86)	(93)
Total common stockholders' equity	3,288	3,613
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 35,293	$ 33,696

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See accompanying Notes to the Consolidated Financial Statements.

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PG&E CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Three months ended March 31,	
	2003	2002

	Three months ended March 31,	
	(Unaudited)	
Cash Flows From Operating Activities		
Net income (loss)	$ (354)	$ 631
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	336	320
Deferred income taxes and tax credits, net	(48)	(82)
Reversal of ISO accrual (Note 2)		(970)
Price risk management assets and liabilities, net	12	23
Other deferred charges and noncurrent liabilities	94	107
Loss on impairment or disposal of assets	200	
Loss from discontinued operations	7	
Cumulative effect of a change in accounting principle	10	
Net effect of changes in operating assets and liabilities:		
Restricted cash	141	5
Accounts receivable	433	428
Inventories	107	120
Accounts payable	177	344
Accrued taxes	(129)	479
Regulatory balancing accounts, net	(51)	125
Other working capital	93	(40)
Payments authorized by the Bankruptcy Court on amounts classified as liabilities subject to compromise (Note 2)	(39)	(248)
Assets and liabilities of operations held for sale, net	(20)	(41)
Other, net	(36)	(11)
Net cash provided by operating activities	933	1,190
Cash Flows From Investing Activities		
Capital expenditures	(472)	(711)
Proceeds from disposal of discontinued operations	102	
Other, net	30	(6)
Net cash used by investing activities	(340)	(717)
Cash Flows From Financing Activities		
Net borrowings under credit facilities		76
Long-term debt issued	152	190
Long-term debt matured, redeemed, or repurchased	(18)	(340)
Rate reduction bonds matured	(75)	(75)
Common stock issued	21	21
Other, net		(20)
Net cash provided (used) by financing activities	80	(148)
Net change in cash and cash equivalents	673	325
Cash and cash equivalents at January 1	3,895	5,355
Cash and cash equivalents at March 31	$ 4,568	$ 5,680

	Three months ended March 31,	

Supplemental disclosures of cash flow information		
Cash received for:		
Reorganization interest income	$ 11	$ 22
Cash paid for:		
Interest (net of amounts capitalized)	149	108
Income taxes paid (refunded), net	1	8
Reorganization professional fees and expenses	22	2
Supplemental disclosures of noncash investing and financing activities		
Transfer of liabilities and other payables subject to compromise from operating assets and liabilities	47	75

See accompanying Notes to the Consolidated Financial Statements.

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

CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions)

	Three months ended March 31,	
	2003	**2002**
	(Unaudited)	
Operating Revenues		
Electric	$ 1,237	$ 1,778
Natural gas	830	675
Total operating revenues	2,067	2,453
Operating Expenses		
Cost of electricity	541	(166)
Cost of natural gas	486	315
Operating and maintenance	646	769
Depreciation, amortization, and decommissioning	310	271
Reorganization professional fees and expenses	35	16
Total operating expenses	2,018	1,205
Operating Income	49	1,248
Reorganization interest income	10	22

	Three months ended March 31,	
Interest income	1	
Interest expense (non-contractual interest of $30 million in 2003 and $65 million in 2002)	(220)	(263)
Other income (expense), net	4	(5)
Income (Loss) Before Income Taxes	(156)	1,002
Income tax provision (benefit)	(84)	406
Income (Loss) Before Cumulative Effect of Changes in Accounting Principles	(72)	596
Cumulative effect of changes in accounting principles (net of income taxes of $(1) million in 2003)	(1)	
Net Income (Loss)	(73)	596
Preferred dividend requirement	6	6
Income Available for (Loss Allocated to) Common Stock	$ (79)	$ 590

See accompanying Notes to the Consolidated Financial Statements.

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

CONSOLIDATED BALANCE SHEETS

(in millions)

	Balance at	
	March 31, 2003	**December 31, 2002**
	(Unaudited)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 3,646	$ 3,343
Restricted cash	191	150
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $63 million in 2003 and $59 million in 2002)	1,511	1,900
Related parties	18	17
Regulatory balancing accounts	126	98
Inventories:		
Gas stored underground and fuel oil	82	154
Materials and supplies	122	121
Income taxes receivable	226	50
Prepaid expenses	66	110
Deferred income taxes		5
Total current assets	5,988	5,948

	Balance at	
Property, Plant and Equipment		
Electric	19,641	18,922
Gas	8,170	8,123
Construction work in progress	491	427
Total property, plant and equipment	28,302	27,472
Accumulated depreciation and decommissioning	(12,485)	(13,515)
Net property, plant and equipment	15,817	13,957
Other Noncurrent Assets		
Regulatory assets	1,949	2,011
Nuclear decommissioning funds	1,314	1,335
Other	1,248	1,300
Total other noncurrent assets	4,511	4,646
TOTAL ASSETS	$ 26,316	$ 24,551

See accompanying Notes to the Consolidated Financial Statements.

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

CONSOLIDATED BALANCE SHEETS

(in millions)

	Balance at	
	March 31, 2003	**December 31, 2002**
	(Unaudited)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
Liabilities Not Subject to Compromise		
Current Liabilities		
Long-term debt, classified as current	$ 591	$ 281
Current portion of rate reduction bonds	290	290
Accounts payable:		
Trade creditors	468	380
Related parties	141	130
Regulatory balancing accounts	337	360
Other	388	374
Interest payable	189	126

	Balance at	
Deferred income taxes	73	
Other	527	625
Total current liabilities	3,004	2,566
Noncurrent Liabilities		
Long-term debt	2,429	2,739
Rate reduction bonds	1,086	1,160
Regulatory liabilities	1,814	1,461
Asset retirement obligations	1,371	
Deferred income taxes	1,529	1,485
Deferred tax credits	139	144
Other	1,293	1,274
Total noncurrent liabilities	9,661	8,263
Liabilities Subject to Compromise		
Financing debt	5,605	5,605
Trade creditors	3,794	3,786
Total liabilities subject to compromise	9,399	9,391
Commitments and Contingencies (Notes 1, 2, and 6)		
Preferred Stock With Mandatory Redemption Provisions		
6.30% and 6.57%, outstanding 5,500,000 shares, due 2002-2009	137	137
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 321,314,760 shares	1,606	1,606
Common stock held by subsidiary, at cost, 19,481,213 shares	(475)	(475)
Additional paid-in capital	1,964	1,964
Reinvested earnings	726	805
Total stockholders' equity	4,115	4,194
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 26,316	$ 24,551

See accompanying Notes to the Consolidated Financial Statements.

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Three months ended March 31, 2003	Three months ended March 31, 2002
	(unaudited)	
Cash Flows From Operating Activities		
Net income (loss)	$ (73)	$ 596
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	310	271
Deferred income taxes and tax credits, net	117	(113)
Other deferred charges and noncurrent liabilities	80	70
Reversal of ISO accrual (Note 2)		(970)
Cumulative effect of a change in accounting principle	2	
Net effect of changes in operating assets and liabilities:		
Restricted cash	(41)	5
Accounts receivable	381	208
Inventories	71	111
Income taxes receivable	(176)	
Accounts payable	122	453
Income taxes payable		519
Regulatory balancing accounts, net	(51)	125
Other working capital	24	95
Payments authorized by the Bankruptcy Court on amounts classified as liabilities subject to compromise (Note 2)	(39)	(225)
Other, net	7	14
Net cash provided by operating activities	734	1,159
Cash Flows From Investing Activities		
Capital expenditures	(371)	(353)
Proceeds from sale of assets	5	
Other, net	9	(7)
Net cash used by investing activities	(357)	(360)
Cash Flows From Financing Activities		
Long-term debt matured, redeemed, or repurchased		(333)
Rate reduction bonds matured	(75)	(75)
Other, net	1	
Net cash used by financing activities	(74)	(408)
Net change in cash and cash equivalents	303	391
Cash and cash equivalents at January 1	3,343	4,341
Cash and cash equivalents at March 31	$ 3,646	$ 4,732

Supplemental disclosures of cash flow information

	Three months ended March 31,	
Cash received for:		
Reorganization interest income	$ 11	$ 22
Cash paid for:		
Interest (net of amount capitalized)	116	65
Reorganization professional fees and expenses	22	2
Supplemental disclosures of noncash investing and financing activities		
Transfer of liabilities and other payables subject to compromise from operating assets and liabilities, net	47	75

See accompanying Notes to the Consolidated Financial Statements.

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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 (the Utility), and its subsidiaries on January 1, 1997. The Utility, incorporated in California in 1905, is the predecessor of PG&E Corporation. The Utility delivers electric service to approximately 4.8 million customers and natural gas service to approximately 3.9 million customers in Northern and Central California. Both PG&E Corporation and the Utility are headquartered in San Francisco. As discussed further in Note 2, on April 6, 2001, the Utility filed a voluntary petition for relief under the provisions of Chapter 11 of the U.S. Bankruptcy Code (Bankruptcy Code) in the U.S. Bankruptcy Court for the Northern District of California (Bankruptcy Court). Pursuant to Chapter 11, the Utility retains control of its assets and is authorized to operate its business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court.

PG&E Corporation's other significant subsidiary is PG&E National Energy Group, Inc. (PG&E NEG) and its subsidiaries, headquartered in Bethesda, Maryland. PG&E NEG was incorporated on December 18, 1998, as a wholly-owned subsidiary of PG&E Corporation. Shortly thereafter, PG&E Corporation contributed various subsidiaries to PG&E NEG. PG&E NEG'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); and
- PG&E Gas Transmission Corporation and its subsidiaries (collectively, PG&E GTC), which includes PG&E Gas Transmission, Northwest Corporation and its subsidiaries (collectively, PG&E GTN), which includes North Baja Pipeline, LLC.

During February and March of 2003, certain lenders of PG&E Corporation exercised options to purchase 3 percent of the shares of PG&E NEG. No gain or loss was recognized by PG&E Corporation upon this transaction.

The Consolidated Financial Statements of PG&E Corporation and of the Utility have been prepared on a going concern basis, which contemplates continuity of operations, realization of assets, and repayment of liabilities in the ordinary course of business. However, as a result of the bankruptcy of the Utility and current liquidity concerns at PG&E NEG and its subsidiaries, as further discussed below, such realization of assets and liquidation of liabilities are subject to uncertainty.

PG&E NEG currently is focused on power generation and natural gas transmission in the United States. As a result of the sustained downturn in the power industry, PG&E NEG and its affiliates have experienced a financial downturn, which caused the major credit rating agencies to downgrade PG&E NEG's and its affiliates' credit ratings in the second half of 2002 to below investment grade. PG&E NEG is currently in default under various recourse debt agreements and guaranteed equity commitments totaling approximately $2.9 billion. In addition, other PG&E NEG subsidiaries are in default under various debt agreements totaling $2.7 billion, but this debt is non-recourse to PG&E NEG.

PG&E NEG, its subsidiaries, and their lenders have been engaged in discussions to restructure PG&E NEG's and its subsidiaries' debt obligations and other commitments since October 2002. No agreement has been reached yet and there can be no assurance that an agreement will be reached. Any restructuring agreement that may be reached would be implemented through a reorganization proceeding under Chapter 11 of the Bankruptcy Code. Although PG&E NEG and its subsidiaries are continuing their efforts to maximize cash and reduce liabilities, such efforts are not expected to restore the financial condition of PG&E NEG and its subsidiaries. Absent a negotiated agreement, the lenders may exercise their default remedies or force PG&E NEG and certain of its subsidiaries into an involuntary proceeding under the Bankruptcy Code. Notwithstanding the status of current negotiations, PG&E NEG and certain of its subsidiaries also may elect to voluntarily seek protection under the Bankruptcy Code as early as the second quarter of 2003. Although PG&E Corporation continues to provide assistance to PG&E NEG, its subsidiaries and its lenders in their negotiations, management does not expect the outcome of any bankruptcy proceeding involving PG&E NEG or any of its subsidiaries to have a material adverse effect on the financial condition of PG&E Corporation or the Utility.

This Quarterly Report on Form 10-Q/A is a combined report of PG&E Corporation and the Utility. Therefore, the Notes to the unaudited Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation's 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 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 Consolidated Financial Statements reflect all adjustments that are necessary to present a fair statement of the consolidated financial position and results of operations for the interim periods. All material adjustments are of a normal recurring nature unless otherwise disclosed in this Form 10-Q/A. All significant intercompany transactions have been eliminated from the 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 included in their combined 2002 Annual Report on Form 10-K, as amended, and PG&E Corporation's and the Utility's other reports filed with the Securities and Exchange Commission (SEC).

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) 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. As these estimates involve judgments on a wide range of factors, including future economic conditions that are difficult to predict, actual results could differ from these estimates.

PG&E Corporation's and 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 Utility's Chapter 11 filing and PG&E NEG's current liquidity concerns, such realization of assets and liquidation of liabilities are subject to uncertainty. Under SOP 90-7, certain liabilities of the Utility existing prior to the Utility's Chapter 11 filing are classified as Liabilities Subject to Compromise on PG&E Corporation's and the Utility's Consolidated Balance Sheets. Additionally, professional fees and expenses directly related to the Chapter 11 proceeding and interest income on funds accumulated during the bankruptcy are reported separately as reorganization items. Finally, the extent to which the Utility's reported interest expense differs from its stated contractual interest is disclosed on the Utility's Consolidated Statements of Operations.

Certain amounts in the 2002 Consolidated Financial Statements have been reclassified to conform to the 2003 presentation. These reclassifications did not affect the consolidated net income reported by PG&E Corporation and the Utility for the periods presented.

Adoption of New Accounting Policies and Summary of Significant Accounting Policies

The accounting principles used by PG&E Corporation and the Utility include those necessary for rate-regulated enterprises, which reflect the ratemaking policies of the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC). Except as disclosed below, PG&E Corporation and the Utility are following the same accounting principles discussed in their combined 2002 Annual Report on Form 10-K, as amended.

Guarantor's Accounting and Disclosure Requirements for Guarantees

PG&E Corporation incorporated the clarified disclosure requirements from Financial Accounting Standards Board (FASB) Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45) into its December 31, 2002, disclosures of guarantees. Beginning January 1, 2003, PG&E Corporation applied the initial recognition and initial measurement provisions of FIN 45 to guarantees issued or modified after December 31, 2002.

FIN 45 elaborates on existing disclosure requirements for most guarantees. It also clarifies that at the time a company issues a guarantee, it must recognize an initial liability for the fair value of the obligation it assumes under that guarantee, including its ongoing obligation to stand ready to perform over the term of the guarantee in the event that specified triggering events or conditions occur. This information also must be disclosed in interim and annual financial statements.

FIN 45 does not prescribe a specific account for the guarantor's offsetting entry when it recognizes the liability at the inception of the guarantee, noting that the offsetting entry would depend on the circumstances in which the guarantee was issued. There also is no prescribed approach included for subsequently measuring the guarantor's recognized liability over the term of the related guarantee. It is noted that the liability typically would be reduced by a credit to earnings as the guarantor is released from risk under the guarantee. The adoption of this interpretation did not have a material impact on the Consolidated Financial Statements of PG&E Corporation or the Utility.

Accounting for Asset Retirement Obligations

On January 1, 2003, PG&E Corporation adopted Statements of Financial Accounting Standards (SFAS) No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143). SFAS No. 143 provides accounting requirements for costs associated with legal obligations to retire tangible long-lived assets. SFAS No. 143 requires that an asset retirement obligation be recorded at fair value in the period in which it is incurred, if a reasonable estimate of fair value can be made. In the same period, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. In each subsequent period, the liability is accreted to its present value and the capitalized cost is depreciated over the useful life of the long-lived asset. Rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with this Statement and costs recovered through the ratemaking process.

The impacts of adopting SFAS No. 143 were as follows:

- The Utility has identified its nuclear generation and certain fossil generation facilities as having asset retirement obligations as of January 1, 2003. No additional asset retirement obligations had been identified as of March 31, 2003. Through December 31, 2002, the Utility had recorded $1.4 billion for its nuclear and fossil decommissioning obligations in accumulated depreciation and decommissioning in the Consolidated Balance Sheets.

- Upon adoption of this Statement, the Utility reclassified the decommissioning liabilities recorded through December 31, 2002, as asset retirement obligations in the Consolidated Balance Sheets. To record the decommissioning liabilities at fair value as required by SFAS No. 143, the Utility then reduced the asset retirement obligations by $53 million. The Utility increased its property, plant and equipment balance by $332 million to reflect the fair value of the asset retirement costs as of the date the obligation was incurred, less accumulated depreciation from the date the obligation was incurred through December 31, 2002. Finally, the Utility recorded a regulatory liability of $387 million to reflect the cumulative effect of adoption for its nuclear facilities. This regulatory liability represents timing differences between recognition of nuclear decommissioning obligations in accordance with GAAP and ratemaking purposes. The cumulative effect of the change in accounting principle for the Utility's fossil facilities as a result of adopting this Statement was a loss of $1 million, after-tax.

- If this Statement had been adopted on January 1, 2002, the pro forma effects on earnings of the accounting change for the three months ended March 31, 2002, would not have been material. The amounts recorded upon adoption of this Statement reflect the pro forma effects on the Consolidated Balance Sheets had this Statement been adopted on December 31, 2002.

- The Utility has established trust funds that are legally restricted for purposes of settling its nuclear decommissioning obligations. As of March 31, 2003, the fair value of these trust funds was approximately $1.3 billion.

- The Utility may have potential asset retirement obligations under various land right documents associated with its transmission and distribution facilities. The majority of the Utility's land rights are perpetual. Any non-perpetual land rights generally are renewed continuously because the Utility intends to utilize these facilities indefinitely. Since the timing and extent of any potential asset retirements are unknown, the fair value of any obligations associated with these facilities cannot be reasonably estimated.

The Utility collects estimated removal costs in rates through depreciation in accordance with regulatory treatment. These amounts do not represent SFAS No. 143 asset retirement obligations and will continue to be recorded within accumulated depreciation. As of March 31, 2003, the Utility estimated the removal costs recorded in accumulated depreciation were approximately $1.7 billion.

PG&E NEG has identified its generating facilities as having asset retirement obligations as of January 1, 2003. Upon implementation of SFAS No. 143, PG&E NEG recorded $2 million to its property, plant and equipment to reflect the fair value of the asset retirement costs as of the date the obligation was incurred, and recognized $3 million for asset retirement obligations. The cumulative effect of the change in accounting principle as a result of adopting this Statement was a loss of

$3 million, after-tax, on PG&E Corporation Consolidated Statements of Operations. The impact to PG&E NEG of implementing SFAS No. 143 by its unconsolidated affiliates is immaterial.

If this Statement had been adopted on January 1, 2002, the pro forma effects on earnings of the accounting change for the three months ended March 31, 2002, would not have been material.

PG&E GTN may have potential asset retirement obligations under various land right documents associated with its gas transmission facilities. The majority of PG&E GTN's land rights are perpetual. Any non-perpetual land rights generally are renewed continuously because PG&E GTN intends to utilize these facilities indefinitely. Since the timing and extent of any potential asset retirements are unknown, the fair value of any obligations associated with these facilities cannot be reasonably estimated.

PG&E GTN collects estimated removal costs in rates through depreciation in accordance with regulatory treatment. These amounts do not represent SFAS No. 143 asset retirement obligations and will continue to be recorded within accumulated depreciation. PG&E GTN estimated the related removal costs accrued within accumulated depreciation were approximately $11.5 million at March 31, 2003.

Accounting for Costs Associated with Exit or Disposal Activities

On January 1, 2003, PG&E Corporation adopted SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." This Statement supersedes previous accounting guidance, principally Emerging Issues Task Force (EITF) Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity" (EITF 94-3). SFAS No. 146 requires that the liability for costs associated with an exit or disposal activity be recognized when the liability is incurred. Under EITF 94-3, a liability for an exit cost is recognized at the commitment date of an exit plan. SFAS No. 146 also establishes that the liability initially should be measured and recorded at fair value. The adoption of this Statement did not have any current impact on the Consolidated Financial Statements of PG&E Corporation or the Utility.

Change from Gross to Net Method of Reporting Revenues and Expenses on Trading Activities

Effective at the quarter ended September 30, 2002, PG&E Corporation changed its method of reporting gains and losses associated with energy trading contracts from the gross method of presentation to the net method. PG&E Corporation believes that the net method provides a more accurate and consistent presentation of energy trading activities on the financial statements. Amounts to be presented under the net method include all gross margin elements related to energy trading activities.

Before implementation of the net method and the subsequent rescission of EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 98-10), as noted below, PG&E Corporation had reported unrealized gains and losses on trading activities on a net basis in operating revenues. However, PG&E Corporation had reported realized gains and losses on a gross basis in operating income, as both operating revenues and costs of commodity sales and fuel. PG&E Corporation now is reporting realized gains and losses from trading activities on a net basis as operating revenues, and in accordance with the rescission of EITF 98-10, unrealized gains and losses on energy trading activities no longer are reported as these contracts are accounted for under the cost method.

Implementation of the net method has no net effect on gross margin, operating income, or net income. Accordingly, PG&E Corporation continues to report realized income from non-trading activities on a gross basis in operating revenues and operating expenses. Prior year financial statements have been reclassified to conform to the net method.

The schedule below summarizes the amounts impacted by the change in methodology on PG&E Corporation's Consolidated Statements of Operations for the three months ended March 31, 2002:

	Prior Method of Presentation (Gross Method)	As Presented (Net Method)
	Three months ended March 31, 2002	Three months ended March 31, 2002
	(in millions)	
Energy commodities and services(1)	$ 2,114	$ 498
Cost of commodities and services(2)	1,956	340
Net Subtotal	$ 158	$ 158

(1) These amounts, as presented in the net method, differ from the financial statements due to the exclusion of equity earnings in affiliates and eliminations and other, which amounted to net charges of $16 million at March 31, 2002.

(2) These amounts, as presented in the net method, differ from the financial statements due to the exclusion of eliminations and other, which amounted to a benefit of $34 million at March 31, 2002.

Rescission of EITF 98-10

In October 2002, the EITF rescinded EITF 98-10. Energy trading contracts that are derivatives 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), will continue to be accounted for at fair value under SFAS No. 133. Contracts that previously were marked to market as trading activities under EITF 98-10 and that did not meet the definition of a derivative now are accounted for at cost, through a one-time adjustment recorded as a cumulative effect of a change in accounting principle. This requirement was effective as of January 1, 2003, and resulted in a $2 million loss, net of tax, reflected on the PG&E Corporation's Consolidated Statements of Operations for the three months ended March 31, 2003. For PG&E Corporation, the majority of trading contracts are derivative instruments as defined in SFAS No. 133. The rescission of EITF 98-10 has no effect on the accounting for derivative instruments used for non-trading purposes, which continue to be accounted for in accordance with SFAS No. 133. The reporting requirements associated with the rescission of EITF 98-10 were applied prospectively for all EITF 98-10 energy trading contracts entered into after October 25, 2002, although the number of energy trading contracts subject to the prospective implementation was considered immaterial.

Earnings (Loss) Per Share

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

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

	Three months ended March 31,	
	2003	2002
	(in millions, except per share amounts)	
Income (loss) from continuing operations	$ (278)	$ 623
Discontinued operations	(70)	8
Net income (loss) before cumulative effect of a change in accounting principle	(348)	631
Cumulative effect of a change in accounting principle	(6)	
Net income (loss)	$ (354)	$ 631

Weighted average common shares outstanding, basic	382	364
Add: Employee stock options and PG&E Corporation shares held by grantor trusts		4
Shares outstanding for diluted calculations	382	368
Earnings (Loss) Per Common Share, Basic		
Income (loss) from continuing operations	$ (0.73)	$ 1.71
Discontinued operations	(0.18)	0.02
Cumulative effect of a change in accounting principle	(0.02)	
Net earnings (loss)	$ (0.93)	$ 1.73
Earnings (Loss) Per Common Share, Diluted		
Income (loss) from continuing operations	$ (0.73)	$ 1.69
Discontinued operations	(0.18)	0.02
Cumulative effect of a change in accounting principle	(0.02)	
Net earnings (loss)	$ (0.93)	$ 1.71

The diluted earnings per share for the three months ended March 31, 2003, excludes approximately one million incremental shares related to employee stock options and shares held by grantor trusts, five million incremental shares related to warrants, and 18 million incremental shares related to the 9.5 percent Convertible Subordinated Notes, and includes associated interest expense of $4 million (net of income taxes of $3 million) due to the anti-dilutive effect upon loss from continuing operations.

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

Stock-Based Compensation

PG&E Corporation and the Utility account for stock-based compensation using the intrinsic value method in accordance with the provisions of Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," as allowed by SFAS No. 123, "Accounting for Stock-Based Compensation," as amended by SFAS No. 148, "Accounting for Stock-Based Compensation Transition and Disclosure, an Amendment of FASB Statement No. 123." Under the intrinsic value method, PG&E Corporation and the Utility do not recognize any compensation expense for stock options, as the exercise price is equal to the fair market value of a share of PG&E Corporation common stock at the time the options are granted. Had compensation expense been recognized using the fair value-based method under SFAS No. 123, PG&E

Corporation's pro forma consolidated earnings (loss) and earnings (loss) per share would have been as follows:

	Three months ended March 31,	
	2003	2002
	(in millions, except per share amounts)	
Net income (loss):		
As reported	$ (354)	$ 631
Deduct: Total stock-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects	(5)	(5)
Pro forma	$ (359)	$ 626
Basic earnings (loss) per share:		
As reported	$ (0.93)	$ 1.73
Pro forma	$ (0.94)	$ 1.72
Diluted earnings (loss) per share:		
As reported	$ (0.93)	$ 1.71
Pro forma	$ (0.94)	$ 1.70

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Had compensation expense been recognized using the fair value-based method under SFAS No. 123, the Utility's pro forma consolidated earnings (loss) would have been as follows:

	Three months ended March 31,	
	2003	2002
	(in millions)	
Income available for (loss allocated to) common stock:		
As reported	$ (79)	$ 590
Deduct: Total stock-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects	(2)	(2)
Pro forma	$ (81)	$ 588

On January 2, 2003, PG&E Corporation awarded 1.6 million shares of restricted PG&E Corporation common stock to eligible employees of PG&E Corporation and its subsidiaries. The shares were granted with restrictions and are subject to forfeiture unless certain conditions are met.

The restricted shares were issued at the grant date and are held in an escrow account. The shares become available to the employees as the restrictions lapse. In general, the restrictions on 80 percent of the shares lapse automatically over a period of four years at the rate of 20 percent per year. Restrictions to the remaining 20 percent of the shares will lapse at a rate of 5 percent per year if PG&E Corporation is in the top quartile of its comparator group as measured by annual total shareholder return for each year ending immediately before each annual lapse date.

Total compensation expense resulting from the restricted stock issuance reflected on PG&E Corporation's Consolidated Statements of Operations for the three months ended March 31, 2003, was $1.4 million, of which $0.8 million was recognized by the Utility.

Comprehensive Income

PG&E Corporation's and the Utility's comprehensive income (loss) consists principally of changes in the market value of certain cash flow hedges under SFAS No. 133, as amended.

	PG&E Corporation		Utility	
	2003	2002	2003	2002
	(in millions)			
Three months ended March 31				
Net income available for (loss allocated to) common stock	$ (354)	$ 631	$ (79)	$ 590
Net gain (loss) in other comprehensive income (OCI) from current period hedging transactions and price changes in accordance with SFAS No. 133	(1)	(75)		
Net reclassification from OCI to earnings	5	5		
Foreign currency translation adjustment	3			
Comprehensive income (loss)	$ (347)	$ 561	$ (79)	$ 590

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The above changes to OCI are stated net of income taxes of $48 million at March 31, 2003, and $38 million at March 31, 2002.

Income Taxes

In 2003, PG&E Corporation increased its valuation allowance due to the continued uncertainty in realizing certain state deferred tax assets arising at PG&E NEG. During the first quarter of 2003, valuation allowances of $10 million were recorded in continuing operations. Additional valuation allowances of $7 million were recorded in discontinued operations, and $5 million in accumulated other comprehensive loss.

In addition to the above reserves, PG&E NEG recorded valuation allowances due to continued uncertainty in realizing federal deferred tax assets. These valuation allowances were determined on a stand-alone basis. During the first quarter of 2003, valuation allowances of $66 million were recorded in continuing operations. Additional valuation allowances of $37 million were recorded in discontinued operations, $3 million recorded in cumulative effect of changes in accounting principles, and $48 million recorded in accumulated other comprehensive loss. These reserves were eliminated in consolidation, as PG&E Corporation believes that it is more likely than not that the federal deferred tax assets will be realized on a consolidated basis.

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 (i.e., direct costs and allocation of overhead costs) or at the higher of fully loaded cost or fair market value, depending on the nature of the services provided. PG&E Corporation also allocates certain other corporate administrative and general costs to the Utility and other subsidiaries using a variety of factors, including the number of employees, operating expenses excluding fuel purchases, total assets, and other cost-causal methods. 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; therefore, no profit results from these transactions. The Utility's significant related party transactions were as follows:

	Three months ended March 31,	
	2003	2002
	(in millions)	

	Three months ended March 31,	
Utility proceeds from:		
Administrative services provided to PG&E Corporation	$ 2	$ 1
Gas reservation services provided to PG&E ET	3	3
Trade deposit due from PG&E GTN	3	
Utility payments for:		
Administrative services received from PG&E Corporation	$ 13	$ 27
Interest accrued on pre-petition liability	2	
Administrative services received from PG&E NEG	1	
Gas commodity and transmission services received from PG&E ET	10	19
Transmission services received from PG&E GTN	15	12
Trade deposit due to PG&E ET	1	

Accounting Pronouncements Issued But Not Yet Adopted

Amendment of Statement 133 on Derivative Instruments and Hedging Activities

In April 2003, the FASB issued Statement No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS No. 149). SFAS No. 149 amends and clarifies the accounting and reporting for derivative instruments, including certain derivatives embedded in other contracts, and for hedging activities under SFAS No. 133. The amendments in SFAS No. 149 require that contracts with comparable characteristics be accounted for similarly. The Statement clarifies under what circumstances a contract with an initial net investment meets the characteristics of a derivative according to SFAS

No. 133 and when a derivative contains a financing component that warrants special reporting in the statement of cash flows. In addition, the Statement amends the definition of an underlying to conform it to language used in FIN No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others", and amends certain other existing pronouncements. The provisions of the Statement that relate to SFAS No. 133 Implementation Issues that have been effective for periods that began prior to June 15, 2003, should continue to be applied in accordance with their respective effective dates.

The requirements of SFAS No. 149 are effective for contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. PG&E Corporation is currently evaluating the impacts, if any, of SFAS No. 149 on its Consolidated Financial Statements.

Consolidation of Variable Interest Entities

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46), which expands upon existing accounting guidance addressing when a company should include in its financial statements the assets, liabilities, and activities of another entity or arrangement it is involved with. FIN 46 notes that many of what are now referred to as "variable interest entities" have commonly been referred to as special-purpose entities or off-balance sheet structures. However, the Interpretation's guidance is to be applied to not only these entities but to all entities and arrangements found within a company. FIN 46 provides some general guidance as to the definition of a variable interest entity. PG&E Corporation is currently evaluating all entities and arrangements it is involved with to determine if they meet the FIN 46 criteria as variable interest entities.

Until the issuance of FIN 46, a company generally included another entity in its Consolidated Financial Statements only if it controlled the entity through voting interests. FIN 46 changes that by requiring a variable interest entity to be consolidated by a company if that company is subject to a majority of the risk of loss from the variable interest entity's activities or entitled to receive a majority of the entity's residual returns, or both. A company that consolidates a variable interest entity is now referred to as the "primary beneficiary" of that entity.

FIN 46 requires disclosure of variable interest entities that the company is not required to consolidate but in which it has a significant variable interest.

The consolidation requirements of FIN 46 apply immediately to variable interest entities created after January 31, 2003. There were no new variable interest entities created by PG&E Corporation between February 1, 2003, and March 31, 2003. The consolidation requirements apply to variable interest entities created before January 31, 2003, in the first fiscal year or interim period beginning after June 15, 2003, so these requirements would be applicable to PG&E Corporation in the third quarter of 2003. Certain new and expanded disclosure requirements must be applied to PG&E Corporation's March 31, 2003 disclosures if there is an assessment that it is reasonably possible that an enterprise will consolidate or disclose information about a variable interest entity when FIN 46 becomes effective. PG&E Corporation is currently evaluating the impacts of FIN 46's initial recognition, measurement, and disclosure provisions on its Consolidated Financial Statements.

2003 Revision

Subsequent to the issuance of PG&E Corporation's quarter ended March 31, 2003 consolidated financial statements, management discovered a misclassification of certain offsetting revenues and expenses within continuing operations. As a result PG&E Corporation's quarter ended March 31, 2003 Consolidated Financial Statements have been revised to reflect the reclassification. The reclassification resulted in a decrease in quarter ended March 31, 2003 Operating Revenues Energy Commodities and Services from $540 million to $334 million, and a similar decrease in Operating Expenses Cost of Energy Commodities and Services from $364 million to $158 million. The reclassification did not result in a change in consolidated operating income or net income, the Consolidated Balance Sheets or the Consolidated Statements of Cash Flows.

NOTE 2: THE UTILITY CHAPTER 11 FILING

Electric Industry Restructuring

In 1998, California implemented electric industry restructuring and established a market framework for electric generation in which generators and other electricity providers were permitted to charge market-based prices for electricity sold on the wholesale market. The restructuring of the electric industry was mandated by the California Legislature in Assembly Bill (AB) 1890. The mandate included a retail electricity 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 strongly encouraged the Utility to sell more than 50 percent of its fossil fuel-fired generation facilities and made it economically unattractive for the Utility to retain its remaining generation facilities. The new market framework called for the creation of the Power Exchange (PX) and the Independent System Operator (ISO). Before it ceased operation in January 2001, the PX established market-clearing prices for electricity. The ISO's role is 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 to buy electricity from independent power generators or retail electricity suppliers (customers who chose to buy from independent power generators or retail electricity suppliers are referred to as direct access customers). Most of the Utility's customers continued to buy electricity from the Utility.

For the seven-month period from June 2000 through December 2000, wholesale electric prices in California averaged $0.18 per kilowatt-hour (kWh). During this period, the Utility's retail electric rates were frozen and provided only approximately $0.05 per kWh to pay for the Utility's electricity costs.

The frozen rates were designed to allow the Utility to recover its authorized costs and, to the extent the frozen rates generated revenues in excess of the Utility's authorized costs, recover its transition costs. During the California energy crisis, frozen rates were insufficient to cover the Utility's electricity procurement and other costs. Since the Utility no longer could conclude that its under-collected purchased power and remaining transition costs were probable of recovery, the Utility charged $6.9 billion to expense for these costs at December 31, 2000. The Utility's inability to recover procurement costs from customers ultimately resulted in billions of dollars in defaulted debt and unpaid bills, and caused the Utility to file a voluntary petition for relief under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court on April 6, 2001.

In January 2001, the CPUC increased electric rates by $0.01 per kWh, and in March 2001 by another $0.03 per kWh, and restricted use of these surcharge revenues to "ongoing procurement costs" and "future power purchases."

In May 2001, the CPUC authorized the Utility to collect an additional $0.005 per kWh in revenues for 12 months to make up for the time lag between March 2001, when the CPUC authorized the $0.03 surcharge, and June 2001, when the Utility began collecting the $0.03 surcharge. Although the collection of this "half-cent" surcharge originally was scheduled to end on May 31, 2002, the CPUC issued a resolution ordering the Utility to continue collecting the half-cent surcharge until further consideration by the CPUC and to record the surcharge revenues in a balancing account.

In November 2002, the CPUC approved a decision modifying the restrictions on the use of revenues generated by the surcharges to permit the revenues to be used for the purpose of securing or restoring the Utility's reasonable financial health, as determined by the CPUC. The CPUC will determine in other proceedings how the surcharge revenues can be used, whether there is any cost or other basis to support specific surcharge levels, and whether the resulting rates are just and reasonable. After the CPUC determines when the AB 1890 rate freeze ended, the CPUC will determine the extent and disposition of the Utility's under-collected costs, if any, remaining at the end of the rate freeze. If the CPUC determines that the Utility recovered revenues in excess of its transition costs or in excess of other permitted uses, the CPUC may require the Utility to refund such excess revenues.

In December 2002, the CPUC issued a decision authorizing the Utility to record amounts related to the $0.01 and $0.03 surcharge revenues as an offset to unrecovered transition costs.

Based on the November and December 2002 CPUC decisions discussed above and an agreement between the CPUC and another California investor-owned utility, Southern California Edison (SCE), in which SCE was allowed to use its half-cent surcharge to offset its California Department of Water Resources (DWR) revenue requirement, the Utility believes it can continue to recognize revenues related to the $0.01, $0.03, and half-cent surcharges after the statutory end of the rate freeze, which was March 31, 2002. As such, the Utility has not recorded a regulatory liability for these surcharge revenues, or any portion thereof, in its financial statements. If the CPUC requires the Utility to refund any of these revenues in the future, the Utility's earnings could be materially affected.

Recovery of Transition Costs

During 2001, the price of wholesale electricity stabilized. In 2001 and 2002, as a result of the wholesale electricity price stabilization and the CPUC-authorized surcharges, the Utility's total generation-related electric revenues were greater than its generation-related costs, resulting in the partial recovery of previously written-off under-collected purchased power and transition costs. As of December 31, 2000, the Utility had accumulated a total of approximately $4.1 billion (after-tax) in unrecovered purchased power and generation-related transition costs. This amount was charged to earnings at that time because the Utility could no longer conclude that such costs were probable of collection through regulated rates. Generation-related costs in excess of generation-related revenues continue to be expensed as they are incurred. As of March 31, 2003, the outstanding balance of the Utility's unrecovered purchased power and transition costs amounted to $2.4 billion (after-tax) compared to a balance of $2.2 billion (after-tax) at December 31, 2002. The increase in the unrecovered balance from December 31, 2002, to March 31, 2003, was due to first quarter 2003 generation-related costs in excess of generation-related revenues. Typically, electric revenues are lower in the winter because of lower consumption and lower winter rates.

The recovery of these remaining under-collected purchased power costs and transition costs will depend on a number of factors, including the ultimate outcome of the Utility's bankruptcy and future regulatory and judicial proceedings, including the outcome of the Utility's filed rate doctrine litigation. (The filed rate doctrine litigation refers to a lawsuit filed in November 2000 in the U.S. District Court for the Northern District of California by the Utility against the CPUC

Commissioners, asking the court to declare that the federally approved wholesale electricity costs that the Utility has incurred to serve its customers are recoverable in retail rates under the federal filed rate doctrine.)

Under AB 1890, the rate freeze was scheduled to end on the earlier of March 31, 2002, or the date that the Utility recovered all of its generation-related transition costs as determined by the CPUC. However, in January 2002, the CPUC issued a decision finding that new California legislation, AB 6X, had materially affected the implementation of AB 1890. 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. In its November 2002 decision regarding the surcharge revenues discussed above, the CPUC reiterated that it had yet to decide when the rate freeze ended and the disposition of any under-collected costs remaining at the end of the rate freeze.

During the third quarter of 2002, and again during the first quarter of 2003, the CPUC represented that, since utilities now are required under state law (AB 6X) to retain their generating assets and the CPUC has regained its traditional rate authority over those assets, costs associated with those assets may be recovered by the utilities in the traditional way under cost-based regulation. Based on these CPUC decisions and representations, the Utility believes it can continue to record revenues collected under its existing overall retail rates, subsequent to the statutory end of the rate freeze.

However, the CPUC's proceedings to consider the impact of AB 6X on the AB 1890 rate freeze and the disposition of the Utility's unrecovered transition costs are still pending. The California Supreme Court currently is considering the authority of the CPUC to enter into a settlement with SCE, which allows SCE to recover under-collected procurement and transition costs in light of the provisions of AB 1890. Oral argument has been set before the California Supreme Court in this case on May 27, 2003. Either in response to judicial decisions such as this one, or on its own initiative, 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. The Utility has not provided reserves for potential refunds of any of these revenues as of

March 31, 2003. If the CPUC requires the Utility to refund any of these revenues in the future, the Utility's earnings could be materially affected.

Electricity Purchases

In January 2001, as wholesale electric prices continued to exceed retail rates, the major credit rating agencies lowered their ratings for the Utility and PG&E Corporation to non-investment grade levels. Consequently, the Utility lost access to its bank facilities and capital markets, and no longer could continue buying electricity to deliver to its customers. As a result, in the first quarter of 2001, the California Legislature and the Governor of California authorized the DWR to purchase electricity for the Utility's customers and to issue revenue bonds to finance electricity purchases (governed by AB 1X). Initially, the DWR indicated that it intended to buy electricity 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 Utility accrued approximately $1 billion for ISO billings for the period January 17, 2001, through April 6, 2001. However, in 2001 and 2002, the FERC issued a series of orders directing the ISO to buy electricity only on behalf of creditworthy entities. The Utility currently acts as a billing and collection agent for electricity provided to its customers by the DWR. As such, revenues associated with these activities are passed through to the DWR and are not included in the Utility's results of operations.

In February 2002, the CPUC approved a decision, which was further modified in March 2002, that set the statewide DWR revenue requirement for 2001 and 2002. The DWR revenue requirement decision allows the DWR to collect amounts from ratepayers to provide the revenues needed by the DWR to procure electricity for the customers of the Utility and the other California investor-owned utilities (IOUs).

The DWR's revenue requirement included the procurement charges previously billed by the ISO and accrued by the Utility. As such, because of certain 2001 and 2002 FERC orders and the February and March 2002 CPUC decisions, in the first quarter of 2002 the Utility reversed the excess of the ISO accrual (for the period from January 17, 2001, through April 6, 2001) over the amount of the additional DWR revenue requirement applicable to 2001, for a net reduction of accrued purchased power costs of approximately $595 million (pre-tax).

In October 2002, the DWR filed a proposed amendment to the CPUC's May 16, 2002, servicing order requesting both prospective and retrospective changes to the calculation that determines the amount of revenue the Utility is required to pass through to the DWR. Under its statutory authority, the DWR may request the CPUC to order utilities to implement such amendments, and the CPUC has approved such amendments in the past without significant change. In December 2002, the CPUC issued an operating order requiring the Utility to perform the operational, dispatch, and administrative functions for the DWR's allocated contracts beginning on January 1, 2003. The operating order, which applies prospectively, includes the DWR's proposed method of calculating the amount of revenues that the Utility must pass through to the DWR but does not change the servicing order relating to the same calculation. In March 2003, the DWR submitted a letter to the CPUC reaffirming its position and quantifying the amount of revenues that the DWR has requested the CPUC to order the Utility to

pass through to the DWR. As a result, the Utility has accrued an additional $96 million (pre-tax) liability for pass-through revenues for electricity previously provided by the DWR to the Utility's customers. In total as of March 31, 2003, the Utility has accrued an additional $539 million (pre-tax) liability for pass-through revenues to the DWR based on the DWR's October 2002 proposed amendment, the CPUC's December 2002 operating order, and the March 2003 letter from the DWR. Of this amount, $369 million (pre-tax) had been accrued at December 31, 2002.

In April 2003, the Utility and the DWR entered into an operating agreement, which has been approved by the CPUC. Effective in April 2003, the operating agreement supersedes the operating order. The operating agreement provides that the Utility will begin passing through revenues to the DWR consistent with the DWR's October 2002 and March 2003 requests for amendments to the servicing order, but subject to the outcome of the CPUC's consideration of the DWR's requests. In addition, if the CPUC grants the DWR's request for changes to the servicing order, the Utility would be required to make additional cash payments to the DWR consistent with its accrual of pass-through revenues to the DWR for the periods prior to the effective date of the operating agreement.

In October 2002, the Utility filed a lawsuit in a California court asking the court to find that the DWR's revenue requirements had not been demonstrated to be "just and reasonable" (as required by AB 1X) and lawful. The Utility asked the court to order the DWR's revenue requirement determination to be withdrawn as invalid, and that the DWR be precluded from imposing its revenue requirements on the Utility and its customers until it has complied with the law. The lawsuit is scheduled to be considered by the court during the third or fourth quarter of 2003.

Senate Bill 1976

Under AB 1X, the DWR is prohibited from entering into new agreements to purchase electricity to meet the net open position of the IOUs after December 31, 2002. In September 2002, the Governor signed California Senate Bill (SB) 1976 into law. As required by SB 1976, each

California IOU submitted an electricity procurement plan to meet the residual net open position associated with that utility's customer demand.

A central feature of the SB 1976 regulatory framework is its direction to the CPUC to create new electric procurement balancing accounts to track and allow recovery of the differences between recorded revenues and costs incurred under an approved procurement plan. The CPUC must review the revenues and costs associated with the Utility's electric procurement plan at least semi-annually and adjust rates or order refunds, as appropriate, to properly amortize the balancing accounts. The CPUC must establish a schedule for amortizing the over-collections or under-collections in the electric procurement balancing accounts so that the aggregate over-collections or under-collections reflected in the accounts do not exceed 5 percent of the IOUs' actual recorded generation revenues for the prior calendar year, excluding revenues collected on behalf of the DWR. Mandatory semi-annual review and adjustment of the balancing accounts will continue until January 1, 2006, after which time the CPUC will conduct electric procurement balancing account reviews and adjust retail ratemaking amortization schedules for the balancing accounts as the CPUC deems appropriate and in a manner consistent with the requirements of SB 1976 for timely recovery of electricity procurement costs. Additionally, in a December 2002 interim opinion, the CPUC established a maximum annual procurement disallowance for administration of all contracts and least-cost dispatch of resources equal to twice the Utility's annual administrative costs of managing procurement activities, including the administration and dispatch of electricity associated with DWR allocated contracts.

In December 2002, the CPUC issued an interim opinion adopting the Utility's electricity procurement plan for 2003. On January 1, 2003, the Utility resumed the function of procuring electricity to meet the portion of its customers' needs that is not covered by the combination of the allocation of electricity from existing DWR contracts and the Utility's own electric resources and contracts. To meet this requirement, the Utility entered into contracts for fuel supply, capacity, and transmission rights that limit exposure to potentially high congestion charges. These one-year term contracts did not have a material impact on the Utility's commitments previously disclosed in its 2002 Annual Report on Form 10-K, as amended.

The Utility filed its long-term procurement plan (long-term plan), which covers the next 20 years, with the CPUC on April 15, 2003. The Utility's long-term plan states that certain important policy issues, including the restoration of the Utility's financial health and investment grade credit rating, should be resolved before the CPUC can adopt a credible long-term plan for the Utility. The long-term plan indicates that a fundamental requirement for restoring the Utility's credit rating is the provision of procurement cost recovery by the CPUC. The Utility also mentions other conditions that the CPUC should consider implementing before adopting its long-term plan, including providing comprehensive guidelines that give the Utility the flexibility to react quickly to changing market conditions and determining which customers the Utility will serve and under what price. In this latter condition, the Utility notes that it will continue to be exposed to unrecovered costs unless the CPUC requires customer classes to pay the full amount of costs incurred on their behalf. While the long-term plan states that there is no immediate need for the Utility to construct or make long-term commitments to new resources, it notes that the Utility's role in future generation development will be directly impacted by its credit rating.

Allocation of DWR Electricity to Customers of the IOUs

Since 2001, the Utility and the other California IOUs have acted as the billing and collection agents for the DWR's sales of its electricity to retail customers. In September 2002, the CPUC issued a decision allocating the electricity provided under existing DWR contracts to the customers of the IOUs. This decision required the Utility, along with the other IOUs, to begin performing all the day-to-day scheduling, dispatch, and administrative functions associated with the DWR contracts allocated to the IOUs' respective portfolios by January 1, 2003.

Although the DWR retains legal and financial responsibility for these contracts, the DWR has stated publicly that it intends to transfer full legal title of, and responsibility for, the DWR electricity contracts to the IOUs as soon as possible. However, SB 1976 does not contemplate a transfer of title of the DWR contracts to the IOUs. In addition, the operating agreement approved by the CPUC in April 2003 (implementing the Utility's operational and scheduling responsibility with respect to the DWR allocated contracts) specifies that the DWR will retain legal and financial responsibility for the contracts. The Utility's proposed plan of reorganization prohibits the Utility from accepting, directly or indirectly, assignment of legal or financial responsibility for the DWR contracts. Either the State of California (State) or the CPUC may seek to provide the DWR with authority to effect such a transfer of legal title in the future. The Utility has informed the CPUC, the DWR, and the State that the Utility would vigorously oppose any attempt to transfer the DWR allocated contracts to the Utility without the Utility's consent.

Chapter 11 Filing

On April 6, 2001, the Utility filed for relief under Chapter 11 of the Bankruptcy Code, causing the Utility to become subject to the jurisdiction of the Bankruptcy Court. Throughout the Chapter 11 proceeding, the Utility has maintained control over its assets and has been authorized to operate its business as a debtor-in-possession. 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 Chapter 11 filing. PG&E Corporation, the Utility's parent, and PG&E NEG have not filed for Chapter 11 and are not included in the Utility's Chapter 11 filing. PG&E Corporation, however, is a co-proponent of the Utility's proposed plan of reorganization (Plan) described below.

In connection with the Utility's Chapter 11 filing, various parties filed claims with the Bankruptcy Court totaling approximately $50.1 billion through March 31, 2003. Of these claims, approximately $26.5 billion have been disallowed or withdrawn. Of the remaining $23.6 billion of filed claims, pursuant to the Plan and alternative plan (discussed below), claims asserted in the amount of approximately $5.5 billion are expected to pass through the bankruptcy proceeding and be determined in the appropriate court or other tribunal during the bankruptcy proceeding or after it concludes.

The Utility has objected to approximately $1 billion of the remaining $23.6 billion of filed claims. These objections are pending in the Bankruptcy Court. The Utility intends to object to approximately $4.4 billion of the remaining $23.6 billion of filed claims. These objections relate primarily to generator claims. Generator claims could be reduced significantly based on the FERC's March 26, 2003, decision finding that electricity suppliers significantly overcharged California buyers, including IOUs, from October 2, 2000, to June 20, 2001. The Utility has recorded its estimate of all valid claims at March 31, 2003, as $9.4 billion of Liabilities Subject to Compromise and $3.0 billion of Long-Term Debt. The Utility has paid certain claims authorized by the Bankruptcy Court, as discussed below, and reduced the amount of outstanding claims accordingly. In addition, since its Chapter 11 filing, the Utility has accrued interest on all claims it considers valid. This additional interest accrual is not included in the original $50.1 billion of claims filed.

In addition to other parties, the City of Palo Alto and the Northern California Power Agency (NCPA) filed an objection to the Plan and the CPUC's alternative proposed plan of reorganization. The objection asserts that, by virtue of the Utility's termination of a wholesale electric transmission contract between the NCPA and the Utility, NCPA members, including Palo Alto, will now be required to obtain transmission service through the California ISO and will be subject to substantial ISO charges. Palo Alto and the NCPA further assert that the Utility's motivation for terminating the NCPA transmission contract was anticompetitive and violated federal antitrust laws. They claim that damages associated with these increased ISO congestion charges could exceed $1 billion (which Palo Alto and the NCPA have indicated they would seek to treble under federal antitrust law). In January 2003, the Bankruptcy Court held an estimation hearing to determine what value to put on a possible future damages award that Palo Alto and the NCPA might receive, should they file, pursue, and establish liability on their antitrust claim. The Utility believes that Palo Alto's and the NCPA's claims are without merit.

The Bankruptcy Court has authorized certain payments and actions necessary for the Utility to continue its normal business operations while operating as a debtor-in-possession. For example, the Utility is authorized to pay employee wages and benefits,

amounts payable to certain qualified facilities (QFs), interest on certain secured and unsecured debt, environmental remediation expenses, and expenditures related to property, plant and equipment. In addition, the Utility is authorized to refund certain customer deposits, use certain bank accounts and cash collateral, and assume responsibility for various hydroelectric contracts. The Utility also has received permission from the Bankruptcy Court to make payments on (1) pre- and post-petition interest on certain claims, (2) pre-petition trade payables to the majority of QFs and to certain other vendors, and (3) pre-petition secured debt that has matured.

As specified in the Plan described below, the Utility has agreed to pay pre- and post-petition interest on Liabilities Subject to Compromise at the rates set forth below, plus additional interest on certain claims as discussed below.

	Amount Owed	Agreed Upon Interest Rate	
	(in millions)	**(per annum)**	
Commercial Paper Claims	$ 873	7.466%	
Floating Rate Notes	1,240	7.583%	(Implied yield of 7.690%)
Senior Notes	680	9.625%	
Medium-Term Notes	287	5.810% to 8.450%	
Revolving Line of Credit Claims	938	8.000%	
Majority of QFs	75	5.000%	
Other Claims	5,306	Various	
Liabilities Subject to Compromise at March 31, 2003	$ 9,399		

Since the Plan did not become effective on or before February 15, 2003, the interest rates for Commercial Paper Claims, Floating Rate Notes, Senior Notes, Medium-Term Notes, and Revolving Line of Credit Claims have been increased by 37.5 basis points above the rates presented above, for periods on and after February 15, 2003. If the Plan does not become effective on or before September 15, 2003, the interest rates for these claims on and after such date will be increased by an additional 37.5 basis points. Finally, if the effective date does not occur on or before March 15, 2004, the interest rates for these claims on and after such date will be increased by an additional 37.5 basis points. For other claims, the Utility has recorded interest at the contractual or FERC-tariffed interest rate. When those rates do not apply, the Utility has recorded interest at the federal judgment rate.

Proposed Plan of Reorganization

The Utility and PG&E Corporation jointly have proposed a plan of reorganization, referred to as the Plan, which would allow the Utility to restructure its businesses and refinance the restructured businesses. The Plan is designed to align the Utility's existing businesses under the regulators that best match the business functions. Retail assets (natural gas and electricity distribution) would remain under the retail regulator, the CPUC. The wholesale assets (electric transmission, interstate natural gas transportation, and electric generation) would be placed under wholesale regulators, the FERC and the Nuclear Regulatory Commission (NRC). After this realignment, the retail-focused business would be a natural gas and electricity distribution company (Reorganized Utility), representing approximately 70 percent of the book value of the Utility's current assets.

In contemplation of the Plan becoming effective, the Utility has created three new limited liability companies, the LLCs, which currently are owned by the Utility's wholly-owned subsidiary, Newco Energy Corporation (Newco). On the effective date of the Plan, the Utility would transfer substantially all the assets and liabilities primarily related to the Utility's electricity generation business to Electric Generation LLC (Gen), the assets and liabilities primarily related to the Utility's electricity transmission business to ETrans LLC (ETrans), and the assets and liabilities primarily related to the Utility's natural gas transportation and storage business to GTrans LLC (GTrans).

The Plan proposes that on the effective date of the Plan, the Utility would distribute to PG&E Corporation 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. Finally, on the effective date of the Plan or as promptly thereafter as practicable, PG&E Corporation would distribute all the shares of the Utility's common stock that it then holds to its existing shareholders in a spin-off transaction. After the spin-off, the Reorganized Utility would be an independent publicly held company. The common stock of the Reorganized Utility generally would be freely tradable by the recipients. The Reorganized Utility

would retain the name "Pacific Gas and Electric Company," and apply to list its common stock on the New York Stock Exchange.

Although the Reorganized Utility would be legally separated from the LLCs, the Reorganized Utility would have significant operating relationships with the LLCs covering a range of functions and services after the effective date of the Plan.

During 2002, the Utility undertook several initiatives to prepare for separation under the Plan. The Utility has spent approximately $43 million in 2002 and approximately $15 million in 2003 on these initiatives. Of this amount, approximately $4 million has been capitalized to Property, Plant and Equipment in the Consolidated Balance Sheets.

The Plan proposes to satisfy allowed claims with cash, long-term notes issued by the LLCs, or a combination of cash and such notes. Each of ETrans, GTrans, and Gen would issue long-term notes to the Reorganized Utility and the Reorganized Utility then would transfer the notes to certain holders of allowed claims. In addition, each of the Reorganized Utility, ETrans, GTrans, and Gen would issue "new money" notes in registered public offerings. These notes would be secured if necessary to obtain investment-grade credit ratings as required by the Plan. The LLCs then would transfer the proceeds of the sale of the new money notes, less working capital reserves, to the Utility for payment of allowed claims.

PG&E Corporation has agreed to contribute up to $700 million in cash to the Utility's capital from the issuance of equity or from other available sources, to the extent necessary to satisfy the cash obligations of the Utility in respect of allowed claims and required deposits into escrow for disputed claims, or to obtain investment-grade ratings for the debt to be issued by the Reorganized Utility and the LLCs. If PG&E Corporation is required to issue equity, PG&E Corporation's amended and restated credit agreement dated October 18, 2002 (Credit Agreement) will require mandatory prepayment of outstanding loans in an amount equal to the net cash proceeds from the issuance or sale of equity by PG&E Corporation. In addition, PG&E Corporation generally is prohibited by the terms of the Credit Agreement from making investments in the Utility, except as specifically permitted by the terms of the loans or as required by applicable law or the conditions adopted by the CPUC with respect to holding companies. To the extent lender consent is required, PG&E Corporation intends to negotiate with its lenders. Absent any required lender consent, PG&E Corporation intends to seek to refinance its indebtedness.

If the Plan is confirmed by the Bankruptcy Court, the Plan requires that certain conditions must be satisfied or waived before the Plan can become effective, including, among other conditions:

All actions, documents, and agreements necessary to implement the Plan shall have been effected or executed;

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;

Standard & Poor's (S&P) and Moody's Investors Services (Moody's) shall have established investment-grade 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;

The Plan shall not have been modified in a material way since the confirmation date; and

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 have not been satisfied or waived, the confirmation order would be vacated and the Utility's obligations with respect to claims and equity interests would remain unchanged.

In connection with the Plan, PG&E Corporation and the Utility contend that bankruptcy law expressly preempts state law in connection with the implementation of a plan of reorganization. The Bankruptcy Court rejected this contention. PG&E Corporation and the Utility appealed this decision to the U.S. District Court for the Northern District of California (District Court). The District Court reversed the Bankruptcy Court's ruling and remanded the case back to the Bankruptcy Court for further proceedings, ruling that the Bankruptcy Code expressly preempts "nonbankruptcy laws that would otherwise apply to bar, among other things, transactions necessary to implement the reorganization plan." The District Court entered judgment on September 19, 2002, and the CPUC and several other parties thereafter initiated an appeal to the U.S. Court of Appeals for the Ninth Circuit. The Ninth Circuit has scheduled arguments to be heard on May 14, 2003.

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On February 27, 2003, the California counties of Alameda, Fresno, San Luis Obispo, Sonoma, and the City and County of San Francisco (collectively, the Counties) filed a motion for summary judgment denying confirmation of the Plan, arguing that the Plan is not feasible because it purports to transfer to Gen, or a subsidiary of Gen, the Utility's beneficial interests in the Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement (Trust). The Counties contend that the contemplated transfer is unlawful because the Utility's interests in the Trust do not constitute property of the Utility's estate. The Counties also argue that prior CPUC approval of the transfer is necessary but the Utility has not requested such approval. The Utility vigorously contests the Counties' allegations.

The CPUC/OCC's Alternative Plan of Reorganization

The CPUC and the Official Committee of Unsecured Creditors (OCC) jointly have proposed an alternative plan of reorganization (CPUC/OCC plan) for the Utility that does not call for realignment of the Utility's existing businesses. The alternative plan instead provides for the continued regulation of all of the Utility's current operations by the CPUC. The alternative plan proposes to satisfy all allowed creditor claims in full either through reinstatement or payment in cash, using a combination of cash on hand and the proceeds from the issuance of $7.3 billion of new senior secured debt and the issuance of $1.5 billion of new unsecured debt and preferred securities. The alternative plan also proposes to establish a $1.75 billion regulatory asset, which would be included in the Utility's rate base and would be amortized over ten years.

The CPUC/OCC plan also provides that it would not become effective until the Utility and the CPUC enter into a "reorganization agreement" under which the CPUC promises to establish retail electric rates on an ongoing basis sufficient to facilitate achieving and maintaining investment grade credit ratings for portions of the Utility's securities and to recover in rates (1) the interest and dividends payable on, and the amortization and redemption of, the securities to be issued under the alternative plan, and (2) certain recoverable costs (defined as the amounts the Utility is authorized by the CPUC to recover in retail electric rates in accordance with historical practice for all of its prudently incurred costs, including capital investment in property, plant and equipment, a return of capital, and a return on capital and equity to be determined by the CPUC from time to time in accordance with its past practices).

PG&E Corporation and the Utility believe the alternative plan is not credible or confirmable. PG&E Corporation and the Utility do not believe the alternative plan would restore the Utility or its debt securities to investment-grade status if the alternative plan is to become effective. Additionally, PG&E Corporation and the Utility believe the alternative plan would violate applicable federal and state law.

Confirmation Hearings

The trial on confirmation of the alternative plan began on November 18, 2002. The trial on the Plan began on December 16, 2002, with objections common to both plans slated for trial during the Plan trial. On March 4, 2003, the Bankruptcy Court ordered the Utility, the CPUC, and other parties involved in the confirmation trial to participate in settlement negotiations. On March 11, 2003, the Bankruptcy Court then issued an order staying nearly all the proceedings in the confirmation trial until May 12, 2003. On April 23, 2003, the Bankruptcy Court extended this stay for an additional 30 days. A status conference is scheduled for June 16, 2003.

The Utility is unable to predict which plan, if any, the Bankruptcy Court will confirm. If either plan is confirmed, implementation of the confirmed plan may be delayed due to appeals, CPUC actions or proceedings, or other regulatory hearings that could be required in connection with the regulatory approvals necessary to implement that plan, and other events. The uncertainty regarding the outcome 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 unable 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, 2003, of $3.6 billion and cash available from operations will provide sufficient liquidity to allow it to continue as a going concern through 2003.

NOTE 3: PG&E NEG LIQUIDITY AND FINANCIAL MATTERS

Credit Ratings

Prior to July 31, 2002, most of the various debt instruments of PG&E NEG and its subsidiaries carried investment-grade credit ratings as assigned by S&P and Moody's, two major credit rating agencies. Since July 31, 2002, PG&E NEG's rated entities have been downgraded several times. The result of these downgrades has left all of PG&E NEG consolidated rated entities and debt instruments at below investment-grade.

The downgrade of PG&E NEG's credit ratings impacted various guarantees and financial arrangements that require PG&E NEG to maintain certain credit ratings from S&P and/or Moody's. Because of the downgrades, PG&E NEG's counterparties have demanded PG&E NEG to provide additional security for performance in the form of cash, letters of credit, acceptable replacement guarantees, or advanced funding of obligations. Other counterparties continue to have the right to make such demands. If PG&E NEG fails to provide this additional collateral within defined cure periods, PG&E NEG may be in default under contractual terms. In addition to agreements containing ratings triggers, other agreements allow counterparties to seek additional security for performance whenever such counterparty becomes concerned about PG&E NEG's or its subsidiaries' creditworthiness. PG&E NEG's credit downgrades constrained its access to additional capital and triggered increases in cost of indebtedness under many of its outstanding debt arrangements.

The credit downgrades also impacted PG&E NEG's and its subsidiaries' ability to service their financial obligations by putting constraints on the ability to move cash from one subsidiary to another or to PG&E NEG itself. PG&E NEG's subsidiaries now must independently determine, in light of each company's financial situation, whether any proposed dividend, distribution, or intercompany loan is permitted and is in such subsidiary's interest.

The effects of the credit downgrades on PG&E NEG's debt facilities and other contractual arrangements are described below. Amounts required to be paid under debt agreements and other significant contractual commitments also are described below.

Debt Restructuring

PG&E NEG is currently in default under various debt agreements and guaranteed equity commitments totaling approximately $2.9 billion. In addition, other PG&E NEG subsidiaries are in default under various debt agreements totaling approximately $2.7 billion, but this debt is non-recourse to PG&E NEG. On November 14, 2002, PG&E NEG defaulted on the repayment of the $431 million 364-day tranche of its corporate revolving credit facility (Corporate Revolver). Loans and letters of credit outstanding as of March 31, 2003, under the two-year tranche of the Corporate Revolver were $258 million, consisting of $185 million of letters of credit and $73 million of loans. The default under the Corporate Revolver also constitutes a cross-default as of March 31, 2003, under (1) PG&E NEG Senior Unsecured Notes ($1 billion outstanding), (2) its guarantee of a turbine revolving credit agreement ($205 million outstanding), and (3) various equity commitment guarantees totaling $960 million. In addition, on November 15, 2002, PG&E NEG failed to pay a $52 million interest payment due under PG&E NEG

Senior Unsecured Notes. PG&E NEG currently does not have sufficient cash to meet its financial obligations and has ceased making payments on its debt and equity commitments.

PG&E NEG, its subsidiaries, and their lenders have been engaged in discussions to restructure PG&E NEG's and its subsidiaries' debt obligations and other commitments since October 2002. No agreement has been reached yet and there can be no assurance that an agreement will be reached. Any restructuring agreement that may be reached would be implemented through a reorganization proceeding under Chapter 11 of the Bankruptcy Code. Although PG&E NEG and its subsidiaries are continuing their efforts to maximize cash and reduce liabilities, such efforts are not expected to restore the financial condition of PG&E NEG and its subsidiaries. Absent a negotiated agreement, the lenders may exercise their default remedies or force PG&E NEG and certain of its subsidiaries into an involuntary proceeding under the Bankruptcy Code. Notwithstanding the status of current negotiations, PG&E NEG and certain of its subsidiaries also may elect to voluntarily seek protection under the Bankruptcy Code as early as the second quarter of 2003. Although PG&E Corporation continues to provide assistance to PG&E NEG, its subsidiaries and its lenders in their negotiations, management does not expect the outcome of any bankruptcy proceeding involving PG&E NEG or any of its subsidiaries to have a material adverse effect on the financial condition of PG&E Corporation or the Utility.

Debt in Default and Long-Term Debt

The schedule below summarizes PG&E NEG's and its subsidiaries' outstanding debt in default and long-term debt as of March 31, 2003, and December 31, 2002:

			Outstanding Balance At	
Description	**Maturity**	**Interest Rates**	**March 31, 2003**	**December 31, 2002**
			(in millions)	
Debt in Default				
PG&E NEG, Inc. Senior Unsecured Notes	2011	10.375%	$ 1,000	$ 1,000
PG&E NEG, Inc. Credit Facility-Tranche B (364-day)	11/14/02	Prime plus credit spread	431	431
PG&E NEG, Inc. Credit Facility-Tranche A (2-year facility with a $258 million maximum commitment)	8/23/03	Prime plus credit spread	73	42
Turbine and Equipment Facility	12/31/03	Prime plus credit spread	205	205
GenHoldings Construction Facility Tranche A	12/5/03	LIBOR plus credit spread	194	118
GenHoldings Construction Facility Tranche B	12/5/03	LIBOR plus credit spread	1,068	1,068
GenHoldings Swap Termination			50	50
Lake Road Construction Facility Tranche A	12/11/02	Prime plus credit spread	227	227
Lake Road Construction Facility Tranche B	12/11/02	Prime plus credit spread	219	219
Lake Road Construction Facility Tranche C		Prime plus credit spread		
Lake Road Working Capital Facility	12/9/03	Prime plus credit spread	27	23
Lake Road Swap Termination	12/11/02		61	61
La Paloma Construction Facility Tranche A	12/11/02	Prime plus credit spread	374	367
La Paloma Construction Facility Tranche B	12/11/02	Prime plus credit spread	296	291
La Paloma Construction Facility Tranche C	12/11/02	Prime plus credit spread	21	20
La Paloma Working Capital Facility	12/9/03		46	29
La Paloma Swap Termination	12/11/02		81	79
Subtotal			$ 4,373	$ 4,230
Long-term debt				
PG&E GTN Senior Unsecured Notes	2005	7.10%	$ 250	$ 250
PG&E GTN Senior Unsecured Debentures	2025	7.80%	150	150
PG&E GTN Senior Unsecured Notes	2012	6.62%	100	100
PG&E GTN Medium-Term Notes	2003	6.96%	6	6
PG&E GTN Credit Facility	5/2/05	LIBOR plus credit spread	40	58
USGenNE Credit Facility	9/1/03	LIBOR plus credit spread	75	75
Plains End Construction Facility	9/6/06	LIBOR plus credit spread	65	56
Other Debt Related to Attala	Various	Principally LIBOR plus credit spread	237	

			Outstanding Balance At	
Mortgage Loan Payable	2010	CP rate + 6.07%	7	7
Other	Various	Various	20	20
Subtotal			$ 950	$ 722
Total Debt in Default and Long-term Debt			$ 5,323	$ 4,952
Amounts Classified as:				
Debt in Default			$ 4,373	$ 4,230
Long-term Debt, Classified as Current			10	17
Long-term Debt			865	630
Amount Related to Liabilities of Operations Held for Sale, Classified as Current			75	75
Total Debt in Default and Long-term Debt			$ 5,323	$ 4,952

Accrued Interest

For the period ended March 31, 2003, accrued interest was recorded on the following debt instruments:

	PG&E NEG (in millions)
PG&E NEG Senior Unsecured Notes	$ 91
PG&E NEG Inc. Credit Facility	17
Turbine and Equipment Facility	7
Lake Road Facilities	16
La Paloma Facilities	4
PG&E GTN Facilities	11
Total	**$ 146**

GenHoldings Construction Facility

In December 2001, PG&E NEG entered into a $1.075 billion 5-year non-recourse credit facility for a portfolio of generating projects held by GenHoldings I, LLC (GenHoldings), a wholly-owned indirect subsidiary of PG&E NEG. The credit facility, which increased to $1.5 billion on April 5, 2002, is secured by the Millennium, Harquahala, Covert, and Athens projects. The facility was intended to be used to reimburse PG&E NEG and lenders for a portion of the construction costs already incurred on these projects and to fund a portion of the balance of the construction costs through completion.

GenHoldings has defaulted under its credit agreement by failing to make equity contributions to fund construction draws for the Athens, Harquahala, and Covert projects. In November and December 2002, GenHoldings' lenders executed waivers and amendments to the credit agreement under which they agreed to continue to waive GenHoldings' equity default until March 31, 2003 and increased loan commitments to cover such shortfall.

In connection with the lenders' waiver of various defaults and additional funding commitments, PG&E NEG has agreed to cooperate with any reasonable proposal by the lenders regarding disposition of the equity in or assets of any or all of the PG&E NEG subsidiaries holding the Athens, Covert, Harquahala, and Millennium projects.

As of March 21, 2003, the lenders executed a waiver letter extending to June 30, 2003, the waiver of GenHoldings' equity default. In addition, the waiver letter also waives other existing defaults in order to permit the continued availability of loan facilities to fund construction and operation of the projects until such time as a transfer of the projects to the GenHoldings lenders may be completed. An event of default will occur if such transfer is not accomplished by June 30, 2003. A default would trigger lender remedies, including the right to foreclose on the Millennium, Harquahala, Athens, and Covert projects.

Under the waiver, PG&E NEG has re-affirmed its guarantee of GenHoldings' remaining obligation to make equity contributions to these projects of approximately $355 million. Neither PG&E NEG nor GenHoldings currently expects to have sufficient funds to make this payment. The requirement to pay $355 million will remain an obligation of PG&E NEG that would survive the transfer of the projects.

Lake Road and La Paloma Construction Facilities

In September 1999 and March 2000, Lake Road Generating Company, LP (Lake Road) and La Paloma Generating Company, LLC (La Paloma) entered into Participation Agreements to finance the construction of the two plants. In November 2002, Lake Road and La Paloma defaulted on their obligations to pay interest and swap payments. In addition, as a result of PG&E NEG's downgrade to below investment grade by both S&P and Moody's, PG&E NEG, as guarantor of certain debt obligations of Lake Road and La Paloma, became required to make equity contributions to Lake Road and La Paloma of $230 million and $375 million respectively. The lenders have accelerated all debt existing prior to December 11, 2002, including the guaranteed portion of the debt and made a payment under the PG&E NEG guarantee. Neither PG&E NEG, Lake Road nor La Paloma has sufficient funds to make these payments.

As of December 4, 2002, PG&E NEG and certain subsidiaries entered into various agreements with the respective lenders for each of the Lake Road and La Paloma generating projects providing for (1) funding of construction costs required to complete the La Paloma facility, and (2) additional working capital facilities to enable each subsidiary to timely pay for its fuel requirements and to provide its own collateral to support natural gas pipeline capacity reservations and independent

transmission system operator requirements, as well as for general working capital purposes. Lenders extending new credit under these agreements have received liens on the projects that are senior to the existing lenders' liens. These agreements provide, among other things, that the failure to transfer right, title and interest in, to and under the Lake Road and La Paloma projects to the respective lenders by June 9, 2003 will constitute a default under the agreements. The failure to transfer the facilities would entitle the lenders to accelerate the new indebtedness and exercise other remedies. The requirement to pay $230 million and $375 million for Lake Road and La Paloma, respectively, will remain an obligation of PG&E NEG that would survive the transfer of the projects.

Impairments, Write-offs, and Other Charges

Consolidation and Impairment of Attala Generating Company LLC

On May 7, 2002, Attala Generating Company LLC (Attala Generating), an indirect wholly-owned subsidiary of PG&E NEG, completed a $340 million sale and leaseback transaction whereby it sold and leased back a 526-megawatt (MW) generation facility (Facility) in Mississippi to two third-party special-purpose entities (SPEs). These entities funded the acquisition of their undivided interests in the Facility through proceeds from the issuance of debt and equity. The SPEs funded $103 million, or approximately 30 percent of the total fair value of the Facility on the transaction date, from the issuance of equity. The related transaction was accounted for as a lease because the owners of the SPEs had made an initial substantive residual equity capital investment that was intended to be at risk during the entire term of the lease.

During January 2003, the SPEs distributed cash to their equity holders, which resulted in the SPEs no longer meeting the substantive equity at risk criteria, under current accounting requirements. PG&E NEG now consolidates the assets and liabilities of the SPEs.

The consolidation of the SPEs resulted in an increase in assets of $62 million, representing the estimated fair value of the Facility and related inventories, and debt of $237 million, representing the bonds issued to finance the sale-leaseback transaction. As the liabilities of the SPEs exceed their assets, a pre-tax charge to earnings of $175 million was recorded in the first quarter of 2003.

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46). See Note 1, "General Adoption of New Accounting Policies," for a more complete description of FIN 46. PG&E NEG currently is evaluating the impacts of FIN 46's initial recognition, measurement, and disclosure provisions on its Consolidated Financial Statements when these requirements become effective by the beginning of the third quarter of 2003.

PG&E NEG believes that, upon the adoption of FIN 46, it will not be required to continue to consolidate the SPEs associated with the sale-leaseback of the Facility since it has neither an equity investment nor a significant variable interest in the SPEs. Depending on the method of adopting FIN 46 by PG&E NEG, either the difference between the book values of the SPEs' assets and liabilities will be recognized through earnings, or first quarter 2003 financial statements will be restated to eliminate the impact of initially consolidating the SPEs. Future earnings may also be impacted by the accrual of any probable payments under the Attala guarantee arrangement disclosed in Note 6 of the Notes to the Consolidated Financial Statements.

Shaw Settlement Charges

In connection with the terms of a proposed settlement of all pending disputes among Shaw Group Inc. (Shaw), Harquahala Generating Company, LLC (Harquahala), Covert Generating Company, LLC (Covert) and PG&E NEG, PG&E NEG has recognized a pre-tax charge of approximately $32 million for anticipated legal settlement costs.

Harquahala generating facility, owned by Harquahala, is a 1,092-MW plant in Tonopah, Arizona, with about 88 percent of the construction complete. Covert generating facility, owned by Covert, is a 1,170-MW plant in Covert, Michigan, with about 84 percent of construction complete. The equity in Covert and Harquahala is owned by GenHoldings. On August 13, 2001, Harquahala and Covert entered into engineering procurement and construction contracts (EPCs) with Shaw to design, procure materials and equipment for, and construct these generating facilities.

During November and December 2002, Harquahala commenced arbitration against Shaw seeking a declaration that it was not obligated to withhold payments from a certain third party connected with the construction of the facility. Subsequently, Shaw commenced arbitration against Covert and Harquahala to recover the value of certain change order requests. In addition, Shaw filed a lawsuit against Harquahala, Covert, PG&E NEG, and NEG Construction Finance Company, LLC (CFC), alleging that it had not received adequate assurance of payment from PG&E NEG.

Under the terms of the proposed settlement, PG&E NEG will pay approximately $32 million to Shaw, the EPC contracts will be increased in the aggregate by $65 million (the balance funded by the lenders), the completion deadlines will be extended, the cost-sharing agreements and related guarantees will be terminated, and PG&E NEG's completion guarantees to the lenders will be released. The parties are now negotiating definitive agreements.

Mantua Creek Project

The Mantua Creek project is a nominal 897 MW combined cycle merchant power plant located in the Township of West Depford, New Jersey. Due to liquidity concerns, PG&E NEG could no longer provide equity contributions to the project and beginning in the fourth quarter of 2002, began to suspend or terminate contracts with vendors. At December 31, 2002, PG&E NEG wrote off capitalized development and construction costs of $257 million and established an additional accrual of $22 million for charges and associated termination costs. For the period ending March 31, 2003, various termination cost accruals were adjusted as settlements occurred resulting in an approximate $8 million reduction in impairment expense.

NOTE 4: DISCONTINUED OPERATIONS AND ASSETS HELD FOR SALE

USGen New England

In September 1998, USGen New England, Inc. (USGenNE) acquired the non-nuclear generating assets of the New England Electric System (NEES) for approximately $1.8 billion. These assets included:

- 2,344 MW of coal- and oil-fired power plants in Massachusetts;
- 1,166 MW of hydroelectric facilities in New Hampshire, Vermont, and Massachusetts;
- 495 MW of gas-fired power plants in Rhode Island;
- Above-market power purchase agreements with support payments provided by NEES for the first nine years;

Gas pipeline transportation contracts; and

Transition wholesale load contracts known as Standard Offer Agreements.

Consistent with its previously announced strategy to dispose of certain merchant assets, in December 2002 the Board of Directors of PG&E Corporation approved management's plans for the proposed sale of USGenNE. Under the provisions of SFAS No. 144, the equity of USGenNE has been accounted for as an asset held for sale at December 31, 2002. This requires that the asset be recorded at the lower of fair value, less costs to sell, or book value. Based on the current estimated fair value (based on the estimated proceeds) of a sale of USGenNE, PG&E NEG recorded a pre-tax loss of $1.1 billion in the fourth quarter of 2002. PG&E NEG recorded an additional pre-tax loss on disposal of $23 million in the first quarter of 2003. It was anticipated that the arrangements for the disposition of the USGenNE assets would be made during 2003. However, as a result of required regulatory approval by the FERC, it is anticipated that any disposals will not be consummated until 2004. The operating results from USGenNE are being reported as discontinued operations in the PG&E Corporation Consolidated Statements of Operations for the three months ended March 31, 2003, and 2002. Also under the provisions of SFAS No. 144, no depreciation has been recorded on the restated assets.

Mountain View

On September 17 and 28, 2001, PG&E NEG purchased Mountain View Power Partners, LLC and Mountain View Power Partners II, LLC, respectively (collectively referred to as Mountain View), from SeaWest Wind Power, Inc. These companies own 44- and 22-MW wind energy projects, respectively, near Palm Springs, California (SeaWest). PG&E NEG contracted with SeaWest for the operation and maintenance of the wind units. Total consideration for these two companies was $92 million. The two companies were merged on October 1, 2002. The power is sold to the DWR under a 10-year contract.

In December 2002, the Board of Directors of PG&E Corporation approved the sale of Mountain View. On December 18, 2002, a subsidiary of PG&E NEG entered into an agreement to sell Mountain View to Centennial Power, Inc. The sale occurred on January 3, 2003. PG&E NEG received $102 million in proceeds for the sale of Mountain View, resulting in a $19 million pre-tax gain.

Under the provisions of SFAS No. 144, Mountain View is accounted for as an asset held for sale at March 31, 2003, and December 31, 2002. The operating results from Mountain View are being reported as discontinued operations in the PG&E Corporation Consolidated Statements of Operations for the three months ended March 31, 2003, and 2002.

ET Canada

On March 18, 2003, PG&E Energy Trading-Gas Corporation (ET-Gas), a subsidiary of PG&E NEG, completed the sale of 100 percent of the stock of PG&E Energy Trading, Canada Corporation (ET Canada) to Seminole Canada Gas Company, a Nova Scotia unlimited liability company (Seminole). Seminole transferred approximately $86 million at closing to ET-Gas and several of its affiliates, representing the purchase price and the return of collateral posted by ET-Gas and ET Canada to support ET Canada's energy trading transactions, plus interest. Most of the proceeds were used to repay principal and interest on an outstanding loan of $76 million to another affiliate.

Seminole also has agreed within 30 days after the closing to replace certain letters of credit issued to support ET Canada's energy trading transactions and to obtain the release of ET-Gas and its affiliates, including PG&E GTN and PG&E NEG from obligations under guarantees issued for the same reasons. Seminole has indemnified ET-Gas for any liability under the letters of credit or the guarantees. As previously disclosed, in the fourth quarter of 2002, PG&E NEG recorded a $25 million pre-tax loss on the anticipated disposition of ET Canada. In the first quarter of 2003, an additional $3 million pre-tax loss on disposal was recorded.

The following table reflects the combined operating results of USGenNE, Mountain View, and ET Canada for the three months ended March 31, 2003, and 2002:

	Three months ended March 31,	
	2003	2002

	Three months ended March 31,	
	(in millions)	
Operating Revenues	$ 122	$ 216
Operating Expenses		
Cost of commodity sales and fuel	172	131
Operations, maintenance, and management	52	63
Depreciation and amortization		17
Total operating expense	$ 224	$ 211
Operating Income (Loss)	(102)	5
Interest income	7	10
Interest expense	(1)	
Other expense, net	(4)	(2)
Income (Loss) Before Income Taxes	$ (100)	$ 13
Income tax expense (benefit)	(35)	5
Earnings (Loss) from Assets classified as Discontinued Operations	$ (65)	$ 8

The following table reflects the components of assets and liabilities held for sale of USGenNE at March 31, 2003, and the combined components of assets and liabilities held for sale of USGenNE, Mountain View, and ET Canada at December 31, 2002:

	Balance At	
	March 31, 2003	December 31, 2002
	(in millions)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 52	$ 32
Accounts receivable trade	157	300
Inventory	53	82
Price risk management	2	196

Prepaid expenses, deposits and other	2	97
Total current assets held for sale	266	707
Property, Plant and Equipment		
Total property, plant and equipment(1)	718	799
Accumulated depreciation	(279)	(285)
Net property, plant and equipment	439	514

Other Noncurrent Assets		
Long-term receivables(2)	303	319
Intangible assets, net of accumulated amortization of $37 million and $37 million	20	20
Price risk management	7	30
Other	41	33
Total noncurrent assets held for sale	810	916
TOTAL ASSETS HELD FOR SALE	$ 1,076	$ 1,623
LIABILITIES		
Current Liabilities		
Long-term debt, classified as current	$ 75	$ 75
Accounts payable and Accrued expenses	31	207
Price risk management	161	331
Out-of-market contractual obligations(3)	86	86
Total current liabilities of operations held for sale	353	699
Noncurrent Liabilities		
Price risk management	241	272
Out-of-market contractual obligations(3)	501	501
Other noncurrent liabilities and deferred credit	16	20
Total noncurrent liabilities held for sale	758	793
TOTAL LIABILITIES HELD FOR SALE	1,111	1,492
NET ASSETS (LIABILITIES) HELD FOR SALE	$ (35)	$ 131

(1) Includes impairment charges made against property, plant and equipment.

(2) USGenNE receives payments from a wholly-owned subsidiary of NEES, related to the assumption of power supply agreements, which are payable monthly through January 2008. The long-term receivables are valued at the present value of the scheduled payments using a discount rate that reflects NEES' credit rating on the date of acquisition.

(3) Commitments contained in the underlying Power Purchase Agreements (PPAs) by USGenNE, gas commodity and transportation agreements (collectively, the Gas Agreements), and Standard Offer Agreements acquired by USGenNE in September 1998 were recorded at fair value, based on management's estimate of either or both the gas commodity and gas transportation markets and electric markets over the life of the underlying contracts, discounted at a rate commensurate with the risks associated with such contracts. Standard Offer Agreements reflect a commitment to supply electric capacity and energy necessary for certain affiliates to meet their obligations to supply fixed-rate service. PPAs and Gas Agreements are amortized on a straight-line basis over their specific lives. The Standard Offer Agreements are amortized using an accelerated method, since the decline in value is greater in earlier years due to increasing contract pricing terms designed to reduce demand for supply service over time.

Included in the assets and liabilities held for sale summary above, are certain amounts paid to USGenNE related to the assumption of power supply agreements and certain purchase obligations assumed by USGenNE from the acquisition that occurred in 1998.

NOTE 5: PRICE RISK MANAGEMENT

PG&E NEG is in the process of reducing and unwinding its trading positions. Additionally, asset hedge positions associated with the merchant plants will either remain with the assets or be terminated. PG&E NEG has significantly reduced its energy

trading operations in an ongoing effort to raise cash and reduce debt. PG&E NEG's objective is to limit its asset trading and risk management activities to only what is necessary for energy management services to facilitate the transition of PG&E NEG's merchant generation facilities through their sale, transfer, or abandonment process. PG&E NEG will then further reduce and transition to retain only limited capabilities to ensure fuel procurement and power logistics for PG&E NEG's retained independent power plant operations.

Non-Trading Activities

At March 31, 2003, PG&E Corporation had cash flow hedges of varying durations associated with commodity price risk, interest rate risk, and foreign currency risk, the longest of which extend through December 2011, March 2014, and December 2004, respectively.

The amount of commodity hedges included in Accumulated Other Comprehensive Income or Loss (OCI), net of tax, at March 31, 2003, was a loss of $36 million. The amount of interest rate hedges included in OCI, net of tax, at March 31, 2003, was a loss of $49 million. The amount of foreign currency hedges included in OCI, net of tax, at March 31, 2003, was a loss of $1 million.

PG&E Corporation's net derivative losses included in OCI at March 31, 2003, were $86 million, of which approximately $45 million is expected to be reclassified into earnings within the next 12 months based on the contractual terms of the contracts or the termination of the hedge position. The actual amounts reclassified from OCI to earnings will differ as a result of market price changes. The Utility did not have any cash flow hedges at March 31, 2003, or at March 31, 2002. PG&E Corporation's ineffective portion of changes in amounts of cash flow hedges was immaterial for the three months ended March 31, 2003, and March 31, 2002.

The schedule below summarizes the activities affecting Accumulated Other Comprehensive Income (Loss), net of tax, from derivative instruments:

	Three months ended March 31, 2003		Three months ended March 31, 2002	
	PG&E Corporation	Utility	PG&E Corporation	Utility
	(in millions)			
Derivative gains (losses) included in accumulated other comprehensive income (loss) at beginning of period	$ (90)	$	$ 36	$
Net gain (loss) from current period hedging transactions and price changes	(1)		(75)	
Net reclassification to earnings	5		5	
Derivative gains (losses) included in accumulated other comprehensive income at end of period	(86)		(34)	
Foreign currency translation adjustment			(5)	(2)
Other			(1)	
Accumulated other comprehensive income (loss) at end of period	$ (86)	$	$ (40)	$ (2)

Normally, most non-trading activity earnings are recognized on an accrual basis as revenues are earned and as expenses are incurred. For example, the effective portion of contracts accounted for as cash flow hedges have no mark-to-market effect on earnings; these contracts are presented on a mark-to-market basis on the balance sheet in price risk management (PRM) assets and liabilities and OCI. Other non-trading contracts are exempt from the SFAS No. 133 fair value requirements under the normal purchases and sales exception and thus have no mark-to-market effect on earnings.

Cash flow hedge accounting was discontinued for commodity cash flow hedges on January 1, 2003. Accordingly, such non-trading activities affect PG&E NEG's earnings on a mark-to-market basis. PG&E NEG recognizes the prospective change in fair value relating to commodity hedges and the ineffective portion of the changes in the fair value of all cash flow hedges in earnings. PG&E NEG also has certain derivative contracts that, while they are meant for non-trading purposes, do not qualify for cash flow hedge accounting or for the normal purchases and sales exception to SFAS No. 133. These derivatives are reported in earnings on a mark-to-market basis. These contracts primarily consist of those derivative commodity

contracts for which normal purchases and sales treatment was disallowed upon PG&E NEG's implementation of Derivative Implementation Group (DIG) C15 and C16 effective April 1, 2002.

PG&E NEG's pre-tax earnings for the period ended March 31, 2003, include gains of $50 million related to commodity hedges, previously deferred in OCI, after it became probable that the forecasted transactions will not occur.

Trading Activities

Unrealized gains and losses from trading activities, including the reversal of unrealized gains and losses previously recognized on contracts that go to settlement or delivery, are presented on a net basis in operating revenues. Realized gains and losses from trading activities also are presented on a net basis in operating revenues, beginning in the third quarter of 2002, as more fully described in Note 1 of the Notes to the Consolidated Financial Statements.

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

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

PG&E Corporation's net gains (loss) on trading activities are as follows:

	Three months ended March 31,	
	2003	**2002**
	(in millions)	
Trading activities:		
Unrealized gains (loss), net	$ 8	$ (3)
Realized gains (loss), net	(33)	45
Total	$ (25)	$ 42

Price Risk Management Assets and Liabilities

PRM assets and liabilities on the accompanying PG&E Corporation Consolidated Balance Sheets reflect the aggregation of the fair values of outstanding contracts. These fair values are calculated on a mark-to-market basis for contracts that will be settled in future periods. PRM assets and liabilities at March 31, 2003, include amounts for trading and non-trading activities, as described below:

	PRM Assets		PRM Liabilities		
	Current	Noncurrent	Current	Noncurrent	Net Assets (Liabilities)
			(in millions)		
Trading activities	$ 688	$ 202	$ (632)	$ (247)	$ 11
Non-trading activities	29	62	(10)	(12)	69
Total consolidated PRM assets and liabilities	$ 717	$ 264	$ (642)	$ (259)	$ 80

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Non-trading activities include certain long-term contracts that are not included in PG&E Corporation's trading portfolio but, due to certain pricing provisions and volumetric variability, are unable to receive hedge accounting treatment or the normal purchases and sales exception, as outlined by interpretations of SFAS No. 133. PG&E Corporation has certain other non-trading derivative commodity contracts for the physical delivery of purchases and sales quantities transacted in the normal course of business. These other non-trading activities include contracts that are exempt from SFAS No. 133 fair value requirements under the normal purchases and sales exemption, as described previously. Although the fair value of these other non-trading contracts is not required to be presented on the balance sheet, revenues and expenses generally are recognized in income using the same timing and basis as are used for the non-trading activities accounted for as cash flow hedges. Hence, revenues are recognized as earned and expenses are recognized as incurred.

Credit Risk

Credit risk is the risk of loss that PG&E Corporation and the Utility would incur if counterparties failed to perform their contractual obligations (these obligations are reflected as Accounts Receivable Customers, net; notes receivable included in Other Noncurrent Assets Other; Price Risk Management (PRM) assets; and Assets Held For Sale on the Consolidated Balance Sheets of PG&E Corporation and the Utility, as applicable). PG&E Corporation and the Utility conduct business primarily with customers or vendors, referred to as counterparties, in the energy industry. These counterparties include other investor-owned utilities, 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 because their counterparties may be similarly affected by economic or regulatory changes, or other changes in conditions.

PG&E Corporation and the Utility manage their credit risk in accordance with the PG&E Corporation Risk Management Policy. This establishes processes for assigning credit limits to counterparties before entering into agreements with significant exposure to PG&E Corporation and the Utility. These processes 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 the exposure, or obtain additional collateral, or both. Further, PG&E Corporation and the Utility rely heavily on master agreements that require the counterparty to post security, referred to as credit collateral, 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 for each counterparty as the current mark-to-market value of the contract (that is, the amount that would be lost if the counterparty defaulted today) plus or minus any outstanding net receivables or payables, prior to the application of the counterparty's credit collateral.

During the three months ended March 31, 2003, PG&E Corporation's credit risk decreased primarily due to contract terminations with PG&E NEG counterparties. During the three months ended March 31, 2003, the Utility's credit risk increased due primarily to an increase in commodity prices and to downgrades of some counterparties' credit ratings to levels below investment grade. The downgrades increase the Utility's credit risk because any collateral provided by these counterparties in the form of corporate guarantees or eligible securities may be of lesser or no value. Therefore, in the event these counterparties failed to perform under their contracts, the Utility may face a greater potential maximum loss. In contrast, the Utility does not face any additional risk if counterparties' credit collateral is in the form of cash or letters of credit, as this collateral is not affected by a credit rating downgrade.

During the three months ended March 31, 2003, PG&E Corporation and the Utility recognized no losses due to the contract defaults or bankruptcies of counterparties.

At March 31, 2003, PG&E Corporation had no single counterparty that represented greater than 10 percent of PG&E Corporation's net credit exposure. At March 31, 2003, the Utility had one investment-grade counterparty that represented 17 percent of the Utility's net credit exposure.

The schedule below summarizes PG&E Corporation's and the Utility's credit risk exposure to counterparties that are in a net asset position, with the exception of exchange-traded futures (the exchange provides for contract settlement on a daily basis), as well as PG&E Corporation's and the Utility's credit risk exposure to counterparties with a greater than 10 percent net credit exposure, at March 31, 2003, and December 31, 2002:

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	Gross Credit Exposure Before Credit Collateral(1)	Credit Collateral(2)	Net Credit Exposure(2)	Number of Counterparties >10 percent	Net Exposure of Counterparties >10 percent
			(in millions)		
At March 31, 2003					
PG&E Corporation	$ 789	$ 198	$ 591	$	$
Utility(3)	306	116	190	1	32
At December 31, 2002					
PG&E Corporation	$ 1,165	$ 195	$ 970	$	$
Utility(3)	288	113	175	2	55

(1) Gross credit exposure equals mark-to-market value, notes receivable, and net (payables) receivables where netting is allowed. Gross and net credit exposure amounts reported above do not include adjustments for time value, liquidity, model, or credit reserves.

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

(3) The Utility's gross credit exposure includes wholesale activity only. Retail activity and payables incurred prior to the Utility's bankruptcy filing are not included. Retail activity at the Utility consists of the accounts receivable from the sale of gas and electricity to millions of residential and small commercial customers.

The schedule below summarizes the credit quality of PG&E Corporation's and the Utility's net credit risk exposure to counterparties at March 31, 2003, and December 31, 2002.

Credit Quality(1)	Net Credit Exposure(2)	Percentage of Net Credit Exposure
	(in millions)	
At March 31, 2003		
PG&E Corporation		
Investment-grade(3)(4)	$ 380	64%
Noninvestment-grade	119	20%
Not rated(4)	92	16%
Total	$ 591	100%

Credit Quality(1)	Net Credit Exposure(2)	Percentage of Net Credit Exposure
Utility		
Investment-grade(3)(4)	$ 110	58%
Noninvestment-grade	80	42%
Not rated(4)		
Total	$ 190	100%
At December 31, 2002		
PG&E Corporation		
Investment-grade(3)(4)	$ 700	72%
Noninvestment-grade	205	21%
Not rated(4)	65	7%
Total	$ 970	100%
Utility		
Investment-grade(3)(4)	$ 111	63%
Noninvestment-grade	64	37%
Not rated(4)		

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Total	$ 175	100%

(1) Credit ratings are determined by using publicly available credit ratings of the counterparty. If the counterparty provides a guarantee by a higher rated entity (e.g., its parent), the rating determination is based on the rating of its guarantor.

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

(3) Investment-grade is determined using publicly available information, i.e., rated at least Baa3 by Moody's Investors Services and BBB- by Standard & Poor's.

(4) Most counterparties with no ratings are governmental authorities which are not rated but which PG&E Corporation has assessed as equivalent to investment-grade based upon an internal credit rating of credit quality, and are designated as "investment-grade" above. Other counterparties with no rating, and designated as "not rated" above, are subject to an internal assessment of their credit quality and a credit rating designation.

PG&E Corporation has regional concentrations of credit exposure to counterparties that conduct business primarily throughout North America. The Utility has a regional concentration of credit risk associated with its receivables from residential and small commercial customers in Northern California. However, the risk of material loss due to nonperformance from these customers is not considered likely. Reserves for uncollectible accounts receivable are provided for the potential loss from nonpayment by these customers based on historical experience. At March 31, 2003, the Utility had a net regional concentration of credit exposure totaling $190 million to counterparties that conduct business primarily throughout North America.

NOTE 6: COMMITMENTS AND CONTINGENCIES

PG&E Corporation has substantial financial commitments and contingencies in connection with agreements entered into supporting the Utility's and PG&E NEG's operating, construction, and development activities. These commitments and contingencies are discussed more fully in the PG&E Corporation and Utility combined 2002 Annual Report on Form 10-K, as amended. The following summarizes PG&E Corporation's, the Utility's, and PG&E NEG's contingencies and cancelled, new, and significantly modified commitments since the combined 2002 Annual Report on Form 10-K, as amended, was filed.

Utility

The Utility has significant gain and loss contingencies related to California electric industry restructuring and its Chapter 11 filing. See Note 2 for a discussion of these matters.

Nuclear Insurance

The Utility has several types of nuclear insurance for its Diablo Canyon Power Plant (DCPP) and Humboldt Bay Power Plant (HBPP). The Utility has insurance coverage for property damages and business interruption losses as a member of Nuclear Electric Insurance Limited (NEIL). NEIL is a mutual insurer owned by utilities with nuclear facilities. Under this insurance, if any nuclear generating facility insured by NEIL suffers severe losses, the NEIL Board of Directors could require the Utility to pay additional premiums of up to $32 million to cover property damages and business interruption for DCPP and up to $1.4 million to cover property damages for HBPP.

Under federal law, the Price-Anderson Act (Act), public liability claims from a nuclear incident are limited to $9.5 billion. As required by the Act, the Utility has purchased the maximum available public liability insurance of $300 million for DCPP. The balance of the $9.5 billion of liability protection is covered by a loss-sharing program (secondary financial protection) among utilities owning nuclear reactors. Under the Act, secondary financial protection is required for all reactors of 100 MW or higher. If a nuclear incident results in costs in excess of $300 million, then the Utility may be responsible for up to $88 million per reactor, with payments in each year limited to a maximum of $10 million per incident until the Utility has fully paid its share of the liability. Since the Utility has two nuclear reactors of over 100 MW, 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. In February 2003, a provision extending the Price-Anderson Act through the end of 2003 was adopted by the United States Congress. No other material terms of the Price-Anderson Act changed as a result of the provision.

Additionally, the Utility has purchased $53.3 million of private liability insurance for HBPP and has a $500 million indemnification from the NRC for public liability arising from nuclear incidents covering liabilities in excess of the $53.3 million of private liability insurance for HBPP.

Workers' Compensation Security

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

In February 2001, several surety companies provided cancellation notices because of the Utility's financial situation. The DIR has not agreed to release the canceling sureties from their obligations for claims occurring prior to the cancellation and has continued to apply the cancelled bond amounts, totaling $185 million, towards the $365 million amount of collateral. The Utility was able to supplement the difference through three additional active surety bonds totaling $180 million. At March 31, 2003, the cancelled bonds have not impacted the Utility's self-insured status under California law. PG&E Corporation has guaranteed the Utility's reimbursement obligation associated with these surety bonds and the Utility's underlying obligation to pay workers' compensation claims.

Balancing Account Reserves

In 2002, the CPUC ordered the Utility to create certain electric balancing accounts to track specific electric-related amounts, primarily including revenue shortfalls from baseline allowance increases and costs related to the self-generation incentive program, for which the CPUC has not yet determined a specific recovery method. In the decisions ordering the creation of these balancing accounts, the CPUC indicated that the recovery method of these amounts would be determined in the future. Because the Utility cannot conclude that the amounts in these balancing accounts are considered probable of recovery in future rates, the Utility has reserved these balances by recording a charge against earnings. As of March 31, 2003, the reserve for these balances was approximately $190 million.

PG&E NEG

Letters of Credit

In addition to the outstanding balances under the credit facilities described in Note 3, PG&E NEG has commitments available under facilities to issue letters of credit. The following table lists the various letter of credit facilities that have the capacity to issue letters of credit:

Borrower	Maturity	Letter of Credit Capacity	Letter of Credit Outstanding March 31, 2003
		(in millions)	
PG&E NEG	8/03	$ 185	$ 185
USGenNE	8/03	25	13
PG&E Gen	12/04	7	7
PG&E ET	9/03	19	19
PG&E ET	11/03	35	33

Tolling Agreements

PG&E ET entered into tolling agreements with several counterparties under which it, at its discretion, supplies the fuel to the power plants and then sells the plant's output in the competitive market. Payments to counterparties are reduced if the plants do not achieve agreed-upon levels of performance. The face amount of PG&E NEG's and its subsidiaries' guarantees relating to PG&E ET's tolling agreements is approximately $600 million. The tolling agreements are with: (1) Liberty Electric Power, L.P. (Liberty) guaranteed by both PG&E NEG and PG&E GTN for an aggregate amount of up to $150 million, (2) DTE-Georgetown, LLC (DTE) guaranteed by PG&E GTN for up to $24 million, (3) Calpine Energy Services, L.P. (Calpine) for which no guarantee is in place, (4) Southaven Power, LLC (Southaven) guaranteed by PG&E NEG for up to $175 million, and (5) Caledonia Generating, LLC (Caledonia) guaranteed by PG&E NEG for up to $250 million.

Liberty Liberty has provided notice to PG&E ET that the ratings downgrade of PG&E NEG constituted a material adverse change under the tolling agreement, requiring PG&E ET to replace the guarantee and post security in the amount of $150 million. PG&E ET has not posted such security. Under the terms of the guarantees, Liberty has the right to terminate the agreement and seek recovery of a termination payment for a maximum amount of up to $150 million. Liberty first must proceed against PG&E NEG's guarantee, and can demand payment under PG&E GTN's guarantee only if (1) PG&E NEG is in bankruptcy, or (2) Liberty has made a payment demand on PG&E NEG which remains unpaid five business days after the payment demand is made. In addition, PG&E ET has provided notices to Liberty of several breaches of the tolling agreement by Liberty and has advised Liberty that, unless cured, these breaches would constitute a default under the agreement. If these defaults remain uncured, PG&E ET has the right to terminate the agreement and seek recovery of a termination payment.

DTE-Georgetown By letter dated October 14, 2002, DTE provided notice to PG&E ET that the downgrade of PG&E GTN constituted a material adverse change under the tolling agreement between PG&E ET and DTE and that PG&E ET was required to post replacement security within ten days. By letter dated October 23, 2002, PG&E ET advised DTE that because there had not been a material adverse change with respect to PG&E GTN within the meaning of the tolling agreement, PG&E ET was not required to post replacement security. If PG&E ET was required to post replacement security and it failed to do so, DTE would have the right to terminate the tolling agreement and seek recovery of a termination payment.

Calpine The tolling agreement states that on or before October 15, 2002, Calpine was to have issued a full notice to proceed under its construction contract to its engineering, procurement, and construction contractor for the Otay Mesa facility. On October 16, 2002, PG&E ET asked Calpine to confirm that it had issued this full notice to proceed and Calpine was not able to do so to the satisfaction of PG&E ET. Consequently, PG&E ET advised Calpine by letter dated October 30, 2002, that it was terminating the tolling agreement effective November 29, 2002. Calpine has indicated that this termination was improper and constituted a default under the agreement, but has not taken any further action.

Southaven and Caledonia Tolling Agreements PG&E ET signed a tolling agreement with Southaven dated as of June 1, 2000, under which PG&E ET is required to provide credit support as defined in the tolling agreement. PG&E ET satisfied this obligation by providing an investment-grade guarantee from PG&E NEG as defined in the tolling agreement. The amount of the guarantee now does not exceed $175 million. By letter dated August 31, 2002, Southaven advised PG&E ET that it believed an event of default under the tolling agreement had taken place with respect to this obligation because PG&E NEG was no longer investment-grade as defined in the tolling agreement, and because PG&E ET had failed to provide, within 30 days from the downgrade, substitute credit support that met the requirements of the tolling agreement. Southaven has the right to terminate the agreement and seek a termination payment. In addition, PG&E ET provided Southaven with a notice of default respecting Southaven's performance under the tolling agreement and concerning the inability of the facility to inject its output into the local grid. Southaven has not cured this default and on February 4, 2003, PG&E ET provided a notice of termination.

In addition, PG&E ET signed a tolling agreement with Caledonia dated as of September 20, 2000, under which PG&E ET is required to provide credit support, as defined in the tolling agreement. PG&E ET satisfied this obligation by providing a guarantee from PG&E NEG that was investment-grade, as defined in the tolling agreement. The amount of the guarantee does not exceed $250 million. By letter dated August 31, 2002, Caledonia advised PG&E ET that it believed an event of default under the tolling agreement had taken place with respect to this obligation because PG&E NEG was no longer investment-grade, as defined in the tolling agreement, and because PG&E ET had failed to provide, within 30 days from the downgrade, substitute credit support that met the requirements of the tolling agreement. Caledonia has the right to terminate the tolling agreement and seek a termination payment. In addition, PG&E ET provided Caledonia with a notice of default respecting Caledonia's performance under the tolling agreement and concerning the inability of the facility to inject its output into the local grid. Caledonia has not cured this default and on February 4, 2003, PG&E ET provided a notice of termination.

On February 7, 2003, Southaven and Caledonia filed emergency petitions to compel arbitration or, in the alternative, for a temporary restraining order and preliminary injunction with the Circuit Court of Montgomery County, Maryland (Court). On March 3, 2003, the Court issued an order ruling that PG&E ET must continue to perform under the agreements. PG&E ET appealed this decision to an intermediate Maryland appellate court. However, on April 8, 2003, the highest appellate court in Maryland issued, on its own motion, an order taking jurisdiction of the appeal.

PG&E ET is not able to predict whether the counterparties will seek to terminate the agreements or whether the Court will grant the requested relief. Accordingly, it is not able to predict whether or the extent to which these proceedings will have a material adverse effect on PG&E NEG's financial condition or results of operations.

Under each tolling agreement, determination of the termination payment is based on a formula that takes into account a number of factors, including market conditions such as the price of power and the price of fuel. In the event of a dispute over the amount of any termination payment that the parties are unable to resolve by negotiation, the tolling agreement provides

for mandatory arbitration. The dispute resolution process could take as long as six months to more than a year to complete. To the extent that PG&E ET did not pay these damages, the counterparties could seek payment under the guarantees for an aggregate amount not to exceed $600 million. PG&E NEG is unable to predict whether counterparties will seek to terminate their tolling agreements. PG&E NEG currently does not expect to be able to pay any termination payments that may become due.

Guarantees

PG&E NEG and certain subsidiaries have provided guarantees as of March 31, 2003, to approximately 188 counterparties in support of PG&E ET's energy trading and non-trading activities related to PG&E NEG's merchant energy portfolio in the face amount of $2.2 billion. Typically, the overall exposure under these guarantees is only a fraction of the face value of these guarantees, since not all counterparty credit limits are fully used at any time. As of March 31, 2003, PG&E NEG and its rated subsidiaries' aggregate exposure under these guarantees was approximately $150 million. The amount of such exposure varies daily depending on changes in market prices and net changes in position. In light of the downgrades, some counterparties have sought and others may seek replacement security to collateralize the exposure guaranteed by PG&E NEG and its subsidiaries. PG&E GTN and PG&E ET have terminated the arrangements pursuant to which PG&E GTN provided guarantees on behalf of PG&E ET such that PG&E GTN will provide no new guarantees on behalf of PG&E ET.

At March 31, 2003, PG&E ET's estimated exposure not covered by a guarantee (excluding exposure under tolling agreements) is approximately $96 million.

To date, PG&E ET has met those replacement security requirements properly demanded by counterparties and has not defaulted under any of its master trading agreements, although one counterparty has alleged a default. No demands have been made upon the guarantors of PG&E ET's obligations under these trading agreements. In the past, PG&E ET has been able to negotiate acceptable arrangements and reduce its overall exposure to counterparties when PG&E ET or its counterparties have faced similar situations. There can be no assurance that PG&E ET can continue to negotiate acceptable arrangements in the current circumstances. PG&E NEG cannot quantify with any certainty the actual future calls on PG&E ET's liquidity. PG&E NEG's and its subsidiaries' ability to meet these calls on their liquidity will vary with market price volatility, uncertainty with respect to PG&E NEG's financial condition, and the degree of liquidity in the energy markets. The actual calls for collateral will depend largely upon the ability to enter into forbearance agreements and pre- and early-pay arrangements with counterparties, the continued performance of PG&E NEG companies under the underlying agreements with counterparties, whether counterparties have the right to demand such collateral, the execution of master netting agreements and offsetting transactions, changes in the amount of exposure, and the counterparties' other commercial considerations.

Other Guarantees

PG&E NEG has provided guarantees related to other obligations by PG&E NEG companies to counterparties for goods or services. PG&E NEG does not believe that it has significant exposure under these guarantees. The most significant of these guarantees relates to performance under certain construction contracts. In the event PG&E NEG is unable to provide any additional or replacement security that may be required as a result of rating downgrades, the counterparty providing the goods or services could suspend performance or terminate the underlying agreement and seek recovery of damages. These guarantees represent guarantees of subsidiary obligations for transactions entered into in the ordinary course of business. Some of the guarantees relate to the construction or development of PG&E NEG's power plants and pipelines. These guarantees are described below.

PG&E NEG has issued guarantees to construction financing lenders for the performance of the contractors building the Harquahala and Covert generating projects for up to $555 million.

PG&E NEG has issued $100 million of guarantees to the construction contractor of the Harquahala and Covert projects to cover certain separate cost-sharing arrangements.

PG&E NEG has provided a $300 million guarantee to support a tolling agreement that a wholly-owned subsidiary, Attala Energy Company, LLC, has entered into with another wholly-owned subsidiary, Attala Generating Company, LLC.

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

PG&E Corporation

As further discussed above, PG&E Corporation has guaranteed the Utility's reimbursement obligation associated with certain surety bonds and the Utility's obligation to pay workers' compensation claims.

Environmental Matters

Utility

The Utility may be required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under the Comprehensive Environmental Response Compensation and Liability Act and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous materials. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if the Utility 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 likely clean-up costs can be reasonably estimated. The Utility reviews its remediation liability on a quarterly basis for each site that may be exposed to remediation responsibilities. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring, and site closure using (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 undiscounted environmental remediation liability of $286 million at March 31, 2003, and $331 million at December 31, 2002. During the first quarter, the liability was reduced by $45 million primarily due to a reassessment of the estimated cost of remediation. The $286 million accrued at March 31, 2003, includes (1) $103 million related to the pre-closing remediation liability associated with divested generation facilities, and (2) $183 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 $286 million environmental remediation liability, the Utility has recovered $153 million through rates charged to its customers, and expects to recover approximately $96 million of the balance in future rates. The Utility also is recovering its costs from insurance carriers and from other third parties whenever it is possible.

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. The Utility estimates the upper limit of the range using assumptions least favorable to the Utility, which is based upon a range of reasonably possible outcomes. The Utility's future costs could increase to as much as $396 million if (1) the other potentially responsible parties are not financially able to contribute to these costs, (2) the extent of contamination or necessary remediation is greater than anticipated, or (3) the Utility is found to be responsible for clean-up costs at additional sites.

On June 28, 2001, the Bankruptcy Court authorized the Utility to continue its hazardous waste remediation program and to expend (1) up to $22 million in hazardous substance remediation programs and procedures in each calendar year in which the Chapter 11 case is pending, and (2) any additional amounts 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 totaling approximately $770 million. For most if not all of these sites, the Utility is in the process of remediation in cooperation with the relevant agencies and other parties responsible for contributing to the clean-up in the normal course of business. Since the Utility's proposed plan of reorganization 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.

PG&E NEG

In May 2000, 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 plants with the CAA. No enforcement action has been brought by the EPA to date. USGenNE has had preliminary discussions with the EPA to explore a potential settlement of this matter. Management believes that it is not possible to predict at this point whether any such settlement will occur or, in the absence of a settlement, the likelihood of whether the EPA will bring an enforcement action.

As a result of the EPA Information Request and environmental regulatory initiatives by the Commonwealth of Massachusetts, USGenNE is exploring ways to achieve significant reductions of sulfur dioxide and nitrogen oxide emissions. Additional requirements for the control of mercury and carbon dioxide emissions also will be forthcoming as part of these regulatory initiatives. Management believes that USGenNE would meet these requirements through installation of controls at the Brayton Point and Salem Harbor plants and estimates that capital expenditures on these environmental projects could approximate $376 million over the next four years. These estimates are currently under review and it is possible that actual expenditures may be higher. Based on an emission control plan filed for Brayton Point under the regulations implementing these initiatives, the Massachusetts Department of Environmental Protection (DEP) ruled that Brayton Point is required to meet the newer, more stringent emission limitations for sulfur dioxide and nitrogen oxide by 2006. In April 2002, USGenNE filed with the DEP a revised plan for Salem Harbor that it believes meets the DEP requirements for the 2006 compliance date. However, on June 7, 2002, the DEP ruled that Salem Harbor must satisfy these limitations by 2004. USGenNE has since filed a number of appeals challenging this decision and unless and until the decision is reversed, the compliance date for Salem Harbor remains October 2004. USGenNE and the DEP recently have agreed to enter into negotiations concerning Salem Harbor's compliance schedule with the DEP regulation, in an attempt to develop a schedule that USGenNE could meet, assuming that financing and all other necessary approvals are in place. USGenNE will not be able to operate Salem Harbor unless it is in compliance with these emission limitations. PG&E NEG believes that it is impossible to meet the October 2004 deadline. Therefore, it may not be able to operate the facility after that deadline. USGenNE and the DEP recently have agreed to enter into negotiations concerning a Salem Harbor compliance schedule with the DEP regulation on a schedule that USGenNE could meet, assuming that financing and all other necessary approvals are in place.

Various aspects of the DEP's regulations allow for public participation in the process through which the DEP determines whether the 2004 or 2006 deadline applies and approves the specific activities that USGenNE will undertake to meet the new regulations. A number of local environmental groups are now participants in this process.

The EPA is required under the CAA to establish new regulations for controlling hazardous air pollutants from combustion turbines and reciprocating internal combustion engines. Although the EPA has yet to propose the regulations, the CAA required that they be promulgated by November 2000. Another provision in the CAA requires companies to submit case-by-case Maximum Achievable Control Technology (MACT) determinations for individual plants if the EPA fails to finalize regulations within 18 months past the deadline. The EPA has extended this deadline through previous rulemakings. In late 2002, the EPA proposed a rule that would require the case-by-case MACT applications to be submitted by October 30, 2003, if the EPA has not promulgated a MACT rule as of that date. The EPA intends to finalize the MACT regulations before this date, thus eliminating the need for the plant-specific permits. PG&E NEG will not be able to accurately quantify the economic impact of the future regulations until more details are available through the rulemaking process.

PG&E NEG's existing power plants are subject to federal and state water quality standards with respect to discharge constituents and thermal effluents. Three of the fossil-fueled plants owned and operated by USGenNE (Salem Harbor, Manchester Street, and Brayton Point) are operating pursuant to National Pollutant Discharge Elimination System (NPDES) permits that have expired. For the facilities whose NPDES permits have expired, permit renewal applications are pending, and all three facilities are continuing to operate under existing terms and conditions until new permits are issued. On July 22, 2002, the EPA and the DEP issued a draft NPDES permit for Brayton Point that, among other things, substantially limits the discharge of heat by Brayton Point into Mount Hope Bay. Based on its initial review of the draft permit, USGenNE believes that the draft permit is excessively stringent. It is estimated that USGenNE's cost to comply with the new permit conditions could be as much as $248 million through 2006, but this is a preliminary estimate. There are various administrative and judicial proceedings that must be completed before the draft NPDES permit for Brayton Point becomes final, and these proceedings are not expected to be completed during 2003. In addition, the EPA, as well as local environmental groups, previously expressed concern that the metal vanadium is not addressed at Brayton Point or Salem Harbor under the terms of the old NPDES permits. Based upon the lack of an identified control technology, USGenNE believes it is unlikely that the EPA will require that vanadium be addressed pursuant to a NPDES permit. However, if the EPA does insist on including vanadium in the NPDES permit, USGenNE may have to spend a significant amount to comply with such a provision. In addition, it is possible that the new permits for Salem Harbor and Manchester Street also may contain more stringent limitations than prior permits and that the cost to comply with the new permit conditions could be greater than the current estimate of $4 million. Lastly, the issuance of any final NPDES permits may be affected by the EPA's proposed regulations under Section 316(b) of the Clean Water Act.

On March 27, 2002, the Rhode Island Attorney General notified USGenNE of his belief that Brayton Point "is in violation of applicable statutory and regulatory provisions governing its operations," including "protections accorded by common law" respecting discharges from the facility into Mount 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. PG&E NEG believes that Brayton Point is in full compliance with all applicable permits, laws, and regulations. The complaint has not yet been filed or served. In early May 2002, the Rhode Island Attorney General stated that he did not plan to file the action until the EPA issues a draft Clean Water Act NPDES permit for Brayton Point. The EPA issued this draft permit on July 22, 2002, and the Rhode Island Attorney General has since stated he has no intention of pursuing this matter until he reviews USGenNE's response to the draft permit which was submitted on October 4, 2002. Management is unable to predict whether he will pursue this matter and, if he does, the extent to which it will have a material adverse effect on PG&E NEG's financial condition or results of operations.

On April 9, 2002, the EPA proposed regulations under Section 316(b) of the Clean Water Act for cooling water intake structures. The regulations would affect existing power generation facilities using over 50 million gallons per day typically including some form of "once-through" cooling. Brayton Point, Salem Harbor, and Manchester Street 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 that are intended to reduce impacts to aquatic organisms. The final regulations are scheduled to be promulgated in February 2004. The extent to which they may require additional capital investment will depend on the timing of the NPDES permit proceedings for the affected facilities.

During April 2000, an environmental group served USGenNE and other PG&E NEG subsidiaries with a notice of its intent to file a citizen's suit under the Resource Conservation Recovery Act. 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 2003. PG&E NEG incurred expenditures related to these agreements of $5.4 million in 2000, $2.6 million in 2001, and $4.7 million in 2002. In addition to the costs previously incurred, PG&E NEG maintains a reserve in the amount of $6 million relating to its estimate of the remaining expenditures to fulfill its obligations under these agreements. PG&E NEG has deferred costs associated with capital expenditures and has set up a receivable account for amounts it believes are probable of recovery from insurance proceeds.

PG&E NEG believes that it may be required to spend up to approximately $636 million, excluding insurance proceeds, through 2008 for environmental compliance to continue operating these facilities. This amount may change, however, and the timing of any necessary capital expenditures could be accelerated in the event of a change in environmental regulations or the commencement of any enforcement proceeding against PG&E NEG. PG&E NEG has not made any commitments to spend these amounts. In the event PG&E NEG does not spend or is unable to spend because of liquidity constraints amounts needed in order to comply with these requirements, PG&E NEG may not be able to continue to operate one or all of these facilities.

Global climate change is a significant environmental issue that is likely to require sustained global action and investment over many decades. PG&E NEG has been engaged on the climate change issue for several years and is working with others on developing appropriate public policy responses to this challenge. PG&E NEG continuously assesses the financial and operational implications of this issue; however, the outcome and timing of these initiatives are uncertain.

PG&E NEG emits varying quantities of six greenhouse gases, including carbon dioxide and methane, in the course of its operations. Depending on the ultimate regulatory regime put into place for greenhouse gases, PG&E NEG's operations, cash flows, and financial condition could be adversely affected. Given the uncertainty of the regulatory regime, it is not possible to predict the extent to which climate change regulation will have a material adverse effect on PG&E NEG's financial condition or results of operations.

Legal Matters

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

Chromium Litigation

There are 15 civil suits pending against the Utility in several California state courts. One of these suits also names PG&E Corporation as a defendant. One additional civil suit, *Kearney v. Pacific Gas and Electric Company*, was filed against the Utility and PG&E Corporation after the Utility's bankruptcy filing and was dismissed without prejudice while the plaintiffs sought the right to file and pursue late claims in the Bankruptcy Court. In the *Kearney* case, the Bankruptcy Court ruled that the six adult plaintiffs could not file untimely bankruptcy claims against the Utility. The court also ruled that the 24 minor plaintiffs could file untimely bankruptcy claims against the Utility. The suits allege personal injuries, wrongful death, and loss of consortium and seek compensatory and punitive damages based on claims arising from alleged exposure to chromium in the vicinity of the Utility's gas compressor stations at Hinkley and Kettleman, California, and the area of California near Topock, Arizona. Currently, there are approximately 1,200 plaintiffs in the chromium litigation cases.

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.

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

As of April 6, 2001, the Utility had filed 13 summary judgment motions challenging the claims of the trial test plaintiffs and had completed discovery of plaintiffs' experts. Plaintiffs' discovery of the Utility's experts was underway. Plaintiffs currently are completing discovery of the Utility's experts and of related issues, and four of the 13 summary judgment motions are scheduled for hearing in 2003. At a status conference on March 17, 2003, the Los Angeles Superior Court scheduled a trial of eighteen test cases to commence in March 2004.

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, 2003, the ultimate outcome of this matter will not have a material adverse impact on PG&E Corporation's or the Utility's financial condition or future results of operations.

Natural Gas Royalties Litigation

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

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

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

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

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

Federal Securities Lawsuit

On April 16, 2001, a complaint was filed against PG&E Corporation and the Utility in the U.S. District Court for the Central District of California. The Utility subsequently was dismissed, due to its Chapter 11 bankruptcy filing. By order entered on or about May 31, 2001, the case was transferred to the U.S. District Court for the Northern District of California (District Court). On August 9, 2001, the plaintiff filed a first amended complaint in the District Court. An executive officer of PG&E Corporation also has been named as a defendant. The first amended complaint, purportedly brought on behalf of all persons who purchased PG&E Corporation common stock or certain shares of the Utility's preferred stock between July 20, 2000, and April 9, 2001, claimed that the defendants caused PG&E Corporation's Consolidated Financial Statements for the second and third quarters of 2000 to be materially misleading in violation of federal securities laws as a result of recording as a deferred cost and capitalizing as a regulatory asset the under-collections that resulted when escalating wholesale energy prices caused the Utility to pay far more to purchase electricity than it was permitted to collect from customers. On January 14, 2002, the District Court granted the defendants' motion to dismiss the plaintiffs' first amended complaint, finding that the complaint failed to state a claim in light of the public disclosures by PG&E Corporation, the Utility, and others regarding the under-collections, the risk that they might not be recoverable, the financial consequences of non-recovery, and other information from which analysts and investors could assess for themselves the probability of recovery.

On February 4, 2002, the plaintiffs filed a second amended complaint that, in addition to containing many of the same allegations as were in the first amended complaint, contains many of the same allegations that appear in the California Attorney General's complaint discussed below. The plaintiffs sought an unspecified amount of compensatory damages, plus costs and attorneys' fees. On March 11, 2002, the defendants filed a motion to dismiss the second amended complaint. After a hearing held on June 24, 2002, the District Court issued an order on June 25, 2002, granting the defendants' motion to dismiss the second amended complaint. The dismissal is with prejudice, prohibiting the plaintiffs from filing a further complaint. On November 15, 2002, the plaintiffs filed an appeal in the United States Court of Appeals for the Ninth Circuit, advancing substantially the same arguments that the District Court had rejected previously. The defendants filed their answer to the appeal on January 2, 2003, and expect that oral argument regarding the appeal will be heard in 2003.

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

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

On April 3, 2001, the CPUC issued an OII into whether the California IOUs, 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 also will determine whether additional rules, conditions, or changes are needed to adequately protect ratepayers and the public from dangers of abuse stemming from the holding company structure. The CPUC will investigate whether it should modify, change, or add conditions to the holding company decisions, make further changes to the holding company structure, alter the standards under which the CPUC determines whether to authorize the formation of holding companies, otherwise modify the decisions, or recommend statutory changes to the California Legislature. As a result of the investigation, the CPUC may impose remedies, prospective rules, or conditions, as appropriate.

On January 9, 2002, the CPUC issued an interim decision and order interpreting the "first priority condition" adopted in the CPUC's holding company decision. This condition requires that the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner, be given first priority by the board of directors of the holding company. In the interim order, the CPUC stated, "the first priority condition does not preclude the requirement that the holding company infuse all types of capital into their respective utility subsidiaries where necessary to fulfill the Utility's obligation to serve." The three major California investor-owned energy utilities and their parent holding companies had opposed the broader interpretation, first contained in a proposed decision released for comment on December 26, 2001, as being inconsistent with the prior 15 years' understanding of that condition as applying more narrowly to a priority on capital needed for investment purposes. The CPUC also interpreted the first priority

condition as prohibiting a holding company from (1) acquiring assets of its utility subsidiary for inadequate consideration, and (2) acquiring assets of its utility subsidiary at any price, if such acquisition would impair the utility's ability to fulfill its obligation to serve or to operate in a prudent and efficient manner. The utilities' applications for rehearing were denied on July 17, 2002.

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

The holding companies have filed petitions for review of both the CPUC's capital requirements and jurisdiction decisions in several state appellate courts, and the utilities also have filed petitions for review of the capital requirements decision with the California appellate courts. The CPUC moved to consolidate all proceedings in the San Francisco state appellate court and requested that the court extend the deadline by which the CPUC must file its responses to the petitions for review until after the consolidation occurred. The CPUC's request for consolidation was granted and all of the petitions are now before the First Appellate District in San Francisco, California.

On January 10, 2002, the California Attorney General filed a complaint in the San Francisco Superior Court against PG&E Corporation and its directors, as well as against directors of the Utility, alleging that PG&E Corporation violated various conditions established by the CPUC in decisions approving the holding company formation, among other allegations. The Attorney General also alleged 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 alleged that, through the Utility's bankruptcy proceedings, PG&E Corporation and the Utility engaged in unlawful, unfair, and fraudulent business practices in alleged violation of California Business and Professions Code Section 17200 by seeking to implement the transactions contemplated in the proposed Plan of Reorganization filed in the Utility's bankruptcy proceeding. The complaint also seeks restitution of assets allegedly wrongfully transferred to PG&E Corporation from the Utility. In February 2002, PG&E Corporation filed a notice of removal in the Bankruptcy Court to transfer the Attorney General's complaint to the Bankruptcy Court, as well as a motion to dismiss the lawsuit, or in the alternative, to stay the suit with the Bankruptcy Court. Subsequently, the Attorney General filed a motion to remand the action to state court. In June 2002, the Bankruptcy Court held that federal law preempted the Attorney General's allegations concerning PG&E Corporation's participation in the Utility's bankruptcy proceedings. The Bankruptcy Court directed the Attorney General to file an amended complaint omitting these allegations and remanded the amended complaint to the San Francisco Superior Court. Both parties have appealed the Bankruptcy Court's remand order. The appeal and cross-appeal are pending in the District Court.

On August 9, 2002, the Attorney General filed its amended complaint in the San Francisco Superior Court, omitting the allegations concerning PG&E Corporation's participation in the Utility's bankruptcy proceedings. PG&E Corporation and the directors named in the complaint have filed a motion to strike certain allegations of the amended complaint. In February 2003, the court denied the motions to strike on the grounds that they were premature, and stated that it would defer making a judgment on the merits of the defendants' arguments until the factual context of the case is more fully developed. A status conference has been scheduled for June 4, 2003.

The California Attorney General's case has been coordinated by the San Francisco Superior Court with the cases filed by the City and County of San Francisco and Cynthia Behr, both discussed below.

On February 11, 2002, a complaint entitled *City and County of San Francisco; People of the State of California v. PG&E Corporation, and Does 1-150*, was filed in San Francisco Superior Court. The complaint contains some of the same allegations contained in the Attorney General's complaint, including allegations of unfair competition. In addition, the complaint alleges causes of action for conversion, claiming that PG&E

Corporation "took at least $5.2 billion from the Utility," and for unjust enrichment. The City seeks injunctive relief, the appointment of a receiver, payment to ratepayers, disgorgement, the imposition of a constructive trust, civil penalties, and costs of suit.

After removing the city's action to the Bankruptcy Court in February 2002, PG&E Corporation filed a motion to dismiss the complaint. Subsequently, the City filed a motion to remand the action to state court. In June 2002, the Bankruptcy Court issued an Amended Order on Motion to Remand stating that the Bankruptcy Court retained jurisdiction over the causes of

action for conversion and unjust enrichment, finding that these claims belong solely to the Utility and cannot be asserted by the City and County, but remanding the Section 17200 cause of action to state court. Both parties have appealed the Bankruptcy Court's remand order. The appeal and cross-appeal are pending in the District Court.

Following remand, PG&E Corporation brought a motion to strike. In February 2003, the court denied the motion to strike on the grounds that it was premature, and stated that it would defer making a judgment on the merits of the defendants' arguments until the factual context of the case is more fully developed. A status conference has been scheduled for June 4, 2003.

PG&E Corporation also moved to coordinate this case with the Section 17200 case brought by Cynthia Behr, which is discussed below. That motion was granted. Subsequently, the court coordinated the California Attorney General's case with the *City and County of San Francisco* and *Behr* cases.

In addition, a third case, entitled *Cynthia Behr v. PG&E Corporation, et al.*, was filed on February 14, 2002, by a private plaintiff (who also has filed a claim in bankruptcy) in Santa Clara Superior Court also alleging a violation of California Business and Professions Code Section 17200. The Behr complaint also names the directors of PG&E Corporation and the Utility as defendants. The allegations of the complaint are similar to the allegations contained in the Attorney General's complaint but also include allegations of conspiracy, fraudulent transfer, and violation of the California bulk sales laws. The plaintiff requests the same remedies as the Attorney General's case and in addition requests damages, attachment, and restraints upon the transfer of defendants' property. In March 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. In its June 2002 ruling mentioned above as to the Attorney General's and the City's cases, the Bankruptcy Court retained jurisdiction over Behr's fraudulent transfer claim and bulk sales claim, finding them to belong to the Utility's estate. The Bankruptcy Court remanded Behr's Section 17200 claim to the Santa Clara Superior Court. Both parties have appealed the Bankruptcy Court's remand order. The appeal and cross-appeal are pending in the District Court.

Following remand, PG&E Corporation moved to have the *Behr* case coordinated with the City's case described above. That motion was granted, and the *Behr* case now is proceeding in San Francisco Superior Court. The *Behr* case also has been coordinated with the California Attorney General's case discussed above.

In September 2002, the defendants asked the San Francisco Superior Court to dismiss Behr's complaint. In April 2003, the court denied the request as to Behr's Section 17200 claim, but granted the request with respect to Behr's civil conspiracy cause of action. A status conference has been scheduled for June 4, 2003.

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 believes that the allegations of the complaints are without merit and 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 kWh in allegedly excessive electric rates and a refund of alleged recent over-collections 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. The only alleged over-collection amount calculated in the complaint is approximately $400 million during the last quarter of 2001. On April 2, 2002, the Utility filed an answer, arguing that the complaint should be denied and dismissed immediately as an impermissible collateral action and on the basis that the alleged facts, even if assumed to be true, do not establish that currently authorized electric rates are not reasonable. On May 10, 2002, the Utility filed a motion to dismiss the complaint. The CPUC has not yet issued a decision. However, in November 2002, the CPUC issued a decision jointly in this complaint case and in the rate stabilization proceedings modifying the restrictions on use of revenues generated by the surcharges to permit the revenues to be used for the purpose of securing or restoring the Utility's reasonable financial health, as determined by the CPUC. After the CPUC determines when the AB 1890 rate freeze ended, the CPUC will determine the extent and disposition of the Utility's under-collected costs, if any, remaining at the end of the rate freeze. If the CPUC determines that the Utility recovered revenues in excess of its transition costs or in excess of other permitted uses, the CPUC may require the Utility to refund such excess revenues. If the CPUC requires the Utility to refund any of these revenues in the future, the Utility's earnings could be materially affected.

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Mitsubishi Litigation

Mitsubishi Power Systems, Inc. (MPS) has alleged a default under its contract for the sale and purchase of gas turbines and other equipment for failure to pay $14 million. PG&E NEG's subsidiary has disputed this default notice because the payments were not due until January and July 2003. MPS terminated the contract for this alleged default on November 21, 2002. Although PG&E NEG does not agree that MPS had the right to do so, neither PG&E NEG nor any of its affiliates intended to challenge the termination. On January 31, 2003, PG&E NEG paid $4.5 million of the $14 million.

On May 7, 2003, Mitsubishi Heavy Industries, Inc. (MHI) filed suit in the United States District Court for the District of Maryland against PG&E NEG, PG&E National Energy Group, LLC (NEG LLC), and PG&E National Energy Group Construction Company, LLC (Construction). The defendants have not yet been served. In its complaint, MHI alleges damages totaling approximately $300 million under the turbine purchase agreement and related contracts. MHI's claims arise from a dispute between the parties to a turbine purchase agreement regarding payments allegedly past due from Construction in respect of reservation fees ($9.5 million) and gas generator equipment manufacture ($30 million). MPS also requested that PG&E NEG cash collateralize its $75 million guarantee issued in connection with the turbine purchase agreement. PG&E NEG and Construction have maintained (and will maintain in defense of MHI's claims) that no amounts were or are due.

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.

Recorded Liability for Legal Matters

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 and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular case.

The provision for legal matters is included in PG&E Corporation's and the Utility's Other Noncurrent Liabilities in the Consolidated Balance Sheets and totaled $200 million at March 31, 2003, and $202 million at December 31, 2002.

NOTE 7: SEGMENT INFORMATION

PG&E Corporation has identified three reportable operating segments based on similarities in the following characteristics:

- Economic characteristics;
- Products and services;
- Types of customers;
- Methods of distribution;
- Regulatory environment; and

How information is reported to and used by PG&E Corporation's chief operating decision makers.

The Utility is one reportable operating segment and the other two are part of PG&E NEG. These three reportable operating segments provide different products and services and are subject to different forms of regulation or jurisdictions.

Segment information for the three months ended March 31, 2003, and 2002, was as follows:

		PG&E National Energy Group					
	Utility	Total PG&E NEG	Integrated Energy & Marketing Activities	Interstate Pipeline Operations	PG&E NEG Eliminations	PG&E Corporation, Eliminations and Other(1)	Total
				(in millions)			
Three months ended March 31, 2003							
Operating revenues (as revised)	$ 2,064	$ 337	$ 306	$ 49	$ (18)	$	$ 2,401
Intersegment revenues(2)	3	22	7	15		(25)	
Total operating revenues	2,067	359	313	64	(18)	(25)	2,401
Income (Loss) from continuing operations(3)	(78)	(254)	(150)	16	(120)	54	(278)
Net income (loss)(4)	(79)	(369)	(217)	16	(168)	94	(354)
Three months ended March 31, 2002(5)							
Operating revenues(6)	2,450	485	442	47	(4)		2,935
Intersegment revenues(2)	3	31	19	12		(34)	
Total operating revenues	2,453	516	461	59	(4)	(34)	2,935
Income (Loss) from continuing operations(3)	590	29	18	18	(7)	4	623
Net income (loss)(4)	590	37	26	18	(7)	4	631
Total assets at March 31, 2003(7)	$ 26,316	$ 7,613	$ 7,254	$ 1,350	$ (991)	$ 1,364	$ 35,293
Total assets at March 31, 2002(7)	$ 25,279	$ 10,669	$ 9,212	$ 1,290	$ 167	$ 350	$ 36,298

(1) Includes PG&E Corporation, PG&E Ventures LLC, and elimination entries. For the three months ended March 31, 2003, PG&E Corporation eliminated $106 million of deferred tax asset valuation reserves recorded at PG&E NEG. PG&E Corporation believes it is more likely than not that it will be able to realize these deferred tax assets on a consolidated basis.

(2) Intersegment electric and gas revenues are recorded at market prices, except for the Utility, which uses rates set by the CPUC, and PG&E NEG's Interstate Pipeline Operations, which uses rates set by the FERC.

(3) Corresponds to Utility's Income Available for (Loss Allocated to) Common Stock excluding Cumulative Effect of Changes in Accounting Principles.

(4) Corresponds to Utility's Income Available for (Loss Allocated to) Common Stock.

(5)

Prior period amounts have been restated to reflect the reclassification of USGenNE, Mountain View, and ET Canada operating results to discontinued operations.

(6) Operating revenues and operating expenses reflect the adoption of a new accounting policy in the third quarter of 2002 implementing a retroactive change from gross to net method of reporting revenues and expenses on trading activities. The amounts for trading activities for this period have been reclassified to conform with the new net presentation.

(7) PG&E Corporation's assets exclude its investment in 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, that conducts its business through two principal subsidiaries: Pacific Gas and Electric Company (the Utility), an operating public utility engaged primarily in the business of providing electricity, natural gas distribution, and transmission services throughout most of Northern and Central California, and PG&E National Energy Group, Inc. (PG&E NEG), a company currently engaged in power generation and natural gas transmission.

The Utility filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code (Bankruptcy Code) in the U. S. Bankruptcy Court for the Northern District of California (Bankruptcy Court) on April 6, 2001. 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. The factors causing the Utility to take this action are discussed in this Management's Discussion and Analysis (MD&A) of Financial Condition and Results of Operations and in Note 2 of the Notes to the Consolidated Financial Statements.

PG&E NEG and its 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); and
- PG&E Gas Transmission Corporation and its subsidiaries (collectively, PG&E GTC), which includes PG&E Gas Transmission, Northwest Corporation and its subsidiaries (collectively, PG&E GTN), which includes North Baja Pipeline, LLC.

As a result of the sustained downturn in the power industry, PG&E NEG and its affiliates have experienced a financial downturn, which caused the major credit rating agencies to downgrade PG&E NEG's and its affiliates' credit ratings to below investment grade. PG&E NEG is currently in default under various recourse debt agreements and guaranteed equity commitments totaling approximately $2.9 billion. In addition, other PG&E NEG subsidiaries are in default under various debt agreements totaling $2.7 billion, but this debt is non-recourse to PG&E NEG. At March 31, 2003, PG&E NEG had total liabilities in excess of total assets of approximately $1.4 billion dollars.

PG&E NEG, its subsidiaries, and their lenders have been engaged in discussions to restructure PG&E NEG's and its subsidiaries' debt obligations and other commitments since October 2002. No agreement has been reached yet and there can be no assurance that an agreement will be reached. Any restructuring agreement that may be reached would be implemented through a reorganization proceeding under Chapter 11 of the Bankruptcy Code. Although PG&E NEG and its subsidiaries are continuing their efforts to maximize cash and reduce liabilities, such efforts are not expected to restore the financial condition of PG&E NEG and its subsidiaries. Absent a negotiated agreement, the lenders may exercise their default remedies or force PG&E NEG and certain of its subsidiaries into an involuntary proceeding under the Bankruptcy Code. Notwithstanding the status of current negotiations, PG&E NEG and certain of its subsidiaries also may elect to voluntarily seek protection under the Bankruptcy Code as early as the second quarter of 2003. Although PG&E Corporation continues to provide assistance to PG&E NEG, its subsidiaries and its lenders in their negotiations, management does not expect the outcome of any bankruptcy proceeding involving PG&E NEG or any of its subsidiaries to have a material adverse effect on the financial condition of PG&E Corporation or the Utility.

The factors affecting PG&E NEG's business and causing these defaults as well as the principal actions being taken by PG&E NEG are discussed later in this MD&A and in Note 3 of the Notes to the Consolidated Financial Statements.

The Consolidated Financial Statements of PG&E Corporation and of the Utility have been prepared on a going concern basis, which contemplates continuity of operations, realization of assets, and repayment of liabilities in the ordinary course of business. However, as a result of the bankruptcy of the Utility and current liquidity concerns at PG&E NEG and its subsidiaries, as further discussed below, such realization of assets and liquidation of liabilities are subject to uncertainty.

During the fourth quarter of 2002, PG&E NEG and certain subsidiaries agreed to sell or sold certain assets, abandoned other assets, and significantly reduced energy trading operations. As a result, PG&E NEG incurred significant charges in the fourth quarter of 2002. As a result, PG&E NEG expects to incur substantial charges to earnings in 2003 as it continues to restructure its operations.

PG&E Corporation has identified three reportable operating segments:

- Utility;
- Integrated Energy and Marketing, or the Generation Business; and
- Interstate Pipeline Operations, or the Pipeline Business.

These segments were determined based on similarities in the following characteristics:

- Economic;
- Products and services;
- Types of customers;
- Methods of distribution;
- Regulatory environment; and
- How information is reported to and used by PG&E Corporation's chief operating decision makers.

These three reportable operating segments provide different products and services and are subject to different forms of regulations 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 MD&A explains the general financial condition and the results of operations of PG&E Corporation and its subsidiaries, including:

- Factors that affect each business;

- A comparison of revenues and expenses and why they changed between periods;
- The sources and uses of cash between periods; and
- How all of this along with related commitments and contingencies affects overall financial condition.

This is a combined Quarterly Report on Form 10-Q/A of PG&E Corporation and the Utility and includes separate Consolidated Financial Statements for each of these two entities. The Consolidated Financial Statements of PG&E Corporation reflect the accounts of PG&E Corporation, the Utility, PG&E NEG, and other wholly-owned and controlled subsidiaries. The Consolidated Financial Statements of the Utility reflect the accounts of the Utility and its wholly-owned and controlled subsidiaries. This combined MD&A should be read in conjunction with the Consolidated Financial Statements and Notes to 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 included in their combined 2002 Annual Report on Form 10-K, as amended. As discussed in Note 1 to the Notes to the Consolidated Financial Statements, PG&E Corporation's 2003 Consolidated Statement of Operations has been revised. This management's discussion and analysis gives effect to the revisions.

Forward-Looking Statements and Risk Factors

This combined Quarterly Report on Form 10-Q/A, including this MD&A, contains forward-looking statements 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," "could," "should," "would," "may," 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 the factors that may affect future results, some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include:

Recovery of Under-Collected Power Procurement and Transition Costs Previously Written Off. The extent to which the Utility is able to recover its under-collected power procurement and transition costs previously written off depends on many factors, including:

- What costs the California Public Utilities Commission (CPUC) determines are eligible for recovery as transition costs;
- When the Utility's rate freeze ended, as determined by the CPUC;
- Sales volatility and the level of direct access customers (i.e., those customers who choose an alternative energy provider);
- Changes in the California Department of Water Resources' (DWR) revenue requirements required to be remitted to the DWR from existing retail rates;
- Changes in the Utility's authorized revenue requirements;
- Future regulatory or judicial decisions that determine whether the Utility is allowed under state law to recover under-collected power procurement and transition costs from its customers after the end of the rate freeze; and
- The outcome of the Utility's claims against the CPUC Commissioners for recovery of under-collected power procurement and transition costs based on the federal filed rate doctrine.

Refundability of Amounts Previously Collected. Whether the Utility is required to refund to ratepayers amounts previously collected depends on many factors, including:

Whether the CPUC determines that certain transition or procurement costs recovered in revenues collected by the Utility were not eligible transition costs or otherwise reduces the amount of revenues authorized to recover such transition or procurement costs;

Whether the CPUC makes retroactive changes in the allocation of the DWR's revenue requirements required to be remitted to the DWR from existing retail rates;

Whether the CPUC ultimately determines that certain past power procurement costs incurred by the Utility were not reasonably incurred and should be disallowed; and

The purposes for which the CPUC ultimately determines that surcharges approved by the CPUC in January, March, and May 2001 may be used.

Outcome of the Utility's Bankruptcy Case. The pace and outcome of the Utility's bankruptcy case will be affected by:

Whether the Bankruptcy Court confirms the Utility's proposed plan of reorganization (Plan), the alternative plan sponsored by the CPUC and the Official Committee of Unsecured Creditors (CPUC/OCC Plan), or some other plan of reorganization;

Whether regulatory and governmental approvals required to implement a confirmed plan are obtained and the timing of such approvals;

Whether there are any delays in implementation of a plan due to litigation, including the prosecution of any appeals related to regulatory, governmental, or Bankruptcy Court orders; and

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

Operating Environment. The amount of operating income and cash flows the Utility may record may be influenced by the following:

Future regulatory actions regarding the Utility's procurement of power for its retail customers;

The terms and conditions of the Utility's long-term generation procurement plan as approved by the CPUC;

The extent to which the Utility is able to timely recover in full its costs of service, including its procurement costs;

Future sales levels, which can be affected by general economic and financial market conditions, changes in interest rates, weather, conservation efforts, and the level of direct access customers;

The extent to which the Utility is required to purchase power to meet its customers' needs that is not not supplied by Utility-owned generation or other contractual arrangements;

- The demand for and pricing of natural gas transportation and storage services, which may be affected by weather, overall gas-fired generation, and price spreads between various natural gas delivery points;
- Changes in the Utility's authorized revenue requirements; and
- Acts of terrorism, storms, earthquakes, accidents, mechanical breakdowns, or other events or perils that result in power outages or damages to the Utility's assets or operations, to the extent not covered by insurance.

Legislative and Regulatory Environment. PG&E Corporation's and the Utility's business may be impacted by:

- Changes that may be made to California's electric industry restructuring legislation and to other applicable regulations, including for example, legislation that would repeal major portions of the electric industry restructuring law or that would extend the CPUC's jurisdiction to regulate certain activities of the parent companies of the California investor-owned electric and gas utilities (IOUs);
- Legislative or regulatory changes affecting the electric and natural gas industries in the United States; and
- Heightened regulatory and enforcement agency focus on the merchant energy business including investigations into "wash" or "round-trip" trading, specific trading strategies and other industry issues, with the potential for changes in industry regulations and in the treatment of PG&E NEG by state and federal agencies.

Regulatory Proceedings and Investigations. PG&E Corporation's and the Utility's business may be affected by:

- The outcome of the Utility's various regulatory proceedings pending at the CPUC and at the Federal Energy Regulatory Commission (FERC); and
- The outcome of the CPUC's pending investigation into whether IOUs have complied with past CPUC decisions, rules or orders authorizing their holding company formations and/or governing affiliate transactions, as well as applicable statutes.

Pending Legal Proceedings. PG&E Corporation's and the Utility's future results of operations and financial conditions may be affected by the outcomes of:

- The lawsuits filed by the California Attorney General and the City and County of San Francisco 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;
- 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
- Other pending litigation.

Competition. PG&E Corporation's and the Utility's future results of operations and financial conditions may be affected by:

The threat of municipalization, which may result in stranded Utility investment, loss of customer growth, and additional barriers to cost recovery;

Changes in the level of direct access customer cost responsibility and other surcharges related to direct access, and competition from other service providers to the extent restrictions on direct access are removed;

The development of alternative energy technologies;

The ability to compete for gas transmission services into Southern California and with alternative storage providers throughout California; and

The growth of distributed generation or self-generation.

Environmental and Nuclear Matters. PG&E Corporation's and the Utility's future results of operations and financial conditions may be affected by:

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

Whether the Utility is able to fully recover in rates the costs of complying with existing and future environmental laws, regulations, and policies, the cost of which could be significant; and

Whether the Utility incurs costs in connection with its nuclear facilities that exceed the Utility's insurance coverage and other amounts set aside for decommissioning and other potential liabilities.

Accounting and Risk Management. PG&E Corporation's and the Utility's future results of operations and financial conditions may be affected by:

New accounting pronouncements;

Changes in critical accounting estimates;

Volatility in income resulting from mark-to-market accounting and changes in mark-to-market methodologies;

The extent to which the assumptions underlying critical accounting estimates, mark-to-market accounting, and risk management programs are not realized; and

The volatility of commodity fuel and electricity prices, and the effectiveness of risk management policies and procedures designed to address volatility.

Potential Bankruptcy Filing. The timing and manner in which bankruptcy proceedings involving PG&E NEG and certain of its subsidiaries commence will be affected by:

- The outcome of negotiations between PG&E NEG, its subsidiaries, and their lenders, as well as with representatives of the holders of PG&E NEG's Senior Notes, to restructure PG&E NEG's and its subsidiaries' indebtedness and commitments;

- The inability of PG&E NEG, its merchant asset and other subsidiaries, including USGen New England, Inc. (USGenNE), to maintain sufficient liquidity necessary to meet their commodity and other obligations; and

- The inability of USGenNE to comply with future environmental regulations and the impact such non-compliance would have on USGenNE's ability to operate its generating projects, particularly the Salem Harbor and Brayton Point power plants.

Efforts to Restructure Operations. PG&E NEG's future results of operations and financial condition will be affected by the success of its efforts to restructure its operations, including:

- The extent to which PG&E NEG incurs further charges to earnings as a result of the abandonment, sale, or transfer of assets, or termination of contractual commitments, whether such transactions occur in connection with the restructuring of PG&E NEG's indebtedness or otherwise;

- Any potential charges to income that would result from the reduction and potential discontinuance of PG&E NEG's energy trading and marketing operations, including tolling transactions; and

- The impact of lay-offs and loss of personnel at PG&E NEG.

Current Conditions in the Energy Markets and the Economy. PG&E Corporation's future results of operations and financial condition will be affected by changes in the energy markets, changes in the general economy, wars, embargoes, financial markets, interest rates, other industry participant failures, the markets' perception of energy merchants and other factors.

Actions of PG&E NEG Counterparties. PG&E Corporation's future results of operations and financial condition may be affected by:

- The extent to which counterparties demand additional collateral in connection with PG&E ET's trading and non-trading activities and the ability of PG&E NEG and its subsidiaries to meet the liquidity calls that may be made; and

- The extent to which counterparties seek to terminate tolling agreements and the amount of any termination damages they may seek to recover from PG&E NEG as guarantor.

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

Market Conditions and Business Environment

During 2002, adverse changes in the electric power and gas utility industry and energy markets affected PG&E Corporation, the Utility, and PG&E NEG's business, including:

- Contractions and instability of wholesale electricity and energy commodity markets;

- Significant decline in generation margins (spark spreads) caused by excess supply and reduced demand in most regions of the United States;

Loss of confidence in energy companies due to increased scrutiny by regulators, elected officials, and investors as a result of a string of financial reporting scandals;

Heightened scrutiny by credit rating agencies prompted by these market changes and scandals which resulted in lower credit ratings for many market participants; and

Resulting significant financial distress and liquidity problems among market participants leading to numerous financial restructurings and less market participation.

LIQUIDITY AND FINANCIAL RESOURCES

Utility

In 1998, the State of California implemented electric industry restructuring and established a framework allowing generators and other electricity providers to charge market-based prices for electricity sold on the wholesale market. The implementing legislation also established a retail electricity rate freeze and a plan for recovery of generation-related costs that were expected to be uneconomic under the new market framework. State regulatory action further strongly encouraged the Utility to sell a majority of its fossil fuel-fired generation facilities and made it economically unattractive to retain its remaining generation facilities. The resulting sales of generation facilities and the inability to enter into long-term purchased power contracts in turn made the Utility more dependent on spot purchases from the newly deregulated wholesale electricity market. Beginning in June 2000, wholesale prices for electricity began to increase. Prices moderated somewhat in the fall before increasing to unprecedented levels in November 2000 and later months. Since the Utility's retail rates were frozen, it financed the higher costs of wholesale electricity by issuing debt and drawing on its credit facilities.

In the beginning of 2001, the major credit rating agencies lowered their ratings for the Utility and PG&E Corporation to non-investment grade levels. Consequently, the Utility lost access to its bank facilities and capital markets, and could no longer continue buying electricity to deliver to its customers. As a result of the Utility's lack of creditworthiness and similar conditions at the other California IOUs, in January 2001 the California Legislature and the Governor of California authorized the DWR to begin purchasing electricity for the State of California. Until January 2003, the DWR purchased the electricity needed to cover the Utility's net open position (the amount of electricity needed by retail electric customers that cannot be met by utility-owned generation and electricity under contract to the Utility).

The Utility's inability to recover its electric procurement costs from customers ultimately resulted in billions of dollars in defaulted debt and unpaid bills and caused the Utility to file a voluntary petition for relief under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court on April 6, 2001.

While in bankruptcy, the Utility is not allowed to pay liabilities incurred before it filed for bankruptcy without permission from the Bankruptcy Court. Additionally,

While in bankruptcy, the Utility does not have access to external funding from capital markets.

The Utility is in default under its credit facilities, commercial paper, floating rate notes, senior notes, pollution control loan agreements, and medium-term notes, as a result of its failure to pay certain of its obligations. However, the event of default under each security has been stayed in accordance with the bankruptcy proceedings.

The Utility has been making capital investments (investments in property, plant and equipment) out of its cash on hand under the supervision of the Bankruptcy Court. The Utility anticipates that it will be able to continue making such necessary capital investments in the future, subject to Bankruptcy Court approval.

Since filing for bankruptcy, the Utility has received permission from the Bankruptcy Court to make payments on (1) pre- and post-petition interest on certain claims, (2) pre-petition amounts payable to qualifying facilities (QFs) and certain other vendors, and (3) matured pre-petition secured debt.

Since filing for bankruptcy, the Utility has been accruing interest on its pre-petition liabilities at the required rates included in the Utility's proposed plan of reorganization. As a result, the payment of such interest did not have a material adverse impact on its financial condition or results of operations.

The Utility will continue to accrue interest on its pre-petition liabilities at the required rates in 2003. However, due to the uncertainty of the ultimate outcome of the bankruptcy proceedings, the Utility is not able to estimate the amount of interest that will be paid in 2003 and beyond.

The Utility and PG&E Corporation have jointly filed a proposed plan of reorganization (Plan) that, if approved, would enable the Utility to emerge from bankruptcy. In November 2002, the Bankruptcy Court began the confirmation trial to determine which plan, if any, the Bankruptcy Court will confirm. On March 4, 2003, the Bankruptcy Court ordered the Utility, the CPUC, and other parties involved in the confirmation trial to participate in settlement negotiations. On March 11, 2003, the Bankruptcy Court then issued an order staying nearly all the proceedings in the confirmation trial until May 12, 2003. On April 23, 2003, the Bankruptcy Court extended this stay for an additional 30 days. A status conference is scheduled for June 16, 2003. PG&E Corporation and the Utility are not able to predict the ultimate outcome of the Utility's bankruptcy proceedings, including which plan, if any, the Bankruptcy Court may confirm.

Both the Plan and the alternative plan propose issuing new debt as part of the reorganization. PG&E Corporation and the Utility have incurred, and will continue to incur throughout the reorganization process, legal, accounting, trustee, and other fees associated with the proposed debt issuance. In addition, PG&E Corporation and the Utility have incurred and will continue to incur consulting fees for assistance with the implementation of either plan. Though a small amount of the costs directly related to the proposed debt issuance have been capitalized, the majority of the reorganization costs have been expensed and are included in Reorganization Professional Fees and Expenses in PG&E Corporation's and the Utility's Consolidated Statements of Operations.

Although the Utility still relies on electricity supplied by DWR contracts to service a significant portion of its total load, on January 1, 2003, the Utility and other California IOUs resumed procuring electricity to meet their customers' residual net open

position under California Senate Bill (SB) 1976. In order to enter into short-term purchase contracts needed to cover its residual net open position, the Utility has posted collateral with the ISO and several other counterparties.

For further discussion of the California energy crisis, the Utility's voluntary petition for relief under the Bankruptcy Code, the status of the Chapter 11 confirmation hearings and the provisions of SB 1976, see Note 2 of the Notes to the Consolidated Financial Statements.

PG&E NEG

PG&E NEG currently is focused on power generation and natural gas transmission in the United States. As a result of the sustained downturn in the power industry, PG&E NEG and its affiliates have experienced a financial downturn, which caused the major credit rating agencies to downgrade PG&E NEG's and its affiliates' credit ratings to below investment grade. PG&E NEG is currently in default under various recourse debt agreements and guaranteed equity commitments totaling approximately $2.9 billion. In addition, other PG&E NEG subsidiaries are in default under various debt agreements totaling $2.7 billion, but this debt is non-recourse to PG&E NEG.

PG&E NEG, its subsidiaries, and their lenders have been engaged in discussions to restructure PG&E NEG's and its subsidiaries' debt obligations and other commitments since October 2002. No agreement has been reached yet and there can be no assurance that an agreement will be reached. Any restructuring agreement that may be reached would be implemented through a reorganization proceeding under Chapter 11 of the Bankruptcy Code. Although PG&E NEG and its subsidiaries are continuing their efforts to maximize cash and reduce liabilities, such efforts are not expected to restore the financial condition of PG&E NEG and its subsidiaries. Absent a negotiated agreement, the lenders may exercise their default remedies or force PG&E NEG and certain of its subsidiaries into an involuntary proceeding under the Bankruptcy Code. Notwithstanding the status of current negotiations, PG&E NEG and certain of its subsidiaries also may elect to voluntarily seek protection under the Bankruptcy Code by the end of the second quarter of 2003. Although PG&E Corporation continues to provide assistance to PG&E NEG, its subsidiaries and its lenders in their negotiations, management does not expect the outcome of any bankruptcy proceeding involving PG&E NEG or any of its subsidiaries to have a material adverse effect on the financial condition of PG&E Corporation or the Utility. The factors affecting PG&E NEG's business causing these defaults and the principal actions being taken by PG&E NEG are discussed later in this MD&A and in Note 3 of the Notes to the Consolidated Financial Statements.

PG&E NEG, and its subsidiaries are restructuring their operations to increase cash, reduce financial obligations, dispose of merchant plant facilities, and decrease energy trading operations. PG&E NEG's objective is to limit its asset trading and risk management activities to only what is necessary for energy management services to facilitate the transition of PG&E NEG's merchant generation facilities through their sale, transfer or abandonment. PG&E NEG will then further reduce and transition to retain only limited capabilities to ensure fuel procurement and power logistics for PG&E NEG's retained independent power plant operations.

COMMITMENTS AND CAPITAL EXPENDITURES

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.

Utility

The Utility's contractual commitments include natural gas supply and transportation agreements, purchase power agreements (including agreements with QFs, irrigation districts and water agencies, bilateral power purchase contracts, and renewable energy contracts), nuclear fuel agreements, operating leases, and other commitments.

The Utility's commitments under financing arrangements include obligations to repay first and refunding mortgage bonds, senior notes, medium-term notes, pollution control loan agreements, Deferrable Interest Subordinated Debentures, lines of credit, letters of credit, floating rate notes, and commercial paper.

PG&E Funding LLC, a wholly-owned subsidiary of the Utility, is also obligated to make scheduled principal payments on its rate reduction bonds.

The Utility's contractual commitments and obligations are discussed in PG&E Corporation's 2002 Annual Report with updates to such disclosures included in Note 6 of the Notes to the Consolidated Financial Statements.

PG&E NEG

Guarantees

PG&E NEG's and its subsidiaries' guarantees fall into four broad categories:

- Equity commitments;
- PG&E ET's energy trading and non-trading activities related to PG&E NEG's merchant energy portfolio, excluding tolling agreements;
- Tolling agreements; and
- Other guarantees.

PG&E NEG is currently in default under various debt agreements and guaranteed equity commitments totaling approximately $2.9 billion. In addition, other PG&E NEG subsidiaries are in default under various debt agreements totaling approximately $2.7 billion, but this debt is non-recourse to PG&E NEG. On November 14, 2002, PG&E NEG defaulted on the repayment of the $431 million 364-day tranche of its corporate revolving credit facility (Corporate Revolver). Loans and letters of credit outstanding as of March 31, 2003, under the two-year tranche of the Corporate Revolver was $258 million, $185 million of letters of credit and $73 million of loans. The default under the Corporate Revolver also constitutes a cross-default as of March 31, 2003, under (1) PG&E NEG's Senior Notes ($1 billion outstanding), (2) its guarantee of a turbine revolving credit agreement ($205 million outstanding), and (3) its equity commitment guarantees for the GenHoldings I, LLC (GenHoldings) credit facility ($355 million outstanding), the La Paloma credit facility ($375 million outstanding) and the Lake Road credit facility ($230 million outstanding). In addition, on November 15, 2002, PG&E NEG failed to pay a $52 million interest payment due under the Senior Notes. PG&E NEG currently does not have sufficient cash to meet its financial obligations and has ceased making payments on its debt and equity commitments.

Equity Commitments

GenHoldings Projects

GenHoldings, an indirect subsidiary of PG&E NEG, is obligated under its credit facility to make equity contributions to fund construction of the Harquahala, Covert, and Athens generating projects. This credit facility is secured by these projects in addition to the Millennium generating facility. GenHoldings defaulted under its credit agreement in October 2002, by failing to make equity contributions to fund construction draws for the Athens, Harquahala, and Covert generating projects. Although PG&E NEG has guaranteed GenHoldings' obligations to make equity contributions of up to $355 million, PG&E NEG notified the GenHoldings' lenders that it would not make further equity contributions on behalf of GenHoldings. In November and December 2002, the lenders executed waivers and amendments to the credit agreement under which they agreed to continue to waive, until March 31, 2003, the default caused by GenHoldings' failure to make equity contributions.

In connection with the lenders' waiver of various defaults and additional funding commitments, PG&E NEG has agreed to cooperate with any reasonable proposal by the lenders regarding disposition of the equity in or assets of any or all of the PG&E NEG subsidiaries holding the Athens, Covert, Harquahala, and Millennium projects.

As of March 21, 2003, the lenders executed a waiver letter extending to June 30, 2003, the waiver of GenHoldings' equity default. In addition, the waiver letter also waives other existing defaults in order to permit the continued availability of loan facilities to fund construction and operation of the projects until such time as a transfer of the projects to the GenHoldings lenders may be completed. An event of default will occur if such transfer is not accomplished by such deadline. Such a default would trigger lender remedies, including the right to foreclose on Millennium, Harquahala, Athens, and Covert.

Under the waiver, PG&E NEG has re-affirmed its guarantee of GenHoldings' remaining obligation to make equity contributions to these projects of approximately $355 million. Neither PG&E NEG nor GenHoldings currently expects to have sufficient funds to make this payment. The requirement to pay $355 million will remain an obligation of PG&E NEG that would survive the transfer of the projects.

Lake Road and La Paloma Projects

In September 1999 and March 2000, Lake Road Generating Company, LP (Lake Road) and La Paloma Generating Company, LLC (La Paloma) entered into Participation Agreements to finance the construction of the two plants. In November 2002,

Lake Road and La Paloma defaulted on their obligations to pay interest and swap payments. In addition, as a result of PG&E NEG's downgrade to below investment grade by both S&P and Moody's, PG&E NEG, as guarantor of certain debt obligations of Lake Road and La Paloma, became required to make equity contributions to Lake Road and La Paloma of $230 million and $375 million respectively. The lenders have accelerated all debt existing prior to December 11, 2002, including the guaranteed portion of the debt and made a payment under the PG&E NEG guarantee. Neither PG&E NEG, Lake Road nor La Paloma has sufficient funds to make these payments.

As of December 4, 2002, PG&E NEG and certain subsidiaries entered into various agreements with the respective lenders for each of the Lake Road and La Paloma generating projects providing for (1) funding of construction costs required to complete the La Paloma facility, and (2) additional working capital facilities to enable each subsidiary to timely pay for its fuel requirements and to provide its own collateral to support natural gas pipeline capacity reservations and independent transmission system operator requirements, as well as for general working capital purposes. Lenders extending new credit under these agreements have received liens on the projects that are senior to the existing lenders' liens. These agreements provide, among other things, that the failure to transfer right, title and interest in, to and under the Lake Road and La Paloma projects to the respective lenders by June 9, 2003 will constitute a default under the agreements. The failure to transfer the facilities would entitle the lenders to accelerate the new indebtedness and exercise other remedies. The requirement to pay $230 million and $375 million for Lake Road and La Paloma, respectively, will remain an obligation of PG&E NEG that would survive the transfer of the projects.

Activities Related to Merchant Portfolio Operations

PG&E NEG and certain subsidiaries have provided guarantees as of January 31, 2003, to approximately 188 counterparties in support of PG&E ET's energy trading and non-trading activities related to PG&E NEG's merchant energy portfolio in the face amount of $2.2 billion. Typically, the overall exposure under these guarantees is only a fraction of the face value of these guarantees, since not all counterparty credit limits are fully used at any time. As of March 31, 2003, PG&E NEG and its subsidiaries' aggregate exposure under these guarantees was approximately $150 million. The amount of such exposure varies daily depending on changes in market prices and net changes in position. In light of the downgrades, some counterparties have sought and others may seek replacement security to collateralize the exposure guaranteed by PG&E NEG and its subsidiaries. PG&E GTN and PG&E ET have terminated the arrangements pursuant to which PG&E GTN provided guarantees on behalf of PG&E ET such that PG&E GTN will provide no new guarantees on behalf of PG&E ET.

At March 31, 2003, PG&E ET's estimated exposure not covered by a guarantee (excluding exposure under tolling agreements) is approximately $96 million.

To date, PG&E ET has met those replacement security requirements properly demanded by counterparties and has not defaulted under any of its master trading agreements although one counterparty has alleged a default. No demands have been made upon the guarantors of PG&E ET's obligations under these trading agreements. In the past, PG&E ET has been able to negotiate acceptable arrangements and reduce its overall exposure to counterparties when PG&E ET or its counterparties have faced similar situations. There can be no assurance that PG&E ET can continue to negotiate acceptable arrangements in the current circumstances. PG&E NEG cannot quantify with any certainty the actual future calls on PG&E ET's liquidity. PG&E NEG's and its subsidiaries' ability to meet these calls on their liquidity will vary with market price volatility, uncertainty with respect to PG&E NEG's financial condition, and the degree of liquidity in the energy markets. The actual calls for collateral will depend largely upon the ability to enter into forbearance agreements and pre- and early-pay arrangements with counterparties, the continued performance of PG&E NEG companies under the underlying agreements, whether counterparties have the right to demand such collateral, the execution of master netting agreements and offsetting transactions, changes in the amount of exposure, and the counterparties' other commercial considerations.

Tolling Agreements

PG&E ET has entered into tolling agreements with several counterparties under which at its discretion, it supplies the fuel to the power plants and then sells the plant's output in the competitive market. Payments to the counterparties are reduced if the plants do not achieve agreed-upon levels of performance. The face amount of PG&E NEG's and its subsidiaries' guarantees relating to PG&E ET's tolling agreements is approximately $600 million. The tolling agreements are with: (1) Liberty Electric Power, L.P. (Liberty) guaranteed primarily by PG&E NEG and secondarily by PG&E GTN for an aggregate amount of up to $150 million; (2) DTE-Georgetown, LLC (DTE) guaranteed by PG&E GTN for up to $24 million; (3) Calpine Energy Services, L.P. (Calpine) for which no guarantee is in place; (4) Southaven Power, LLC (Southaven) guaranteed by PG&E NEG for up to $175 million; and (5) Caledonia Generating, LLC (Caledonia) guaranteed by PG&E NEG for up to $250 million.

Liberty

Liberty has provided notice to PG&E ET that the ratings downgrade of PG&E NEG constituted a material adverse change under the tolling agreement requiring PG&E ET to replace the guarantee and post security in the amount of $150 million. PG&E ET has not posted such security. Under the terms of the guarantees, Liberty has the right to terminate the agreement and seek recovery of a termination payment for a maximum amount of up to $150 million. Liberty first must proceed against PG&E NEG's guarantee, and can demand payment under PG&E GTN's guarantee only if PG&E NEG is in bankruptcy or Liberty has made a payment demand on PG&E NEG which remains unpaid five business days after the payment demand is made. In addition, PG&E ET has provided notices to Liberty of several breaches of the tolling agreement by Liberty and has advised Liberty that, unless cured, these breaches would constitute a default under the agreement. If these defaults remain uncured, PG&E ET has the right to terminate the agreement and seek recovery of a termination payment.

DTE Georgetown

By letter dated October 14, 2002, DTE provided notice to PG&E ET that the downgrade of PG&E GTN constituted a material adverse change under the tolling agreement between PG&E ET and DTE and that PG&E ET was required to post replacement security within ten days. By letter dated October 23, 2002, PG&E ET advised DTE that because there had not been a material adverse change with respect to PG&E GTN within the meaning of the tolling agreement, PG&E ET was not required to post replacement security. If PG&E ET was required to post replacement security and it failed to do so, DTE would have the right to terminate the tolling agreement and seek recovery of a termination payment.

Calpine

The tolling agreement states that on or before October 15, 2002, Calpine was to have issued a full notice to proceed under its construction contract to its engineering, procurement, and construction contractor for the Otay Mesa facility. On October 16, 2002, PG&E ET asked Calpine to confirm that it had issued this full notice to proceed and Calpine was not able to do so to the satisfaction of PG&E ET. Consequently, PG&E ET advised Calpine by letter dated October 30, 2002, that it was terminating the tolling agreement effective November 29, 2002. Calpine has indicated that this termination was improper and constituted a default under the agreement, but has not taken any further action.

Southaven and Caledonia Tolling Agreements

PG&E ET signed a tolling agreement with Southaven dated as of June 1, 2000, under which PG&E ET is required to provide credit support as defined in the tolling agreement. PG&E ET satisfied this obligation by providing an investment-grade guarantee from PG&E NEG as defined in the tolling agreement. The amount of the guarantee now does not exceed $175 million. By letter dated August 31, 2002, Southaven advised PG&E ET that it believed an event of default under the tolling agreement had taken place with respect to this obligation because PG&E NEG was no longer investment-grade as defined in the tolling agreement and because PG&E ET had failed to provide, within 30 days from the downgrade, substitute credit support that met the requirements of the tolling agreement. Southaven has the right to terminate the agreement and seek a termination payment. In addition, PG&E ET has provided Southaven with a notice of default respecting Southaven's performance under the agreement and concerning the inability of the facility to inject its output into the local grid. Southaven has not cured this default and on February 4, 2003, PG&E ET provided a notice of termination.

In addition, PG&E ET signed a tolling agreement with Caledonia dated as of September 20, 2000, under which PG&E ET is required to provide credit support as defined in the tolling agreement. PG&E ET satisfied this obligation by providing a guarantee from PG&E NEG that was investment-grade as defined in the tolling agreement. The amount of the guarantee does not exceed $250 million. By letter dated August 31, 2002, Caledonia advised PG&E ET that it believed an event of default under the tolling agreement had taken place with respect to this obligation because PG&E NEG was no longer investment-grade as defined in the tolling agreement and because PG&E ET had failed to provide, within 30 days from the downgrade, substitute credit support that met the requirement of the tolling agreement. Caledonia has the right to terminate the agreement and seek a termination payment. In addition, PG&E ET provided Caledonia with a notice of default respecting Caledonia's performance under the agreement and concerning the inability of the facility to inject its output into the local grid. Caledonia has not cured this default and on February 4, 2003, PG&E ET provided a notice of termination.

On February 7, 2003, Southaven and Caledonia filed an emergency petition to compel arbitration or, in the alternative, for a temporary restraining order and preliminary injunction with the Circuit Court for Montgomery County, Maryland (Court). On March 3, 2003, the Court issued an order ruling that PG&E ET must continue to perform under the agreements. PG&E ET appealed this decision to an intermediate Maryland appellate court. However, on April 8, the highest appellate court in Maryland issued on its own motion and order taking jurisdiction of the appeal.

PG&E ET is not able to predict whether the counterparties will seek to terminate the agreements or whether the Court will grant the requested relief. Accordingly, it is not able to predict whether or the extent to which these proceedings will have a material adverse effect on PG&E NEG's financial condition or results of operations.

Under each tolling agreement, determination of the termination payment is based on a formula that takes into account a number of factors, including market conditions such as the price of power and the price of fuel. In the event of a dispute over the amount of any termination payment that the parties are unable to resolve by negotiation, the tolling agreement provides for mandatory arbitration. The dispute resolution process could take as long as six months to more than a year to complete. To the extent that PG&E ET did not pay these damages, the counterparties could seek payment under the guarantees for an aggregate amount not to exceed $600 million. PG&E NEG is unable to predict whether counterparties will seek to terminate their tolling agreements. PG&E NEG currently does not expect to be able to pay any termination payments that may become due.

Other Guarantees

PG&E NEG has provided guarantees related to other obligations by PG&E NEG companies to counterparties for goods or services. PG&E NEG does not believe that it has significant exposure under these guarantees. The most significant of these guarantees relates to performance under certain construction contracts. In the event PG&E NEG is unable to provide any additional or replacement security that may be required as a result of rating downgrades, the counterparty providing the goods or services could suspend performance or terminate the underlying agreement and seek recovery of damages. These guarantees represent guarantees of subsidiary obligations for transactions entered into in the ordinary course of business. Some of the guarantees relate to the construction or development of PG&E NEG's power plants and pipelines. These guarantees are described below.

PG&E NEG has issued guarantees to construction financing lenders for the performance of the contractors building the Harquahala and Covert generating projects for up to $555 million. The construction contractor and various equipment vendors currently are performing under their underlying contracts.

PG&E NEG has issued $100 million of guarantees to the constructor of the Harquahala and Covert projects to cover certain separate cost-sharing arrangements.

PG&E NEG has provided a $300 million guarantee to support a tolling agreement that a wholly-owned subsidiary, Attala Energy, has entered into with another wholly-owned subsidiary, Attala Generating Company, LLC.

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

PG&E NEG has the following credit facilities outstanding at March 31, 2003 (in millions):

	Total Bank Commitment	Balance
PG&E NEG Inc. Tranche A (2 year facility)(a)	$ 258	$ 258
PG&E NEG Inc. Tranche B (364 day facility)(a)	431	431
PG&E ET & Subsidiaries Facility One	35	33
PG&E ET & Subsidiaries Facility Two	19	19
PG&E Gen	7	7
USGenNE	100	88
PG&E GTC and Subsidiaries	125	40
Total	$ 975	$ 876

(a) PG&E NEG is currently in default on both its Tranche A and Tranche B credit facility.

CASH FLOWS

Utility

The following section discusses the Utility's significant cash flows from operating, investing, and financing activities for the three months ended March 31, 2003, and 2002.

Operating Activities

Results from the Utility's consolidated cash flows from operating activities for the three months ended March 31, 2003, and 2002 are as follows:

	Three months ended March 31,	
	2003	2002
	(in millions)	
Net income (loss)	$ (73)	$ 596
Non-cash (income) expenses:		
Depreciation and amortization	310	271
Net reversal of ISO accrual and DWR revenue requirement adjustment		(970)
Increase in accounts payable	122	453
Other items of cash:		
Payments authorized by the Bankruptcy Court on amounts classified as liabilities subject to compromise	(39)	(225)

	Three months ended March 31,	
Change in income tax receivable	(176)	
Other changes in operating assets and liabilities	590	1,034
Net cash provided by operating activities	$ 734	$ 1,159

Cash provided by operating activities decreased by $425 million during the three months ended March 31, 2003, in comparison to the same period in the prior year. This decrease was mainly due to the following:

Net income decreased by $669 million due primarily to lower electric sales volumes, an increase in revenues passed through to the DWR and an increase in the cost of electricity. See discussion of factors impacting the Utility's net income in the "Results of Operations" section of this MD&A. Net income for the three months ended March 31, 2003, included net non-cash expense of $509 million, including $310 million of depreciation. Net income in the three months ended March 31, 2002, included net non-cash income totaling $742 million, including $271 million in depreciation and a reversal of ISO charges of $970 million.

Payments on amounts classified as liabilities subject to compromise decreased by $186 million in 2003 compared to 2002 due to significant pre-petition amounts paid to QF's in the first quarter of 2002 based on Bankruptcy Court approved settlements.

Other changes in operating assets and liabilities provided cash flows of $491 million in the first quarter of 2003 and $478 million in the first quarter of 2002 primarily through the collection of customer receivables and the usage of stored gas and fuel oil inventories.

Investing Activities

Results from the Utility's consolidated cash flows from investing activities for the three months ended March 31, 2003, and 2002 are as follows:

	Three months ended March 31,	
	2003	**2002**
	(in millions)	
Capital expenditures	$ (371)	$ (353)
Net proceeds from sales of assets	5	
Other investing activities	9	(7)
Net cash used by investing activities	$ (357)	$ (360)

Net cash used by investing activities decreased by $3 million during the three months ended March 31, 2003, in comparison to the same period in the prior year. The variance is mainly attributable to proceeds from the sale of assets during the first quarter of 2003 offset by an increase in capital expenditures.

Financing Activities

Results from the Utility's consolidated cash flows from financing activities for the three months ended March 31, 2003, and 2002 are as follows:

	Three months ended March 31,			
	2003		2002	
	(in millions)			
Long-term debt issued, matured, redeemed, or repurchased	$		$	(333)
Rate reduction bonds matured		(75)		(75)
Other financing activities		1		
Net cash used by financing activities	$	(74)	$	(408)

Net cash used by financing activities decreased by $334 million during the three months ended March 31, 2003, in comparison to the same period in the prior year. The variance is mainly due to $333 million in principal repaid on mortgage bonds in the first quarter of 2002 with no such repayments in the first quarter of 2003.

PG&E NEG

PG&E NEG's cash from operations for the three months ended March 31, 2003, and 2002 will not be indicative of its future cash flow from operations due to the changes in the operations of PG&E NEG discussed above. To the extent that the commitments of PG&E NEG and its subsidiaries can be restructured, future cash from operations will be principally generated by the PG&E NEG pipeline business as well as dividends from PG&E NEG independent power producer project companies which are principally accounted for under the equity method of accounting. If the commitments are not restructured, PG&E NEG will not generate sufficient funds to meet its outstanding cash requirements.

In addition to the impacts of PG&E NEG's downgrades, PG&E NEG's and its subsidiaries' ability to service these obligations is impacted by constraints on the ability to move cash from one subsidiary to another or to PG&E NEG itself. PG&E National Energy Group, LLC, a wholly owned subsidiary of PG&E Corporation, owns 97 percent of the stock of PG&E NEG. GTN Holdings LLC owns 100 percent of the stock of PG&E GTN, and PG&E Energy Trading Holdings, LLC owns 100 percent of the stock of PG&E ET. The organizational documents of PG&E NEG and these limited liability companies require unanimous approval of their respective boards of directors, including at least one independent director, before they can (a) consolidate or merge with any entity, (b) transfer substantially all of their assets to any entity, or (c) institute or consent to bankruptcy, insolvency or similar proceedings or actions. The limited liability companies may not declare or pay dividends unless the respective boards of directors unanimously approve such action and PG&E NEG meets specified financial requirements.

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PG&E NEG's subsidiaries must now independently determine, in light of each company's financial situation, whether any proposed dividend, distribution or intercompany loan is permitted and is in such subsidiary's interest. Therefore, Consolidated Statements of Cash Flows quantifying PG&E NEG's cash and cash equivalents do not reflect the cash actually available to PG&E NEG or any particular subsidiary to meet its obligations.

At March 31, 2003, PG&E NEG and its subsidiaries had the following unrestricted cash and short-term investment balances:

	(in millions)	
PG&E NEG	$	110
PG&E ET and Subsidiaries		153
PG&E Gen and Subsidiaries		172
PG&E GTN and Subsidiaries		29
Other		49
Consolidated PG&E NEG	$	513

Operating Activities

Results from PG&E NEG's consolidated cash flows from operating activities for the three months ended March 31, 2003 and 2002 are as follows on a summarized basis:

	Three Months Ended March 31, 2003	Three Months Ended March 31, 2002
	(in millions)	
Net income (loss)	$ (369)	$ 37
Adjustments to reconcile net income to net cash (used in) provided by operating activities before price risk management assets and liabilities	240	(20)
Subtotal	(129)	17
Price risk management assets and liabilities, net	(46)	21
Net effect of changes in operating assets and liabilities:		
Restricted cash	(65)	(12)
Net, accounts receivable, accounts payable and accrued liabilities	83	109
Inventories, prepaids, deposits and other	157	(92)
Net cash provided by operating activities	$	$ 43

During the three months ended March 31, 2003, PG&E NEG did not provide any net cash from operating activities versus cash generated from operating activities of $43 million for the three months ended March 31, 2002. Net cash from operating activities before changes in operating assets and liabilities and price risk management assets and liabilities was $146 million less for the three months ended March 31, 2003 versus 2002, principally as a result of operating losses. Change in price risk management assets and liabilities resulted in a $46 million use of cash for the three months ended March 31, 2003 versus $21 million provided for the same period in 2002 primarily due to realized losses from pricing changes and trade terminations. The change in inventories, prepaid expenses, deposits, and other liabilities created cash flow of $157 million for the three months ended March 31, 2003, versus $92 million used for the same period in 2002 primarily due to reduced inventory levels and prepaid expenses. Adding to these cash outflows were $65 million of increased restricted cash requirements.

Investing Activities

The cash outflows from PG&E NEG's investing activities for the three months ended March 31, 2003, and 2002 will not be indicative of the future cash outflow from investing activities due to the changes in the operations of PG&E NEG (discussed above). Future cash outflows from investing operations will be principally related to maintenance of capital expenditures in the pipeline business.

Results from PG&E NEG's consolidated cash flows from investing activities for the three months ended March 31, 2003, and 2002 are as follows:

	Three months ended March 31, 2003	Three months ended March 31, 2002
	(in millions)	
Capital expenditures	$ (101)	$ (358)
Proceeds from disposal of discontinued operations	102	
Other, net	16	1
Net cash provided by (used) in investing activities	$ 17	$ (357)

Total capital expenditures detailed by business segment and expenditure amount associated with construction work in progress for the three months ended March 31, 2003, and 2002 are as follows:

	Three months ended March 31,	
	2003	2002
	(in millions)	
Integrated Energy and Marketing Activities	$ 100	$ 313
Interstate Pipeline Operations	1	45
Total Capital Expenditures	$ 101	$ 358
Expenditure associated with Construction work in progress	$ 90	$ 315

During the three months ended March 31, 2003, PG&E NEG used net cash before proceeds of sale of assets of $85 million in investing activities compared to $357 million for the same period in 2002, or a decrease of $272 million. The decrease in cash used in investing activities from period to period was primarily due to reduced construction activities. In addition, PG&E NEG received proceeds on the sale of Mountain View during the first quarter of 2003 with no comparable like event occurring in the first quarter of 2002. Capital expenditures related to construction work in progress for the three months ended March 31, 2003 were $90 million versus $315 million in 2002 and were financed by non-recourse debt. In connection with the lenders' waiver of PG&E NEG's failure to make required equity contributions under its guarantees, these construction projects are required to be transferred to lenders during 2003.

Included in investing activities for the three months ended March 31, 2003, and 2002, are cash flows of $16 million and $21 million, respectively, related to the long-term receivable from New England Power Company associated with the assumption of power purchase agreements. These cash flows offset cash payments made to New England Power Company which are reflected in operating activities.

Financing Activities

Results from PG&E NEG's consolidated cash flows from financing activities for the three months ended March 31, 2003, and 2002 are as follows:

	Three months ended March 31,	
	2003	2002
	(in millions)	
Net borrowings under credit facilities	$	$ 76
Long-term debt issued	152	190
Long-term debt matured, redeemed, or repurchased	(18)	(7)
Deferred financing costs	(1)	(20)
Net cash provided by financing activities	$ 133	$ 239

During the three months ended March 31, 2003, PG&E NEG provided net cash flows from financing activities of $133 million compared to $239 million for the same period in 2002. PG&E NEG's cash inflows from financing activities were primarily attributable to increases in long-term debt issued relating to increased borrowings under PG&E NEG's continuing construction facilities.

PG&E Corporation

The following section discusses PG&E Corporation's significant cash flows from operating, investing, and financing activities for the three months ended March 31, 2003, and 2002.

Operating Activities

PG&E Corporation's sources and uses of cash from operating activities for the three months ended March 31, 2003, and 2002 are as follows:

	Three months ended March 31,	
	2003	**2002**
	(in millions)	
Net income (loss)	$ (354)	$ 631
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	336	320
Net effect of changes in operating assets and liabilities:		
Restricted cash	141	5
Accounts receivable	433	428
Accounts payable	177	344
Payments authorized by the Bankruptcy Court on amounts classified as liabilities subject to compromise	(39)	(248)
Assets and liabilities of operations held for sale	(20)	(41)
Other, net	259	(249)
Net cash provided by operating activities	$ 933	$ 1,190

Net cash provided by operating activities was $933 million in 2003 and $1,190 million in 2002. The decrease in 2003 was due primarily to the following factors:

The release of loan proceeds of $246 million, net of $54 million interest reserve, to PG&E Corporation from escrow during the first quarter of 2003. The amount was reclassified from Restricted Cash to Cash and Cash Equivalent on the PG&E Corporation Consolidated Balance Sheet for the three months ended March 31, 2003.

A decrease in the Utility's net income for the first three months of 2003 as a result of lower electric sales volumes, an increase in revenues passed through to the DWR and an increase in the cost of electricity. This was offset by a decrease in payments on amounts classified as liabilities subject to compromise. Other changes in the Utility's operating assets and liabilities are the result of changes in collection of customer receivables and the usage of stored gas and fuel oil inventories.

PG&E NEG's net cash provided from operating activities decreased as a result of realized losses from pricing changes and trade terminations and increased restricted cash requirements, partially off-set by a reduction in inventory levels and prepaid expenses.

Investing Activities

PG&E Corporation's sources and uses of cash from investing activities for the three months ended March 31, 2003, and 2002 are as follows:

	Three months ended March 31,	
	2003	2002
	(in millions)	
Capital expenditures	$ (472)	$ (711)
Proceeds from disposal of discontinued operations	102	
Other, net	30	(6)
Net cash used by investing activities	$ (340)	$ (717)

Net cash used by investing activities was $340 million in 2003 and $717 million in 2002. The decrease in 2003 was due primarily to PG&E NEG's reduced construction activities, following PG&E NEG's failure to make required equity contributions under its guarantee. In addition, PG&E NEG received proceeds on the sale of Mountain View during the first quarter of 2003 with no comparable event occurring in the first quarter of 2002.

Financing Activities

PG&E Corporation's sources and uses of cash from financing activities for the three months ended March 31, 2003, and 2002 are as follows:

	Three months ended March 31,	
	2003	2002
	(in millions)	
Net borrowings under credit facilities	$	$ 76
Long-term debt issued	152	190
Long-term debt matured, redeemed, or repurchased	(18)	(340)
Rate reduction bonds matured	(75)	(75)
Common stock issued	21	21
Other, net		(20)
Net cash provided (used) by financing activities	$ 80	$ (148)

Net cash provided by financing activities was $80 million in 2003 and net cash used by financing activities was $148 million in 2002. The increase in 2003 was due primarily to the following factors:

The Utility repaid $333 million of mortgage bonds in the first quarter of 2002, with no such repayments in the first quarter of 2003.

PG&E NEG's reduction of long-term debt issued and net borrowings in the first quarter of 2003, as a result of the credit rating downgrades.

RESULTS OF OPERATIONS

In this section, PG&E Corporation discusses earnings and the factors affecting them for each operating segment. The table below details certain items from the accompanying Consolidated Statements of Operations by operating segment for the three months ended March 31, 2003, and 2002.

		PG&E National Energy Group					
	Utility	Total PG&E NEG	Integrated Energy & Marketing Activities	Interstate Pipeline Operations	PG&E NEG Eliminations	PG&E Corporation, Eliminations and Other(1)	Total
	(in millions)						
Three months ended March 31, 2003							
Operating revenues	$ 2,067	$ 359	$ 313	$ 64	$ (18)	$ (25)	$ 2,401
Operating expenses	2,018	538	481	27	30	(26)	2,530
Operating income (loss)	49	(179)	(168)	37	(48)	1	(129)
Interest income							14
Interest expense							(375)
Other income (expenses), net							3
Loss before income taxes							(487)
Income taxes							(209)
Loss from continuing operations							(278)
Net loss							$ (354)
Three months ended March 31, 2002(2)							
Operating revenues(3)	$ 2,453	$ 516	$ 461	$ 59	$ (4)	$ (34)	$ 2,935
Operating expenses	1,205	460	429	26	5	(31)	1,634
Operating income (loss)	1,248	56	32	33	(9)	(3)	1,301
Interest income							32
Interest expense							(334)
Other income (expenses), net							20
Income before income taxes							1,019
Income taxes							396
Income from continuing operations							623
Net income							$ 631

(1)

PG&E Corporation eliminates all inter-segment transactions in consolidation.

(2) Prior period amounts have been restated to reflect the reclassification of USGenNE, Mountain View, and ET Canada operating results to discontinued operations.

(3) Operating revenues and operating expenses reflect the adoption of a new accounting policy in the third quarter of 2002 implementing a retroactive change from gross to net method of reporting revenues and expenses on trading activities. Amounts for trading activities for this period have been reclassified to conform with the new net presentation.

PG&E Corporation Consolidated

Overall Results

PG&E Corporation's net loss for the three months ended March 31, 2003, was $354 million, compared to net income of $631 million for the same period in 2002.

The significant changes to items affecting net income attributable to the Utility and PG&E NEG for the three months ended March 31, 2003, as compared to the same period in 2002, are summarized in the table below:

	(in millions)
Utility	
Electric revenues	$ (541)
Natural gas revenues	155
Cost of electricity	(707)
Cost of natural gas	(171)
Operating and maintenance expenses	123
Depreciation,amortization, and decommissioning	(39)
Reorganization fees and expenses	(19)
Interest and other income	(2)
Interest expense	43
PG&E NEG	
Operating revenues	(157)
Cost of commodity sales and fuel	157
Impairments, write-offs, and other charges	(200)
Operations maintenance, and management expenses	(20)
Administrative and general expenses	(16)
Depreciation and amortization	5
Interest expense	(89)
Discontinued operations	(115)
Cumulative effect of changes in accounting principles	(8)

PG&E Corporation's results of operations continue to be impacted by the California energy crisis, the Utility's bankruptcy filing, and the current liquidity and financial downturn at PG&E NEG. The results of the Utility and PG&E NEG are discussed separately below. See the "Liquidity and Financial Resources" section of this MD&A, and Notes 2 and 3 of the Notes to the Consolidated Financial Statements for more information.

Dividends

No dividends were declared in 2003 or 2002 in accordance with the Credit Agreement with Lehman Commercial Paper, Inc., which prohibits PG&E Corporation from declaring or paying dividends until the term loans have been repaid.

Utility

Electric Revenues

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

	Three months ended March 31,	
	2003	2002
	(in millions)	
Residential	$ 921	$ 945
Commercial	845	881
Industrial	305	336

Agricultural	68	65
Miscellaneous	(64)	40
Direct access credits	(81)	(109)
DWR pass-through revenue	(757)	(380)
Total electric operating revenues	$ 1,237	$ 1,778

Electric revenues in the first quarter of 2003 decreased $541 million, or 30.4 percent, from 2002 primarily due to the following factors:

Amounts recorded as pass-through revenues to the DWR increased by $377 million in the first quarter of 2003 from 2002. The Utility passes revenue through to the DWR for electricity provided by the DWR to the Utility's customers. The increase in DWR pass-through revenues in the first quarter of 2003 was primarily due to (1) DWR's and CPUC's changes to the methodology used to calculate DWR remittances beginning in the third quarter of 2002 as well as the additional bond charges approved by the CPUC in November 2002 (see Note 2 of the Notes to the Consolidated Financial Statements), and (2) an increase in the volume provided by DWR contracts due to a decrease in the amount of electricity generated by the Utility primarily due to a scheduled outage at the Diablo Canyon power plant.

Lower electric sales volume and a lower average sales price due to mild weather, and a May 2002 CPUC decision that increased baseline quantity allowances. An increase to a customer's baseline quantity allowances increases the amount of their monthly usage that is covered under the lowest possible rate and is exempt from surcharges.
From January 2001 through December 2002, the DWR was responsible for procuring electricity required to cover the Utility's net open position (the amount of electricity needed by retail electric customers that cannot be met by utility-owned generation or electricity under contract to the Utility.) The Utility resumed procuring electricity on the open market in January 2003 but still relies on electricity provided by DWR contracts to service a significant portion of its total load. Revenues collected on behalf of the DWR and the related costs are not included in the Utility's Consolidated Statements of Operations, reflecting the Utility's role as a billing and collection agent for the DWR's sales to Utility's customers.

Cost of Electricity

The following table shows a breakdown of the Utility's cost of electricity:

	Three months ended March 31,	
	2003	2002

	Three months ended March 31,	
	(in millions)	
Cost of purchased power	$ 524	$ 405
Fuel used in own generation	17	24
Adjustments to purchased power accruals		(595)
Total cost of electricity	$ 541	$ (166)
Average cost of purchased power per kWh	$ 0.089	$ 0.069
Total purchased power (GWh)	5,879	5,906

The cost of electricity in the first quarter of 2003 increased $707 million from 2002 primarily due to the following factors:

A net $595 million reduction to the cost of electricity recorded in March 2002 as a result of FERC and CPUC decisions, which allowed the Utility to reverse previously accrued ISO charges and to adjust for the amount previously accrued as payable to the DWR for their 2001 revenue requirement (see Note 2 of the Notes to the Consolidated Financial Statements).

An increase in the average cost of purchased power because of less electricity provided by QFs, which provided electricity at a lower cost. QFs supplied less electricity to the Utility in 2003 due to an overall decrease in QF production caused

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primarily by higher gas prices and rescheduled maintenance outages. In addition, as a result of the Utility's resumed responsibility to cover its net open position, the Utility began buying electricity on the spot market and entered into new short-term purchased power agreements, which provided electricity at a higher cost. (See discussion of "SB 1976" in Note 2 of the Notes to the Consolidated Financial Statements).

Natural Gas Revenues

Natural gas revenues are made up of bundled gas revenues and transportation-only revenues.

The following table shows a breakdown of the Utility's natural gas revenue:

	Three months ended March 31,	
	2003	2002
	(in millions)	
Bundled gas revenues	$ 949	$ 773
Transportation service only revenue	66	80
Other	(185)	(178)
Total natural gas revenues	$ 830	$ 675

In the first quarter of 2003, natural gas revenues increased $155 million, or 23 percent, from 2002 primarily as a result of a higher average cost of natural gas, which was passed along to customers through higher rates. The average bundled price of natural gas sold in the first quarter of 2003 was $9.03 per thousand cubic feet (Mcf) as compared to $6.84 per Mcf in the first quarter of 2002.

The decrease in transportation service-only revenue resulted primarily from a decrease in demand for gas transportation services by gas-fired electric generators in California and warmer weather conditions in the first quarter of 2003.

Other natural gas revenue consists primarily of natural gas balancing account revenues. The Utility tracks natural gas revenues and costs in natural gas balancing accounts. Over-collections and under-collections are deferred until they are refunded to or received from the Utility's customers through rate adjustments.

Cost of Natural Gas

The following table shows a breakdown of the Utility's cost of natural gas:

	Three months ended March 31,	
	2003	**2002**
	(in millions)	
Cost of natural gas sold	$ 450	$ 290
Cost of gas transportation	36	25
Total cost of natural gas	$ 486	$ 315

In the first quarter of 2003, the Utility's cost of natural gas increased $171 million, or 54 percent, from 2002 primarily due to an increase in the average market price of natural gas purchased from $2.79 per Mcf in 2002 to $4.63 per Mcf in 2003.

The Utility's cost to transport gas to its service area increased in the first quarter of 2003 due to new pipeline demand charges paid on the El Paso pipeline. The Utility, along with other California utilities, was ordered by the CPUC in July 2002 to enter into long-term contracts to purchase transportation on the El Paso pipeline (see discussion in the "Regulatory Matters" section of this MD&A).

Operating and Maintenance

In the first quarter of 2003, the Utility's operating and maintenance expenses decreased $123 million, or 16 percent, from 2002. This decrease was primarily due to lower recorded costs for legal and environmental matters, and a decrease in the Utility's recorded liabilities for regulatory matters due to FERC and CPUC decisions on previous transmission owner rate cases and other matters. These decreases were partially offset by increases in employee benefit plan-related expenses and maintenance expenses due to maintenance performed during the scheduled refueling outage at the Diablo Canyon power plant.

Depreciation, Amortization, and Decommissioning

Depreciation, amortization, and decommissioning expenses increased $39 million, or 14 percent, in the first quarter of 2003. This increase was due mainly to an increase in amortization of the rate reduction bond regulatory asset, which began at the end of January 2002. Amortization of the rate reduction bond regulatory asset increased $23 million in the first quarter of 2003 from 2002. The increase reflects the amortization of the regulatory asset for all three months in the first quarter of 2003, as compared to the amortization of the regulatory asset for only two months 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 reports reorganization interest income separately on the Consolidated Statements of Operations. Such income primarily includes interest earned on cash accumulated during the bankruptcy proceedings. Interest income decreased $11 million, or 50 percent, in the first quarter of 2003. The decrease in interest income in 2003 was due primarily to lower average interest rates on the Utility's short-term investments.

Interest Expense

In the first quarter of 2003, the Utility's interest expense decreased $43 million, or 16 percent, from the same period in 2002. This decrease was due to a reduction of interest on rate reduction bonds and a lower level of unpaid debts accruing interest.

Reorganization Fees and Expenses

In accordance with SOP 90-7, the Utility reports reorganization fees and expenses separately on the Consolidated Statements of Operations. Such costs primarily include professional fees for services in connection with Chapter 11 proceedings and totaled $35 million in the first quarter of 2003 and $16 million in the first quarter of 2002.

PG&E NEG

PG&E NEG has experienced significant impacts to its results of operations from various acquisitions, disposals, and more recently from its efforts to raise cash and reduce indebtedness through sale, transfer or abandonment of assets.

Overall Results

PG&E NEG's net loss was $369 million for the three months ended March 31, 2003, a decrease of $406 million from the three months ended March 31, 2002.

The three months ended March 31, 2003 included a net pre-tax loss recognized on disposals and planned disposals of assets held for sale of $7 million. This amount related to the gain on sale of Mountain View of $19 million, offset by additional losses on USGenNE of $23 million and the sale of ET Canada of $3 million. No gains or losses on disposal of assets held for sale were reflected in the comparative period in 2002. In addition, pre-tax losses from discontinued operations were $100 million for the three months ended March 31, 2003 or a $108 million decrease as compared to the same period in 2002. These losses from discontinued operations were primarily due to lower gross margin results from USGenNE. Gross margin is defined as the difference between revenues and cost of commodity.

PG&E NEG's pre-tax operating loss of $293 million for the three months ended March 31, 2003 was $327 million lower as compared to the same period in 2002. The reduced pre-tax operating levels period over period were principally due to $200 million of impairment and write-offs charged to income in the first quarter 2003 resulting primarily from the consolidation and impairment of Attala Generating Company, LLC and the Shaw settlement as further discussed in Note 3 of the Notes to

the Consolidated Financial Statements. In addition, gross margins were $7 million less in the first quarter 2003 compared to the same period in 2002 primarily due to the winding down of PG&E NEG's energy trading operations. Increased operation and maintenance costs of $20 million and increased interest expense of $89 million in the first quarter 2003 compared to the same period in 2002 adversely impacted pre-tax operating income and were primarily due to new merchant plants in operation. Administrative and general expense were $16 million higher in the first quarter 2003 compared to 2002 primarily due to costs associated with PG&E NEG's debt restructuring efforts.

The following highlights PG&E NEG's principal changes in operating revenues and operating expenses.

Operating Revenues

PG&E NEG's operating revenues were $359 million in the three months ended March 31, 2003, a decrease of $157 million from the three months ended March 31, 2002. These decreases occurred primarily in the Integrated Energy and Marketing Activities segment and are primarily a result of the activities associated with the winding down of PG&E NEG's energy trading operations. Interstate Pipeline Operations operating revenues increased $5 million primarily due to the addition of the North Baja pipeline operations compared to the same period last year.

Operating Expenses

PG&E NEG's operating expenses were $538 million in the three-month period ended March 31, 2003, an increase of $78 million from the same period in the prior year. These increases occurred primarily as a result of $200 million impairment and write-off charges in the first quarter

2003. The cost of commodity sales and fuel decreased $157 million in line with decreases in operating revenues and were primarily attributable to the activities associated with the winding down of PG&E NEG's energy trading operations. Operations, maintenance and management costs increased $20 million in the first quarter of 2003 as compared to the same period last year principally due to additional merchant generation facilities in operations. Administrative and general expenses were $16 million higher in the first quarter 2003 compared to 2002 primarily due to costs associated with PG&E NEG's restructuring efforts.

REGULATORY MATTERS

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

The Utility is the only subsidiary with significant regulatory proceedings or issues at this time. The discussion of these matters below should be read in conjunction with the regulatory matters discussed in PG&E Corporation's and the Utility's combined 2002 Annual Report on Form 10-K, as amended. Regulatory proceedings associated with electric industry restructuring are further discussed in Note 2 of the Notes to the Consolidated Financial Statements.

DWR Revenue Requirement and Servicing Order

In accordance with Assembly Bill (AB) 1X, the DWR began purchasing the amount of electricity needed by the California IOUs' customers that could not be provided by the IOUs, either through their own generation or by suppliers under contracts with the IOUs. In addition to purchasing electricity on the spot market, the DWR entered into long-term contracts for the supply of electricity. Although AB 1X prohibits the DWR from purchasing on the spot market and from entering into new agreements to purchase electricity after December 31, 2002, the DWR is still legally and financially responsible for the long-term contracts it entered into before December 31, 2002. In September 2002, the CPUC allocated the DWR contracts among the California IOUs.

The DWR pays for its costs of purchasing electricity from a revenue requirement charged to Utility ratepayers (power charge) and from proceeds of the DWR's $11.3 billion bond financing completed in November 2002 (see "DWR Bond Charge" below). The DWR's statewide revenue requirements for 2001 and 2002 were approximately $9 billion, of which $4.4 billion was allocated to the Utility's customers.

The Utility provides billing, collection and other services on behalf of the DWR pursuant to a servicing order issued by the CPUC in May 2002. The servicing order contains the method for calculating the amount of money the Utility is required to remit to the DWR from customers. In October 2002, the DWR filed a proposed amendment to the servicing order requesting both prospective and retrospective changes to the calculation that determines the amount of revenues the Utility is required to pass through to the DWR.

The DWR's revised remittance methodology is also contained in a CPUC-approved operating order of December 2002, that requires the Utility to perform the operational, dispatch, and administrative functions for the DWR's contracts allocated to the Utility. However, the operating order did not change the servicing order relating to the same calculation. In March 2003, the DWR submitted a letter to the CPUC reaffirming its position and quantifying the amount of revenues that the DWR has requested the CPUC to order the Utility to pass through to the DWR. As a result, the Utility has accrued an additional $96 million (pre-tax) liability for pass-through revenues for electricity previously provided by the DWR to the Utility's customers. In total as of March 31, 2003, the Utility has accrued an additional $539 million (pre-tax) liability for pass-through revenues to the DWR based on the DWR's October 2002 proposed amendment, the CPUC's December 2002 operating order, and the March 2003 letter from the DWR. Of this amount, $369 million (pre-tax) had been accrued at December 31, 2002.

In April 2003, the Utility and the DWR entered into an operating agreement, which also has been approved by the CPUC. Effective in April 2003, the operating agreement supersedes the operating order. The operating agreement provides that the Utility will begin passing through revenues to the DWR consistent with the DWR's October 2002 and March 2003 requests for amendments to the servicing order but subject to the outcome of the CPUC's consideration of the DWR's requests. In addition, if the CPUC grants the DWR's request for changes to the servicing order, the Utility would be required to make additional cash payments to the DWR consistent with its accrual of pass-through revenues to the DWR for the periods prior to the effective date of the operating agreement. See "Operating Agreement" below.

A separate proceeding will consider a revision or adjustment for the revenue requirements remitted to the DWR for 2002 and 2001 costs once final 2002 cost data is available. This adjustment proceeding is scheduled for later in 2003. At this point, it is not possible to predict the extent to which the Utility's share of the DWR's $9 billion 2001-2002 revenue requirement, currently set at $4.4 billion, which will be revised.

In December 2002, the CPUC issued a decision allocating approximately $2 billion of the DWR's 2003 revenue requirement related to power charges to the Utility's customers. This revenue requirement includes the costs associated with the DWR contracts allocated to the

Utility's customers by the CPUC in September 2002. The DWR plans to submit a revised 2003 power charge-related revenue requirement to the CPUC later in 2003.

In October 2002, the Utility filed a lawsuit in a California court asking the court to find that the DWR's revenue requirements had not been demonstrated to be "just and reasonable" (as required by AB 1X) and lawful. The Utility asked that the court order the DWR's revenue requirement determination to be withdrawn as invalid, and that the DWR be precluded from imposing its revenue requirements on the Utility and its customers until it has complied with the law. The lawsuit is scheduled to be considered by the court during the third or fourth quarter of 2003.

Until the CPUC modifies the current frozen rate structure, changes to the DWR's 2003 revenue requirement may affect the Utility's future earnings. Because the Utility acts as a collection agent for the DWR, amounts collected on behalf of the DWR (related to its revenue requirement) are excluded from the Utility's revenues.

DWR Bond Charge

In October 2002, the CPUC issued a decision that, in part, imposes bond charges to recover the DWR's bond costs from bundled and direct access customers starting November 15, 2002, as described below, although the decision found that the Utility would not need to increase customers' overall rates to incorporate the bond charge. The Utility expects to pass through approximately $340 million in bond-related charges during the 12 months ending November 14, 2003.

Until the CPUC implements bottoms-up billing (billing for specific rate components) for the Utility, any bond charges will reduce the amount of revenue available to recover previously written-off under-collected electricity procurement and transition costs.

Senate Bill 1976

Under AB 1X, the DWR is prohibited from entering into new agreements to purchase electricity to meet the net open position of the California IOUs after December 31, 2002. In September 2002, the Governor signed California SB 1976 into law. As required by SB 1976, each California IOU submitted an electricity procurement plan to meet the residual net open position associated with that utility's customer demand.

A central feature of the SB 1976 regulatory framework is its direction to the CPUC to create new electric procurement balancing accounts to track and allow recovery of the differences between recorded revenues and costs incurred under an approved procurement plan. The CPUC must review the revenues and costs associated with the IOU's electric procurement plan at least semi-annually and adjust rates or order refunds, as appropriate, to properly amortize the balancing accounts. The

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CPUC must establish the schedule for amortizing the over-collections or under-collections in the electric procurement balancing accounts so that the aggregate over-collections or under-collections reflected in the accounts do not exceed 5 percent of the IOU's actual recorded generation revenues for the prior calendar year, excluding revenues collected on behalf of the DWR. Mandatory semi-annual review and adjustment of the balancing accounts will continue until January 1, 2006. Thereafter, the CPUC is required to conduct electric procurement balancing account reviews and adjust retail ratemaking amortization schedules for the balancing accounts, as the CPUC deems appropriate and in a manner consistent with the requirements of SB 1976 for timely recovery of electric procurement costs.

Allocation of DWR Electricity to Customers of the IOUs

In September 2002, the CPUC issued a decision to allocate the electricity provided under existing DWR contracts to the customers of the IOUs. This decision required the Utility, along with the other IOUs, to begin performing all the day-to-day scheduling, dispatch, and administrative functions associated with the DWR contracts allocated to the IOUs' respective portfolios on January 1, 2003. The DWR retains legal and financial responsibility for these contracts.

Under AB 1X, the CPUC has no review authority over the reasonableness of procurement costs in the DWR's contracts, although the Utility's administration of DWR contracts allocated to its customers and its dispatch of the electricity associated with those contracts may be subject to reasonableness reviews. See further discussion below under "Energy Procurement."

The DWR has stated publicly that it intends to transfer full legal title of, and responsibility for, the DWR electricity contracts to the IOUs as soon as possible. However, SB 1976 does not contemplate a transfer of title of the DWR contracts to the IOUs. In addition, the operating agreement approved by the CPUC in April 2003 governing the Utility's operational and scheduling responsibility with respect to the DWR allocated contracts specifies that the DWR will retain legal and financial responsibility for the contracts and that the operating agreement does not result in an assignment of the DWR allocated contracts to the Utility (See further discussion below under "Operating Agreement.").

However, either the State of California or the CPUC may provide the DWR with authority to affect such a transfer of legal title in the future. The Utility has informed the CPUC, the DWR, and the State of California that the Utility would vigorously oppose any attempt to transfer the DWR allocated contracts to the Utility without its consent.

Operating Agreement

In December 2002, the CPUC approved an operating order requiring the Utility to perform the operational, dispatch, and administrative functions for the DWR's allocated contracts beginning on January 1, 2003. In April 2003, the CPUC approved an operating agreement between the DWR and the Utility that effectively terminates the operating order but keeps a framework that is substantially similar to the operating order.

Although the operating order and the operating agreement have fundamentally the same objectives, the operating agreement, among other things:

- Provides an adequate contractual basis for establishing a limited agency relationship between the Utility and the DWR;
- Limits the Utility's contractual liability to the DWR and other parties to $5 million per year plus 10 percent of damages in excess of $5 million with a limit of $50 million over the term of the agreement; and
- Clarifies that the DWR does not intend to, nor is it the DWR's responsibility to, review the Utility's least-cost dispatch performance, other than to verify compliance with the supplier contracts.

Both the Utility and the DWR have filed petitions to modify certain terms of the operating agreement.

Energy Procurement

In October 2002, the CPUC issued a decision ordering the Utility to resume full procurement on January 1, 2003. In December 2002, the CPUC issued an interim opinion adopting the revised electricity procurement plan for 2003 that the Utility submitted in 2002 and authorized the Utility to enter into contracts designed to hedge its residual net open position in 2003 and the first quarter of 2004. The CPUC found that the maximum annual procurement disallowance exposure for administration of all contracts and least-cost dispatch of resources that each IOU should face for all of its procurement activities should be limited to twice the IOU's annual administrative costs of managing procurement activities, including its administration and dispatch of electricity associated with DWR contracts allocated to its customers. The Utility's direct annual administrative costs of managing procurement activities requested in the 2003 General Rate Case (GRC) are approximately $18 million.

Effective January 1, 2003, the Utility established the Energy Resource Recovery Account (ERRA) to record and recover electricity costs, excluding the DWR's electricity contract costs, associated with the Utility's authorized procurement plan. Electricity costs recorded in the ERRA include, but are not limited to, fuel costs for retained generation, QF contracts, inter- utility contracts, ISO charges, irrigation district contracts, other power purchase agreements, bilateral contracts, forward hedges, prepayments, collateral requirements associated with procurement, and ancillary services. The Utility offsets these costs by reliability-must-run revenues, the Utility's allocation of revenues from surplus electricity sales, and the ERRA revenue requirement.

In April 2001, the California Public Utilities Code was amended to require that the CPUC ensure that errors in estimates of demand elasticity or sales by the Utility do not result in material over-collections or under-collections of costs by the Utility. The Utility intends to address implementation of this new law in connection with pending proceedings at the CPUC relating to recovery of components of its costs of service.

The CPUC has authorized the Utility to file an application to change retail electricity rates at any time that its forecasts indicate it will face an under-collection of electricity procurement costs in excess of 5 percent of its prior year's generation and procurement revenues, excluding amounts collected for the DWR. The Utility currently estimates that its 5 percent threshold amount will be approximately $224 million. Actual implementation of the rate change as triggered by Utility under-collections is subject to further review by the CPUC.

In February 2003, the Utility filed its 2003 ERRA forecast application requesting that the CPUC reset the Utility's 2003 ERRA revenue requirement to $1.4 billion and that the ERRA trigger threshold of $224 million be adopted. The CPUC will examine the Utility's forecast of costs for 2003 and will finalize the Utility's starting ERRA revenue requirement and ERRA trigger threshold when it reviews the Utility's ERRA application.

The Utility filed its long-term procurement plan (long-term plan), covering the next 20 years, on April 15, 2003. The Utility's long-term plan states that certain important policy issues, including the restoration of the Utility's financial health and investment grade credit rating, should be resolved before the CPUC can adopt a credible long-term plan for the Utility. The long-term plan indicates that a fundamental requirement for restoring the Utility's credit rating is the provision of procurement cost recovery by the CPUC. The Utility also mentions other conditions that the CPUC should consider implementing before adopting its long-term plan including providing comprehensive guidelines which give the Utility the flexibility to react quickly to changing market conditions and determining which customers the Utility will serve and under what price. In this latter condition, the Utility notes that it will continue to be exposed to unrecovered costs unless the CPUC requires customer classes to pay the full amount of costs incurred on their behalf. While the long-term plan states that there is no immediate need for the Utility to construct or make long-term commitments to new resources, it goes on to indicate that the Utility's role in future generation development will be directly impacted by its credit rating.

The Utility plans to file its 2004 short-term procurement plan by May 15, 2003. The CPUC has stated that it plans to issue a final decision on the Utility's long-term procurement plan in November 2003.

2001 Annual Transition Cost Proceeding: Review of Reasonableness of Electricity Procurement

On January 11, 2002, as directed by the CPUC, the Utility filed a report with the CPUC detailing the reasonableness of the Utility's electric procurement and generation scheduling and dispatch activities for the period July 1, 2000, through June 30, 2001. In this proceeding, the CPUC will review the reasonableness of the Utility's procurement of wholesale electricity from the Power Exchange (PX) and the ISO during the height of the 2000-2001 California energy crisis. With the exception of a limited right to purchase electricity from third parties beginning in August 2000, all of the Utility's wholesale electric purchases during this period were required to be made exclusively from or through the PX and ISO markets pursuant to FERC-approved tariffs. Prior CPUC decisions have determined that such purchases should be deemed reasonable. In addition, the Utility's complaint against the CPUC Commissioners asserts that the costs of such purchases are recoverable in the Utility's retail rates without further review by the CPUC under the federal filed rate doctrine. However, a CPUC administrative law judge is asserting jurisdiction to review the reasonableness of the Utility's wholesale electric purchases from the PX and the ISO in the proceeding. A report from the CPUC's Office of Ratepayer Advocates (ORA) regarding the Utility's procurement activities for the covered period was issued on April 28, 2003, recommending that the CPUC disallow recovery of $434 million of the Utility's procurement costs based on an allegation that the Utility's market purchases during the period were imprudent due to a failure to develop and execute a reasonable hedging strategy. The ORA recommendation does not take into account any FERC-ordered refunds of the Utility's procurement costs during this period, which refunds could effectively reduce the amount of the recommended disallowance. The Utility believes that the ORA recommendation is unlawful, contrary to prior CPUC decisions, and factually unsupported, and intends to contest the recommendation vigorously. Hearings will be scheduled this year on the ORA recommendation, and a CPUC decision is expected later this

year or early next year. The Utility cannot predict whether the outcome of this decision will have a material adverse effect on its results of operations or financial condition.

Retained Generation Revenue Requirement

The CPUC approved a 2002 revenue requirement of $3 billion for recovery of costs for generation the Utility retains, including electric purchased power, depreciation, operating expenses, taxes, and return on investment, based on an assumed rate base of $1.9 billion adopted by the decision as of December 31, 2000.

The CPUC authorized the Utility to recover reasonable costs incurred in 2002 for its own electric generation, subject to reasonableness review in the Utility's 2003 GRC or other proceeding. The decision does not change retail electric rates and the Utility does not expect it to have an impact on its results of operations. Instead, the decision defers consideration of future rate changes until the CPUC addresses the status of the retail rate freeze. The CPUC also deferred addressing recovery of the Utility's past unrecovered generation-related costs.

The CPUC is currently considering the Utility's 2003 non-fuel generation revenue requirement request of $1 billion in its 2003 GRC proceeding. This represents an increase in non-fuel generation revenue requirements of $149 million over the amount approved for 2002. On April 11, 2003, the CPUC ORA provided to the Utility and other parties the ORA's report on the Utility's 2003 GRC application. In its report, the ORA recommends a decrease of $2 million for utility-retained generation compared to the Utility's requested increase of $149 million. (See "2003 GRC" below.) Recovery of fuel and purchased power generation-related costs for 2003 was addressed in the Utility's ERRA proceeding (see "Energy Procurement" above).

Divestiture of Retained Generation Facilities

The California Legislature passed AB 6X in January 2001 prohibiting utilities from divesting their remaining power plants before January 1, 2006. The Utility believes this law does not supersede or repeal existing provisions of AB 1890, California's 1996 electric industry restructuring legislation, requiring the CPUC to establish a market value for the Utility's remaining generating assets by the end of 2001, based on appraisal, sale, or other divestiture. The Utility has filed comments on this matter with the CPUC. However, the CPUC has not yet issued a decision.

On January 2, 2002, the CPUC issued a decision finding that AB 6X had materially affected the implementation of AB 1890. The CPUC scheduled further proceedings to address the impact of AB 6X on the AB 1890 rate freeze and to determine the extent and disposition of the Utility's remaining unrecovered transition costs. In its November 2002 decision regarding surcharge revenues (see "One-Cent, Three-Cent, and Half-Cent Surcharge Revenues" below), the CPUC reiterated that it had yet to decide when the rate freeze ended and the disposition of any under-collected costs remaining at the end of the rate freeze.

On January 17, 2002, the Utility filed an administrative claim with the State of California Victim Compensation and Government Claims Board (Claims Board) alleging that AB 6X violates the Utility's statutory rights under AB 1890. The Utility's claim seeks compensation for the denial of its right to at least a $4.1 billion market value of its retained generating facilities. On March 7, 2002, the Claims Board formally denied the Utility's claim. Having exhausted remedies before the Claims Board, on September 6, 2002, the Utility filed a complaint against the State of California for breach of contract in the California Superior Court. On January 9, 2003, the Superior Court granted the State's request to dismiss the Utility's complaint, finding that AB 1890 did not constitute a contract. The Utility filed a notice of appeal on March 7, 2003.

Direct Access Suspension and Cost Responsibility Surcharge

Until September 2001, California utility customers could choose to buy their electricity from the Utility (bundled customers) or from an alternative power supplier through "direct access" service. Direct access customers receive distribution and transmission service from the Utility, but purchase electricity (generation) from their alternative provider. In September 2001, the CPUC, pursuant to AB 1X, suspended the right of retail end-use customers to choose direct access service, thereby preventing additional customers from entering into contracts to purchase electricity from alternative providers. Customers that entered into direct access contracts on or before September 20, 2001, were permitted to remain on direct access.

In November 2002, the CPUC issued a decision assessing an exit fee, or non-bypassable charge, on direct access customers to avoid a shift of costs from direct access customers to bundled service customers.

The decision establishes the Cost Responsibility Surcharge (CRS) and imposes a cap of $0.027 per kWh. The CPUC required the utilities to implement this capped surcharge on January 1, 2003. The CPUC also has indicated that it will reach a decision on whether this cap should be adjusted and whether trigger mechanisms for adjusting the cap should be established, by July 1, 2003. The Utility implemented the $0.027 per kWh capped CRS on January 1, 2003.

When the direct access credit was established, direct access customers paid the full bundled rate less a credit based on the Schedule PX price. Under this methodology, when the Schedule PX price exceeded the bundled rates, the direct access customer received a bill credit. As a result, during the energy crisis, direct access customers did not contribute to the Utility's transition cost recovery nor did they pay for transmission and distribution services. When the CPUC established the CRS, direct access customers began paying a $0.027 per kWh capped surcharge, and stopped paying the $0.01 per kWh surcharge as discussed below. To implement this charge, the Utility adjusted the direct access credit such that the customer pays all transmission and distribution charges plus the $0.027 per kWh capped surcharge.

The CRS currently collects the direct access share of DWR power charges. The CRS may be expanded later to include the above-market portion of the Utility's ongoing procurement and generation costs as well as the DWR bond charge. Direct access customers subject to the CRS who have returned to bundled service will still be responsible for their share of the unrecovered costs resulting from the capping of the CRS. However, the CPUC has not authorized a method for collection of these costs from these customers. To the extent the cap results in an under-collection of DWR charges, the shortfall would have to be remitted to the DWR from bundled customers' funds. Since DWR pass-through revenues are determined based upon a fixed revenue requirement, to the extent that the Utility remits additional CRS revenues to the DWR, the Utility expects those remittances to reduce the amount of revenues it must pass through for bundled customers. The Utility expects to collect approximately $110 million per year more from direct access customers due to the CRS. On an interim basis while the CPUC examines a long-term plan for financing the CRS, interest on under-collections will be assessed at the interest rate paid by the DWR on bonds issued to finance electricity purchases.

The Utility does not expect that the CPUC's implementation of this decision or the level of the CRS cap will have a material adverse effect on its results of operations or financial condition.

One-Cent, Three-Cent, and Half-Cent Surcharge Revenues

In January 2001, the CPUC increased electric rates by $0.01 per kWh, and in March 2001 by another $0.03 per kWh, and restricted use of these revenues to "ongoing procurement costs" and "future power purchases."

In May 2001, the CPUC authorized the Utility to collect an additional $0.005 per kWh surcharge revenue for 12 months to make up for the time lag between March 2001, when the CPUC authorized the $0.03 per kWh surcharge, and June 2001, when the Utility began collecting the $0.03 per kWh surcharge. Although the collection of this "half-cent" surcharge was originally scheduled to end on May 31, 2002, the CPUC issued a resolution ordering the Utility to continue collecting the half-cent surcharge until further consideration by the CPUC and to record the surcharge revenues in a balancing account.

In November 2002, the CPUC approved a decision modifying the restrictions on the use of revenues generated by the surcharges to permit use of the revenues for the purpose of securing or restoring the Utility's reasonable financial health, as determined by the CPUC. The CPUC will determine in other proceedings how the surcharge revenues can be used, whether there is any cost or other basis to support specific surcharge levels, and whether the resulting rates are just and reasonable. After the CPUC determines when the AB 1890 rate freeze ended, the CPUC will determine the extent and disposition of the Utility's under-collected costs, if any, remaining at the end of the rate freeze. If the CPUC determines that the Utility recovered revenues in excess of its transition costs or in excess of other permitted uses, the CPUC may require the Utility to refund such excess revenues.

In December 2002, the CPUC issued a decision authorizing the Utility to record amounts related to the $0.01 per kWh and $0.03 per kWh surcharge revenues as an offset to unrecovered transition costs.

Based on the November and December CPUC decisions discussed above and an agreement between the CPUC and another California IOU, Southern California Edison (SCE), in which SCE was allowed to use its half-cent surcharge to offset its DWR revenue requirement, the Utility believes it can continue to recognize revenues related to the $0.01 per kWh, $0.03 per kWh, and half-cent surcharges after the statutory end of the rate freeze, which was March 31, 2002. As such, as of March 31, 2003, the Utility does not have a regulatory liability recorded for these surcharge revenues in its financial statements.

The California Supreme Court is currently considering the authority of the CPUC to enter into a settlement agreement with SCE that allows SCE to recover under-collected procurement and transition costs in light of the provisions of AB 1890. Oral argument has been set before the California Supreme Court for May 27, 2003. Either in response to judicial decisions such as

this one, or on its own initiative, 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. (See further discussion in the "Recovery of Transition Costs" section of Note 2 of the Notes to the Consolidated Financial Statements). The Utility has not provided reserves for potential refunds of any of these revenues as of March 31, 2003.

If the CPUC requires the Utility to refund any of these revenues in the future, the Utility's earnings could be materially affected.

1999 GRC

Through a GRC proceeding, 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.

The 1999 GRC decision ordered an audit to assess the contribution of the Utility's 1999 electric and gas distribution capital additions to system reliability, capacity, and adequacy of service. The audit began in February 2002 and a final report was issued on November 8, 2002. The final report concludes, "in general the [Utility's] 1999 overall capital expenditure program appears quite acceptable." The final report offers recommendations to improve the Utility's distribution capital investment process, but recommends no adjustments to the Utility's distribution rate base.

In October 2001, the CPUC reopened the record in the 1999 GRC to review the Utility's actual 1998 capital spending on electric distribution compared with the forecast used to determine 1999 rates. On April 3, 2003, the CPUC issued a final decision that would result in an adjustment of the adopted 1998 capital spending forecast level to conform to the 1998 recorded level. The Utility has 45 days from the date of the final decision to file its adjusted revenue requirements with the CPUC for approval. The Utility does not expect a material impact on its financial position or results of operations from the remaining proceedings.

2003 GRC

In the 2003 GRC, the CPUC will determine the amount of authorized base revenues the Utility can collect from ratepayers to recover its basic business and operational costs for gas and electric distribution operations for 2003 through 2005. On November 8, 2002, the Utility requested a $447 million increase in its electric distribution revenue requirements and a $105 million increase in its gas distribution revenue requirements, over the current authorized amounts. The Utility will also seek an attrition rate adjustment (ARA) increase for 2004 and 2005. The ARA mechanism is designed to avoid a reduction in earnings in years between GRCs to reflect increases in rate base and expenses.

The electric distribution revenue requirement increase would not increase overall bundled electric rates over their current authorized levels. However, the gas bill for a typical residential customer would rise by approximately 4.1 percent, or $1.56 per month.

Additionally, as directed by the CPUC in the Utility's 2002 retained generation proceeding (see "Retained Generation Revenue Requirement" above), the Utility submitted testimony supporting the costs of operating the Utility's generation facilities, fuel, and purchased power costs. The Utility requested an increase of approximately $61 million over the interim 2002 retained generation revenue requirement authorized by the CPUC. In October 2002, the CPUC issued a decision ordering the Utility to resume the procurement function on January 1, 2003. That decision also directed the Utility to amend its GRC application to remove certain generation-related fuel and purchased power costs from its GRC and instead to include them in its ERRA proceeding (see "Energy Procurement" above). For the remaining non-fuel generation revenue requirement, the Utility requests an increase of $149 million over the amount approved for 2002.

On December 17, 2002, the CPUC granted the Utility's request that the revenue requirement established in the 2003 GRC be effective January 1, 2003, even though the CPUC will not issue a final decision on the 2003 GRC until sometime after that date. The CPUC Commissioner assigned to the 2003 GRC has adopted a schedule for this proceeding that includes a target date for a final decision on February 5, 2004.

On April 11, 2003, the ORA provided to the Utility and other parties the ORA's report on the Utility's 2003 GRC application. In its report, the ORA recommends an increase of $170 million in electric base revenues compared to the Utility's request for an increase of $447 million, and an increase in gas base revenues of $3.7 million compared to the Utility's request for an increase of $105 million over the current authorized amounts. The ORA also recommends a decrease of $2 million for utility-retained generation compared to the Utility's requested increase of $149 million.

The two largest components of the difference are administrative and general (A&G) expenses, which comprise 35 percent of the total difference, and depreciation expenses, which comprise 23 percent of the total difference. With respect to A&G expenses, the ORA recommends rejection of the Utility's request for pension fund contributions, reduction of certain employee incentive payments, and disallowance of certain allocated holding company costs, resulting in an A&G forecast of $188 million less in A&G expenses than the Utility's estimate. With respect to the $123 million difference between the Utility's and the ORA's estimates for depreciation expenses, the primary difference is due to the ORA's recommended rejection of the Utility's request for higher depreciation rates to reflect the increased costs to remove and dispose of aging utility distribution infrastructure. In addition, the ORA recommended that the Utility's next test year GRC be delayed until 2007, rather than 2006, and that the Utility file an ARA request for 2006.

The CPUC may accept all, part, or none of the ORA's recommendations. The Utility cannot predict what amount of revenue requirements, if any, the CPUC will authorize for the 2003 through 2005 period. In the event of an adverse decision by the CPUC, and if the Utility is unable to conform to the base revenue amounts adopted by the CPUC while maintaining safety and system reliability standards, the ability of the Utility to earn its authorized rate of return for the years until the next general rate case would be adversely affected. Any change in revenue requirements will not be recorded until such time that a final decision is received.

2002 ARA Request

In April 2002, the CPUC conditionally authorized a request by the Utility for interim attrition relief and made any attrition relief ultimately granted effective as of April 22, 2002. In June 2002, the Utility filed its 2002 ARA application, requesting a $76.7 million increase to its annual electric distribution revenue requirement, and a $19.5 million increase to its annual gas distribution revenue requirement. On March 13, 2003, the CPUC denied the Utility's request, finding that the Utility's recorded numbers were out of date because a review of the Utility's costs had not been made since its 1999 GRC and that the escalation rates were too uncertain to sustain a finding of just and reasonableness for a 2002 base revenue increase.

On April 16, 2003, the Utility filed an application for rehearing of the March 2003 decision, which denied the Utility's request for an annual total base revenue requirement increase of approximately $96.2 million for 2002. In the filing, the Utility argues that the CPUC's denial of attrition relief was in error because the decision applied the wrong legal standard and because its findings were not supported by substantial evidence. The Utility cannot predict when the CPUC will rule upon this application for rehearing, nor whether any decision the CPUC ultimately issues will have a material impact on the Utility's results of operations or financial condition.

Cost of Capital Proceedings

Each year, the Utility files an application with the CPUC to determine the authorized rate of return the Utility may earn on its electric and gas distribution and electric generation assets.

For its gas and electric distribution operations and electric generation operations, the Utility's currently authorized return on common equity (ROE) is 11.22 percent and its currently authorized cost of debt is 7.57 percent. The Utility also has a currently authorized capital structure of 48.00 percent common equity, 46.20 percent long-term debt, and 5.80 percent preferred equity. The November 2002 decision in the Utility's 2003 Cost of Capital proceeding adopted these authorized figures and held open the case to address the impact on the Utility's ROE, costs of debt and preferred stock, and ratemaking capital structure of the implementation and financing of a bankruptcy plan of reorganization. Subsequently, on February 21, 2003, the Utility filed a petition to modify the November 2002 decision to waive the normal requirement for the Utility to file a test year 2004 Cost of Capital application. If the Utility's request is granted, its currently authorized cost of capital will continue until the CPUC authorizes a new cost of capital for the Utility in the 2003 updated case, or in the Utility's next Cost of Capital application. If the petition is denied, the Utility will proceed with a 2004 Cost of Capital proceeding in which the CPUC may authorize a new cost of capital or capital structure for the Utility.

FERC Prospective Price Mitigation Relief

In response to the unprecedented increase in wholesale electricity prices during 2000 and 2001, the FERC issued a series of orders in the spring and summer of 2001 and July 2002 aimed at mitigating future extreme wholesale energy prices. These orders established a cap on bids for real-time electricity and ancillary services of $250 per megawatt-hour (MWh) and established various automatic mitigation procedures. Recently, the FERC proposed to adopt a safety net bid cap as part of the mitigation plan for wholesale energy markets and has requested comments on the appropriate value for such a bid cap.

Also, in June and July 2001, the FERC's chief administrative law judge (ALJ) conducted settlement negotiations among power sellers, the State of California, and the California IOUs in an attempt to resolve disputes regarding past electric sales.

Various parties, including the Utility and the State of California, are seeking up to $8.9 billion in refunds for electricity overcharges on behalf of buyers. The negotiations did not result in a settlement, but the judge recommended that the FERC conduct further hearings to determine possible refunds and what the power sellers and buyers are each owed. On December 12, 2002, a FERC ALJ issued an initial decision finding that power companies overcharged the utilities, the State of California, and other buyers from October 2, 2000 to June 2001 by $1.8 billion, but that California buyers still owe the power companies $3.0 billion, leaving $1.2 billion in unpaid bills. The time period reviewed in the FERC hearings excludes the claims for refunds for overcharges that occurred before October 2, 2000, and after June 2001 when the DWR entered into contracts to buy electricity.

On March 26, 2003, the FERC confirmed most of the ALJ's findings, but modified the refund methodology in part, as discussed below. A FERC spokesman has estimated the total potential refunds, using the modified methodology, at $3.3 billion. This higher estimate reflects the FERC Staff Final Report on Price Manipulation in Western Markets recommending recalculation of natural gas prices using a new gas proxy methodology for calculating mitigated market prices. The FERC said the recalculation was necessary because of faulty natural gas price indices that were used previously. The FERC stated that it would allow the electricity suppliers and generators to obtain an additional fuel cost allowance if they submit evidence showing that their actual gas costs were higher than the new calculated price, which, if accepted by the FERC, would reduce the amount of the calculated overcharges.

The Utility has recorded $1.8 billion of claims filed by various power generators in its bankruptcy case as Liabilities Subject to Compromise. The Utility currently estimates that these claims would have been reduced to approximately $1.2 billion based on the recalculation of market prices according to the refund methodology recommended in the ALJ's initial decision. The recent recalculation of market prices according to the revised methodology adopted by the FERC could result in an additional several hundred million dollar decrease in the amount of the generators' claims offset by the amount of any additional fuel cost allowance for generators accepted by the FERC. If these claims are reduced, it would also reduce the Utility's previously written-off under-collected purchased power and transition costs.

Additional evidence of market manipulation and artificially inflated prices for electricity and natural gas for the period from January 1, 2000, to June 20, 2001, was presented to the FERC through March 3, 2003, and various power suppliers filed responsive materials by March 20, 2003. The FERC is still reviewing these materials. The California parties, including the Utility, have requested that the FERC apply its refund methodology to power purchases during the period from May 1, 2000, through October 1, 2000. The FERC has indicated that, rather than applying the refund methodology to this period, it may order disgorgement of profits from, or impose other remedies on, certain sellers.

El Paso Settlement

On March 21, 2003, the Utility, along with a number of other parties, entered into a memorandum of understanding (MOU) with El Paso Corporation (El Paso) to settle claims against El Paso relating to the sale or delivery of natural gas and/or electricity to or in the western United States from September 1996 to present, including claims that El Paso took actions that resulted in artificially inflated gas prices during the California energy crisis of 2000 and 2001. Under the terms of the MOU, which has a nominal value of $1.7 billion, the parties plan to proceed to document and execute a final comprehensive settlement agreement. As consideration for the release of claims against it, among other terms of the proposed settlement, El Paso will pay $100 million in cash upon execution of the final settlement agreement and will issue $125 million in stock no later than the effective date of the settlement. El Paso will also make additional cash payments of $440 million, or $22 million each year for 20 years, starting one year after the final settlement agreement is executed. (El Paso has the option of making up to 50 percent of any such payment in stock.)

In addition, El Paso has agreed to deliver natural gas valued at $45 million per year to the California border over the next 20 years, beginning in January 2004. Also, the DWR's long-term contract with El Paso will be reduced by $125 million over the remaining term of the contract.

The agreement in principle will be finalized once a final settlement is signed and approved by required state and federal regulators and courts, including the CPUC, the FERC, and the Bankruptcy Court. It is uncertain whether a final executed agreement will be reached, whether required approvals will be obtained, and how the final agreement would affect the Utility's financial condition and results of operations.

Scheduling Coordinator Costs

The Utility serves as the scheduling coordinator to schedule transmission with the ISO for some of the Utility's existing wholesale transmission customers. The ISO bills the Utility for providing certain services associated with these customers' loads and resources. These ISO charges are referred to as "scheduling coordinator (SC) costs."

In November 1999, the Utility filed the Scheduling Coordinator Services (SCS) Tariff to recover the SC costs from the existing wholesale transmission customers. In January 2000, the FERC accepted the SCS Tariff and conditionally granted the Utility's request that the tariff be effective retroactive to March 31, 1998. However, the FERC also suspended the SCS Tariff case pending the outcome of another related FERC proceeding and ordered the Utility to defer billing SC customers while the SCS Tariff case was suspended. In August 2002, the FERC issued a final order in the related proceeding, and issued a subsequent order on rehearing in November 2002. In December 2002, the Utility and the SCS Tariff customers filed a joint brief asking the FERC to reactivate the SCS Tariff case. On March 28, 2003, the Utility submitted a supplemental filing for recovery of $83.1 million in SC costs for the period March 31, 1998, through August 31, 2002.

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

In 1998, the Utility implemented a ratemaking pact called the Gas Accord, separating its gas transportation and storage services from its distribution services, and changing the terms of service and rate structure for gas transportation. The Gas Accord allows residential and small commercial customers (core customers) to purchase gas from competing suppliers, establishes an incentive mechanism whereby the Utility recovers its core procurement costs, and establishes gas transportation rates through 2002 and gas storage rates through March 2003. Under the Gas Accord, the Utility is at risk for recovery of its gas transportation and storage costs and does not have regulatory balancing account protection for over-collections or under-collections of revenues. Under the Gas Accord, the Utility sells a portion of the transmission and storage capacity at competitive market-based rates. Revenues are sensitive to changes in the weather, levels of natural gas-fired generation, and price spreads between two delivery or pricing points.

In August 2002, the CPUC approved a settlement agreement among the Utility and other parties that provided for a one-year extension of its existing gas transportation and storage rates, referred to as the Gas Accord II settlement. The settlement also provided for a one-year extension of terms and conditions of service, including the Core Procurement Incentive Mechanism (for further discussion see "Utility Natural Gas Commodity Price Risk" below), as well as rules governing contract extensions and an open season for new contracts. The Gas Accord II settlement left open to subsequent litigation the issues raised in the application in so far as they relate to the second year of the two-year application.

In January 2003, the Utility filed an amended Gas Accord II application with the CPUC proposing to permanently retain the Gas Accord market structure, requesting a $55 million increase in the Utility's rates for gas transmission service for 2004, and for storage service for the period from April 1, 2004, to March 31, 2005. This request represented a 12.9 percent increase in the Utility's gas transmission and storage revenue requirement and a 13.4 percent return on equity for the gas transmission and storage assets. Subsequently, the CPUC removed the cost of capital issues from this proceeding and ordered the Utility to use a return on equity of 11.22 percent as a placeholder, pending resolution of this issue in the Utility's 2004 Cost of Capital proceeding. The change resulted in a $25 million reduction in the Utility's revenue requirement request. These proposals, if adopted, would be implemented only if the Utility's gas transmission and storage assets remain under CPUC jurisdiction beyond 2003.

The Gas Accord II proposal for 2004 requests a rate increase, calculated on a demand or throughput forecast basis. In addition, for the 12-month period ending December 31, 2004, for transmission capacity and for the 12-month period ending March 31, 2005, for storage capacity, the Utility proposes to provide an option for current holders of capacity to extend their rights and for an open season to be held for any capacity that is not contracted. The Utility may experience a material reduction in operating revenues if (1) the Utility were unable to renew or replace existing transportation contracts at the beginning or throughout the Gas Accord II period, (2) the Utility were to renew or replace those contracts on less favorable terms than adopted by the CPUC, or (3) overall demand for transportation and storage services were less than adopted by the CPUC in setting rates. In any of these cases, the Utility's financial condition and results of operations could be adversely affected. A decision in this proceeding is expected in early October 2003.

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

El Paso Capacity Decision

In July 2002, the CPUC ordered California IOUs to contract for certain El Paso pipeline capacity. The CPUC pre-approved such costs as just and reasonable.

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The decision also addressed current capacity issues. It ordered the utilities to retain their current capacity levels on any interstate pipeline and to sell any excess capacity to a third party under short-term capacity release arrangements. It also ordered that to the extent the utilities comply with the decision, they will be able to fully recover their costs associated with existing capacity contracts.

In Phase II of this proceeding, the CPUC is addressing other issues that relate to these proposed rules, including (1) cost allocation of the El Paso pipeline capacity among the Utility's customers, (2) short-term capacity releases, and (3) details about the guaranteed rate recovery of the utilities' costs for subscription to interstate pipeline capacity. Phase II hearings began in late April 2003 and a decision is not expected until later in 2003.

Since the July CPUC decision, the Utility has signed contracts for capacity on the El Paso pipeline totaling approximately $50.8 million beginning November 2002 through December 2007, assuming no contracts set to expire before the end of 2007 are extended. The Utility has filed with the CPUC to recover both prepayments made to El Paso and ongoing capacity costs on the El Paso pipeline and the Transwestern Pipeline Company (Transwestern) pipelines. Under a previous CPUC decision, the Utility could not recover any costs paid to Transwestern for gas pipeline capacity through 1997. The Gas Accord (see "Gas Accord II" above) provided for partial recovery of Transwestern costs from 1998 forward. However, because of the El Paso decision, the Utility may be authorized to recover its future gas pipeline capacity purchases.

On December 19, 2002, the CPUC issued a resolution that would delay the Utility's recovery of some of these costs. The resolution grants the Utility's request to recover in rates El Paso pipeline capacity costs and prepayments made to El Paso. However, a petition for rehearing on this resolution was filed by The Utility Reform Network (TURN) and granted by the CPUC in April 2003. Pending the results of the rehearing, Phase II of this proceeding would allocate the cost of the transportation capacity between customer groups and would also determine the date on which all transportation capacity costs held by the Utility prior to July 2002 would be recoverable. In the meantime, the December resolution orders the Utility to continue to treat Transwestern capacity costs as it had prior to the July 2002 CPUC decision. The Utility does not expect the outcome of this matter to have a material adverse impact on its financial position or results of operations.

Annual Earnings Assessment Proceeding for Energy Efficiency Program Activities

The Utility administers general and low-income energy efficiency programs, and has been authorized to earn 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. Each year the Utility files an earnings claim in the Annual Earnings Assessment Proceeding (AEAP), a forum for stakeholders to comment on, and for the CPUC to verify, the Utility's claim. On March 21, 2002, the CPUC eliminated the opportunity for shareholder incentives in connection with the California IOUs' 2002 energy efficiency programs. This decision does not preclude the opportunity to recover shareholder incentives in connection with previous years' energy efficiency programs.

In May 2002, 2001, and 2000, the Utility filed its annual applications claiming incentives of approximately $106 million. The CPUC has delayed action on these proceedings and the Utility has not included any earnings associated with incentives in the Utility's Consolidated Statements of Operations.

On March 13, 2002, an ALJ for the CPUC requested comments on whether incentives adopted for pre-1998 energy efficiency programs should be reduced or eliminated for claims in future years. Out of the total $106 million in shareholder incentives claimed by the Utility for its 2002, 2001, and 2000 AEAP filings, $74 million is related to pre-1998 energy efficiency programs. On March 19, 2003, an ALJ's ruling set forth the schedule and scope for the combined 2002, 2001, and 2000 AEAP filings. Further hearings for claims related to post-1997 energy efficiency programs are scheduled for July and October of this year.

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

Baseline Allowance Increase

In April 2002, the CPUC required the Utility to increase baseline allowances for certain residential customers by May 1, 2002. An increase to a customer's baseline allowance increases the amount of their monthly usage that is covered under the lowest possible rate and is exempt from the $0.03 per kWh surcharge. The CPUC deferred consideration of corresponding rate changes until a later phase of the proceeding and ordered the utilities to track the under-collections associated with their respective baseline quantity changes in an interest-bearing balancing account. The Utility estimates the annual revenue shortfall to be approximately $101 million for electric and $11 million for gas. The Utility is charging the electric-related shortfall against earnings because it cannot predict the outcome of the second phase of the proceeding, nor can it conclude

that recovery of the electric-related balancing account is probable. The total electric revenue shortfall for the period May through December 2002 was $70 million; the total electric revenue shortfall for the period January 1, 2003, through March 31, 2003, was $23 million.

Issues that may be resolved during the second phase of the proceeding in early 2003 include items that could involve additional revenues at risk such as demographic revisions to baseline allowances, special allowances, and changes to baseline territories or seasons. The Utility estimated additional annual revenue shortfalls from this second phase, if adopted, of $80 million for electric service and $11 million for gas service, plus $12 million in administration costs spread out over three to five years.

The Utility cannot predict what the outcome of the second phase of the proceeding will be, nor can it conclude that recovery of the electric baseline related balancing account is probable. Any electric revenue shortfalls will continue to be charged to earnings and will reduce revenue available to recover previously written-off under-collected purchased power costs and transition costs.

RISK MANAGEMENT ACTIVITIES

PG&E Corporation and the Utility are exposed to various risks associated with their operations, the marketplace, contractual obligations, financing arrangements, and other aspects of their business. PG&E Corporation and the Utility actively manage these risks through risk management programs. These programs are designed to support business objectives, minimize costs, discourage unauthorized risk, reduce the volatility of earnings, and manage cash flows. At PG&E Corporation and the Utility, risk management activities often include the use of energy and financial derivative instruments and other instruments and agreements. These derivatives include forward contracts, futures, swaps, options, and other contracts.

PG&E Corporation uses derivatives for both non-trading (i.e., risk mitigation) and trading (i.e., speculative) purposes. The Utility uses derivatives for non-trading purposes only. PG&E Corporation and the Utility may use energy and financial derivatives and other instruments and agreements to mitigate the risks associated with an asset (e.g., the natural position embedded in asset ownership and regulatory arrangements), liability, committed transaction, or probable forecasted transaction. Additionally, PG&E Corporation may engage in trading activities for purposes of generating profit, gathering market intelligence, creating liquidity, and maintaining a market presence. These instruments are used in accordance with approved risk management policies adopted by a senior officer-level risk oversight committee. Derivative activity is permitted only after the risk oversight committee approves appropriate risk limits for such activity. The organizational unit proposing the activity must successfully demonstrate that there is a business need for such activity and that the market risks will be adequately measured, monitored, and controlled.

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

	Three months ended March 31,	
	2003	**2002**
	(in millions)	
Fair values of trading contracts at beginning of period	$ (22)	$ 33
Net (gain) loss on contracts settled during the period	33	(45)
Fair value of new trading contracts when entered into		
Other changes in fair values		43
Fair values of trading contracts outstanding at end of period	11	31
Fair value of non-trading contracts at the end of the period	(324)	(28)
Net price risk management assets (liabilities) at end of period	$ (313)	$ 3
Net price risk management assets (liabilities) held for sale	$ (393)	
Net price risk management assets (liabilities) reported on the Consolidated Balance Sheets	$ 80	

PG&E Corporation estimates the gross mark-to-market value of its non-trading and trading contracts at March 31, 2003, using the mid-point of quoted bid and ask prices, where available. When market data is not available, PG&E Corporation

uses a model that estimates forward power prices using the mid-point of the marginal cost curve (the lowest variable cost of generation available in a region) and the forecast curve (the price at which a generation unit will recover its capital costs and a return on investment). Interpolation methods are used for intermediate periods when broker quotes are unavailable. The gross mark-to-market valuation is then adjusted for the time value of money, creditworthiness of contractual counterparties, market liquidity in future periods, and other adjustments necessary to determine fair value. Most of PG&E Corporation's risk management models are reviewed by or purchased from third-party experts in specific derivative applications.

The following table shows the fair value of PG&E Corporation's trading contracts grouped by maturity at March 31, 2003.

	Fair Value of Trading Contracts(1)				
Source of Prices Used in Estimating Fair Value	**Maturity Less than One Year**	**Maturity One-Three Years**	**Maturity Four-Five Years**	**Maturity in Excess of Five Years**	**Total Fair Value**
			(in millions)		
Actively quoted markets(2)	$ 18	$ 11	$	$	$ 29
Provided by other external sources	59	(82)	(18)		(41)
Based on models and other valuation methods(3)	(20)	(8)	1	50	23
Total Mark-to-Market	$ 57	$ (79)	$ (17)	$ 50	$ 11

(1) Excludes all non-trading contracts, including non-trading contracts that receive mark-to-market accounting treatment.

(2) Actively quoted markets are exchange traded quotes.

(3) 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. The future value of trading contracts may be impacted by changes in underlying valuations, new transactions, market liquidity, and PG&E Corporation's risk management portfolio needs and strategies.

Market Risk

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

Price Risk

Price risk is the risk that changes in commodity market prices will adversely affect earnings and cash flows. Below are descriptions of the Utility's and PG&E NEG's specific price risks.

Also described below is the value-at-risk methodology, which is PG&E Corporation's and the Utility's method for assessing the prospective risk that exists within a portfolio for price risk.

Utility Price Risk

The Utility is exposed to price risk which consists of electric commodity (including purchased power and nuclear fuel) and natural gas commodity price risks, as described below.

Utility Electric Commodity Price Risk

Purchased Power In compliance with regulatory requirements, the Utility manages commodity price risk independently from the activities in PG&E Corporation's unregulated businesses. The Utility also reports its commodity price risk separately for its electric and natural gas businesses.

During 2001 and 2002, the DWR was responsible for procuring electricity required to cover the Utility's net open position. Under AB 1X, the DWR was prohibited from entering into new agreements to purchase electricity to meet the Utility's net open position after December 31, 2002. The DWR, however, remains legally and financially responsible for electricity contracts that it entered into before December 31, 2002 (existing contracts), and the Utility still relies on electricity provided by these contracts to service a significant portion of its total load. For further discussion, see "Allocation of DWR Electricity to Customers of the IOUs" in the "Regulatory Matters" section of this MD&A or Note 2 of the Notes to the Consolidated Financial Statements.

The Utility bills its customers for these DWR electricity purchases under existing contracts and remits amounts collected to the DWR based on the DWR's CPUC-approved revenue requirement. To the extent that the CPUC increases the portion of the DWR's revenue requirement allocated to the Utility's customers, and available revenues do not cover the Utility's procurement costs, the CPUC is obligated to increase rates if the shortfall exceeds 5 percent of the Utility's prior year's generation revenues, excluding amounts collected for the DWR. Additionally, the Utility is exposed to price risk to the extent that the cost of new electricity purchases increases, or the revenue from new wholesale sales decreases to the point where costs exceed available revenues. Furthermore, changes in the cost of new electricity purchases may also impact the amount of previously written-off purchased power and transition costs that the Utility is able to recover. For further discussion, see "Senate Bill 1976" and "Energy Procurement" in the "Regulatory Matters" section of this MD&A.

During the last half of 2002, SB 1976 and CPUC orders were approved that required the California IOUs, including the Utility, to resume responsibility for procuring the electricity to meet the residual net open position by January 1, 2003.

In December 2002, the CPUC issued an interim opinion granting the Utility authority to enter into contracts designed to meet and to hedge the residual net open position through the first quarter of 2004. The CPUC's interim opinion also established a maximum annual procurement disallowance for administration of all contracts and least-cost dispatch of resources equal to twice the Utility's annual administrative costs of managing procurement activities, including the administration and dispatch of electricity associated with DWR allocated contracts. However, the CPUC may increase or eliminate this maximum annual procurement disallowance in the future. Such a change would increase the Utility's exposure to electric commodity price risk.

The residual net open position is expected to increase over time due to periodic expirations of existing and DWR allocated procurement contracts. The Utility expects that electricity will continue to be available for purchase in quantities sufficient to satisfy the residual net open position for the short term. Over the longer term, when the western region of the United States has a need for new generation for reliability purposes, the Utility cannot assure that the electricity will continue to be available for purchase in quantities sufficient to satisfy the residual net open position. Even with purchases of electricity in quantities sufficient to satisfy the residual net open position, the Utility would be exposed to wholesale electricity commodity price fluctuations and uncertain commercial and credit terms.

Conversely, the amount of energy provided by the DWR contracts will likely result in significant excess electricity during various periods, which the Utility will be required to attempt to sell on the open market. If the Utility is unable to sell this excess electricity on the open market under terms and conditions that would recover its costs, its financial condition or results of operations may be adversely affected.

Nuclear Fuel The Utility has purchase agreements for nuclear fuel components and services for use in operating the Diablo Canyon generating facility. The Utility relies on large, well-established international producers for its long-term agreements in order to diversify its commitments and ensure security of supply. Pricing terms are also diversified, ranging from fixed prices to base prices that are adjusted using published information.

In January 2002, the U.S. International Trade Commission (ITC) imposed tariffs of up to 50 percent on imports from certain countries providing nuclear fuel. As of March 2003, the tariffs are still being imposed; however, the Court of International Trade in New York City is reviewing the ITC decision. The Utility's nuclear fuel costs have not increased based on the imposed tariffs because the terms of the existing long-term contracts did not include such costs. However, once these contracts expire in 2004, the costs under new nuclear fuel contracts may be higher than those under previous contracts if these tariffs remain in place. As noted above, the CPUC is obligated to change retail electricity rates at any time that the Utility's forecasts indicate it will face an under-collection of electricity procurement costs, including the cost of nuclear fuel, in excess of 5 percent of its prior year's generation revenues, excluding amounts collected for the DWR. Additionally, changes in the cost of nuclear fuel purchases may also impact the amount of previously written-off purchased power and transition costs that the Utility is able to recover.

Utility Natural Gas Commodity Price Risk

Through 2003, the Core Procurement Incentive Mechanism (CPIM) determines how much of the cost of procuring natural gas for its customers may be included in the Utility's natural gas procurement rates. Under the CPIM, the Utility's procurement costs are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas price indices at the points where the Utility typically purchases natural gas. Costs that fall within a range, or tolerance band, of 99 percent to 102 percent around the benchmark, are considered reasonable and may be fully recovered in customer rates. Ratepayers and shareholders share equally the costs and savings outside the tolerance band.

In addition, the Utility has contracts for transportation capacity on various natural gas pipelines. A recent CPUC decision found that the Utility's acquisition of additional interstate transportation capacity was reasonable and that all interstate transportation capacity already held by the Utility was also reasonable. A petition for rehearing on the CPUC decision regarding recovery of already held capacity was filed by TURN and granted by the CPUC in April 2003. Pending the results of the rehearing, a future decision would allocate the cost of the transportation capacity between customer groups and would also determine the date on which all transportation capacity costs held by the Utility prior to July 2002 would be recoverable.

Under the Gas Accord, shareholders are at risk for revenues from the sale of capacity on the Utility's gas transmissions and storage facilities. Capacity is sold at competitive market-based rates, within a cost-of-service tariff framework. Based on the underlying tariffs, revenues are generally lower when throughput volumes are lower than expected or when the price spread narrows between the gas transportation system's two principal receipt points. In August 2002, the CPUC approved a settlement agreement between the Utility and other parties that provided for a one-year extension of the Utility's existing gas transmission and storage rates and terms and conditions of service through the end of 2003. (The Gas Accord was originally scheduled to expire on December 31, 2002.) For further discussion, see "Gas Accord II" in the "Regulatory Matters" section of this MD&A.

PG&E NEG Price Risk

PG&E NEG is exposed to price risk from its portfolio of proprietary trading contracts and its portfolio of electric generation assets and supply contracts that serve wholesale and industrial customers, and various merchant plants currently in development and construction.

As described above, PG&E NEG is in the process of reducing and unwinding its trading positions. Additionally, asset hedge positions associated with the merchant plants will either remain with the assets or be terminated. PG&E NEG has significantly reduced its energy trading operations in an ongoing effort to raise cash and reduce debt. PG&E NEG's objective is to limit its asset trading and risk management activities to only what is necessary for energy management services to facilitate the transition of PG&E NEG's merchant generation facilities through their sale, transfer, or abandonment process. PG&E NEG will then further reduce and transition asset trading and risk management activities to only retain limited capabilities to ensure fuel procurement and power logistics for PG&E NEG's retained independent power plant operations.

Value-at-Risk

PG&E Corporation and the Utility measure price risk exposure using value-at-risk and other methodologies that simulate future price movements in the energy markets to estimate the probability of future potential losses. Price risk is quantified using what is referred to as the variance-covariance technique of measuring value-at-risk, which provides a consistent measure of risk across diverse energy markets and products. This methodology requires the selection of a number of important assumptions, including a confidence level for losses, price volatility, market liquidity, and a specified holding period. This technique uses historical price movement data and specific, defined mathematical parameters to estimate the characteristics of and the relationships between components of assets and liabilities held for price risk management activities. PG&E Corporation therefore uses the historical data for calculating the expected price volatility of its portfolio's contractual positions to project the likelihood that the prices of those positions will move together.

PG&E Corporation's and the Utility's value-at-risk calculation is a dollar amount reflecting the maximum potential one-day loss in the fair value of their portfolios due to adverse market movements over a defined time horizon within a specified confidence level. This calculation is based on a 95 percent confidence level, which means that there is a 5 percent probability that PG&E Corporation's portfolios will incur a loss in value in one day at least as large as the reported value-at-risk. For example, if the value-at-risk is calculated at $5 million, there is a 95 percent probability 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. There would also be a 5 percent probability that a one-day price movement would be greater than $5 million.

The value-at-risk exposure for the Utility's non-trading activities includes all derivatives in the gas portfolio over the entire length of the terms of the transactions. Since January 1, 2003, when the Utility resumed procurement of electricity, the Utility has been measuring certain of the risks embedded in the electric portfolio, and ensuring that it is within the risk limits adopted in the CPUC's December 2002 interim opinion on the Utility's electricity procurement plan. The Utility is in the process of developing a value-at-risk model and other methodologies appropriate for risk measurement of its electric portfolio. PG&E NEG's value-at-risk model includes all commodity derivatives and other financial instruments over the entire length of the terms of the transactions in the trading and non-trading portfolios.

The following table illustrates the potential one-day unfavorable impact for price risk as measured by the value-at-risk model, based on a one-day holding period. A comparison of daily values-at-risk as of March 31, 2003, and as of December 31, 2002, is included in order to provide context around the one-day amounts.

	March 31, 2003	December 31, 2002
	(in millions)	
Utility		
Non-trading activities(1)	$ 4	$ 4
PG&E NEG		
Trading activities	16	8
Non-trading activities:		

	March 31, 2003	December 31, 2002
Non-trading contracts that receive mark-to-market accounting treatment(2)	10	3
Non-trading contracts accounted for as hedges(3)	12	9

(1) Includes the Utility's gas portfolio only.

(2) Includes derivative power and fuel contracts that do not qualify as normal purchases and normal sales exceptions and do not qualify to be accounted for as cash flow hedges under Statement of Financial Accounting Standards (SFAS) No. 133.

(3) Includes only the risk related to the derivative instruments that serve as hedges and does not include the related underlying hedged item. Any gain or loss on these derivative commodity instruments would be substantially offset by a corresponding gain or loss on the hedged commodity positions, which are not included.

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 and legislative risks currently facing the Utility or the risks relating to the Utility's bankruptcy proceedings.

PG&E NEG's value-at-risk for trading and non-trading activities has increased as of March 31, 2003, as compared to levels as of December 31, 2002, due to strong prices and increased market volatility across all commodities. As PG&E NEG continues to wind down its trading positions, additional increases in prices or volatility could cause value-at-risk levels to increase. See the discussion above in the "Liquidity and Financial Resources PG&E NEG" section of this MD&A for further information regarding PG&E NEG's current financial situation.

Interest Rate Risk

Interest rate risk is the risk that changes in interest rates could adversely affect earnings or cash flows. Specific interest rate risks for PG&E Corporation and the Utility include the risk of increasing interest rates on working capital facilities, variable rate tax-exempt pollution control bonds, and other variable rate debt.

PG&E Corporation may use the following interest rate instruments to manage its interest rate exposure: interest rate swaps, interest rate caps, floors or collars, swaptions, or interest rate forward and futures contracts. Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At March 31, 2003, if interest rates changed by 1 percent for all variable rate debt at PG&E Corporation and the Utility, the change would affect net income by approximately $45 million for PG&E Corporation and $28 million for the Utility, based on variable rate debt and hedging 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 in relation to the U.S. dollar.

PG&E Corporation and the Utility are exposed to such risk associated with foreign currency exchange variations related to Canadian-denominated purchase and swap agreements. PG&E Corporation and the Utility may use forwards, swaps, and options to hedge foreign currency exposure.

For the Utility, changes in gas purchase costs due to fluctuations in the value of the Canadian dollar would be passed through to customers in rates, as long as the overall costs of purchasing gas are within a 99 percent to 102 percent tolerance band around the benchmark price under the CPIM mechanism, as discussed above. The Utility's customers and shareholders would share in the costs or savings outside of the tolerance band equally.

PG&E Corporation and the Utility use sensitivity analysis to measure their exchange rate exposure to the Canadian dollar. Based on a sensitivity analysis at March 31, 2003, 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 failed to perform their contractual obligations (these obligations are reflected as Accounts Receivable Customers, net; notes receivable included in Other Noncurrent Assets Other; Price Risk Management (PRM) assets; and Assets Held For Sale on the Consolidated Balance Sheets of PG&E Corporation and the Utility, as applicable). PG&E Corporation and the Utility conduct business primarily with customers or vendors, referred to as counterparties, in the energy industry. These counterparties include other investor-owned utilities, 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 because their counterparties may be similarly affected by economic or regulatory changes, or other changes in conditions.

PG&E Corporation and the Utility manage their credit risk in accordance with the PG&E Corporation Risk Management Policy. This establishes processes for assigning credit limits to counterparties before entering into agreements with significant exposure to PG&E Corporation and the Utility. These processes 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 the exposure, or obtain additional collateral, or both. Further, PG&E Corporation and the Utility rely heavily on master agreements that require the counterparty to post security, referred to as credit collateral, 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 for each counterparty as the current mark-to-market value of the contract (that is, the amount that would be lost if the counterparty defaulted today) plus or minus any outstanding net receivables or payables, prior to the application of the counterparty's credit collateral.

During the three months ended March 31, 2003, PG&E Corporation's credit risk decreased primarily due to contract terminations with PG&E NEG counterparties. During the three months ended March 31, 2003, the Utility's credit risk increased due primarily to an increase in commodity prices and to downgrades of some counterparties' credit ratings to levels below investment grade. The downgrades increase the Utility's credit risk because any collateral provided by these counterparties in the form of corporate guarantees or eligible securities may be of lesser or no value. Therefore, in the event these counterparties failed to perform under their contracts, the Utility may face a greater potential maximum loss. In contrast, the Utility does not face any additional risk if counterparties' credit collateral is in the form of cash or letters of credit, as this collateral is not affected by a credit rating downgrade.

During the three months ended March 31, 2003, PG&E Corporation and the Utility recognized no losses due to the contract defaults or bankruptcies of counterparties.

At March 31, 2003, PG&E Corporation had no single counterparty that represented greater than 10 percent of PG&E Corporation's net credit exposure. At March 31, 2003, the Utility had one investment-grade counterparty that represented 17 percent of the Utility's net credit exposure.

The schedule below summarizes PG&E Corporation's and the Utility's credit risk exposure to counterparties that are in a net asset position, with the exception of exchange-traded futures (the exchange provides for contract settlement on a daily basis),

as well as PG&E Corporation's and the Utility's credit risk exposure to counterparties with a greater than 10 percent net credit exposure, at March 31, 2003, and December 31, 2002:

	Gross Credit Exposure Before Credit Collateral(1)	Credit Collateral(2)	Net Credit Exposure(2)	Number of Counterparties >10 percent	Net Exposure of Counterparties >10 percent

			(in millions)		
At March 31, 2003					
PG&E Corporation	$ 789	$ 198	$ 591	$	$
Utility(3)	306	116	190	1	32
At December 31, 2002					
PG&E Corporation	$ 1,165	$ 195	$ 970	$	$
Utility(3)	288	113	175	2	55

(1) Gross credit exposure equals mark-to-market value, notes receivable, and net (payables) receivables where netting is allowed. Gross and net credit exposure amounts reported above do not include adjustments for time value, liquidity, model, or credit reserves.

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

(3) The Utility's gross credit exposure includes wholesale activity only. Retail activity and payables incurred prior to the Utility's bankruptcy filing are not included. Retail activity at the Utility consists of the accounts receivable from the sale of gas and electricity to millions of residential and small commercial customers.

The schedule below summarizes the credit quality of PG&E Corporation's and the Utility's net credit risk exposure to counterparties at March 31, 2003, and December 31, 2002.

Credit Quality(1)	Net Credit Exposure(2)	Percentage of Net Credit Exposure
	(in millions)	
At March 31, 2003		
PG&E Corporation		
Investment-grade(3)(4)	$ 380	64%
Noninvestment-grade	119	20%
Not rated(4)	92	16%
Total	$ 591	100%
Utility		
Investment-grade(3)(4)	$ 110	58%
Noninvestment-grade	80	42%
Not rated(4)		
Total	$ 190	100%
At December 31, 2002		
PG&E Corporation		
Investment-grade(3)(4)	$ 700	72%
Noninvestment-grade	205	21%
Not rated(4)	65	7%
Total	$ 970	100%

Credit Quality(1)	Net Credit Exposure(2)	Percentage of Net Credit Exposure
Utility		
Investment-grade(3)(4)	$ 111	63%
Noninvestment-grade	64	37%
Not rated(4)		
Total	$ 175	100%

(1) Credit ratings are determined by using publicly available credit ratings of the counterparty. If the counterparty provides a guarantee by a higher rated entity (e.g., its parent), the rating determination is based on the rating of its guarantor.

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

(3) Investment-grade is determined using publicly available information, i.e., rated at least Baa3 by Moody's Investors Services and BBB- by Standard & Poor's.

(4) Most counterparties with no ratings are governmental authorities which are not rated but which PG&E Corporation has assessed as equivalent to investment-grade based upon an internal credit rating of credit quality, and are designated as "investment-grade" above. Other counterparties with no rating, and designated as "not rated" above, are subject to an internal assessment of their credit quality and a credit rating designation.

PG&E Corporation has regional concentrations of credit exposure to counterparties that conduct business primarily throughout North America. The Utility has a regional concentration of credit risk associated with its receivables from residential and small commercial customers in Northern California. However, the risk of material loss due to nonperformance from these customers is not considered likely. Reserves for uncollectible accounts receivable are provided for the potential loss from nonpayment by these customers based on historical experience. At March 31, 2003, the Utility had a net regional concentration of credit exposure totaling $190 million to counterparties that conduct business primarily throughout North America.

CRITICAL ACCOUNTING POLICIES

The preparation of Consolidated Financial Statements in accordance with accounting principles generally accepted in the United States of America involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Certain of these estimates and assumptions are considered to be Critical Accounting Policies, due to their complexity, subjectivity, and uncertainty, along with their relevance to the financial performance of PG&E Corporation. Actual results may differ substantially from these estimates. These policies and their key characteristics are outlined below.

Derivatives and Energy Trading Activities

In 2001, PG&E Corporation and the Utility adopted Statements of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Hedging Activities" (collectively, SFAS No. 133), which required all derivative instruments to be recognized in the financial statements at their fair value. Prior to its rescission, PG&E Corporation accounted for its energy trading activities in accordance with Emerging Issues Task Force (EITF) No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," and SFAS No. 133, which require certain energy trading contracts to be accounted for at fair values using mark-to-market accounting.

Effective for the third quarter ended September 30, 2002, PG&E Corporation adopted the net method of recognizing realized gains and losses on energy trading contracts. Under the net method, revenues and expenses are netted and trading gains (or losses) are reflected in revenues on the statement of operations, as opposed to reporting revenues and expenses under the previously used gross method.

PG&E Corporation and the Utility have derivative commodity contracts for the physical delivery of purchase and sale quantities such as natural gas and power transacted in the normal course of business. These derivatives are exempt from the requirements of SFAS No. 133 under the normal purchases and sales exception, and are not reflected on the balance sheet at fair value. See further discussion in Notes 1 and 5 of the Notes to the Consolidated Financial Statements.

Unbilled and Surcharge Revenues

The Utility records revenue as electricity and natural gas are delivered. A portion of the revenue recognized has not yet been billed. Unbilled revenues are determined by factoring the actual load (energy) delivered with recent historical usage and rate patterns.

Since the CPUC authorized the collection of incremental surcharge revenues in January, March, and May 2001, the Utility has used generation-related revenues in excess of generation-related costs to recover approximately $1.7 billion (after-tax) in

previously written-off under-collected purchased power and generation-related costs. The Utility has not provided reserves for potential refunds of these surcharges as it believes that recent regulatory orders and actions provide evidence that it is not probable that a refund will be ordered. However, it is possible that subsequent decisions by the CPUC may affect the amount and timing of these surcharge revenues recovered by the Utility and that subsequent CPUC decisions may order the Utility to refund all or a portion of the surcharge revenues collected. See Note 2 of the Notes to the Consolidated Financial Statements and the risk factors discussion within the "Overview" section of this MD&A for further discussion.

Regulatory Assets and Liabilities

PG&E Corporation and the Utility apply SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," to their regulated operations. Under SFAS No. 71, regulatory assets represent capitalized costs that would otherwise be charged to expense. These costs are later recovered through regulated rates. Regulatory liabilities are rate actions of a regulator that will later be credited to customers through the rate making process. Regulatory assets and liabilities are recorded when it is probable that these items will be recovered or reflected in future rates. If it is determined that these items are no longer likely to be recovered under SFAS No. 71, they will be written-off at that time. At March 31, 2003, PG&E Corporation reported regulatory assets of $2.1 billion, including current regulatory balancing accounts receivable, and regulatory liabilities of $2.2 billion, including current regulatory balancing accounts payable.

Environmental Remediation Liabilities

The Utility records an environmental remediation liability when site assessments indicate that remediation is probable and the cost can be reasonably estimated. This liability is based on site investigations, remediation, operations, maintenance, monitoring, and closure. This liability is reviewed on a quarterly basis, and is recorded at the lower range of estimated costs, unless there is a better estimate available. At March 31, 2003, the Utility's undiscounted environmental remediation liability was $286 million. The Utility's future cost could increase to as much as $396 million if (1) the other potentially responsible parties are not financially able to contribute to these costs, (2) the extent of contamination or necessary remediation is greater than anticipated, or (3) the Utility is found to be responsible for clean-up costs at additional sites.

The process of estimating remediation liabilities is difficult and changes in the estimate could occur, given the uncertainty concerning the Utility's ultimate liability, the complexity of environmental laws and regulations, the selection of compliance alternatives, and the financial resources of other responsible parties. PG&E NEG estimates that it may be required to spend up to approximately $636 million before insurance proceeds for environmental compliance at certain of its operating facilities through 2008. To date, PG&E NEG has spent approximately $13 million on environmental compliance. See Note 6 of the Notes to the Consolidated Financial Statements.

Chapter 11 Filing

Due to the Utility's Chapter 11 filing in 2001, the financial statements for both PG&E Corporation and the Utility are prepared in accordance with SOP 90-7, "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code," which is used by reorganizing entities operating under the Bankruptcy Code. Under SOP 90-7, certain claims against the Utility prior to its bankruptcy filing are classified as Liabilities Subject to Compromise. The Utility reported a total of $9.4 billion of Liabilities Subject to Compromise at March 31, 2003. While the Utility operates under the protection of the Bankruptcy Court, the realization of assets and the liquidation of liabilities is subject to uncertainty, as additional claims to Liabilities Subject to Compromise can change due to such actions as the resolution of disputed claims or certain Bankruptcy Court actions. See Note 2 of the Notes to the Consolidated Financial Statements for further discussion of the Utility's Chapter 11 status.

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

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

Amendment of Statement 133 on Derivative Instruments and Hedging Activities

In April 2003, the Financial Accounting Standards Board (FASB) issued Statement No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS No. 149). SFAS No. 149 amends and clarifies the accounting and reporting for derivative instruments, including certain derivatives embedded in other contracts, and for hedging activities under SFAS No. 133. The amendments in SFAS No. 149 require that contracts with comparable characteristics be accounted for similarly. The Statement clarifies under what circumstances a contract with an initial net investment meets the characteristics of a derivative according to SFAS No. 133 and when a derivative contains a financing component that

warrants special reporting in the statement of cash flows. In addition, the Statement amends the definition of an underlying to conform it to language used in FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others", and amends certain other existing pronouncements. The provisions of the Statement that relate to SFAS No. 133 Implementation Issues that have been effective for periods that began prior to June 15, 2003, should continue to be applied in accordance with their respective effective dates.

The requirements of SFAS No. 149 are effective for contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. PG&E Corporation is currently evaluating the impacts, if any, of SFAS No. 149 on its Consolidated Financial Statements.

Consolidation of Variable Interest Entities

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46), which expands upon existing accounting guidance addressing when a company should include in its financial statements the assets, liabilities, and activities of another entity or arrangement it is involved with. FIN 46 notes that many of what are now referred to as "variable interest entities" have commonly been referred to as special-purpose entities or off-balance sheet structures. However, the Interpretation's guidance is to be applied to not only these entities but to all entities and arrangements found within a company. FIN 46 provides some general guidance as to the definition of a variable interest entity. PG&E Corporation is currently evaluating all entities and arrangements it is involved with to determine if they meet the FIN 46 criteria as variable interest entities.

Until the issuance of FIN 46, a company generally included another entity in its Consolidated Financial Statements only if it controlled the entity through voting interests. FIN 46 changes that by requiring a variable interest entity to be consolidated by a company if that company is subject to a majority of the risk of loss from the variable interest entity's activities or entitled to receive a majority of the entity's residual returns, or both. A company that consolidates a variable interest entity is now referred to as the "primary beneficiary" of that entity.

FIN 46 requires disclosure of variable interest entities that the company is not required to consolidate but in which it has a significant variable interest.

The consolidation requirements of FIN 46 apply immediately to variable interest entities created after January 31, 2003. There were no new variable interest entities created by PG&E Corporation between February 1, 2003, and March 31, 2003. The consolidation requirements apply to variable interest entities created before January 31, 2003, in the first fiscal year or interim period beginning after June 15, 2003, so these requirements would be applicable to PG&E Corporation in the third quarter of 2003. Certain new and expanded disclosure requirements must be applied to PG&E Corporation's March 31, 2003 disclosures if there is an assessment that it is reasonably possible that an enterprise will consolidate or disclose information about a variable interest entity when FIN 46 becomes effective. PG&E Corporation is currently evaluating the impacts of FIN 46's initial recognition, measurement, and disclosure provisions on its Consolidated Financial Statements.

TAXATION MATTERS

The Internal Revenue Service (IRS) has completed its audit of PG&E Corporation's 1997 and 1998 consolidated U.S. federal income tax returns and has assessed additional federal income taxes of $71 million (including interest). PG&E Corporation has filed protests contesting certain adjustments made by the IRS in that audit and is currently discussing these adjustments with the IRS' Appeals Office. The IRS also is auditing PG&E Corporation's 1999 and 2000 consolidated U.S. federal income tax returns, but has not issued its final report. However, the IRS has proposed adjustments totaling $78 million (including interest). The resolution of these matters with the IRS is not expected to have a material adverse effect on PG&E Corporation's earnings. All of PG&E Corporation's federal income tax returns prior to 1997 have been closed. In addition, California and certain other state tax authorities currently are auditing various state tax returns. The results of these audits are not expected to have a material adverse effect on PG&E Corporation's earnings.

In 2003, PG&E Corporation increased its valuation allowance due to the continued uncertainty in realizing state deferred tax assets arising at PG&E NEG. During the first quarter of 2003, valuation allowances of $10 million were recorded in continuing operations. Additional valuation allowances of $7 million were recorded in discontinued operations, and $5 million in accumulated other comprehensive loss.

In addition to the above reserves, PG&E NEG recorded valuation allowances due to continued uncertainty in realizing federal deferred tax assets. These valuation allowances were determined on a stand-alone basis. During the first quarter, valuation allowances of $66 million were recorded in continuing operations, $3 million were recorded in cumulative effect of changes in

accounting principles, and $48 million were recorded accumulated other comprehensive loss. Additional valuation allowances of $37 million were recorded in discontinued operations. These reserves were eliminated in consolidation, as PG&E Corporation believes that it is more likely than not that the federal deferred tax assets will be realized on a consolidated basis.

ADDITIONAL SECURITY MEASURES

Various federal regulatory agencies including the Nuclear Regulatory Commission (NRC) have recently issued guidance regarding additional security measures to be taken at various facilities owned by PG&E Corporation and the Utility. Facilities affected by PG&E Corporation's and the Utility's assessments include generation facilities, transmission substations, and gas transmission facilities. The current and pending orders may require additional capital investment and an increased level of operating costs. However, neither PG&E Corporation nor the Utility believes these costs will have a material impact on their consolidated financial position or results of operations.

OTHER LONG-TERM CAPITAL EXPENDITURES

During a routine inspection conducted as part of DCPP's last refueling of Unit 2, the Utility has found indications of steam generator tube cracking in locations not previously detected. Though the Utility has restarted the unit with the NRC's approval and the Utility believes it has technical justification to operate without further steam generator inspection until Unit 2's next scheduled refueling in the fall of 2004, it is possible that the Utility might be required by the NRC to take a mid-cycle steam generator inspection outage towards the end of 2003 or beginning of 2004. In addition, added inspections of steam generators that the Utility now will need to perform at each refueling until the steam generators are replaced will lengthen future refueling outages. The Utility is also now planning to accelerate the replacement of steam generators, which is estimated to cost approximately $300 million for the two units combined, to 2008 and 2009 rather than 2009 and 2010 as originally contemplated.

UTILITY CUSTOMER INFORMATION SYSTEM

The Utility implemented a new customer information system at the end of 2002 and continues to work through various billing and collection issues associated with the change over to the new system. The implementation has, among other things, required the Utility to put into place new processes for recording and estimating revenues and electric related costs. The Utility does not expect the system changes to have a significant impact on its financial position and results of operations.

ENVIRONMENTAL AND LEGAL MATTERS

PG&E Corporation and the Utility are subject to laws and regulations established both to 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 to remedy effects on the environment. Also, in the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits. See Note 6 of the Notes to the Consolidated Financial Statements for further discussion of environmental matters and significant pending legal matters.

ITEM 3: QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PG&E Corporation's and Pacific Gas and Electric Company's (the Utility) primary market risk results from changes in energy prices and interest rates. PG&E Corporation engages in price risk management activities for both trading and non-trading purposes. The Utility engages in price risk management activities for non-trading purposes only. Both PG&E Corporation and the Utility may engage in these price management activities using forwards, futures, options, and swaps to hedge the impact of market fluctuations on energy commodity prices, interest rates, and foreign currencies. (See the "Risk Management Activities" section included in Item 1: Management's Discussion and Analysis of Financial Condition and Results of Operations filed as a part of this amended report on Form 10-Q/A.

PART II. OTHER INFORMATION

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a)
Exhibits:

Exhibit 3.1	Restated Articles of Incorporation of PG&E Corporation effective as of May 29, 2002 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609), Exhibit 3.1)
Exhibit 3.2	Bylaws of PG&E Corporation amended as of February 19, 2003 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 3.3)
Exhibit 3.3	Bylaws of Pacific Gas and Electric Company amended as of February 19, 2003 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2002 (File No. 1-2348), Exhibit 3.5)
Exhibit 10.1	Operating Agreement between Pacific Gas and Electric Company and California Department of Water Resources dated as of April 17, 2003 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609 and File No. 1-2348), Exhibit 10.1)
Exhibit 10.2*	PG&E Corporation Executive Stock Ownership Program Guidelines dated as of February 19, 2003 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2)
Exhibit 10.3	Waiver Letter dated as of March 21, 2003, among GenHoldings I, LLC, various lenders identified as the GenHoldings Lenders, the Administrative Agent, and acknowledged and agreed to by PG&E National Energy Group, Inc. (incorporated by reference to PG&E Corporation's and PG&E National Energy Group, Inc.'s Form 8-K filed April 2, 2003 (File Nos. 1-12609 and 333-66032), Exhibit 99.1)
Exhibit 10.4	Commitment Letter dated March 5, 2003, between PG&E Corporation and Lehman Brothers, Inc. (incorporated by reference to PG&E Corporation's Form 8-K filed March 6, 2003 (File No. 1-12609), Exhibit 99.2)
Exhibit 11	Computation of Earnings Per Common Share (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609), Exhibit 11)
Exhibit 12.1	Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-2348), Exhibit 12.1)
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Exhibit 99.2	Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002

* Management contract or compensatory agreement

(b) The following Current Reports on Form 8-K(1) were filed during the first quarter of 2003 and through the date hereof:

1.	January 6, 2003	Item 5.	Other Events A. Resumption of Power Procurement B. Motion to Extend Exclusivity Period C. 2003 General Rate Case D. Pacific Gas and Electric Company bankruptcy 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 November 30, 2002, and Balance Sheet dated November 30, 2002
2.	January 16, 2003	Item 5.	Other Events PG&E Corporation and PG&E National Energy Group, Inc.
		Item 7.	Financial Statements, Pro Forma Financial Information, and Exhibits Exhibit 99.1 Fourth Waiver and Amendment dated as of December 23, 2002, among GenHoldings I, LLC, various lenders identified as the GenHoldings Lenders, the Administrative Agent, and acknowledged and agreed to by PG&E National Energy Group, Inc. Exhibit 99.2 Second Omnibus Restructuring Agreement dated as of December 4, 2002, among La Paloma Generating Company, LLC, La Paloma Generating Trust, Ltd., and various other parties, including PG&E National Energy Group, Inc. Exhibit 99.3 Priority Credit and Reimbursement Agreement among La Paloma Generating Company, LLC, La Paloma Generating Trust Ltd., Wilmington Trust Company, in its individual capacity and as Trustee, Citibank, N.A., as the Priority Working Capital L/C Issuer, the Several Priority Lenders from time to time parties hereto, Citibank, N.A., as administrative agent, and Citibank, N.A., as priority agent, dated as of December 4, 2002 Exhibit 99.4 Second Omnibus Restructuring Agreement dated as of December 4, 2002, among Lake Road Generating Company, LLC, Lake Road Generating Trust, Ltd., and various other parties, including PG&E National Energy Group, Inc. Exhibit 99.5 Priority Credit and Reimbursement Agreement among Lake Road Generating Company, LLC, Lake Road Trust Ltd., Wilmington Trust Company, in its individual capacity and as Trustee, Citibank, N.A., as the Priority L/C Issuer, the Several Priority Lenders from time to time parties hereto, Citibank, N.A., as administrative agent, and Citibank, N.A., as priority agent, dated as of December 4, 2002

3.	March 6, 2003	Item 5.	Other Events: Pacific Gas and Electric Company Bankruptcy A. Updated Trial Schedule for Confirmation Hearings and Order Scheduling Pre-Settlement Conference B. Monthly Operating Report C. Proposed Securities Offerings in Connection with the Utility's Plan
		Item 7.	Financial Statements, Pro Forma Financial Information, and Exhibits

			Exhibit 99.1 Pacific Gas and Electric Company Income Statement for the month ended January 31, 2003, and Balance Sheet dated January 31, 2003
			Exhibit 99.2 Commitment Letter dated March 5, 2003, between PG&E Corporation and Lehman Brothers Inc.
4.	March 12, 2003	Item 5.	Other Events: Pacific Gas and Electric Company Bankruptcy A. Stay of Confirmation Trial B. Express Preemption Appeal
5.	March 17, 2003	Item 5.	Other Events Pacific Gas and Electric Company's 2002 Attrition Revenue Adjustment
6.	April 2, 2003	Item 5.	Other Events A. Agreement with El Paso Corporation B. FERC Decision to Increase Amount of Power Refunds C. Pacific Gas and Electric Company Bankruptcy Monthly Operating Report
		Item 7.	Financial Statements, Pro Forma Financial Information, and Exhibits Exhibit 99.1 Pacific Gas and Electric Company Income Statement for the month ended February 28, 2003 and Balance Sheet dated February 28, 2003
7.	April 2, 2003	Item 5.	Other Events PG&E Corporation and PG&E National Energy Group, Inc. A. GenHoldings I, LLC B. Options to Purchase Shares of PG&E NEG
		Item 7.	Financial Statements, Pro Forma Financial Information, and Exhibits Exhibit 99.1 Waiver Letter dated as of March 21, 2003, among GenHoldings I, LLC, various lenders identified as the GenHoldings Lenders, the Administrative Agent, and acknowledged and agreed to by PG&E National Energy Group, Inc.
8.	April 21, 2003	Item 5.	Other Events Pacific Gas and Electric Company's General Rate Case Proceeding
9.	April 24, 2003	Item 5.	Other Events Pacific Gas and Electric Company Bankruptcy Further Stay of Confirmation Trial

(1) Unless otherwise noted, all reports were filed under Commission File Number 1-2348 (Pacific Gas and Electric Company) and Commission File Number 1-12609 (PG&E Corporation).

SIGNATURE

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

PG&E CORPORATION

BY: /S/ CHRISTOPHER P. JOHNS

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

PACIFIC GAS AND ELECTRIC COMPANY

BY: /S/ DINYAR B. MISTRY

DINYAR B. MISTRY
Vice President and Controller
(duly authorized officer and principal accounting officer)

Dated: June 30, 2003

102

I, Robert D. Glynn, Jr., certify that:

1. I have reviewed this quarterly report on Form 10-Q/A of PG&E Corporation;

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

evaluated the effectiveness of the registrant's disclosure controls and procedures within 90 days prior to the filing date of this quarterly report (the Evaluation Date); and

presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: June 30, 2003

/S/ ROBERT D. GLYNN, JR.

ROBERT D. GLYNN, JR.
Chairman, Chief Executive Officer and President
PG&E Corporation

103

I, Peter A. Darbee, certify that:

1. I have reviewed this quarterly report on Form 10-Q/A of PG&E Corporation;

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

evaluated the effectiveness of the registrant's disclosure controls and procedures within 90 days prior to the filing date of this quarterly report (the Evaluation Date); and

presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: June 30, 2003

/S/ PETER A. DARBEE

PETER A. DARBEE

Senior Vice President and Chief Financial Officer
PG&E Corporation

104

I, Gordon R. Smith, certify that:

1. I have reviewed this quarterly report on Form 10-Q/A of Pacific Gas and Electric Company;

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

evaluated the effectiveness of the registrant's disclosure controls and procedures within 90 days prior to the filing date of this quarterly report (the Evaluation Date); and

presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: June 30, 2003

/S/ GORDON R. SMITH

GORDON R. SMITH

President and Chief Executive Officer

Pacific Gas and Electric Company
105

I, Kent M. Harvey, certify that:

1. I have reviewed this quarterly report on Form 10-Q/A of Pacific Gas and Electric Company;

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

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5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: June 30, 2003

/S/ KENT M. HARVEY

KENT M. HARVEY
Senior Vice President, Chief Financial Officer, and Treasurer
Pacific Gas and Electric Company
106

Exhibit Index

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Management contract or compensatory agreement.

QuickLinks