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

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

FORM 10-Q/A
Amendment No. 1 to

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

For the quarterly period ended September 30, 2001

OR

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

For the transition period from ___________ to __________

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

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

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

Registrant's telephone number, including area code

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

Yes x No __________

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

Common Stock Outstanding, October 31, 2001:
PG&E Corporation 387,257,572 shares

Pacific Gas and Electric Company Wholly-owned by PG&E Corporation

INTRODUCTORY NOTE

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

PG&E CORPORATION AND
PACIFIC GAS AND ELECTRIC COMPANY,
Form 10-Q/A
FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2001
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PART I. FINANCIAL INFORMATION

ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

	Three months ended September 30,		Nine months ended September 30,	
	2001	2000	2001	2000
		As revised, see Note 10		
Operating Revenues				
Utility	$ 2,937	$ 2,523	$ 7,808	$ 7,037
Energy commodities and services	3,361	4,979	10,173	11,104
Total operating revenues	6,298	7,502	17,981	18,141
Operating Expenses				
Cost of energy for utility	697	2,234	3,997	4,187
Deferred electric procurement costs	-	(2,176)	-	(2,789)
Cost of energy commodities and services	3,041	4,618	9,215	10,137
Operating and maintenance	713	958	2,293	2,411
Depreciation, amortization and decommissioning	270	1,239	784	2,268
Reorganization professional fees and expenses	25	-	33	-
Total operating expenses	4,746	6,873	16,322	16,214
Operating Income	1,552	629	1,659	1,927
Reorganization interest income	32	-	64	-
Interest income	29	59	106	109
Interest expense	(317)	(191)	(876)	(556)

Other income (expense), net	(38)	(14)	(43)	(37)
Income Before Income Taxes	1,258	483	910	1,443
Income tax provision	487	239	340	671
Income From Continuing Operations	771	244	570	772
Discontinued Operations				
Loss on disposal of PG&E Energy Services (net of applicable income taxes of $13 million)	-	(19)	-	(19)
Net Income	$ 771	$ 225	$ 570	$ 753
Weighted average common shares outstanding	363	362	363	361
Earnings (Loss) Per Common Share, Basic				
Income from continuing operations	$ 2.12	$ 0.67	$ 1.57	$ 2.14
Discontinued operations	-	(0.05)	-	(0.05)
Net Earnings	$ 2.12	$ 0.62	$ 1.57	$ 2.09
Earnings (Loss) Per Common Share, Diluted				
Income from continuing operations	$ 2.12	$ 0.67	$ 1.57	$ 2.12
Discontinued operations	-	(0.05)	-	(0.05)
Net Earnings	$ 2.12	$ 0.62	$ 1.57	$ 2.07
Dividends Declared Per Common Share	$ -	$ 0.30	$ -	$ 0.90

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

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PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(in millions)

	Balance at	
	September 30, 2001	December 31, 2000
	As revised, see Note 10	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 1,020	$ 925
Short-term investments	4,609	1,634
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $93 million and $71 million, respectively)	3,046	4,340
Regulatory balancing accounts	88	222
Price risk management	152	2,039

Inventories	539	392
Income taxes receivable	-	1,241
Prepaid expenses and other	240	406
Total current assets	9,694	11,199
Property, Plant, and Equipment		
Utility	24,617	23,872
Non-utility:		
Electric generation	2,748	2,008
Gas transmission	1,584	1,542
Construction work in progress	2,054	1,605
Other	129	147
Total property, plant, and equipment (at original cost)	31,132	29,174
Accumulated depreciation and decommissioning	(12,520)	(11,878)
Net property, plant, and equipment	18,612	17,296
Other Noncurrent Assets		
Regulatory assets	1,929	1,773
Nuclear decommissioning funds	1,324	1,328
Price risk management	52	2,026
Other	3,181	2,530
Total other noncurrent assets	6,486	7,657
TOTAL ASSETS	$ 34,792	$ 36,152

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

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

	Balance at	
	September 30, 2001	December 3 2000
	As revised, see Note 10	
LIABILITIES AND EQUITY		
Liabilities Not Subject to Compromise		
Current Liabilities		
Short-term borrowings	$ 319	$ 4,530
Long-term debt, classified as current	48	2,391
Current portion of rate reduction bonds	290	290
Accounts payable:		
Trade creditors	1,226	5,896
Regulatory balancing accounts	293	196
Other	519	459

Price risk management	52	1,999
Other	1,560	1,570
Total current liabilities	4,307	17,331
Noncurrent Liabilities		
Long-term debt	7,649	5,550
Rate reduction bonds	1,527	1,740
Deferred income taxes	1,865	1,656
Deferred tax credits	163	192
Price risk management	33	1,867
Other	3,754	3,864
Total noncurrent liabilities	14,991	14,869
Liabilities Subject to Compromise		
Financing debt	5,828	-
Trade creditors	5,485	-
Total liabilities subject to compromise	11,313	-
Preferred Stock of Subsidiaries	480	480
Utility Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures	-	300
Common Stockholders' Equity		
Common stock, no par value, authorized 800,000,000 shares, issued 387,173,251 and 387,193,727 shares, respectively	5,971	5,971
Common stock held by subsidiary, at cost, 23,815,500 shares	(690)	(690)
Accumulated deficit	(1,533)	(2,105)
Accumulated other comprehensive loss	(47)	(4)
Total common stockholders' equity	3,701	3,172
Commitments and Contingencies (Notes 1, 2, 3, and 8)	-	-
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 34,792	$ 36,152

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

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

	Nine months ended September 30,	
	2001	2000
	As revised, see Note 10	
Cash Flows From Operating Activities		
Net income	$ 570	$ 753

Adjustments to reconcile net income to net cash provided by operating activities:		
Loss on disposal of businesses	-	19
Deferred electric procurement costs	-	(2,789)
Depreciation, amortization, and decommissioning	784	2,268
Deferred income taxes and tax credits, net	180	545
Price risk management assets and liabilities, net	37	(98)
Other deferred charges and non-current liabilities	(604)	861
Net effect of changes in operating assets and liabilities:		
Short-term investments	(2,975)	(632)
Accounts receivable	1,294	(813)
Inventories	(147)	123
Accounts payable	875	1,342
Accrued taxes	1,241	(506)
Regulatory balancing accounts payable	231	(360)
Other working capital	158	514
Other, net	155	30
Net cash provided by operating activities	1,799	1,257
Cash Flows From Investing Activities		
Capital expenditures	(1,818)	(1,691)
Net proceeds from sales of businesses	-	103
Other, net	(235)	(426)
Net cash used by investing activities	(2,053)	(2,014)
Cash Flows From Financing Activities		
Net borrowings (repayments) under credit facilities	(1,159)	894
Long-term debt issued	2,580	615
Long-term debt matured, redeemed, or repurchased	(963)	(432)
Common stock issued	-	52
Dividends paid	(109)	(325)
Net cash provided by financing activities	349	804
Net change in cash and cash equivalents	95	47
Cash and cash equivalents at January 1	925	282
Cash and cash equivalents at September 30	$ 1,020	$ 329
Supplemental disclosures of cash flow information		
Cash paid for:		
Interest (net of amount capitalized)	$ 421	$ 487
Income taxes paid (refunded) - net	(1,241)	23
Transfer of liabilities and other payables subject to compromise from operating payables and liabilities	11,313	

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

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

	Three months ended September 30, 2001	2000
Operating Revenues		
Electric	$ 2,509	$ 1,999
Gas	428	524
Total operating revenues	2,937	2,523
Operating Expenses		
Cost of electric energy	434	2,056
Deferred electric procurement costs	-	(2,176)
Cost of gas	263	178
Operating and maintenance	563	730
Depreciation, amortization, and decommissioning	224	1,202
Reorganization professional fees and expenses	25	-
Total operating expenses	1,509	1,990
Operating Income	1,428	533
Reorganization interest income	32	-
Interest income	7	31
Interest expense (contractual interest of $241 million and $694 million for the three and nine months ended September 30, 2001, respectively)	(245)	(150)
Other income (expense), net	(6)	(1)
Income Before Income Taxes	1,216	413
Income tax provision	472	196
Net Income	744	217
Preferred dividend requirement	7	6
Income Available for Common Stock	$ 737	$ 211

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

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

	Balance at September 30, 2001	December 31, 2000

ASSETS		
Current Assets		
Cash and cash equivalents	$ 151	$ 111
Short-term investments	4,336	1,283
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $51 million and $52 million, respectively)	1,676	1,711
Related parties	17	6
Regulatory balancing accounts	88	222
Inventories:		
Gas stored underground and fuel oil	292	146
Materials and supplies	130	134
Income taxes receivable	-	1,120
Prepaid expenses and other	85	45
Total current assets	6,775	4,778
Property, Plant, and Equipment		
Electric	16,998	16,335
Gas	7,619	7,537
Construction work in progress	247	249
Total property, plant, and equipment (at original cost)	24,864	24,121
Accumulated depreciation and decommissioning	(11,656)	(11,120)
Net property, plant, and equipment	13,208	13,001
Other Noncurrent Assets		
Regulatory assets	1,901	1,716
Nuclear decommissioning funds	1,324	1,328
Other	1,582	1,165
Total noncurrent assets	4,807	4,209
TOTAL ASSETS	$ 24,790	$ 21,988

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

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

	Balance at	
	September 30, 2001	December 31 2000
LIABILITIES AND SHAREHOLDERS' EQUITY		

Liabilities Not Subject to Compromise		
Current Liabilities		
Short-term borrowings	$ -	$ 3,07
Long-term debt, classified as current	-	2,37
Current portion of rate reduction bonds	290	29
Accounts payable:		
Trade creditors	194	3,68
Related parties	31	13
Regulatory balancing accounts	293	19
Other	276	36
Income taxes payable	359	
Deferred income taxes	89	17
Other	615	67
Total current liabilities	2,147	10,97
Noncurrent Liabilities		
Long-term debt	3,431	3,34
Rate reduction bonds	1,527	1,74
Deferred income taxes	1,168	92
Deferred tax credits	163	19
Other	2,884	2,96
Total noncurrent liabilities	9,173	9,17
Liabilities Subject to Compromise		
Financing debt	5,828	
Trade creditors	5,664	
Total liabilities subject to compromise	11,492	
Preferred Stock With Mandatory Redemption Provisions		
6.30% and 6.57%, outstanding 5,500,000 shares, due 2002-2009	137	13
Company Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures, 7.9%, 12,000,000 shares, due 2025	-	30
Stockholders' Equity		
Preferred stock without mandatory redemption provisions		
Nonredeemable, 5% to 6%, outstanding 5,784,825 shares	145	14
Redeemable, 4.36% to 7.04%, outstanding 5,973,456 shares	149	14
Common stock, $5 par value, authorized 800,000,000 shares, issued 321,314,760 shares	1,606	1,60
Common stock held by subsidiary, at cost, 19,481,213 shares	(475)	(47
Additional paid in capital	1,964	1,96
Accumulated deficit	(1,546)	(1,97
Accumulated other comprehensive loss	(2)	
Total stockholders' equity	1,841	1,41
Commitments and Contingencies (Notes 1, 2, 3, and 8)	-	
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 24,790	$ 21,98

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

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

	Nine months ended September 30, 2001	Nine months ended September 30, 2000
Cash Flows From Operating Activities		
Net income	$ 452	$ 673
Adjustments to reconcile net income to net cash provided by operating activities:		
Deferred electric procurement costs	-	(2,789)
Depreciation, amortization, and decommissioning	663	2,160
Deferred income taxes and tax credits, net	127	540
Other deferred charges and non-current liabilities	(658)	640
Net effect of changes in operating assets and liabilities:		
Short-term investments	(3,053)	(221)
Accounts receivable	493	(117)
Income tax receivable	1,120	(295)
Inventories	(142)	11
Accounts payable	1,003	1,093
Accrued taxes	359	(118)
Regulatory balancing accounts	231	(360)
Other working capital	663	100
Other, net	21	(20)
Net cash provided by operating activities	1,279	1,297
Cash Flows from Investing Activities		
Capital expenditures	(889)	(874)
Other, net	3	38
Net cash used by investing activities	(886)	(836)
Cash Flows From Financing Activities		
Net borrowings (repayments) under credit facilities	(28)	468
Long-term debt matured, redeemed, or repurchased	(325)	(291)
Common stock repurchased	-	(275)
Dividends paid	-	(375)
Net cash used by financing activities	(353)	(473)
Net change in cash and cash equivalents	40	(12)
Cash and cash equivalents at January 1	111	80
Cash and cash equivalents at September 30	$ 151	$ 68
Supplemental disclosures of cash flow information		
Cash paid for:		
Interest (net of amount capitalized)	$ 300	$ 295
Income taxes paid (refunded) - net	(1,120)	-
Transfer of liabilities and other payables subject to compromise from operating payables and liabilities	11,492	-

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

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

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Note 1: GENERAL

Basis of Presentation

PG&E Corporation was incorporated in California in 1995 and became the holding company of Pacific Gas and Electric Company, a debtor-in-possession, (the Utility) and its subsidiaries on January 1, 1997. The Utility, incorporated in California in 1905, is the predecessor of PG&E Corporation. As discussed further in Note 3, on April 6, 2001, the Utility filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code (Bankruptcy Code) in the United States Bankruptcy Court for the Northern District of California (Bankruptcy Court). Under Chapter 11, the Utility retains control of its assets and is authorized to operate its business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court. On September 20, 2001, the Utility and PG&E Corporation jointly filed with the Bankruptcy Court a proposed plan of reorganization (the Plan) of the Utility under Chapter 11 of the Bankruptcy Code and their proposed disclosure statement describing the Plan.

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 Condensed Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation's unaudited Condensed Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and PG&E Corporation's wholly owned and controlled subsidiaries. The Utility's unaudited Condensed Consolidated Financial Statements include its accounts as well as those of its wholly owned and controlled subsidiaries.

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

Certain amounts in the prior year's unaudited Condensed Consolidated Financial Statements have been reclassified to conform to the 2001 presentation. Results of operations for interim periods are not necessarily indicative of results to be expected for a full year.

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

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

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Accounting for Price Risk Management Activities

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

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

PG&E Corporation has derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business. In June 2001, the Financial Accounting Standards Board (FASB) approved an interpretation issued by the Derivatives Implementation Group (DIG) that changed the definition of normal purchases and sales for certain power contracts. PG&E Corporation must implement this interpretation on January 1, 2002, and is currently assessing the impact of these new rules. The FASB has also approved another DIG interpretation that disallows normal purchases and sales treatment for commodity contracts (other than power contracts) that contain volumetric variability or optionality. Certain of PG&E Corporation's derivative commodity contracts may no longer be exempt from the requirements of the Statement. PG&E Corporation is evaluating the impact of this implementation guidance on its financial statements, and will implement this guidance, as appropriate, by the implementation deadline of April 1, 2002.

As of September 30, 2001, the maximum length of time over which PG&E Corporation has hedged its exposure to the variability in future cash flows associated with commodity price risk is through December 2005.

The Utility is party to various electric and gas bilateral contracts, some of which were terminated in the first six months of 2001 (see Note 2). The value of certain financial gas contracts terminated during the first six months of the year was being amortized out of accumulated other comprehensive income (loss) over the life of the related physical contracts previously being hedged, in accordance with the provisions of SFAS No. 133. Through the second quarter of 2001, the Utility had amortized $20 million of losses associated with these contracts. Those losses were partially offset through the second quarter of 2001 by gains from the hedged transactions. In the third quarter of 2001, a $66 million (after-tax) loss associated with the terminated contracts included primarily in accumulated other comprehensive loss was recognized in earnings. The loss was recognized in earnings due to changes in market conditions that made

it unlikely that this loss would be offset when the related physical contracts are recognized in earnings. SFAS No. 133 requires an entity to immediately reclassify into earnings amounts in accumulated other comprehensive income (loss) that are not expected to be recovered when the hedged transactions are recognized in earnings in future periods.

Earnings Per Share

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

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

	Three months ended September 30,		Nine mo Sept
	2001	2000	2001
(in millions)			
Income from continuing operations	$ 771	$ 244	$ 570
Discontinued operations	-	(19)	-
Net income	$ 771	$ 225	$ 570
Weighted average common shares outstanding	363	362	363
Add: Outstanding options reduced by the number of shares that could be repurchased with the proceeds from such purchase	1	3	-
Shares outstanding for diluted calculations	364	365	363
Earnings (Loss) Per Common Share, Basic			
Income from continuing operations	$ 2.12	$ 0.67	$ 1.57
Discontinued operations	-	(0.05)	-
Net earnings	2.12	0.62	1.57
Earnings (Loss) Per Common Share, Diluted			
Income from continuing operations	2.12	0.67	1.57
Discontinued operations	-	(0.05)	-
Net earnings	$ 2.12	$ 0.62	$ 1.57

Accumulated Other Comprehensive Income (Loss)

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

New Accounting Pronouncements

In June 2001, the FASB issued SFAS No. 141, "Business Combinations." This

Statement, which applies to all business combinations accounted for under the purchase method completed after June 30, 2001, prohibits the use of pooling-of-interests method of accounting for business combinations and provides a new definition of intangible assets. PG&E Corporation and the Utility do not expect that implementation of this Statement will have a significant impact on their financial statements.

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

In July 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." This Statement is effective for fiscal years beginning after June 15, 2002. SFAS No. 143 provides accounting requirements for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. Under the Statement, the asset retirement obligation is recorded at fair value in the period in which it is incurred by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value in each subsequent period and the capitalized cost is depreciated over the useful life of the related assets. PG&E Corporation and the Utility have not yet determined the effects of this Statement on their financial statements.

In October 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets", which addresses financial accounting and reporting for the impairment or disposal of long-lived assets. SFAS No. 144 supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of", but retains the fundamental provisions for recognizing and measuring impairment of long-lived assets to be held and used or disposed of by sale. The Statement also supersedes the accounting and reporting provisions for the disposal of a segment of a business, and eliminates the exception to consolidation for a subsidiary for which control is likely to be temporary. SFAS No. 144 eliminates the conflict between accounting models for treating the disposition of long-lived assets that existed between SFAS No. 121 and the guidance for a segment of a business accounted for as a discontinued operation by adopting the methodology established in SFAS No. 121, and also resolves implementation issues related to SFAS No. 121. This Statement is effective for fiscal years beginning after December 15, 2001. PG&E Corporation and the Utility have not yet determined the effects of this Statement on their financial statements.

NOTE 2: THE CALIFORNIA ENERGY CRISIS

Transition Period and Rate Freeze

In 1998, California implemented electric industry restructuring and established a market framework for electric generation in which generators and other power providers were permitted to charge market-based prices for wholesale power. The restructuring of the electric industry was mandated by the California Legislature

in Assembly Bill (AB) 1890. The electric industry restructuring law established a transition period, mandated a rate freeze, and included a plan for recovery of generation-related costs that were expected to be uneconomic under the new market (transition costs). The California Public Utilities Commission (CPUC) required the California investor-owned utilities to file a plan to voluntarily divest at least 50% of their fossil-fueled generation facilities and discouraged utility operation of their remaining facilities by reducing the return on such assets. The new market framework called for the creation of the Power Exchange (PX) and the Independent System Operator (ISO). Before it ceased operating in March 2001, the PX established market-clearing prices for electricity. The ISO's role was to schedule delivery of electricity for all market participants and operate certain markets for electricity. Until December 15, 2000, the Utility was required to sell all of its owned and contracted generation to, and purchase all electricity for its retail customers from, the PX. Customers were given the choice of continuing to buy electricity from the Utility or buying electricity from independent power generators or retail electricity suppliers. Most of the Utility's customers continued to buy electricity through the Utility.

The rate freeze established by AB 1890 was scheduled to end on the earlier of March 31, 2002, or the date the Utility recovers all of its transition costs as determined by the CPUC.

Beginning in June 2000, wholesale spot prices for electricity sold through the PX and ISO began to escalate. While forward and spot prices moderated somewhat in September and October 2000, such prices skyrocketed in November and December 2000 to levels substantially higher than during the summer months. The average price of electricity purchased by the Utility for the benefit of its customers was $0.182 per kilowatt-hour (kWh) for the period of June 1 through December 31, 2000, compared to $0.042 per kWh during the same period in 1999. The Utility was only permitted to collect approximately $0.054 per kWh in frozen retail rates from its customers during that period. The increased cost of the purchased electricity strained the financial resources of the Utility. Because of the rate freeze, the Utility has been unable to pass on the increases in power costs to its customers.

Because the Utility was unable to pass through the increase to its customers, it continued to finance the higher costs of wholesale power. During the third and fourth quarter of 2000, the Utility increased its lines of credit to $1,850 million (a net increase of $850 million), issued $1,240 million of debt under a

364-day facility, and issued $680 million of five-year notes.

In November 2000, the Utility filed a proposed Rate Stabilization Plan (RSP), which sought to end the rate freeze and thereby enable the Utility to pass on the increased wholesale electric costs to customers through increased rates. The CPUC evaluated the Utility's proposal, and on January 4, 2001, denied the Utility's request for a rate increase. Instead, the CPUC allowed the Utility to establish an interim energy procurement surcharge of $0.01 per kWh, to remain in effect for 90 days from the effective date of the decision. This increase, which could not be used to recover past procurement costs, resulted in approximately $70 million of additional revenue per month, which was not sufficient to cover the higher wholesale costs of electricity, nor did it help with the costs already incurred.

The Utility accumulated a total of $6.9 billion in under-collected power costs and generation-related transition costs at December 31, 2000. The under-collected purchased power costs generally would be deferred for future recovery as a regulatory asset subject to future collection from customers in rates. However, due to the lack of regulatory, legislative, or judicial relief, the Utility determined that it could no longer conclude that its uncollected wholesale electricity costs and remaining transition costs were probable of recovery in future rates. Therefore, the Utility charged to earnings the under-

collected electricity costs and the unamortized transition costs at December 31, 2000. For the three- and nine-month periods ended September 30, 2001, the Utility has expensed all power generation and procurement costs as incurred. Beginning in the second quarter of 2001, the Utility's generation-related component of electric revenues was greater than its generation-related costs. This differential resulted in an increase to earnings of $687 million and $124 million for the three- and nine-month periods ending September 30, 2001, and represents the partial recovery of previously written off generation-related transition costs. This includes $327 million (after-tax) related to the market value of certain terminated bilateral contracts.

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

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

The Utility filed an application for rehearing of the CPUC's retroactive accounting change alleging that the adoption of the accounting change violates AB 1890, exceeds the CPUC's authority, constitutes an unconstitutional taking of the Utility's property, violates the Utility's federal and state due process and equal protection rights, and constitutes unlawful retroactive ratemaking. The CPUC has not acted on the application for rehearing. Nonetheless, the CPUC's decision does not alter or otherwise affect the amount or nature of wholesale electricity procurement and transition costs that the Utility has incurred or the amount of the Utility's retail rate revenues available to pay for those wholesale costs. The Utility believes the decision neither complies with controlling federal law nor furnishes a basis for the CPUC to avoid such compliance. The Utility requested that the Bankruptcy Court enjoin the CPUC from requiring the Utility to implement the regulatory accounting changes. On June 1, 2001, the Bankruptcy Court denied the Utility's application for a preliminary injunction, and an appeal of the Bankruptcy Court's decision is now pending.

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

transition costs. The Utility has submitted testimony to the CPUC that it believes the market value of its hydroelectric generating facilities is $4.1 billion. Based on that value and after restating its regulatory accounts to comply with the CPUC's March 2001 accounting order, the Utility believes it would have recovered its transition costs as early as March 2000 when the Utility had not yet incurred any under-collected power procurement costs on behalf of its retail customers. However, the CPUC has not yet accepted the Utility's estimated market valuation of its hydroelectric assets nor has the CPUC determined that the rate freeze has ended.

On March 27, 2001, the CPUC authorized an average increase in retail rates of $0.03 per kWh, which was in addition to the emergency $0.01 per kWh interim surcharge as discussed above. The revenue generated by this rate increase was to be used only for power procurement costs that are incurred after March 27, 2001 and could not be used to pay amounts owed to creditors. Although the rate increase was authorized immediately, the Utility did not begin collecting in rates the $0.03 per kWh surcharge until June 1, 2001, when the rate design was adopted by the CPUC. Accordingly, the CPUC authorized an additional interim $0.005 per kWh increase to be collected from ratepayers from June 1, 2001 to June 1, 2002.

California Department of Water Resources Purchases

In January 2001, the California Legislature and the Governor of California authorized the California Department of Water Resources (DWR) to begin purchasing wholesale electric energy on behalf of the Utility's retail customers. On February 1, 2001, the Governor signed into law AB 1X authorizing the DWR to enter into contracts for the supply of electricity. In addition to certain contracts it has subsequently entered into, the DWR continues to purchase power on the spot market at prevailing market prices.

On March 27, 2001, the CPUC issued an interim order requiring the Utility and the other California investor-owned utilities to pay the DWR a per-kWh price for the power purchased by the DWR for the Utility's customers. The CPUC determined that the generation-related component of retail rates should be the total bundled electric rate less the following non-generation related rates or charges: transmission, distribution, public purpose programs, nuclear decommissioning, and the fixed transition amount. The CPUC determined that the company-wide average generation related rate is $0.06471 per kWh before June 1, 2001. On March 27, 2001, the CPUC adopted an additional rate surcharge of $0.03 per kWh. The additional surcharge did not go into effect until June 1, 2001, at which time it was increased by approximately $0.005 per kWh for twelve months to amortize the under-collection in surcharge revenues that occurred between March 27 and June 1, 2001. The resulting generation rate is $0.09987 per kWh. The CPUC ordered the Utility to pay the DWR within 45 days after the DWR supplies power to its retail customers, subject to penalties for each day that the payment is late.

The Utility has acted as an agent for the DWR with respect to the collection of the portion of the Utility's retail rates that must be paid to the DWR for the purchases of power on behalf of the Utility's customers.

Initially, the DWR indicated that it intended to buy power only at "reasonable prices" to meet the Utility's net open position (the amount of power needed by retail electric customers that cannot be met by utility-owned generation or power under contract to the Utility), leaving the ISO to purchase the remainder in order to avoid blackouts. The ISO billed the Utility for its costs to purchase power to cover the amount of the Utility's net open position not covered by the DWR. The Utility does not believe it is responsible to pay for the ISO's purchases (see ISO Purchases below).

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

Since the Utility is merely a collection agent for the DWR's costs and related revenues, the Utility does not reflect these amounts in its Condensed Consolidated Statements of Operations. For the nine-month period ended September 30, 2001, electricity billings to the Utility's customers totaled $7,058 million of which the portion attributable to the DWR totaled $1,793 million. The Utility records these pass-through amounts based on the CPUC's interim order on March 27, 2001 at the generation-related rate per kWh, and not based on the proposed DWR revenue requirement discussed below.

On July 23, 2001, the DWR filed information concerning its revenue requirement with the CPUC. The DWR stated that it seeks to collect $13.072 billion from the electric customers of the three California investor-owned utilities for the period January 17, 2001 through December 2002. Of this amount, the DWR seeks to collect approximately $5.2 billion from the Utility's customers. The DWR's filing indicated that the average cost it is seeking from California utility customers is $0.108 per kWh for 2001 and $0.137 per kWh in 2002. On July 24, 2001, the Utility requested that the DWR hold a public hearing on its revenue requirement because the DWR's filing lacked sufficient detail to determine the impact of its revenue requirement on ratepayers and the Utility.

On September 4, 2001, a CPUC Administrative Law Judge (ALJ) issued a proposed decision (PD) establishing DWR charges for the three California utilities. The PD would allocate the DWR revenue requirement among the three California utilities on a "cost of service" basis, causing the Utility's share of the DWR revenue requirement to be approximately $6.5 billion, which is higher than the "equal cents per kWh" allocation recommended by DWR. However, the PD would not change the Utility's retail rates. Evidentiary hearings in the DWR's cost allocation proceedings are scheduled to begin on November 13, 2001.

On October 19, 2001, the DWR issued a draft revised revenue requirement, which reduces its overall revenue requirement statewide to $10.2 billion for the two-year period 2001 to 2002. The reasons for the reduction include lower spot power prices and lower gas prices under which some of DWR's power contracts are indexed. The DWR intends to formally submit this revised revenue requirement to the CPUC in the near future after considering public comments. The revised DWR revenue requirement does not resolve issues relating to allocation of DWR's costs among the three utilities, which are pending before the CPUC in a separate proceeding. Nor does the DWR revised revenue requirement resolve issues concerning how the DWR request would be reconciled with the Utility's existing rates, including those for its retained generation facilities.

Finally, the revised DWR revenue requirement does not address the dispute between the DWR and the CPUC regarding the form and substance of a rate agreement which the DWR has requested for the purpose of financing its bonds, but which the CPUC rejected on October 4, 2001.

ISO Purchases

As previously stated, the ISO billed the Utility for its costs to purchase power to cover the Utility's net open position not covered by the DWR. The Utility believes that since it has not met the creditworthiness standards under the ISO's tariff since early January 2001, the Utility should not be responsible for the

ISO's purchases made to meet the Utility's net open position.

On February 14, 2001, the Federal Energy Regulatory Commission (FERC) ordered that the ISO could only buy power on behalf of creditworthy entities. The FERC order also stated that the ISO could continue to schedule power for the Utility as long as it comes from its own generation units and is routed over its own transmission lines. Despite the FERC orders, the ISO continued to bill the Utility for the ISO's wholesale power purchases.

On April 6, 2001, the FERC issued a further order directing the ISO to implement its prior order, which the FERC clarified, applying to all third-party transactions whether scheduled or not. In light of the FERC's April 6, 2001 order, the Utility has not recorded any such estimated ISO charges after April 6, 2001, except for the ISO's grid management charge. However, the Utility has accrued the full amount of the ISO's previous charges of approximately $1 billion, since the Utility was not creditworthy through April 6, 2001, in the accompanying financial statements. On June 13, 2001, the FERC denied the ISO's request for rehearing of its April 6, 2001 order. The Utility believes it is not responsible for these costs since it has not met the creditworthiness standards under the ISO tariff since early January 2001.

Furthermore, on June 26, 2001, the Bankruptcy Court issued a preliminary injunction prohibiting the ISO from charging the Utility for the ISO's wholesale power purchases made in violation of bankruptcy law, the ISO's tariff, and the FERC's February 14 and April 6, 2001 orders. In issuing the injunction, the Bankruptcy Court noted that the FERC orders permit the ISO to schedule transactions that involve either a creditworthy buyer or a creditworthy counter-party, and noted the existence of unresolved issues regarding how to ensure these creditworthiness requirements for real-time transactions and emergency dispatch orders issued by the ISO to power sellers.

A proceeding is pending before the FERC to consider potential refunds for wholesale prices paid to power sellers for purchases made in the ISO and PX spot markets between October 2, 2000 and June 20, 2001. A decision is not expected until the second quarter of 2002.

QF Contracts

As a result of the energy crisis and the Utility's Bankruptcy filing, a number of QFs requested the Bankruptcy Court to either terminate their contracts requiring them to sell power to the Utility or have the contracts suspended for the summer of 2001 so the QFs can sell power at market-based rates. In July 2001, the Utility signed five-year agreements with 197 of its QFs, ensuring the Utility and its customers receive a reliable supply of electricity at an average energy price of $0.0537 per kWh. Under the terms of the agreements, the Utility will assume the QF contracts and pay the pre-petition debt on these 197 QF contracts, totaling $845 million, on the effective date of the Plan. The total amount the Utility owed to QFs when it filed for bankruptcy protection was approximately $1 billion. The agreements represent 85% of debt owed to QFs. For certain of these QFs, if the effective date has not occurred by July 15, 2003, the Utility will pay 2% of the principal amount of the pre-petition debt per month until the effective date of the Plan or until July 15, 2005, when it will pay the remaining pre-petition debt. By locking into the average fixed cost, the Utility will help protect its customers from the price fluctuations in the wholesale market. Each of the agreements requires formal approval from the Bankruptcy Court. Most of the agreements have already been approved by the Bankruptcy Court, and the Utility will be making filings for the remainder in the near future.

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Bilateral Contracts

As a response to the energy crisis, in October 2000, the Utility entered into multiple bilateral contracts with suppliers for long-term electricity deliveries. However, some of these contracts were terminated by the counter-parties who were entitled to do so in the event of the Utility triggering early termination provisions caused by the filing for Chapter 11 bankruptcy protection and the decline in the Utility's credit quality to below investment grade. The terms of the contracts require that at termination, the contracts be settled at the then market value of the contract. One contract has been settled with the counter-party for $426 million. The parties are negotiating various issues regarding the two remaining contracts. The settled contract and the estimated market value for the contracts under negotiation total $552 million and have been recognized as a reduction to the Cost of Electric Energy in the Condensed Consolidated Statements of Operations. As of September 30, 2001, remaining individual contracts range in size from approximately 30,800 megawatt hours (MWh) to 3,504,000 MWhs of supply annually. The contracts extend to 2003.

The Utility had PX block-forward contracts, which were seized by California Governor Gray Davis in February 2001 for the benefit of the state, acting under California's Emergency Services Act (the Act). The block-forward contracts had an estimated unrealized gain of $243 million at the time they were seized. The Utility, the PX, and some of the PX market participants have filed administrative claims and state court litigation against the State to recover the value of the seized contracts. The administrative claims, as well as the state court litigation, are pending.

Note 3: VOLUNTARY PETITION FOR RELIEF UNDER CHAPTER 11 AND PLAN OF REORGANIZATION

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

Certain claims against the Utility in existence prior to its filing of the petition for relief are stayed while the Utility continues business operations as a debtor-in-possession. The Utility has reflected its estimate of all such valid claims in the September 30, 2001, Condensed Consolidated Balance Sheets as Liabilities Subject to Compromise. Additional claims or changes to Liabilities Subject to Compromise may arise subsequent to the filing date resulting from:

1. Negotiations,
2. Rejection of executory contracts, including leases,
3. Actions by the Bankruptcy Court,
4. Further developments with respect to disputed claims,
5. Proofs of claim, or
6. Other events

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

On September 20, 2001, the Utility and its parent company, PG&E Corporation, jointly filed with the Bankruptcy Court a proposed plan of reorganization (the Plan) of the Utility under the Bankruptcy Code and their proposed disclosure statement describing the Plan. To approve the form of disclosure statement, the Bankruptcy Court must determine that it contains adequate information to make an informed judgment in voting to accept or reject the Plan. The Bankruptcy Court has set a hearing date of December 19, 2001, to consider the adequacy of the disclosure statement. Upon Bankruptcy Court approval, the disclosure statement will be sent to holders of claims against, and equity interests in, the Utility in connection with the solicitation of acceptances of the Plan. Bankruptcy Court approval of the disclosure statement does not constitute a determination by the Bankruptcy Court as to the merits of the Plan or an indication that the Bankruptcy Court will confirm the Plan.

If the court approves the disclosure statement by the end of 2001, the confirmation process could occur as early as the spring of 2002. Among the requirements for confirmation are that the Plan is:

1. Accepted by all impaired classes of claims and equity interests or, if rejected by an impaired class, that the Plan does not discriminate unfairly and is fair and equitable as to such class,
2. Feasible, and
3. In the best interests of creditors and shareholders that are impaired under the Plan.

The proposed Plan would create three new California limited liability companies and separate the Utility's operations into four lines of business: gas and electric distribution (the reorganized Utility), electric transmission (ETrans), gas transmission (GTrans), and electric generation (Gen)(collectively, the Internal Restructuring). PG&E Corporation and the Utility believe that the Plan will enable the Utility to successfully reorganize its business and accomplish the objectives of Chapter 11 of the Bankruptcy Code, and that acceptance of the Plan is in the best interests of the Utility, its creditors and all parties in interest. Throughout the process of developing the Plan, PG&E Corporation and the Utility have been working closely with the Official Committee of Unsecured Creditors (the Committee). On October 2, 2001, the Utility filed with the Bankruptcy Court the Support Agreement between the Utility and the Committee under which the Committee has agreed to support the Plan under the conditions specified in the agreement.

Under the Plan, the majority of the assets and liabilities associated with the Utility's electric transmission business would be transferred to ETrans, the majority of the assets and liabilities associated with the Utility's gas transmission business would be transferred to GTrans, and the majority of the assets and liabilities associated with the Utility's generation business (including the conventional hydroelectric generating plants, the Helms Pumped Storage Plant, the Diablo Canyon Nuclear Power Plant, beneficial interests in the Diablo Canyon Nuclear Facilities Decommissioning Master Trust, and the irrigation district power purchase contracts) would be transferred to Gen. The Plan further contemplates that the Utility would create a separate holding corporation (Newco) to hold the membership interests of each of ETrans, GTrans and Gen, and that the Utility would be the sole shareholder of Newco. After the transfer of Utility assets to the newly-formed entities or their subsidiaries or affiliates, the

Utility would distribute the outstanding common stock of Newco to PG&E Corporation, and each of ETrans, GTrans and Gen would thereafter be an indirect wholly-owned subsidiary of PG&E Corporation.

The Plan contemplates that on or as soon as practicable after the date on which the Plan becomes effective (the Effective Date), PG&E Corporation will distribute the shares of the reorganized Utility's common stock it holds to the holders of PG&E Corporation common stock on a pro rata basis (the Spin-Off). The reorganized Utility would thereafter operate as a stand-alone electric and gas distribution business, would continue to own the majority of Utility assets, and would continue to provide electric and gas distribution services to customers. Pursuant to the Plan, the Utility's currently outstanding preferred stock would remain in place as shares of preferred stock of the reorganized Utility. It is contemplated that holders of preferred stock would receive on the Effective Date, and in cash, any dividends unpaid and sinking fund payments accrued in respect of such preferred stock through the last scheduled payment date before the Effective Date. The common stock of the reorganized Utility would be registered pursuant to the Securities Exchange Act of 1934, and would generally be freely tradable by the recipients on the Effective Date or as soon as practicable thereafter. The reorganized Utility would apply to list the common stock of the reorganized Utility on the New York Stock Exchange.

In addition, the Plan proposes that all valid creditor claims will be paid in full with interest, using a combination of cash and long-term notes. The majority of creditors, those with allowed claims of $100,000 or less, will receive cash payments for the full amount of their allowed claims on the effective date of the Plan. The majority of secured creditors will also receive 100% of their allowed claims in cash. Finally, unsecured creditors with allowed claims in excess of the $100,000 threshold will be paid 60% in cash and 40% in long-term notes.

Pursuant to the Plan and as discussed further in Note 2, the reorganized Utility would seek a Bankruptcy Court order prohibiting the Utility from reassuming the responsibility to purchase power to meet the net open position not already provided through the DWR's power purchase contracts, until such time as:

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

The Utility also would seek a Bankruptcy Court order prohibiting the reorganized Utility from accepting the assignment, directly or indirectly, of wholesale electric power procurement contracts executed by the DWR. Also, pursuant to the Plan, Gen and the reorganized Utility would enter into a 12-year bilateral power sales agreement under which the reorganized Utility would purchase output generated by Gen's facilities and procured under its power purchase agreements.

Implementation of the Plan is subject to obtaining certain regulatory approvals from certain government agencies, including among others, the FERC, the SEC, the CPUC, and the Nuclear Regulatory Commission (NRC). Additionally, because the Internal Restructuring is intended to qualify as tax-free reorganizations and the Spin-Off is intended to qualify as a tax-free spin-off, PG&E Corporation and the

Utility will seek a private letter ruling from the Internal Revenue Service confirming the tax-free treatment of these transactions.

The Plan asks the Bankruptcy Court to issue the following orders:

1. Approve the Plan documents, authorizing the Utility to execute, enter into and deliver the Plan documents and to execute, implement and take all actions necessary or appropriate to give effect to the transactions contemplated by the Plan and the Plan documents,
2. Determine that the Utility, PG&E Corporation and their affiliates are not liable or responsible for any DWR power contracts or purchases of power by the DWR, and any liabilities associated therewith,
3. Prohibit the reorganized Utility from accepting an assignment of the DWR contracts,
4. Prohibit the reorganized Utility from reassuming the net open position unless the conditions discussed above are satisfied,
5. Approve the execution of the proposed power sales contract between Gen and the reorganized Utility and a proposed gas transmission and storage contract between GTrans and the reorganized Utility,
6. Prohibit the CPUC and the state of California from taking any action related to the allocation or other treatment of any gain on sale related to assets transferred or disposed of under the Plan that would adversely impact the value or usefulness of any assets of the reorganized Utility,
7. Find that the CPUC affiliate transaction rules are not applicable to the restructuring transactions,
8. Find that the approval of state and local agencies of California, including, but not limited to, the CPUC, shall not be required in connection with the restructuring transactions because Section 1123 of the Bankruptcy Code preempts such state and local laws,
9. Find that neither PG&E Corporation nor the Utility is required to comply with certain provisions of the California Corporations Code relating to corporate distributions and the sale of substantially all of a corporation's assets because Section 1123 of the Bankruptcy Code preempts such state law, and
10. Approve the commitment of ETrans to join a FERC-approved Regional Transmission Organization (RTO) and authorizing ETrans to join such FERC-approved RTO at such time as it is operational.

In addition, the confirmation order must be, in form and substance, acceptable to PG&E Corporation and the Utility. Any of these conditions may be waived by PG&E Corporation and the Utility.

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

1. The confirmation order, in form and substance acceptable to PG&E Corporation and the Utility, shall have been signed by the Bankruptcy Court on or before June 30, 2002, and shall have become a final order,
2. The Effective Date shall have occurred on or before January 1, 2003,
3. All actions, documents and agreements necessary to implement the Plan shall have been effected or executed,
4. 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,
5. Standard & Poor's (S&P) and Moody's Investors Service (Moody's) shall have established credit ratings for each of the securities to be issued by the reorganized Utility, ETrans, GTrans, and Gen that are acceptable to PG&E Corporation and the Utility,
6. The Plan shall not have been modified in a material way since the confirmation date, and

7. The disaggregated entities shall have consummated each of the debt offerings contemplated by the Plan.

If one or more of the conditions to the Effective Date described above have not occurred or been waived by January 1, 2003:

1. The confirmation order shall be vacated,
2. No distributions under the Plan shall be made,
3. The Utility and all holders of claims and equity interests shall be restored to the status quo ante as of the day immediately preceding the confirmation date as though the confirmation date never occurred, and
4. The Utility's obligations with respect to claims and equity interests shall remain unchanged.

Although PG&E Corporation and the Utility are not able to predict all of the factors that may affect whether the Plan will be confirmed, or whether, if confirmed, it will become effective, some of the factors that could affect the outcome materially include: the pace of the Bankruptcy Court proceedings; the extent to which the Plan is amended or modified; legislative and regulatory initiatives regarding deregulation and restructuring of the electric and natural gas industries in the United States, particularly in California; whether the Utility is able to obtain timely regulatory approvals or whether the Utility is able to obtain regulatory approvals at all; risks relating to the issuance of new debt securities by each of the disaggregated entities, including higher interest rates than are assumed in the financial projections which could affect the amount of cash raised to satisfy allowed claims, and the inability to successfully market the debt securities due to, among other reasons, an adverse change in market conditions or in the condition of the disaggregated entities before completion of the offerings; whether the Bankruptcy Court exercises its authority to pre-empt relevant non-bankruptcy law and if so, whether, and the extent to which such assertion of jurisdiction is successfully challenged; whether a favorable tax ruling or opinion is obtained regarding the tax-free nature of the Internal Restructuring and the Spin-Off; and the ability of the Utility to successfully disaggregate its businesses. However, the Utility believes, based on information presently available to it, that cash available from operations will provide sufficient liquidity to allow it to continue as a going concern for the foreseeable future.

NOTE 4: PRICE RISK MANAGEMENT

PG&E Corporation's net gain (loss) on trading contracts for the three- and nine-month periods ended September 30, 2001, are $44 million and $166 million, respectively.

PG&E Corporation's and the Utility's ineffective portion of changes in fair values of cash flow hedges are immaterial for the three- and nine-month periods ended September 30, 2001. PG&E Corporation's and the Utility's estimated net derivative gains or losses included in accumulated other comprehensive loss at September 30, 2001 that are expected to be reclassified into earnings within the next twelve months are net losses of $39 million and $0.2 million, respectively. The actual amounts reclassified from accumulated other comprehensive loss to earnings can differ as a result of market price changes.

The schedule below summarizes the activities affecting accumulated other comprehensive income (loss) from derivative instruments for the three- and nine-month periods ended September 30, 2001.

(in millions)	Three months ended September 30, 2001 PG&E Corporation	Utility
Beginning derivative gains (losses) included in accumulated other comprehensive income (loss)	$ (106)	$ (41)
Net gain (loss) of current period hedging transactions	21	1
Net reclassification to earnings	43	40
Ending derivative gains (losses) included in accumulated other comprehensive loss	(42)	-
Foreign currency translation adjustment	(5)	(2)
Ending accumulated other comprehensive loss at September 30, 2001	$ (47)	$ (2)

Credit Risk

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

PG&E Corporation and the Utility did not experience any losses due to the non-performance of counter-parties during the three- and nine-month periods ended September 30, 2001. At September 30, 2001, PG&E Corporation's and the Utility's gross credit risk exposure amounted to $870 million and $83 million, respectively. Counter-parties considered to be investment grade or higher comprise 78% and 94% of the total credit exposure for PG&E Corporation and the Utility, respectively.

NOTE 5: SHORT-TERM BORROWINGS AND CREDIT FACILITIES

PG&E National Energy Group

In order to support their energy trading operations and other working capital requirements, PG&E National Energy Group (PG&E NEG) entered into a $550 million revolving credit facility on June 15, 2001. This facility, which has an initial term of 364 days, provides for bank borrowings and letters of credit. Borrowings under the facility bear interest based on LIBOR plus a credit spread of 1.75%, which is based on PG&E NEG's BBB rating for this instrument. On August 23, 2001, this facility was increased to $1.25 billion. At September 30, 2001, $156 million of letters of credit, and borrowings of $295 million were outstanding under this facility.

On June 18, 2001, PG&E NEG reduced one of its $550 million revolving credit

facilities at PG&E Generating Company, LLC (GenLLC) to $500 million to meet the requirements of the new facility, described above. On August 23, 2001, this facility and a $550 million 5-year revolving credit facility, at GenLLC, were cancelled.

NOTE 6: LONG-TERM DEBT

PG&E Corporation

Commencing on March 2, 2001, PG&E Corporation refinanced its debt obligations with $1 billion in aggregate proceeds from two term loans under a common credit agreement with General Electric Corporation and Lehman Commercial Paper Inc., maturing on March 1, 2003. In accordance with the credit agreement, the proceeds, together with other PG&E Corporation cash, were used to pay $501 million in commercial paper (including $457 million of commercial paper on which PG&E Corporation had defaulted), $434 million in borrowings under PG&E Corporation's long-term revolving credit facility, and $109 million to PG&E Corporation shareholders of record as of December 15, 2000, in satisfaction of a defaulted fourth quarter 2000 dividend. Further, approximately $99 million was used to pre-pay the first year's interest under the credit agreement and to pay transaction expenses associated with the debt restructuring.

PG&E Corporation itself had cash and short-term investments of $256 million at September 30, 2001, and believes that the funds will be adequate to maintain its continuing operations through 2002. In addition, PG&E Corporation believes that the holding company and its non-CPUC regulated subsidiaries are protected from the bankruptcy of the Utility.

PG&E NEG

On May 22, 2001, PG&E NEG issued senior notes in an aggregate principal amount of $1 billion. These notes, which mature on May 16, 2011, bear interest at 10.375% and require semiannual interest payments on May 15 and November 15. On July 27, 2001, PG&E NEG registered the bonds in an S-4 registration with the SEC and commenced an exchange offer to allow the senior note holders to exchange their senior notes for exchange notes with substantially similar terms as the senior notes. The senior notes were exchanged by October 1, 2001 to exchange notes.

PG&E NEG has used a portion of the proceeds and intends to use the balance of the senior notes issuance, net of $28 million of debt discount and note issuance costs, to pay down existing revolving debt, fund investments in generating facilities and pipeline assets, working capital requirements and other general corporate requirements.

On September 6, 2001, a subsidiary of PG&E NEG entered into a credit agreement for $69.4 million. The debt facility will be used to fund construction of the

Plains End project. This facility expires upon the earlier of five years after commercial operations have been declared or September 30, 2007. The facility provides for borrowings that bear interest based on LIBOR plus a credit spread. On September 19, 2001 and September 27, 2001, the subsidiary executed accreting and amortizing interest rate swaps and forwards to hedge approximately 80% of loans expected to be drawn.

During 2000 and 1999, two indirect wholly owned subsidiaries of PG&E NEG entered into two commitments relating to the acquisition of turbine equipment and two commitments relating to generation projects that are under construction, for

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which they act as the construction agent for the owners. Upon completion of the construction projects, expected to be in 2002, PG&E NEG will lease these facilities under lease terms of five years and three years, respectively. At the conclusion of each of the lease terms, PG&E NEG has the option to extend the leases at fair market value, purchase the projects, or act as remarketing agent for the lessors for sales to third parties. If PG&E NEG elects to remarket the projects, then PG&E NEG would be obligated to the lessors for up to 85% of the project costs if the proceeds are deficient to pay the lessor's investors. PG&E Corporation has committed to fund up to $604 million in the aggregate of equity to support PG&E NEG's obligation to the lessors during the construction and post-construction periods. In addition, PG&E NEG entered into operative agreements with a special purpose entity that will own and finance construction of another facility totaling $775 million. PG&E Corporation has committed to fund up to $122 million of equity support commitments to meet the obligations to the entity. In 2001, PG&E NEG replaced PG&E Corporation equity support commitments with substitute commitments of PG&E NEG. The trusts associated with these facilities have been consolidated in the accompanying financial statements.

NOTE 7: UTILITY OBLIGATED MANDATORILY REDEEMABLE PREFERRED SECURITIES OF TRUST HOLDING SOLELY UTILITY SUBORDINATED DEBENTURES

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

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

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

On March 16, 2001, the Utility deferred quarterly interest payments on the

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

On April 12, 2001, Bank One, N.A., as successor-in-interest to The First National Bank of Chicago, gave notice that an Event of Default exists under the Trust Agreement in that the Utility on April 6, 2001, filed a voluntary petition for relief under the Bankruptcy Code. Pursuant to the Trust Agreement, the bankruptcy filing by the Utility constitutes an Early Termination Event. The

Trust Agreement directs that upon the occurrence of an Early Termination Event, the Trust shall be liquidated by the Trustees as expeditiously as the Trustees determine to be possible by distributing, after satisfaction of liabilities to creditors of the Trust, to each Security holder a like amount of the Utility's 7.90% Deferrable Interest Subordinated Debentures, Series A, due 2025. As of September 30, 2001, the QUIPS have been reclassified to Liabilities Subject to Compromise on the Condensed Consolidated Balance Sheet.

NOTE 8: COMMITMENTS AND CONTINGENCIES

Nuclear Insurance

The Utility has insurance coverage for property damage and business interruption losses as a member of Nuclear Electric Insurance Limited (NEIL). Under this insurance, if a nuclear generating facility suffers a loss due to a prolonged accidental outage, the Utility may be subject to maximum retrospective assessments of $13 million (property damage) and $4 million (business interruption), in each case per policy period, in the event losses exceed the resources of NEIL. Effective November 15, 2001, the maximum retrospective assessments will be increased to $26 million and $9 million for property damage and business interruption, respectively.

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

Workers' Compensation Security

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

In February 2001, several surety companies provided cancellation notices, citing concerns about the Utility's financial situation. However, the cancellation of surety bonds is not possible unless released by the DIR. Such surety bonds totaling $185 million guarantee workers' compensation claims prior to February 2001. However, the state has continued to apply the canceled bond amounts towards the approved $401 million amount. The Utility was able to supplement the difference for any new obligations since February 2001, through three additional active surety bonds totaling $216 million. The cancelled bonds have not, to date, impacted the Utility's self-insured status under California law, or its ability to meet current plan obligations.

Environmental Remediation

Utility

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

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

As of September 30, 2001, the Utility expects to spend $319 million for hazardous waste remediation costs at identified sites, including divested fossil-fueled power plants. The cost of the hazardous substance remediation ultimately undertaken by the Utility is difficult to estimate. A change in estimate may occur in the near term due to uncertainty concerning the Utility's responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives. If other potentially responsible parties are not financially able to contribute to these costs or further investigation indicates that the extent of contamination or necessary remediation is greater than anticipated, the Utility could spend as much as $471 million on these costs. The Utility estimates the upper limit of the range using assumptions least favorable to the Utility, based upon a range of reasonably possible outcomes. Costs may be higher if the Utility is found to be responsible for clean-up costs at additional sites or expected outcomes change.

The Utility had an environmental remediation liability of $319 million and $320 million at September 30, 2001, and December 31, 2000, respectively. The $319 million accrued at September 30, 2001, includes (1) $139 million related to the pre-closing remediation liability, associated with the divested generation facilities, and (2) $180 million related to remediation costs for those generation facilities that the Utility still owns, manufactured gas plant sites, and gas gathering compressor stations. Of the $319 million environmental remediation liability, the Utility has recovered $193 million through rates, and expects to recover another $109 million in future rates. The Utility also is recovering its costs from insurance carriers and from other third parties as appropriate.

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

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

In December 1999, the Utility was notified by the purchaser of its former Moss Landing power plant that it had identified a cleaning procedure used at the plant that released heated water from the intake, and that this procedure is not specified in the plant's National Pollutant Discharge Elimination System (NPDES) permit issued by the Central Coast Regional Water Quality Control Board (Central Coast Board). The purchaser notified the Central Coast Board of its findings. In March 2000, the Central Coast Board requested the Utility to provide specific information regarding the "backflush" procedure used at Moss Landing. The Utility's investigation indicated that while it owned Moss Landing, significant amounts of water were discharged from the cooling water intake. While the Utility's investigation did not clearly indicate that discharged waters had a temperature higher than ambient receiving water, the Utility believes that the temperature of the discharged water was higher than that of the ambient receiving water. In December 2000, the executive officer of the Central Coast Board made a settlement proposal to the Utility under which it would pay $10 million, a portion of which would be used for environmental projects and the balance of which would constitute civil penalties. A proof of claim has been filed by the California Attorney General in the Utility's bankruptcy proceeding on behalf of the Central Coast Board seeking unspecified penalties for alleged discharges of heated cooling water from Moss Landing. Settlement negotiations are continuing.

The Utility's Diablo Canyon employs a "once through" cooling water system, which is regulated under a NPDES Permit, issued by the Central Coast Board. This permit allows Diablo Canyon to discharge the cooling water at a temperature no more than 22 degrees above ambient receiving water, and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, marine and wildlife habitat, shellfish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft Cease and Desist Order (CDO) alleging that, although the temperature limit has never been exceeded, the Diablo Canyon's discharge was not protective of beneficial uses. In October 2000, the Central Coast Board and the Utility reached a tentative settlement of this matter pursuant to which the Central Coast Board has agreed to find that the Utility's discharge of cooling water from the Diablo Canyon plant protects beneficial uses and that the intake technology reflects the "best technology available", under Section 316(b) of the Federal Clean Water Act. As part of the settlement, the Utility will take measures to preserve certain acreage north of the plant and will fund approximately $4.5 million in environmental projects related to coastal resources. The parties are negotiating the documentation of the settlement. The final agreement will be subject to public comment and will be incorporated in a consent decree to be entered in California's Superior Court. A claim has been filed by the California Attorney General in the Utility's bankruptcy proceeding on behalf of the Central Coast Board seeking unspecified penalties and other relief in connection with the Diablo Canyon's operation of its cooling water system.

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

operations.

PG&E NEG

In May 2000, 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 PG&E NEG to provide certain information, relative to the compliance of the Brayton Point and Salem Harbor Generating Stations with the CAA. No enforcement action has been brought by the EPA to date. PG&E NEG has had very preliminary discussions with the EPA to explore a potential settlement of this matter. As a result of this and related regulatory initiatives by the Commonwealth of Massachusetts, PG&E NEG is exploring initiatives that would assist it to achieve significant reductions of sulfur dioxide and nitrogen oxide emissions by as early as 2006 to 2010. PG&E NEG believes that it 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 will be approximately $265 million through 2006. PG&E NEG 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.

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

In September 2000, PG&E NEG settled a legal claim through certain agreements that require PG&E NEG to alter its existing wastewater treatment facilities at its Brayton Point and Salem Harbor generating facilities. PG&E NEG began the activities during 2000 and is expected to complete them in 2002 as the review and permitting process with the state has caused some delays. In addition to costs incurred in 2000, at December 31, 2000, PG&E NEG recorded a reserve in the amount of $3.2 million relating to its estimate of the remaining environmental expenses to fulfill its obligations under the agreement. In addition, PG&E NEG expects to incur approximately $4 million in capital expenditures during 2001 and into 2002 to complete the project.

LEGAL MATTERS

Utility

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

Chromium Litigation

Twelve civil suits are pending against the Utility in several California state courts. One of these suits also names PG&E Corporation as a defendant. The suits seek an unspecified amount of compensatory and punitive damages for alleged personal injuries resulting from alleged exposure to chromium in the vicinity of the Utility's gas compressor stations at Hinkley, Kettleman, and Topock, California. Currently, there are claims pending on behalf of approximately 1,250

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individuals.

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

There have been approximately 1,240 claims filed with the Bankruptcy Court (by most of the plaintiffs in the twelve cases and other individuals) alleging that exposure to chromium in soil, air or water near the Utility's compressor stations at Hinkley, Kettleman, or Topock, California caused personal injuries, wrongful death or other injuries. Approximately 1,050 of these claimants have filed claims for damages that total more than $500 million. The remaining claims seek recovery for an unknown amount of claimed damages.

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 as of December 31, 2000, the ultimate outcome of this matter will not have a material adverse impact on PG&E Corporation's or the Utility's financial condition or future results of operations.

Federal Securities Lawsuit

A complaint, Gillam, et al. v. PG&E Corporation, et al., is pending in the U.S. District Court for the Northern District of California. Certain executive officers of PG&E Corporation have also been named as defendants. 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, claims that 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 by recording as a deferred cost and capitalizing as a regulatory asset the undercollections 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. Plaintiff seeks damages in excess of $2.4 billion, punitive damages, interest, injunctive relief, and attorneys' fees.

The defendants have filed a motion to dismiss, based largely on public disclosures by PG&E Corporation, the Utility and others regarding the undercollections, 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. The motion is scheduled to be heard on December 10, 2001.

PG&E Corporation believes the allegations to be without merit and intends to present a vigorous defense.

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

Recorded Liability for Legal Matters

In accordance with SFAS No. 5, "Accounting for Contingencies," PG&E Corporation makes a provision for a liability when both it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. These

provisions are reviewed quarterly and adjusted to reflect the impacts of negotiations, settlements, rulings, advice of legal counsel, and other information and events pertaining to a particular case. The following table reflects the current year's activity to the recorded liability for legal matters for PG&E Corporation and the Utility:

(in millions)	
Beginning balance, January 1, 2001	$ 185
Provisions for liabilities	6
Payments	(2)
Adjustments	10
Ending balance, September 30, 2001	$ 199

NOTE 9: SEGMENT INFORMATION

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

Utility

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

PG&E NEG

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

services unit, PG&E Energy Services Corporation.

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

		PG&E National Energy Grou			
(in millions)	Utility	Total NEG	Integrated Energy & Marketing	Interstate Pipeline Operations	N E n
Three months ended September 30, 2001					
Operating revenues	$ 2,934	3,364	$ 3,326	$ 46	$
Intersegment revenues /(1)/	3	(3)	(14)	11	

Total operating revenues	2,937	3,361	3,312	57	
Net income (loss)	737	77	64	19	
Three months ended September 30, 2000 /(4)/					
Operating revenues	2,519	4,983	4,671	310	
Intersegment revenues /(1)/	4	29	17	12	
Total operating revenues	2,523	5,012	4,688	322	
Income (loss) from continuing operations	211	43	25	16	
Net income (loss)	211	24	25	16	
Nine months ended September 30, 2001					
Operating revenues	7,799	10,182	10,029	157	
Intersegment revenues /(1)/	9	138	109	29	
Total operating revenues	7,808	10,320	10,138	186	
Net income (loss)	433	202	152	57	
Total assets at September 30, 2001 /(3)/	24,790	9,785	8,447	1,198	
Nine months ended September 30, 2000 /(4)/					
Operating revenues	7,026	11,115	10,265	847	
Intersegment revenues/(1)/	11	84	47	37	
Total operating revenues	7,037	11,199	10,312	884	
Income (loss) from continuing operations	655	127	81	43	
Net income (loss)	655	108	81	43	
Total assets at September 30, 2000 /(3)/	$ 24,183	10,853	$ 8,424	$ 2,124	$

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

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

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

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

NOTE 10: REVISION FOOTNOTE

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

(in millions)	As Previously Reported	As Revised	As P R
	Three months ended S		
	2001		
Condensed Statements of Consolidated Operations:			
Total Operating Revenues	$ 6,301	$ 6,298	$
Total Operating Expenses	4,749	4,746	
	Nine months ended Se		
	2001		
Total Operating Revenues	$ 17,989	$ 17,981	$
Total Operating Expenses	16,330	16,322	
	Balance at		
	September 30, 2001		
Condensed Consolidated Balance Sheets:			
Cash and cash equivalents	$ 976	$ 1,020	$
Accounts Receivable - Customers	3,047	3,046	
Prepaid expenses and other	239	240	
Property, plant and equipment - Construction work-in-progress	983	2,054	
Other non-current assets	3,181	3,181	
Total Assets	33,677	34,792	
Accounts payable - Trade creditors	1,177	1,226	
Other current liabilities	1,554	1,560	
Long-term debt	6,589	7,649	
	Nine months ended Se		
	2001		
Condensed Consolidated Statements of Cash Flows:			
Accounts receivable	$ 1,295	$ 1,294	$
Accounts payable	866	875	
Other - net	157	155	
Capital Expenditures	(1,584)	(1,818)	

Long-term debt issued	2,334	2,580
Cash and cash equivalents at September 30	976	1,020
Cash paid for interest (net of amounts capitalized)	367	421

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS

PG&E Corporation is an energy-based holding company headquartered in San Francisco, California. PG&E Corporation's Northern and Central California energy utility subsidiary, Pacific Gas and Electric Company (the Utility), delivers electric service to approximately 4.6 million customers and natural gas service to approximately 3.8 million customers. On April 6, 2001, the Utility filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code (Bankruptcy Code) in the United States Bankruptcy Court for the Northern District of California (Bankruptcy Court). Under Chapter 11, the Utility retains control of its assets and is authorized to operate its business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court. On September 20, 2001, the Utility and PG&E Corporation jointly filed with the Bankruptcy Court a proposed plan of reorganization (the Plan) of the Utility under Chapter 11 of the Bankruptcy Code and their proposed disclosure statement describing the Plan. The factors causing the Utility to take this action are discussed in this Management's Discussion and Analysis (MD&A) and in Notes 2 and 3 of the Notes to the Condensed Consolidated Financial Statements.

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

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

Subsequent to the issuance of PG&E Corporation's 2000 and 1999 consolidated financial statements and unaudited report for the quarterly period ended September 30, 2001, management determined that the assets and liabilities relating to certain leases should have been consolidated. The facilities associated with the leases were under construction during 2001 (see Note 10).

This combined Quarterly Report on Form 10-Q/A, including this MD&A, contains forward-looking statements, including statements regarding management's guidance regarding earnings per share and future growth, that are necessarily subject to

various risks and uncertainties. PG&E Corporation continues to expect that its net income from operations for 2001 will be in the range of $2.70 to $2.75 per share. Management also expects that earnings per share from operations will grow by 8% to 10% in 2002. Earnings from operations exclude items impacting comparability and should not be considered an alternative to net income or an indicator of a Company's operating performance. These statements are based on current expectations and assumptions which management believes are reasonable and on information currently available to management. These forward looking statements are identified by words such as "estimates," "expects," "anticipates," "plans," "believes," and other similar expressions. Actual results could differ materially from those contemplated by the forward-looking statements. Although PG&E Corporation and the Utility are not able to predict all of the factors that may affect future results, some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or historical results include:

- the outcome of the Utility's regulatory proceedings, including the 2001 Attrition Rate Adjustment application, the retained generation ratemaking proceeding, the 1999 General Rate Case (GRC), and the succeeding GRC for the test year 2003;
- whether and to what extent the Utility is determined to be responsible for the California Independent System Operator's (ISO) charges billed to the Utility;
- the extent to which the California Department of Water Resources' (DWR) revenue requirement is allocated to the Utility and the impact such allocation may have on the Utility's financial condition and results of operation;
- the pace of the Bankruptcy Court proceedings and the effect on PG&E Corporation and PG&E NEG;
- whether the Utility's proposed plan of reorganization is confirmed by the Bankruptcy Court and becomes effective;
- the regulatory, judicial, or legislative actions (including ballot initiatives) that may be taken to meet future power needs in California, mitigate the higher wholesale power prices, provide refunds for prior power costs, or address the Utility's financial condition;
- the extent to which the Utility's under-collected wholesale power purchase costs may be collected from customers;
- any changes in the amount of transition costs the Utility is allowed to collect from its customers, and the timing of the completion of the

Utility's transition cost recovery;

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

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

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

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

- future sales levels, general economic and financial market conditions, and;

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

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

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

- the extent to which unfavorable conditions in the general economy, the energy markets or equity markets affect PG&E NEG's ability to obtain capital for its planned development projects and future acquisitions on acceptable terms while preserving PG&E NEG's credit quality;

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

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

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

- the outcome of pending litigation.

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

LIQUIDITY AND FINANCIAL RESOURCES

Utility

The California energy crisis described in Note 2 of the Notes to the Condensed Consolidated Financial Statements has had a significant negative impact on the liquidity and financial resources of the Utility. Beginning in June 2000, the wholesale price of electric power in California steadily increased to an average cost of $0.182 per kilowatt-hour (kWh) for the seven-month period June 2000 through December 2000, as compared to an average cost of $0.042 per kWh for the same period in 1999. Under California Assembly Bill (AB) 1890, the Utility's

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electric rates were frozen at levels that allowed approximately $0.054 per kWh to be charged to the Utility's customers as reimbursement for power costs incurred by the Utility on behalf of its retail customers. The excess of wholesale electricity costs above the generation-related cost component available in frozen rates resulted in an under-collection at December 31, 2000, of approximately $6.6 billion.

The difference between the actual costs incurred to purchase power and the amount recovered from customers was funded through a series of borrowings during the last quarter of 2000.

On January 16 and 17, 2001, the outstanding bonds of the Utility were downgraded to below-investment grade status. This downgrade to below investment grade status was an event of default under one of the Utility's revolving credit facilities and precluded the Utility from additional access to the capital markets. As a result, the banks stopped funding under the revolving credit facility. On January 17, 2001, the Utility began to default on maturing commercial paper obligations. In addition, the Utility was no longer able to meet its obligations to generators, qualifying facilities (QFs), the ISO, and the Power Exchange (PX), and began making partial payments of amounts owed.

After the downgrade, the PX notified the Utility that the ratings downgrade required the Utility to post collateral for all transactions in the PX day-ahead market. Since the Utility was unable to post such collateral, the PX suspended the Utility's trading privileges effective January 19, 2001, in the day-ahead market. The PX also sought to liquidate the Utility's block-forward contracts for the purchase of power. In February 2001, California Governor Gray Davis, acting under California's Emergency Services Act, commandeered the contracts valued at $243 million for the benefit of the State. The Utility, the PX, and some of the PX market participants have filed administrative claims and state court litigation against the State to recover the value of the seized contracts. The administrative claims, as well as the state court litigation, are pending. On January 19, 2001, the Utility was no longer able to continue purchasing power for its customers because of lack of creditworthiness and the State of California authorized the DWR to purchase electricity for the Utility's customers. AB 1X was passed on February 1, 2001, authorizing the DWR to enter into contracts for the purchase and sale of electric power and to issue revenue bonds to finance electricity purchases. The DWR has entered into long-term contracts with several generators for the supply of electricity. However, it continues to purchase amounts of power on the spot market at prevailing market prices.

In response to the growing crisis, on January 4, 2001, the California Public Utilities Commission (CPUC) approved an interim energy procurement rate increase of $0.01 per kWh. In addition, on March 27, 2001, the CPUC authorized an additional average rate increase in retail rates of $0.03 per kWh to pay future procurement costs.

As previously stated, beginning in June 2000, the wholesale costs of the electricity purchased from the PX and the ISO on behalf of the Utility's retail customers escalated. The Utility believes that since it has not met the creditworthiness standards under the ISO's tariff since early January 2001, the Utility should not be responsible for the ISO's purchases made to meet the Utility's net open position. (The net open position is the amount of power needed by retail electric customers that cannot be met by utility-owned generation or power under contract to the utilities.) On February 14, 2001, the Federal Energy Regulatory Commission (FERC) ordered that the ISO could buy power only on behalf of creditworthy entities. The FERC order also stated that the ISO could continue to schedule power for the Utility as long as it comes from its own generation units and is routed over its own transmission lines. Despite the FERC orders, the ISO continued to bill the Utility for the ISO's wholesale power purchases. On April 6, 2001, the FERC issued a further order directing the ISO

to implement its prior order, which the FERC clarified, applies to all third-party transactions whether scheduled or not. In light of the FERC's April 6, 2001 order, the Utility has not recorded any such estimated ISO charges after April 6, 2001 except for the ISO's grid management charge, although the Utility has accrued the full amount of the ISO charges up to April 6, 2001 in the accompanying financial statements. On June 13, 2001, the FERC denied the ISO's request for rehearing of its April 6, 2001 order.

The Utility filed a complaint in Bankruptcy Court against the ISO to prohibit the ISO from continuing to bill the Utility for the ISO's wholesale power purchases, unless and until the Utility is permitted to recover the costs of such power purchases through retail electric rates. On June 26, 2001, the Bankruptcy Court issued a preliminary injunction prohibiting the ISO from charging the Utility for the ISO's wholesale power purchases made in violation of bankruptcy law, the ISO's tariff, and the FERC's February 14 and April 6, 2001 orders. In issuing the injunction, the Bankruptcy Court noted that the FERC orders permit the ISO to schedule transactions that involve either a creditworthy buyer or a creditworthy counter-party, but noted the existence of unresolved issues regarding how to ensure these creditworthiness requirements for real-time transactions and emergency dispatch orders issued by the ISO to power sellers.

As a result of the failure of the DWR to assume the full procurement responsibility for the Utility's net open position, as was provided under AB 1X, the negative impact of the CPUC decision that created new payment obligations for the Utility and undermined its ability to return to financial viability, a lack of progress in negotiations with the State of California to provide a solution for the energy crisis, and the adoption by the CPUC of an illegal and retroactive accounting change that would appear to eliminate the Utility's true under-collected purchased power costs, the Utility filed a voluntary petition for relief under provisions of the Bankruptcy Code on April 6, 2001.

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

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

The Bankruptcy Court has appointed an Official Unsecured Creditors' Committee

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(Committee). In accordance with the provisions of the Bankruptcy Code, the Committee has the right to be heard on all matters that come before the Bankruptcy Court.

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

On September 20, 2001, the Utility and PG&E Corporation, jointly filed with the Bankruptcy Court a proposed plan of reorganization (the Plan) of the Utility under the Bankruptcy Code and their proposed disclosure statement describing the Plan (see Note 3 for a description of the Plan). On October 2, 2001, the Utility filed with the Bankruptcy Court the Support Agreement between the Utility and the Committee under which the Committee has agreed to support the Plan under the conditions specified in the agreement. The Bankruptcy Court must find that the disclosure statement contains adequate information to make an informed judgment in voting to accept or reject the Plan. The Bankruptcy Court has set a hearing date of December 19, 2001, to consider the adequacy of the disclosure statement. Upon Bankruptcy Court approval, the disclosure statement will be sent to holders of claims against, and equity interests in, the Utility in connection with the solicitation of acceptances of the Plan. Bankruptcy Court approval of the disclosure statement does not constitute a determination by the Bankruptcy Court as to the merits of the Plan or an indication that the Bankruptcy Court will confirm the Plan.

Whether the Plan becomes effective and whether the Plan is implemented in accordance with management's projections and assumptions, are necessarily subject to various risks and uncertainties that could cause actual results to differ materially from those contemplated by management. Some of the factors that could affect the outcome materially include: the pace of the Bankruptcy Court proceedings; the extent to which the Plan is amended or modified; risks relating to the issuance of new debt securities by each of the disaggregated entities, including higher interest rates than are assumed in the financial projections which could affect the amount of cash raised to satisfy allowed claims, and the inability to successfully market the debt securities due to, among other reasons, an adverse change in market conditions or in the condition of the disaggregated entities before completion of the offerings; whether the Bankruptcy Court exercises its authority to pre-empt relevant non-bankruptcy law and if so, whether and the extent to which such assertion of jurisdiction is successfully challenged; whether a favorable tax ruling or opinion is obtained regarding the tax-free nature of the Internal Restructuring and the Spin-Off (as such terms are defined in Note 3 of the Notes to the Consolidated Financial Statements); and the ability of the Utility to successfully disaggregate its businesses.

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

PG&E Corporation

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

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

PG&E Corporation itself had cash and short-term investments of $256 million at September 30, 2001, and believes that the funds will be adequate to maintain PG&E Corporation's continuing operations through 2002. In addition, PG&E Corporation believes that the holding company and its non-CPUC regulated subsidiaries are protected from the bankruptcy of the Utility.

PG&E NEG

General

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

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

On May 22, 2001, PG&E NEG completed an offering of $1 billion in senior unsecured notes and received net proceeds after bond discount of approximately $972 million. PG&E NEG used a portion of the proceeds and intends to use the balance of the senior notes issuance, net of $28 million of debt discount and note issuance costs, to pay down existing revolving debt, fund investments in generating facilities and pipeline assets, working capital requirements, and other general corporate requirements. These senior notes have an aggregate

principal amount of $1 billion, bear interest at 10.375% per annum, and mature on May 16, 2011.

In addition, PG&E Corporation historically has provided to PG&E NEG credit support for a range of contractual commitments. With respect to generating facilities, this credit support has included agreements to infuse equity in specific projects when these projects begin operations or when a project that has been leased is purchased. PG&E Corporation also has provided guarantees of PG&E NEG obligations under several long-term tolling arrangements and as collateral for commitments under various energy trading contracts entered into by its energy trading operations to provide short-term collateral to counter-parties. As of September 30, 2001, except for $8 million of guarantees relating to various energy trading master contracts, all PG&E Corporation equity infusion agreements and guarantees have been replaced with PG&E NEG equity infusion agreements, guarantees, or other forms of security.

In connection with the replacement of PG&E Corporation guarantees with PG&E NEG guarantees, and with the continued growth of energy trading and marketing positions, PG&E NEG has experienced a substantial increase in the need for various liquidity facilities to provide letters of credit and cash deposits with various counter-parties. On June 15, 2001, PG&E NEG established a $550 million revolving credit facility (which includes the ability to issue letters of credit) with a syndicate of banks to support PG&E NEG's energy trading operations and other working capital requirements. The $550 million revolving credit facility was subsequently increased to $1.25 billion on August 23, 2001. On September 30, 2001, $156 million of letters of credit, and $295 million in borrowings were outstanding under this facility.

Generating Projects in Development

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

Further, PG&E Corporation has previously stated that it expects PG&E NEG to contribute 30% to consolidated earnings per share from operations by the end of 2002. Given the current circumstances of the energy and equity markets as discussed above, management does not expect that this goal can be achieved. Nevertheless, management expects that PG&E NEG will contribute roughly 20% to 25% to consolidated earnings from operations in 2001 and that it will contribute roughly the same percentage in 2002.

STATEMENTS OF CASH FLOWS

PG&E Corporation normally funds investing activities from cash provided by operations after capital requirements, and to the extent necessary, external

financing. Our policy is to finance our investments with a capital structure that minimizes financing costs, maintains financial flexibility, and with regard to the Utility, complies with regulatory guidelines. However, the Utility is currently operating as a debtor-in-possession under Chapter 11 of the Bankruptcy Code. While certain pre-petition debts are stayed, the Utility does not have access to external funding from the capital markets.

PG&E Corporation Consolidated

Net cash provided by PG&E Corporation's operating activities totaled $1,799 million and $1,257 million for the nine months ended September 30, 2001 and 2000, respectively. The increase of $542 million between 2001 and 2000 is attributable to the volatility caused by the California energy crisis previously discussed.

Cash Flows from Investing Activities

Cash used in investing activities was $2,053 million during the nine months ended September 30, 2001, compared with $2,014 million used during the same period for 2000. In 2001, the primary use of cash for investing activities was $1,818 million for additions to property, plant, and equipment, compared with $1,691 million used for similar purposes in 2000.

Cash Flows from Financing Activities

Cash generated through financing activities was $349 million and $804 million for the nine months ended September 30, 2001, and 2000, respectively. A loan in 2001 netted $906 million in proceeds which together with cash on hand and from operating activities, were used to repay defaulted commercial paper, other loans, and the $109 million in dividends. The $804 million provided by financing activities in 2000 resulted from increased borrowings of $894 million offset by a dividend payment of $325 million.

Utility

The following section discusses the Utility's significant cash flows from operating, investing, and financing activities for the nine-month periods ended September 30, 2001 and 2000.

Cash Flows from Operating Activities

Net cash provided by the Utility's operating activities totaled $1,279 million and $1,297 million for the nine months ended September 30, 2001 and 2000, respectively. The decrease of $18 million between 2001 and 2000 is primarily attributable to higher cost of gas, offset by partial payment of pre-petition obligations.

Cash Flows from Investing Activities

The primary uses of cash for investing activities are additions to property,

plant, and equipment. The Utility's capital expenditures for the nine months ended September 30, 2001, were $889 million.

Cash Flows from Financing Activities

During the nine months ended September 30, 2001, the Utility did not declare any preferred or common stock dividends, compared with a payment of dividends on its common and preferred stock of $375 million for the nine months ended September 30, 2000. The Utility has suspended payment of its common and preferred dividends due to its financial condition. Dividends on preferred stock are cumulative. Until cumulative dividends on preferred stock are paid, the Utility may not pay any dividends on its common stock to, or repurchase its common stock from, PG&E Corporation and PG&E Holdings, LLC.

The Utility's long-term debt that either matured, was redeemed, or was repurchased during the nine months ended September 30, 2001, totaled $325 million. Of this amount, $213 million related to the Utility's rate reduction bonds maturing, $93 million related to mortgage bonds maturing, and $19 million related to the maturities and redemption of various Utility medium-term notes and other debt.

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

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

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

Due to the bankruptcy filing, the Utility is unable at this time to repay unsecured pre-petition creditors. The Utility has not made interest payments on the following unsecured debt: medium-term notes, pollution control loan agreements, the 7.375% senior notes, the $1.24 billion floating rate notes, commercial paper, bank loans, or other unsecured debt. The Utility has not made principal payments on $1,242 million of unsecured debt that matured from July 2001 through October 2001.

The Utility is accruing interest on all unpaid debt obligations and compounding interest at interest rates described in the Plan.

The Utility is in default under the credit provider's reimbursement agreements, and consequently four credit providers have declared $454 million of the pollution control loan agreements due and payable. The redemptions were funded by drawdowns on the letters of credit. Interest payments are current on the remaining $814 million pollution control loan agreements.

The Utility received notice from the trustee of the Cumulative Quarterly Income Preferred Securities (QUIPS) that the Utility's bankruptcy filing was an event of default under the trust agreement and that the trustee will take steps to liquidate the trust and distribute the 7.90% deferrable interest subordinated

debentures to bondholders. As of September 30, 2001, the Company Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures have been reclassified to liabilities subject to compromise on the Condensed Consolidated Balance Sheets.

PG&E NEG

The following section discusses PG&E NEG's significant cash flows from operating, investing, and financing activities for the nine-month period ended September 30, 2001 and 2000.

Cash Flows from Operating Activities

During the nine months ended September 30, 2001, PG&E NEG generated net cash of $334 million in operating activities. Net cash from operating activities before changes in other working capital accounts was $149 million, primarily driven by increased net income. Net cash inflow related to certain other working capital accounts was $185 million, driven primarily by deliveries of previously held forward positions in trading.

Cash Flows from Investing Activities

During the nine months ended September 30, 2001, PG&E NEG used net cash of $1,165 million in investing activities. PG&E NEG's cash outflows from investing activities were primarily attributable to capital expenditures on generating projects in construction, turbine prepayments, and advanced development of generating capacity.

Cash Flows from Financing Activities

Net cash generated by financing activities was $837 million for the nine months ended September 30, 2001 principally from the net proceeds related to the senior notes.

RESULTS OF OPERATIONS

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

		PG&E National Energy Group			
	Utility	Total NEG	Integrated Energy & Marketing	Interstate Pipeline Operations	NEG Elimi-nations

(in millions)					
Three months ended September 30, 2001					
Operating revenues	$ 2,937	$ 3,361	$ 3,312	$ 57	$ (8)
Operating expenses	1,509	3,225	3,205	28	(8)
Operating income					
Reorganization interest income					
Interest income					
Interest expense					
Other income (expenses), net					
Income taxes					
Net income					
Net cash provided by operating activities					
Net cash used by investing activities					
Net cash provided by financing activities					
EBITDA/(2)/	1,639	177	132	42	3
Three months ended September 30, 2000/3/					
Operating revenues	2,523	5,012	4,688	322	2
Operating expenses	1,990	4,919	4,646	272	1
Operating income					
Interest income					
Interest expense					
Other income (expenses), net					
Income taxes					
Income from continuing operations					
Net income					
Net cash used by operating activities					
Net cash used by investing activities					
Net cash provided by financing activities					
EBITDA/(2)/	(446)	104	68	54	(18)
Nine months ended September 30, 2001					
Operating revenues	7,808	10,320	10,138	186	(4)
Operating expenses	6,464	9,974	9,897	80	(3)
Operating income					
Reorganization interest income					
Interest income					
Interest expense					
Other income (expenses), net					
Income taxes					
Net income					
Net cash provided by operating activities					
Net cash used by investing activities					
Net cash provided by financing activities					
EBITDA/(2)/	1,976	468	324	141	3
Nine months ended September 30,					

2000					
Operating revenues	7,037	11,199	10,312	884	3
Operating expenses	5,382	10,914	10,180	732	2
Operating income					
Interest income					
Interest expense					
Other income (expenses), net					
Income taxes					
Income from continuing operations					
Net income					
Net cash provided by operating activities					
Net cash used by investing activities					
Net cash provided by financing activities					
EBITDA/(2)/	$ 1,006	$ 357	$ 205	$ 170	$ (18)

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

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

/(3)/ Segment information for the prior period has been restated to conform with new segment presentation (see Note 9 of the Notes to the Condensed Consolidated Financial Statements).

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Overall Results

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

PG&E Corporation's net income for the third quarter ended September 30, 2001, was $771 million, compared to net income of $225 million for the same period in 2000, representing an increase of $546 million. The Utility's net income available for common stock for the quarter ended September 30, 2001, accounted for $526 million of the increase.

PG&E Corporation's net income for the nine-month period ended September 30, 2001, was $570 million compared to net income of $753 million for the same period in 2000. Of the $183 million net decrease from the prior nine-month period in 2000, the Utility was responsible for virtually all of the decrease, somewhat offset by a $94 million increase in net income at PG&E NEG.

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

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

.. Due to the lack of a regulatory, legislative, or judicial solution to the California energy crisis, the Utility cannot defer for future recovery its under-collected purchased power costs. These costs have been expensed as incurred, and as a result the Utility's earnings were affected. Beginning in June 2001, the Utility began collecting revenues associated with the CPUC's March 27, 2001 interim energy procurement surcharges. As a result, the Utility's generation-related component of its electric revenues was greater than its generation-related costs. This differential resulted in an increase to earnings of $687 million in the third quarter of 2001, and $124 million year-to-date. In addition, for the nine-month period ended September 30, 2001, revenues include $327 million (after-tax) related to the market value of certain terminated bilateral contracts.

.. As a result of the liquidity crisis attributable to the California energy crisis, PG&E Corporation has significantly increased its borrowings and unpaid debts accruing interest. Additionally, the effective interest rate paid on these new borrowings has also increased because of the higher risk associated with PG&E Corporation's financial position. The incremental cost of these borrowings was $62 million, after-tax, for the quarter ended September 30, 2001, and $165 million, after-tax, for the nine-month period ended September 30, 2001.

.. The Utility's filing of a petition of reorganization under Chapter 11 of the Bankruptcy Code has resulted in incremental expenses associated with the development of a plan of reorganization. For the quarter ended September 30, 2001, these fees and expenses amounted to approximately $25 million after-tax. For the nine-month period ended September 30, 2001, total incremental expenses

were approximately $50 million after-tax.

.. During the three-month period ending September 30, 2001, the Utility incurred losses of approximately $66 million after-tax associated with the involuntary termination of gas transportation hedges caused by a decline in the Utility's credit rating.

.. During the third quarter of 2001, the CPUC issued two decisions modifying its previous decision in the Utility's 1999 General Rate Case. The first, to correct a tax computation error, had the impact of adding approximately $33 million to net income (approximately $24 million related to 1999 and 2000) and the second modification had the impact of decreasing net income by approximately $21 million of which $15 million related to 1999 and 2000.

.. PG&E NEG increased earnings by $56 million for the three-month period ended September 30, 2001, over the same period in 2000. For the nine-month period ended September 30, 2001, earnings increased by $94 million as compared to the same period in 2000. This increase was the result of higher gross margins at the wholesale energy business, the sale of a development project, and a lower effective federal tax rate. In addition, a $19 million loss on discontinued operations was recorded in the third quarter of 2000, which had a favorable impact on the comparative results for the three- and nine-month periods ended September 30, 2001.

Dividends

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

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

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

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

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Utility

Overall Results

The Utility's income available for common stock was $737 million for the quarter ended September 30, 2001, compared to $211 million for the same period in 2000. This increase in income of $526 million, or 249%, was primarily the result of increased generation-related electric operating revenues no longer subject to balancing account deferrals and decreased depreciation, amortization, and decommissioning expenses associated with previously written-off generation-related transition costs. The increased income was reduced somewhat by increased interest expenses and costs associated with the bankruptcy.

The Utility's income available for common stock was $433 million for the nine-month period ended September 30, 2001, compared to $655 million for the same period in 2000. This decrease in income of $222 million is primarily attributable to the increased cost of electric energy partially offset by decreased depreciation, amortization, and decommissioning expenses associated with generation-related transition costs previously written-off, and increased interest expense and costs associated with the bankruptcy.

Operating Income

The Utility's operating income was $1,428 million for the quarter ended September 30, 2001, compared to operating income of $533 million for the same period in 2000. This increase in operating income is primarily attributable to the increase in generation-related electric revenues no longer subject to balancing account deferrals as well as lower depreciation expenses during the period as a result of the write-off taken in December 2000.

The Utility's operating income was $1,344 million for the nine months ended September 30, 2001, compared to operating income of $1,655 million for the same period in 2000. This decrease in operating income is primarily due to decreased electric revenues, and increased cost of electric energy partially offset by decreased depreciation, amortization, and decommissioning expenses, as a result of the write-off taken in December 2000.

Operating Revenues

The Utility's operating revenues for the quarter ended September 30, 2001, were $2,937 million in 2001, and $2,523 million in 2000, an increase of 16%. Electric revenues increased by $510 million, or 26%, for the quarter ended September 30, 2001, primarily due to the interim energy procurement surcharges, which were levied in 2001. Historically, these revenues would have been recorded in a balancing account and applied against transition costs. Those costs were written-off in 2000 and all generation-related revenues and costs are recognized as incurred. The total surcharges billed for the third quarter of 2001 were approximately $1 billion, but were reduced by approximately $645 million of revenues collected for electricity provided to the Utility's customers by DWR.

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Revenues collected on behalf of the DWR and the related costs are not reflected in the Utility's Condensed Consolidated Statements of Operations as the Utility is a collection agent for the DWR. In addition, electric revenues increased because of lower direct access credits and partially offset by customer conservation.

The Utility's gas revenues decreased $96 million for the quarter ended September 30, 2001, compared with the same period in 2000 due to customer conservation efforts and decreased usage by retail customers resulting from milder weather conditions.

The Utility's operating revenues for the nine-month period ended September 30, 2001, were $7,808 million compared to operating revenues of $7,037 million for the same period in 2000. The increase of $771 million, or 11%, is due to the increase in gas revenues of $907 million and decrease in electric revenues of $136 million for the nine-month period ended September 30, 2001, compared with the same period in 2000, respectively. The increase in gas revenues was primarily due to higher average costs of gas, which are passed on directly to retail customers.

The decrease in electric revenues was primarily the result of the reduction to revenue resulting from a portion of the Utility's billed revenues being passed through directly to the DWR for the DWR's electricity purchases. This reduction was largely offset by increased revenues from energy procurement and the 2001 interim energy procurement surcharges. Revenues increased by $1.5 billion for the surcharges billed but were reduced by $1.8 billion of revenue collected for electricity provided to the Utility's customer by the DWR. In addition, revenues decreased because the Utility experienced lower usage due to customer conservation efforts offset by lower direct access credits.

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

For the nine-month period ended September 30, 2001, the estimated total of accumulated credits for direct access customers is approximately $368 million. Such amounts are reflected on the Utility's Condensed Consolidated Balance Sheet. The actual amount that will be refunded to ESPs or directly to the customer will be dependent upon the outcome of the Utility's bankruptcy proceeding, when the rate freeze ends, and whether there are any adjustments made to wholesale energy prices by the FERC.

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Operating Expenses

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

	Three months ended September 30, 2001	Three months ended September 30, 2000	Increase (Decrease)	Perce Inc (Dec
Operating Expenses				
Cost of electric energy	$ 434	$ 2,056	$ (1,622)	
Deferred electric procurement costs	-	(2,176)	2,176	
Cost of gas	263	178	85	
Operating and maintenance	563	730	(167)	
Depreciation, amortization, and decommissioning	224	1,202	(978)	
Reorganization professional fees and expenses	25	-	25	
Total operating expenses	$ 1,509	$ 1,990	$ (481)	

	Nine months ended September 30, 2001	Nine months ended September 30, 2000	Increase (Decrease)	Perc Inc (Dec
Operating Expenses				
Cost of electric energy	$ 2,389	$ 3,544	$ (1,155)	
Deferred electric procurement costs	-	(2,789)	2,789	

Cost of gas	1,608	643	965
Operating and maintenance	1,771	1,824	(53)
Depreciation, amortization, and decommissioning	663	2,160	(1,497)
Reorganization professional fees and expenses	33	-	33
Total operating expenses	$ 6,464	$ 5,382	$ 1,082

The cost of electric energy decreased by $1,622 million for the quarter ended September 30, 2001, compared to the same period in 2000 due to wholesale electricity purchases made by the DWR for the Utility's net short position in 2001, which are not reflected in the Utility's financial statements, and due to the lower average cost of electricity in 2001. The average cost was $0.18 per kWh in the summer of 2000, compared with $0.10 per kWh in the summer of 2001.

The cost of electric energy decreased by $1,155 million for the nine-month period ended September 30, 2001, compared to the same period in 2000. This was due to wholesale electricity purchases made by the DWR for the Utility's net open position in 2001, which are not reflected in the Utility's financial statements, and due to the lower average cost of electricity in 2001 compared with 2000. The average cost in 2001 decreased by approximately $0.08 per kWh, compared with the 2000 average cost. In addition, there was a statewide energy conservation campaign in effect, and cooler summer weather throughout the region in the third quarter of this year, which moderated customers' usage, compared with the same period last year.

For the three- and nine-month periods ended September 30, 2000, generation-related costs of $2.1 billion and $2.8 billion, respectively, were deferred and subsequently written off at December 31, 2000.

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The cost of gas increased by $85 million for the quarter ended September 30, 2001 due to losses associated with the involuntary termination of gas transportation hedges caused by a decline in the Utility's credit rating.

The cost of gas increased by $965 million for the nine-month period ended September 30, 2001, compared to the same period in 2000. The average cost of gas was $6.38 per decatherm (DTh) for the nine-month period ended September 30, 2001, compared to $2.93 per DTh for the same period in the prior year. The procurement costs for gas are passed directly to the customers.

The Utility's operating and maintenance expenses decreased $167 million for the quarter ended September 30, 2001, and decreased $53 million for the nine-month period ended September 30, 2001, compared to the same periods in 2000. The decrease of $167 million is primarily attributable to the impact in 2000 of an unscheduled 10-day outage at Diablo Canyon with no such outage in 2001, and the decrease in other generation-related costs

Depreciation, amortization, and decommissioning decreased by $978 million for the quarter ended September 30, 2001, and $1,497 million for the nine-month period ended September 30, 2001, compared to the same periods in 2000. These decreases were the result of the lower depreciation expenses due to last year's accelerated amortization of generation-related assets and the write-off of generation-related transition costs in December 2000.

Dividends

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

PG&E NEG

Operating Income

Operating income at PG&E NEG was $136 million for the third quarter ended September 30, 2001, compared to $93 million for the same period in 2000. For the nine-month period ended September 30, 2001, operating income was $346 million, compared to $285 million for the same period in 2000.

Operating Revenues

Operating revenues were $3.4 billion in the three months ended September 30, 2001, a decrease of $1.7 billion, or 33%, from the three months ended September 30, 2000. This decline in operating revenues occurred principally in the wholesale energy trading business with a decrease of $1.4 billion primarily due to a decline in volume and realized prices in the third quarter of 2001 as compared to the same period last year. In the pipeline segment, the decline in operating revenues of $265 million is primarily due to the sale of PG&E GTT in December 2000.

Operating revenues were $10.3 billion in the nine months ended September 30, 2001, a decrease of $879 million, or 8%, from the nine months ended September 30, 2000. This decline in operating revenues occurred principally in the wholesale energy trading business mainly due to a decline in volume and realized prices, primarily in the third quarter of 2001, as compared to the prior year. In the pipeline segment, the decline in operating revenues of $698 million is primarily due to the sale of PG&E GTT in December 2000.

Operating Expenses

Operating expenses were $3.2 billion in the three months ended September 30, 2001, a decrease of $1.7 billion, or 34%, from the three months ended September 30, 2000. This decline in operating expenses occurred principally in the wholesale energy trading business with a decrease of $1.4 billion due to a decline in volume and realized prices in the third quarter of 2001 as compared to the same period last year. In the pipeline segment, the decline in operating expenses of $244 million is primarily due to the sale of PG&E GTT in December 2000.

Operating expenses were $10 billion in the nine months ended September 30, 2001, a decrease of $940 million, or 9%, from the nine months ended September 30, 2000. This decline in operating expenses occurred principally in the wholesale energy trading business mainly due to a decline in volume and realized prices, primarily in the third quarter of 2001, as compared to the prior year. In the pipeline segment, the decline in operating expenses of $652 million is primarily due to the sale of PG&E GTT in December 2000.

Dividends

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

REGULATORY MATTERS

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

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

The Utility's 1999 GRC

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

On October 16, 2001, the CPUC issued a decision, voted on at the CPUC's October 10, 2001 meeting, granting applications for rehearing that had been filed by The Utility Reform Network (TURN) and another party with respect to the CPUC's February 17, 2000 decision in the Utility's 1999 GRC for the period 1999 to 2001. As previously disclosed, the applications for rehearing which had been pending since March 2000, alleged that the CPUC committed legal error by approving funding in certain areas that were not adequately supported by record evidence.

In the decision, the CPUC found that in proposing a general rate increase, the Utility has the obligation to produce clear and convincing evidence for each component of its proposed revenue requirements, and the CPUC cannot grant the requested increase to the extent the Utility fails to meet that obligation. In the rehearing decision, the CPUC reversed in part its prior determination regarding the adequacy of the evidence supporting the original 1999 GRC decision and reduced the adopted electric and gas distribution annual revenue requirement by approximately $40 million.

In addition, the decision orders the record to be reopened to receive evidence of the actual level of 1998 electric distribution capital spending in relation to the forecast used to determine 1999 rates, possibly resulting in an adjustment of the adopted 1998 forecast level to conform to the 1998 recorded level.

Following the 1998 capital spending rehearing and resolution of all other outstanding matters, a final Results of Operations analysis will be performed, and a final revenue requirement will be determined. The decision apparently intends that the revised revenue requirement would be made retroactive to January 1, 1999.

The Utility is evaluating further CPUC and judicial review options. A petition for review of the rehearing decision by the California Supreme Court or the Court of Appeal would be filed by November 14, 2001.

The Utility's 2002 GRC

As previously disclosed, the procedural schedule in the Utility's 2002 GRC, which would determine revenue requirements for the period 2002 through 2005, has been delayed. On October 25, 2001, the CPUC issued a decision requiring the Utility to file a 2003 test year GRC (rather than a 2002 test year) by November 14, 2001. The CPUC stated that its goal is to have new rates "in place" by January 1, 2003.

In the order, the CPUC requested that the Utility and others file comments by November 9, 2001 on whether the Utility needs a 2002 attrition rate adjustment (ARA) as compared to rates authorized in the Utility's 1999 GRC. The Utility intends to file comments stating the need for a 2002 ARA increase.

The Utility's Retained Generation Ratemaking Proceeding

In June 2001, the Utility filed its proposed ratemaking for retained utility generation facilities and procurement costs still incurred by the Utility. The Utility's proposal requested that the ratemaking for its retained generating facilities be set in accordance with previous and still effective CPUC decisions under AB 1890. Under Public Utilities Code (PUC) Section 377, as amended in January 2001, utilities are prohibited from divesting their retained generating plants before January 1, 2006. However, PUC Section 377 as amended does not modify or repeal PUC Section 367, which still requires the CPUC to market value the generating assets of each utility by no later than December 31, 2001 based on appraisal, sale, or other divestiture. Under the CPUC's previous AB 1890 decisions, the market valuation of the Utility's retained non-nuclear generating

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facilities is to be used to pay off transition costs. The Utility believes it is entitled to recover whatever market value is credited against transition cost recovery. Further, the ratemaking for the Utility's Diablo Canyon is based on a specific "benefit sharing" formula established in a 1997 CPUC decision.

On October 25, 2001, the CPUC issued a decision denying the Utility's request that the market value of its retained utility generating facilities be used to establish prospective ratemaking for those facilities in the CPUC's retained generation proceeding. The CPUC said its decision did not address how to treat past uneconomic costs incurred by the Utility and that when issues concerning the termination of the rate freeze are resolved, the CPUC should address any impacts on ratemaking for the Utility's retained generation. Although hearings were concluded in July 2001, the CPUC has not yet issued a proposed decision establishing the Utility's retained generation revenue requirement. Once a proposed decision is issued, the Utility will have a chance to comment on it before the CPUC issues the final decision.

Order Instituting Investigation into Holding Company Activities

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

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

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

in the ratesetting category.

The Utility's 2001 ARA

In July 2000, the Utility filed an ARA application with the CPUC to increase its 2001 electric distribution revenues by $189 million, effective January 1, 2001. The increase reflects inflation and the growth in capital investments necessary to serve customers. The Utility did not request an increase in gas distribution revenues. In December 2000, the CPUC issued an interim order finding that a decision on the application could not be rendered by January 1, 2001, and determining that if attrition relief is eventually granted, that relief will be effective as of January 1, 2001. This matter was heard and briefed in June, July, and August 2001. During the course of hearings, the Utility reduced its requested electric rate increase to $185 million. Although the CPUC's Office of Ratepayer Advocates and one other party recommended that the Utility's request be denied on policy grounds, the Utility believes that their recommendations are unreasonable and that the Utility's request for an electric revenue increase is fully justified by the record in this proceeding. The ALJ has issued a draft decision authorizing an increase in electric distribution revenues of approximately $151 million, effective January 1, 2001. The matter is currently scheduled to be considered at the CPUC's December 11, 2001 decision conference.

The Utility's Cost of Capital Proceedings

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

The Utility's FERC Transmission Rate Cases

Electric transmission revenues, and both wholesale and retail transmission rates are subject to authorization by the FERC. The FERC has not yet acted upon a settlement filed by the Utility that, if approved, would allow the Utility to recover $391 million in electric transmission rates for the 14-month period of April 1, 1998, through May 31, 1999. During this period, somewhat higher rates have been collected, subject to refund. A FERC order approving this settlement is expected by the end of 2001. The Utility has accrued $29 million for potential refunds related to the 14-month period ended May 31, 1999. In April 2000, the FERC approved a settlement that permits the Utility to recover $298

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

In March 2001, the Utility filed at FERC to increase its power and transmission related rates to the Western Area Power Administration (Western). The majority of the requested increase is related to passing through market power prices billed to the Utility by the ISO and others for services, which apply to Western under a pre-existing contract between the Utility and Western. On September 21, 2001, the FERC Administrative Law Judge (ALJ) issued an Initial Decision denying the Utility the ability to increase the rates as requested. On October 24, 2001, the FERC confirmed the ALJ Initial Decision in its entirety. Pending any decision by the Utility to appeal the FERC decision, until December 31, 2004, the date the Western contract expires, Western's rates will continue to be calculated on a yearly basis pursuant to the formula specified in Western's contact. Any revenue shortfall resulting from these rates is collectible as a retail customer stranded cost.

The Utility's Gas Accord II Application

On October 9, 2001, the Utility filed a Gas Accord II Application with the CPUC, requesting a two-year extension, without modification, of the existing Gas Accord. This filing was made in response to a recent CPUC order, which directed the Utility to file a Gas Accord II application.

Under the Utility's proposal, those provisions of the Gas Accord currently scheduled to expire on January 1, 2003, will be extended through December 31, 2004, while certain storage-related provisions scheduled to expire on April 1, 2003 will be extended through March 31, 2005. No change in the previously approved rates in effect as of December 2002 or, in the case of certain storage provisions, as of March 31, 2003, is proposed. The Utility believes the two-year extension that has been proposed will allow for resolution of many uncertainties affecting gas markets today, including the Utility's proposed plan of reorganization.

The Utility's Federal Lawsuit

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

On May 2, 2001, the court dismissed the Utility's complaint, without prejudice to refile the lawsuit at a later time, on the ground that the suit was premature since two of the challenged CPUC decisions were not yet final. On August 6, 2001, the Utility refiled its complaint in the United States District Court for

the Northern District of California, based on the fact that the CPUC's decisions referenced in the Court's order had become final under California law. The CPUC and TURN filed motions to dismiss the complaint. The previously scheduled hearing date for the motions of November 7, 2001, has been postponed by the court and a new hearing date has not been set.

ENVIRONMENTAL MATTERS

PG&E Corporation and the Utility are subject to laws and regulations established to both maintain and improve the quality of the environment. Where PG&E Corporation's and the Utility's properties contain hazardous substances, these laws and regulations require PG&E Corporation and the Utility to remove those substances or remedy effects on the environment. See Note 8 of the Notes to the Consolidated Financial Statements for further discussion of environmental matters.

Utility

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

At September 30, 2001, the Utility expects to spend $319 million, undiscounted, for hazardous waste remediation costs at identified sites, including divested fossil-fueled power plants. The cost of the hazardous substance remediation ultimately undertaken by the Utility is difficult to estimate. A change in the estimate may occur in the near term due to uncertainty concerning the Utility's responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives. If other potentially responsible parties are not financially able to contribute to these costs or further investigation indicates that the extent of contamination or necessary remediation is greater than anticipated, the Utility could spend as much as $471 million on these costs. The Utility estimates the upper limit of the range using assumptions least favorable to the Utility, based upon a range of reasonably possible outcomes. Costs may be higher if the Utility is found to be responsible for clean-up costs at additional sites or expected outcomes change.

The Utility had an environmental remediation liability of $319 million and $320 million at September 30, 2001, and December 31, 2000, respectively. The $319 million accrued at September 30, 2001, includes (1) $139 million related to the pre-closing remediation liability, associated with divested generation facilities, and (2) $180 million related to remediation costs for those generation facilities that the Utility still owns, manufactured gas plant sites, and gas gathering compressor stations. Of the $319 million environmental remediation liability, the Utility has recovered $193 million through rates, and expects to recover another $109 million in future rates. The Utility also is recovering its costs from insurance carriers and from other third parties as appropriate.

On June 28, 2001, the Bankruptcy Court entered its "Order on Debtor's Motion for Authority to Continue Its Hazardous Substances Cleanup Program." The Utility is

authorized to expend (i) up to $22 million in each calendar year in which the Chapter 11 case is pending to continue its hazardous substance remediation programs and procedures, and (ii) any additional amounts necessary in emergency situations involving post-petition releases or threatened releases of hazardous substances, if such excess expenditures are necessary in the Utility's reasonable business judgment to prevent imminent harm to public health and safety or the environment (provided that the Utility seeks the Court's approval of such emergency expenditures at the earliest practicable time), in each case as described in the Utility's motion.

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

In December 1999, the Utility was notified by the purchaser of its former Moss Landing power plant that it had identified a cleaning procedure used at the plant that released heated water from the intake, and that this procedure is not specified in the plant's National Pollutant Discharge Elimination System (NPDES) permit issued by the Central Coast Regional Water Quality Control Board (Central Coast Board). The purchaser notified the Central Coast Board of its findings. In March 2000, the Central Coast Board requested the Utility to provide specific information regarding the "backflush" procedure used at Moss Landing. The Utility provided the requested information to the Board in April 2000. The Utility's investigation indicated that while it owned Moss Landing, significant amounts of water were discharged from the cooling water intake. While the Utility's investigation did not clearly indicate that discharged waters had a temperature higher than ambient receiving water, the Utility believes that the temperature of the discharged water was higher than that of the ambient receiving water. In December 2000, the executive officer of the Central Coast Board made a settlement proposal to the Utility under which the Utility would pay $10 million, a portion of which would be used for environmental projects and the balance of which would constitute civil penalties. A proof of claim has been filed by the California Attorney General in the Utility's bankruptcy proceeding on behalf of the Central Coast Board seeking unspecified penalties for alleged discharges of heated cooling water from Moss Landing. Settlement negotiations are continuing.

The Utility's Diablo Canyon employs a "once through" cooling water system, which is regulated under a NPDES Permit, issued by the Central Coast Board. This permit allows Diablo Canyon to discharge the cooling water at a temperature no more than 22 degrees above ambient receiving water and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, marine and wildlife habitat, shellfish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft Cease and Desist Order (CDO) alleging that, although the temperature limit has never been exceeded, Diablo Canyon's discharge was not protective of beneficial uses. In October 2000, the Central Coast Board and the Utility reached a tentative settlement of this matter pursuant to which the Central Coast Board has agreed to find that the Utility's discharge of cooling water from the Diablo Canyon plant protects beneficial uses and that the intake technology reflects "best technology available" under Section 316(b) of the Federal Clean Water Act. As part of the settlement, the Utility will take measures to preserve certain acreage north of the plant and will fund approximately $5 million in environmental projects related to coastal resources. The parties are negotiating the documentation of the settlement. The final agreement will be subject to public comment and will be incorporated in a consent decree to be entered in California Superior Court. A claim has been filed by the California Attorney General in the Utility's bankruptcy proceeding on behalf of the Central Coast Board seeking unspecified penalties and other relief in connection with the Diablo Canyon's operation of its cooling water system.

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

PG&E NEG

In May 2000, 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 PG&E NEG to provide certain information, relative to the compliance of the Brayton Point and Salem Harbor Generating Stations with the CAA. No enforcement action has been brought by the EPA to date. PG&E NEG has had very preliminary discussions with the EPA to explore a potential settlement of this matter. As a result of this and related regulatory initiatives by the Commonwealth of Massachusetts, PG&E NEG is exploring initiatives that would assist it to achieve significant reductions of sulfur dioxide and nitrogen oxide emissions by as early as 2006 to 2010. PG&E NEG believes that it 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 will be approximately $265 million through 2006. PG&E NEG 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.

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

In September 2000, PG&E NEG settled a legal claim through certain agreements that require PG&E NEG to alter its existing wastewater treatment facilities at its Brayton Point and Salem Harbor generating facilities. PG&E NEG began the activities during 2000 and is expected to complete them in 2002 as the review and permitting process with the state has caused some delays. In addition to costs incurred in 2000, at December 31, 2000, PG&E NEG recorded a reserve in the amount $3.2 million relating to its estimate of the remaining environmental expenses to fulfill its obligations under the agreement. In addition, PG&E NEG expects to incur approximately $4 million in capital expenditures during 2001 and into 2002 to complete the project.

PRICE RISK MANAGEMENT ACTIVITIES

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

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

Market Risk

Commodity Price Risk

Commodity price risk is the risk that changes in market prices will adversely affect earnings and cash flows. PG&E Corporation and the Utility are primarily exposed to the commodity price risk associated with energy commodities such as electricity and natural gas. Therefore, PG&E Corporation's and the Utility's strategy for reducing its commodity price risk exposure for its price risk management activities primarily involves buying and selling fixed-price commodity commitments into the future.

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

Utility Electric Commodity Price Risk

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

As explained in Note 3 of the Notes to the Condensed Consolidated Financial Statements, on September 20, 2001, PG&E Corporation and the Utility filed a proposed plan of reorganization of the Utility with the Bankruptcy Court. Upon the effective date of the Plan, the reorganized Utility will transfer its generation assets to the Gen entity under PG&E Corporation. Gen will operate as an independent power producer thereafter. As an independent owner/operator, Gen could face increased price risk associated with variability in power prices. Additionally, the reorganized Utility could face price risk if and when it resumes the net open position not already provided for by the DWR's contracts. The reorganized Utility may reassume this responsibility at an unknown future date when it regains an investment grade credit rating. Under the Plan, the Utility requested from the Bankruptcy Court an order to prohibit it from reassuming the net open position until objective and timely cost pass-through and procurement pre-approval reassured. To manage this risk for both companies and to provide a sufficiently stable framework for financing, Gen will sell its generation output to the reorganized Utility under a power sales agreement having a term of 12 years. As a result, during the term of the agreement, the price risk should be limited to replacement power requirements, if any, brought about by low hydroelectric availability and/or unit outages that may occur.

Utility Natural Gas Commodity Price Risk

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

Under a ratemaking pact called the Gas Accord, currently scheduled to be in effect through December 2002, shareholders are at risk for any revenues from the sale of capacity on the Utility's pipelines and gas storage fields held by the California Gas Transmission (CGT) business unit. The Utility is generally exposed to reduced revenues when price spreads narrow and when throughput volumes are lower than expected.

PG&E NEG Commodity Price Risk

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

Value-at-Risk

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

PG&E Corporation uses historical data for calculating the price volatility of our contractual positions and how likely the prices of those positions will move together. The model includes all derivatives and commodity instruments in our trading and non-trading portfolios. PG&E Corporation and the Utility express value-at-risk as a dollar amount of the potential loss in the fair value of our portfolios based on a 95% confidence level using a one-day liquidation period. Therefore, there is a 5% probability that PG&E Corporation and its subsidiaries portfolios will incur a loss in one day greater than its value-at-risk.

The Utility's daily value-at-risk commodity price risk exposure for non-trading activities as of September 30, 2001, was $6 million for its natural gas business. The Utility believes that there is currently no commodity price risk associated with fluctuating electric power prices, because the Utility is not currently responsible for managing the net open position.

PG&E NEG's daily value-at-risk commodity price risk exposure as of September 30, 2001, was $8 million for trading activities and $19 million for non-trading activities.

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

Interest Rate Risk

PG&E Corporation and the Utility are exposed to changes in interest rates primarily as a result of their variable rate commercial paper, bonds, bank loans, floating rate notes, project financing, and investing activities. In addition, the Utility is exposed to changes in interest rates on interest accruing on loan payments and trade payables currently in default. Upon confirmation of the Plan, PG&E Corporation and the Utility plan to re-finance existing fixed and floating

rate debt through a fixed income offering. Prior to the pricing of this debt, PG&E Corporation and the Utility are significantly exposed to rising interest rates.

For a complete discussion of the risk management strategies and financial instruments used to manage interest rate risk, see PG&E Corporation's 2000 Annual Report on Form 10-K. PG&E Corporation and the Utility use sensitivity analysis to measure their interest rate price risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. As of September 30, 2001, if interest rates had averaged 1% higher, PG&E Corporation's and the Utility's earnings would have decreased by approximately $37 million and $34 million, respectively.

Foreign Currency Risk

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

LEGAL MATTERS

In the normal course of business, both the Utility and PG&E Corporation are named as parties in a number of claims and lawsuits. See Note 8 of the Notes to the Condensed Consolidated Financial Statements for further discussion of significant pending legal matters.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Pacific Gas and Electric Company Bankruptcy

As previously reported, on April 6, 2001, Pacific Gas and Electric Company (the Utility) filed a voluntary petition for relief under the provisions of Chapter 11 of the United States Bankruptcy Code (Bankruptcy Code) in the United States Bankruptcy Court for the Northern District of California (Bankruptcy Court). Bankruptcy law imposes an automatic stay to prevent parties from making certain claims or taking certain actions that would interfere with the estate or property of a Chapter 11 debtor. In general, the Utility may not pay pre-petition debts without the Bankruptcy Court's permission. Under the Bankruptcy Code, the Utility has the right to reject or assume executory contracts (contracts that require future performance). Since the filing, the Bankruptcy Court has approved various requests by the Utility to permit the Utility to carry on its normal business operations and to pay certain pre-petition obligations. For a discussion of some of these proceedings see the Quarterly Reports on Form 10-Q filed by PG&E Corporation and Pacific Gas and Electric Company for the quarters ended March 31 and June 30, 2001.

On September 20, 2001, the Utility and PG&E Corporation jointly filed with the Bankruptcy Court a proposed plan of reorganization (the Plan) and Disclosure Statement under Chapter 11 of the U.S. Bankruptcy Code. For a description of the Plan, see Note 3 of the Notes to the Consolidated Financial Statements in Part I, Item 1 of this report. On October 2, 2001, the Utility filed with the Bankruptcy Court the Support Agreement between the Utility and the Official Unsecured Creditors' Committee under which the committee has agreed to support the Plan under the conditions specified in the agreement.

At a status conference held on October 9, 2001, the Bankruptcy Court set the following dates: objections to the Disclosure Statement are due November 27, 2001, a status conference will be held on December 4, 2001, and the Disclosure Statement hearing will be held on December 19, 2001. At the October 9, 2001 status conference, the California Public Utilities Commission (CPUC) argued that the Utility should be required to initiate adversary proceedings in the Bankruptcy Court to decide certain legal issues before the plan confirmation hearing. The CPUC argued that unless the Disclosure Statement described how these legal issues were resolved, the Disclosure Statement was insufficient. The Bankruptcy Court ordered that the CPUC and any other party submit its brief in support of its position that adversary proceedings are required by November 6, 2001. The Utility's brief in opposition is due November 27, 2001.

Through September 5, 2001, the last day for non-governmental creditors to file proofs of claim, non governmental claims had been submitted for an approximate aggregate amount of $42.1 billion. This amount includes claims filed by generators, which the Utility believes have been overstated and claims by financial institutions, which the Utility believes contains significant duplication. In addition, through October 3, 2001, the last day for governmental entities to file proofs of claims, claims had been submitted by various governmental agencies for an approximate aggregate amount of $1.9 billion. These include, but are not limited to, contingent environmental claims, claims for federal, state and local taxes, and claims submitted by the California Department of Water Resources for approximately $430 million for certain energy purchases made on behalf of the Utility's retail customers.

The claims resolution process in bankruptcy can range from estimation, which may involve a mini-trial held before plan confirmation to establish the amount of claims for purposes such as voting on the Plan and the feasibility of the Plan, and determination of the amount of the claim for distribution purposes, which may involve a full trial. In addition, it is very common to negotiate with creditors to achieve an agreed settlement of their claims. The Utility intends to explore settlement of claims wherever possible and as appropriate and necessary to pursue estimation or litigation.

Compressor Station Chromium Litigation

As described in PG&E Corporation and the Utility's Annual Report on Form 10-K for the year ended December 31, 2000 and Quarterly Report on Form 10-Q for the quarter ended March 31, 2001, ten cases have been pending in California courts against the Utility. One of these suits also names PG&E Corporation as a defendant.

On or about September 24, 2001, the Utility discovered that another complaint, Bowers v. PG&E, was filed in Los Angeles Superior Court on April 20, 2001 on behalf of 40 plaintiffs who allege personal injuries resulting from alleged exposure to chromium at the Utility's gas compressor station located at Kettleman, California. The complaint does not name PG&E Corporation and has not yet been served on the Utility. The Utility has filed a notice of stay with the Los Angeles Superior Court.

Further, on or about October 28, 2001, the Utility discovered that another complaint titled Martinez v. PG&E was filed in San Bernardino Superior Court on June 29, 2001, on behalf of four plaintiffs. The Utility has not been served. The complaint alleges personal injuries, wrongful death, and loss of consortium, arising from alleged exposure to chromium at the Utility's gas compressor station located at Hinkley, California. Plaintiffs seek compensatory and punitive damages. The complaints do not name PG&E Corporation as a defendant. The Utility intends to file a notice of stay with the San Bernardino Superior Court.

Including these new cases, there are now twelve cases comprising the compressor station chromium litigation. There are now approximately 1,250 plaintiffs in these cases. The Utility believes that all twelve cases have been stayed by the automatic stay provisions of the Bankruptcy Code. The one case in which PG&E Corporation has been named as a defendant remains pending.

There have been approximately 1,240 claims filed with the Bankruptcy Court in the Utility's bankruptcy case (by most of the plaintiffs in the chromium litigation and other individuals) alleging that exposure to chromium in soil, air or water near the Utility's compressor stations at Kettleman, Hinkley or Topock, California caused personal injuries, wrongful death or other injuries. Approximately 1,050 of these claimants have filed claims for damages that total more than $500 million. The remaining claims seek recovery for an unknown amount of claimed damages.

PG&E Corporation and the Utility believe that, after taking into account the reserves recorded as of December 31, 2000, the ultimate outcome of this matter will not have a material adverse effect on their financial condition or results of operation.

Pacific Gas and Electric Company v. California Public Utilities Commissioners

As described in PG&E Corporation's and the Utility's Annual Report on Form 10-K for the year ended December 31, 2000 and Quarterly Report on Form 10-Q for the quarter ended March 31, 2001, the Utility's lawsuit against the CPUC Commissioners, asking the court to declare that the federally approved wholesale power costs the Utility has incurred to serve its customers are recoverable in retail rates, was dismissed on May 2, 2001 on the grounds that the suit was premature as the court found that two of the challenged CPUC decisions were not then final. On August 6, 2001, the Utility re-filed its complaint in the United States District Court for the Northern District of California, based on the fact that the CPUC decisions referenced in the court's order had become final under California law. The CPUC and The Utility Reform Network, a ratepayer advocacy group, have filed motions to dismiss the complaint. The previously scheduled hearing date for the motions of November 7, 2001 has been postponed by the court, and no new hearing date has been set yet.

Federal Securities Lawsuit

As previously disclosed in the Quarterly Reports on Form 10-Q filed by PG&E Corporation and the Utility for the quarters ended March 31 and June 30, 2001, the plaintiff voluntarily dismissed the Utility from the action entitled Pacific Gas and Electric Company, and DOES 6 to 10, Inclusive. On August 9, 2001, the plaintiff filed a first amended complaint entitled Jack Gillam, et al. vs. PG&E Corporation, Robert D. Glynn, Jr., and Peter A. Darbee, in the U.S. District Court for the Northern District of California. 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, claims that defendants caused PG&E Corporation's Condensed Consolidated Financial Statements for the second and third quarters of 2000 to be materially misleading in violation of federal securities laws by recording as a deferred cost and capitalizing as a regulatory asset the undercollections 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. The defendants have filed a motion to dismiss the first amended complaint, based largely on public disclosures by PG&E Corporation, the Utility and others regarding the undercollections, 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. The motion is scheduled to be heard on December 10, 2001.

Management believes the case is without merit and intends to present a vigorous defense. PG&E Corporation is unable to predict whether the outcome of this litigation will have a material adverse effect on its financial condition or results of operations.

Moss Landing Power Plant

As previously disclosed in the Annual Report on Form 10-K filed by PG&E Corporation and the Utility for the year ended December 31, 2000, the Utility has been negotiating with the Central Coast Regional Water Quality Control Board (Central Coast Board) regarding certain cleaning procedures used at the Utility's former Moss Landing power plant that released heated water and organic debris from the intake. A proof of claim has been filed in the Bankruptcy Court by the California Attorney General on behalf of the Central Coast Board seeking unspecified penalties for alleged discharges of heated cooling water at Moss Landing. As previously reported, in December 2000 the Central Coast Board demanded $10 million, comprised of civil penalties and environmental projects in an unspecified ratio to settle its claim with respect to the alleged Moss Landing discharges.

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

In re: Natural Gas Royalties Qui Tam Litigation

This matter is a consolidation of approximately 77 False Claims Act cases that were filed by Jack J. Gyrnberg (called a relator in the parlance of the False Claims Act) on behalf of the United States of America, against more than 330 defendants, entitled In re: Natural Gas Royalties Qui Tam Litigation, that is pending in the United States District Court, District of Wyoming. Two of Grynberg's complaints named as defendants the Utility, Pacific Gas Transmission (now PG&E Gas Transmission, Northwest Corporation (PG&E GT-NW)) and various former PG&E Corporation entities. On October 20, 1999, these cases were transferred to the United States District Court, District of Wyoming, along with most of the other cases, for pretrial purposes.

Under the procedure established by the False Claims Act, a complaint is filed under seal. While the case is under seal, 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. Under the False Claims Act, if a case is successful, the relator may receive a percentage of any recovery obtained on behalf of the United States.

The current case grows out of prior litigation brought by the same relator in 1995. On April 17, 1995, Mr. Grynberg sued approximately 70 defendants (most of which were interstate pipelines) and the Utility, in an action entitled <u>United States of America ex rel. Jack Grynberg v. Alaska Pipeline Company, et al.,</u> (Grynberg I). The United States declined to intervene in Grynberg I, and the complaint was unsealed on March 13, 1996. The case went forward and was prosecuted by the relator. Upon the defendants' motions, the case was dismissed without prejudice for improper joinder of defendants and failure to plead fraud with particularity. Grynberg appealed to the United States Court of Appeals for the District of Columbia Circuit. In September 1998, that court summarily affirmed the district court's decision on the ground of improper joinder.

After the district court's initial dismissal, in 1997 and 1998, the relator filed a second wave of False Claims Act cases (Grynberg II) against the original defendants and hundreds of additional parties in nine jurisdictions where the defendants could be located. Approximately 77 cases were filed against more than 330 defendants, including the Utility, PG&E GT-NW, and various former PG&E Corporation entities that were sold in December 2000. (The buyer of these entities assumed liability for this matter as to the acquired entities.) As discussed above, most of the Grynberg II cases were consolidated and transferred to the United States District Court, District of Wyoming.

All of the Grynberg II complaints allege that the various defendants (most of which are pipeline companies or their affiliates) mismeasured the volume and heating content of natural gas produced from federal or Indian leases. As a result, the relator alleges 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. In April 1999, the DOJ declined to intervene in any of the cases.

The complaint seeks to recover all royalties, which the government should have received if the heating content of natural gas produced from the leases in question had been properly calculated, together with appropriate interest. The complaint does not seek a specific dollar amount or quantify the royalties claim. In addition, the complaint seeks treble damages that are provided by the False Claims Act, civil penalties of not less than $5,000 and not more than $10,000

against each defendant for each violation of the False Claims Act, an order requiring the defendants to discontinue certain measurement practices, and reasonable expenses, attorney's fees, and costs incurred in connection with the litigation.

On November 19, 1999, the Utility and PG&E GT-NW were part of a group of 255 coordinated defendants, which moved to dismiss the cases on a number of procedural and substantive legal grounds before any discovery is taken. On May 18, 2001, after a hearing held in March 2001, the court denied the motion. Shortly thereafter, many defendants asked the district court to certify a question of law involved in the decision to the Tenth Circuit. That motion is pending.

On July 20, 2000, the government moved to dismiss Grynberg's valuation claims (essentially claims that defendants sell gas to affiliates at an artificially low prices and use those prices for the royalty calculation). Briefing on the government's motion is complete and oral argument was held on February 22, 2001. A decision has not yet been issued. Even if the court grants the government's motion, other claims would remain.

By its terms, the complaint alleges that mismeasurement (and hence underpayment of royalties) occurred in every month for every federal or Indian lease for approximately a 10-year period. Because of the relator's failure to plead with particularity, the complaint does not allege facts that would allow one to estimate the alleged damages. Nevertheless, the relator has filed a claim in the Bankruptcy Court in the Utility's bankruptcy case for $2.48 billion, $2 billion of which is based on Gyrnberg's calculation of penalties against the Utility, which he alleges "may range up to $25,000 per violation per day since at least 1987."

Management believes the case is without merit and is vigorously defending it. However, because the case has not progressed past its initial stages, it is not possible to predict whether the outcome will have a material adverse impact on PG&E Corporation's or the Utility's financial position or results of operations.

Baldwin Associates

On or about September 5, 2001, Baldwin Associates, Inc. (Baldwin) filed a claim in the Bankruptcy Court in the Utility's bankruptcy case. The proof of claim form seeks relief of $5 billion and indicates that the basis of the claim is "taxes" and "other" ("economic and personal injury."). The form also indicates that the debt was incurred "[b]eginning at least [sic] September 6, 2000." The alleged claim does not provide any additional detail.

Analysis of Baldwin's alleged claim is at a preliminary stage, but the Utility believes it to be without merit and intends to present rigorous objections to the claim and to vigorously defend against it.

PG&E Corporation and the Utility are unable to predict whether the outcome of this litigation will have a material adverse affect on their financial condition or results of operation.

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

As previously disclosed in the Quarterly Reports on Form 10-Q filed by PG&E Corporation and the Utility, two complaints were filed against PG&E Corporation and the Utility in the Superior Court of the State of California, San Francisco

County: Richard D. Wilson v. Pacific Gas and Electric Company, et al. (Wilson I), and Richard D. Wilson v. Pacific Gas and Electric Company, et al. (Wilson II). The Utility filed notice of automatic stay on April 11, 2001, pursuant to the Bankruptcy Code. On April 19, 2001, the court signed orders based on stipulation between PG&E Corporation and plaintiffs to stay all proceedings in the cases as against PG&E Corporation. On September 7, 2001, plaintiffs dismissed both actions without prejudice. A claim filed by Wayne Roberts in the Utility's bankruptcy proceeding contains allegations that are similar but not identical to the allegations contained in the Wilson cases. See discussion below.

Wayne Roberts

On or about September 5, 2001, Wayne Roberts filed a purported "secured" claim against the Utility in the Bankruptcy Court in the Utility's bankruptcy case. The proof of claim form stated the total amount of claim as $40.00, although, in the materials attached to the form, the claimant seeks payment to "PG&E electricity ratepayers" of not less than $4 billion, plus interest, restitution, attorneys' fees and costs. The claimant purports to bring the claim on behalf of "himself, the public, and [a] class composed of PG&E electricity ratepayers," as creditors. The allegations of the claim are similar but not identical to the allegations in two actions earlier filed in the San Francisco Superior Court, but then dismissed without prejudice, entitled Richard D. Wilson v. Pacific Gas and Electric Company et al. The same lawyers who represent Wayne Roberts in his alleged bankruptcy claim, represented plaintiff Richard D. Wilson in the earlier Wilson cases.

Mr. Roberts asserts various legal theories including, but not limited to, purported violations of California Business & Profession Code Section 17200, California Public Utilities Code Sections 453, 817, 818, 841, and 851, 15 U.S.C. Section 79i(a)(2), various "regulations," and the doctrines of "public trust" and/or "public use," as well as constructive fraud, allegedly arising out of: (a) formation of PG&E Corporation; (b) alleged dividend payments, and repurchases of Utility common stock, made by the Utility; and (c) alleged tax payments made by the Utility to PG&E Corporation through consolidated tax preparation for the Utility and affiliate companies of PG&E Corporation.

Mr. Robert's claim contends that allegations, which relate to PG&E Corporation, will be made in an adversary proceeding of the Bankruptcy Court, or in a state court, provided the Bankruptcy Court permits Mr. Roberts to lift the automatic stay.

Analysis of Mr. Roberts' claim is at a preliminary stage, but the Utility and PG&E Corporation believe it to be without merit and intend to present rigorous objections to the claim and to vigorously defend against it.

PG&E Corporation and the Utility are unable to predict whether the outcome of this litigation will have a material adverse affect on their financial condition or results of operation.

Item 3. Defaults Upon Senior Securities

The Utility has authorized 75 million shares of First Preferred Stock ($25 par value) and 10 million shares of $100 First Preferred Stock ($100 par value), which may be issued as redeemable or non-redeemable preferred stock. (The Utility has not issued any $100 First Preferred Stock.) At September 30, 2001, the Utility had issued and outstanding 5,784,825 shares of non-redeemable preferred stock and 5,973,456 shares of redeemable preferred stock. The Utility's redeemable preferred stock is subject to redemption at the Utility's option, in whole or in part, if the Utility pays the specified redemption price

plus accumulated and unpaid dividends through the redemption date. The Utility's redeemable preferred stock with mandatory redemption provisions consists of 3 million shares of the 6.57 percent series and 2.5 million shares of the 6.30 percent series at December 31, 2000. The 6.57 percent series and 6.30 percent series may be redeemed at the Utility's option beginning in 2002 and 2004, respectively, at par value plus accumulated and unpaid dividends through the redemption date. These series of preferred stock are subject to mandatory redemption provisions entitling them to sinking funds providing for the retirement of stock outstanding. At December 31, 2000, the redemption requirements for the Utility's redeemable preferred stock with mandatory redemption provisions are $4 million per year beginning 2002, and $3 million per year beginning 2004, for the series 6.57 percent and 6.30 percent, respectively.

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

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

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and equal preference in dividend and liquidation rights. Accumulated and unpaid dividends for the three-month periods ended January 31, April 30, and July 31, 2001, amounted to $19 million. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series. Until cumulative dividends on its preferred stock are paid, the Utility may not pay any dividends on its common stock, nor may the Utility repurchase any of its common stock.

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

With regard to certain pollution control bond-related debt of the Utility, the Utility has been in default under the credit agreements with the banks that provide letters of credit as credit and liquidity support for the underlying pollution control bonds. These defaults included the Utility's non-payment of other debt in excess of $100 million, the Utility's filing of a petition for reorganization under Chapter 11 of the Bankruptcy Code and non-payment of interest. As a result of these defaults, several of the letter of credit banks caused the acceleration and redemption of four series of pollution control bonds. All of these redemptions were funded by the letter of credit banks resulting in loans from the banks to the Utility, which have not been paid. As of September 30, 2001, the total principal of the bonds (and related loans) accelerated and redeemed was $454 million. As of September 30, 2001, the Utility did not make interest payments of $10.7 million on pollution control bonds series 96C, 96E, 96F, and 97B. As of September 30, 2001, the Utility did not make an interest payment of $2.7 million on pollution control bond series 96A backed by bond insurance. With regard to certain pollution control bond-related debt of the Utility backed by the Utility's mortgage bonds, an event of default has occurred under the relevant loan agreements with the California Pollution Control Financing Authority due to the Utility's bankruptcy filing.

The Utility's filing of a petition for reorganization under Chapter 11 of the Bankruptcy Code also constitutes a default under the indenture that governs its

medium-term notes ($287 million aggregate amount outstanding), five-year 7.375% senior notes ($680 million aggregate amount outstanding), and floating-rate notes ($1.24 billion aggregate amount outstanding). In addition, as of September 30, 2001, the Utility did not make interest payments on its medium-term notes, its 7.375% senior notes, and its $1.24 billion floating rate notes. As of September 30, 2001, the total arrearage of these interest payments was $79.1 million. Also as of September 30, 2001, the Utility did not make principal payments on unsecured long-term debt of $2 million.

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

Item 5. Other Information

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

Pacific Gas and Electric Company's earnings to fixed charges ratio for the nine months ended September 30, 2001, was 1.98. Pacific Gas and Electric Company's earnings to combined fixed charges and preferred stock dividends ratio for the nine months ended September 30, 2001, was 1.91. The statement of the foregoing ratios, together with the statements of the computation of the foregoing ratios filed as Exhibits 12.1 and 12.2 hereto, are included herein for the purpose of incorporating such information and exhibits into Registration Statement Nos. 33-62488, 33-64136, 33-50707, and 33-61959, relating to Pacific Gas and Electric Company's various classes of debt and first preferred stock outstanding.

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits:

Exhibit 10.1	Pacific Gas and Electric Company Management Retention Program (incorporated by reference from PG&E Corporation and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, Exhibit 10.1)
Exhibit 10.2	PG&E Corporation Management Retention Program (incorporated by reference from PG&E Corporation and

Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, Exhibit 10.2)

Exhibit 11	Computation of Earnings Per Common Shares (incorporated by reference from PG&E Corporation and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001, Exhibit 11.)
Exhibit 12.1	Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company (incorporated by reference from PG&E Corporation and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the

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quarter ended September 30, 2001, Exhibit 12.1.)

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

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

1.	July 9, 2001	Item 5.	Other Events
		Item 7.	Financial Statements, Pro Forma, Financial Information, and Exhibits
			Exhibit 99 - Pacific Gas and Electric Company Income Statements for the months ended April 30 and May 31, 2001 and Balance Sheets dated April 30 and May 31, 2001, respectively
2.	July 30, 2001	Item 5.	Other Events
3.	September 7, 2001	Item 5.	Other Events
		Item 7.	Financial Statements, Pro Forma, Financial Information, and Exhibits
			Exhibit 99 - Pacific Gas and Electric Company Income Statement for the month ended July 30, 2001, and Balance Sheet dated July 30, 2001.

4.	September 20, 2001	Item 5. Item 7.	Other Events Financial Statements, Pro Forma, Financial Information, and Exhibits Exhibit 99 - Proposed form of disclosure statement filed by PG&E Corporation and Pacific Gas and Electric Company, together with Exhibit A (Proposed plan of reorganization under Chapter 11 of the Bankruptcy Code for Pacific Gas and Electric Company), Exhibit C (Projected Financial Information and Underlying Assumptions), and Exhibit D (Summary of Terms of Long-Term Debt).
5.	October 2, 2001	Item 5. Item 7.	Other Events Financial Statements, Pro Forma, Financial Information, and Exhibits Exhibit 99 - Pacific Gas and Electric Company Income Statement for the month ended August 31, 2001, and Balance Sheet dated August 31, 2001.
6.	October 25, 2001	Item 5.	Other Events Pacific Gas and Electric Company's 1999 General Rate Case Proceeding
7.	November 1, 2001	Item 5.	Other Events

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A. Pacific Gas and Electric Company's 2002 General Rate Case Proceeding B. Pacific Gas and Electric Company's Retained Generation Ratemaking Proceeding

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SIGNATURE

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

PG&E CORPORATION

By Christopher P. Johns

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

PACIFIC GAS AND ELECTRIC COMPANY

By Kent M. Harvey

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

Dated: March 5, 2002

Exhibit Index

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