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

Form 10-Q

(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, 2003

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 1-14365

El Paso Corporation

(Exact Name of Registrant as Specified in its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	**76-0568816** (I.R.S. Employer Identification No.)
El Paso Building **1001 Louisiana Street** **Houston, Texas** (Address of Principal Executive Offices)	**77002** (Zip Code)

Telephone Number: **(713) 420-2600**
Internet Website: www.elpaso.com

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes ☑ No ☐

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

Common stock, par value $3 per share. Shares outstanding on November 7, 2003: 599,424,353

EL PASO CORPORATION

TABLE OF CONTENTS

Below is a list of terms that are common to our industry and used throughout this document:

/d	= per day	Mcf	= thousand cubic feet
Bbl	= barrels	Mcfe	= thousand cubic feet of natural gas equivalents
BBtu	= billion British thermal units	MMBtu	= million British thermal units
Bcf	= billion cubic feet	MMcf	= million cubic feet
Bcfe	= billion cubic feet of natural gas equivalents	Tcfe	= trillion cubic feet of natural gas equivalents
MBbls	= thousand barrels	MMWh	= million megawatt hours

When we refer to natural gas and oil in "equivalents," we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which one Bbl of oil is equal to six Mcf of natural gas. Also, when we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

When we refer to "us", "we", "our", "ours", or "El Paso", we are describing El Paso Corporation and/or our subsidiaries.

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

EL PASO CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(In millions, except per common share amounts)
(Unaudited)

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
Operating revenues	$1,539	$1,696	$ 5,143	$6,433
Operating expenses				
Cost of products and services	351	546	1,370	1,929
Operation and maintenance	471	463	1,533	1,476
Depreciation, depletion and amortization	328	316	1,049	1,000
Ceiling test charges	2	—	2	267
(Gain) loss on long-lived assets	54	3	477	(24)
Western Energy Settlement	(20)	—	103	—
Taxes, other than income taxes	81	58	230	194
	1,267	1,386	4,764	4,842
Operating income	272	310	379	1,591
Earnings (losses) from unconsolidated affiliates	79	58	31	(36)
Other income	49	66	132	162
Other expenses	—	(14)	(129)	(277)
Interest and debt expense	(474)	(343)	(1,350)	(950)
Distributions on preferred interests of consolidated subsidiaries	(8)	(37)	(45)	(120)
Income (loss) before income taxes	(82)	40	(982)	370
Income taxes	15	16	(463)	120
Income (loss) from continuing operations	(97)	24	(519)	250
Discontinued operations, net of income taxes	(49)	(93)	(1,187)	(149)
Cumulative effect of accounting changes, net of income taxes	—	—	(22)	168
Net income (loss)	$ (146)	$ (69)	$(1,728)	$ 269
Basic earnings per common share				
Income (loss) from continuing operations	$(0.16)	$ 0.04	$ (0.87)	$ 0.46
Discontinued operations, net of income taxes	(0.08)	(0.16)	(1.99)	(0.27)
Cumulative effect of accounting changes, net of income taxes	—	—	(0.04)	0.30
Net income (loss)	$(0.24)	$(0.12)	$ (2.90)	$ 0.49
Diluted earnings per common share				
Income (loss) from continuing operations	$(0.16)	$ 0.04	$ (0.87)	$ 0.46
Discontinued operations, net of income taxes	(0.08)	(0.16)	(1.99)	(0.27)
Cumulative effect of accounting changes, net of income taxes	—	—	(0.04)	0.30
Net income (loss)	$(0.24)	$(0.12)	$ (2.90)	$ 0.49
Basic average common shares outstanding	596	586	596	548
Diluted average common shares outstanding	596	586	596	549
Dividends declared per common share	$ 0.04	$ 0.22	$ 0.12	$ 0.65

See accompanying notes.

EL PASO CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS
(In millions, except share amounts)
(Unaudited)

	September 30, 2003	December 31, 2002
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,643	$ 1,591
Accounts and notes receivable		
Customers, net of allowance of $204 in 2003 and $176 in 2002	2,171	4,123
Affiliates	229	774
Other	296	451
Inventory	203	252
Assets from price risk management activities	627	1,007
Margin and other deposits on energy trading activities	505	1,003
Assets of discontinued operations	1,575	2,154
Other	821	569
Total current assets	8,070	11,924
Property, plant and equipment, at cost		
Pipelines	18,335	18,049
Natural gas and oil properties, at full cost	15,526	14,940
Power facilities	2,109	959
Gathering and processing systems	775	1,101
Other	1,013	767
	37,758	35,816
Less accumulated depreciation, depletion and amortization	14,704	14,052
Total property, plant and equipment, net	23,054	21,764
Other assets		
Investments in unconsolidated affiliates	5,107	4,891
Assets from price risk management activities	2,471	1,844
Goodwill and other intangible assets, net	1,234	1,367
Assets of discontinued operations	—	1,911
Other	2,740	2,523
	11,552	12,536
Total assets	$42,676	$46,224

See accompanying notes.

EL PASO CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS — (Continued)
(In millions, except share amounts)
(Unaudited)

	September 30, 2003	December 31, 2002
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 1,511	$ 3,581
Affiliates	32	29
Other	507	742
Short-term financing obligations, including current maturities	1,047	2,075
Notes payable to affiliates	9	189
Liabilities from price risk management activities	688	1,041
Western Energy Settlement	616	100
Liabilities of discontinued operations	755	1,373
Accrued interest	431	324
Other	821	896
Total current liabilities	6,417	10,350
Debt		
Long-term financing obligations	22,524	16,106
Notes payable to affiliates	—	201
	22,524	16,307
Other		
Liabilities from price risk management activities	993	1,374
Deferred income taxes	3,056	3,576
Western Energy Settlement	419	799
Liabilities of discontinued operations	—	87
Other	2,049	1,934
	6,517	7,770
Commitments and contingencies		
Securities of subsidiaries		
Preferred interests of consolidated subsidiaries	400	3,255
Minority interests of consolidated subsidiaries	65	165
	465	3,420
Stockholders' equity		
Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 605,707,395 shares in 2003 and 605,298,466 shares in 2002	1,817	1,816
Additional paid-in capital	4,414	4,444
Retained earnings	1,142	2,942
Accumulated other comprehensive loss	(372)	(529)
Treasury stock (at cost) 6,646,342 shares in 2003 and 5,730,042 shares in 2002	(220)	(201)
Unamortized compensation	(28)	(95)
Total stockholders' equity	6,753	8,377
Total liabilities and stockholders' equity	$42,676	$46,224

See accompanying notes.

EL PASO CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)
(Unaudited)

	Nine Months Ended September 30,	
	2003	**2002**
Cash flows from operating activities		
Net income (loss)	$(1,728)	$ 269
Less loss from discontinued operations, net of income taxes	(1,187)	(149)
Net income (loss) from continuing operations	(541)	418
Adjustments to reconcile net income (loss) to net cash from operating activities		
Depreciation, depletion and amortization	1,049	1,000
Ceiling test charges	2	267
Non-cash gains from trading and power activities	(84)	(560)
(Gain) loss on long-lived assets	477	(24)
Undistributed earnings of unconsolidated affiliates	224	223
Deferred income tax expense (benefit)	(493)	106
Cumulative effect of accounting changes	22	(168)
Non-cash portion of Western Energy Settlement	93	—
Other non-cash income items	418	213
Working capital changes	584	192
Non-working capital changes and other	13	(333)
Cash provided by continuing operations	1,764	1,334
Cash provided by (used in) discontinued operations	2	(170)
Net cash provided by operating activities	1,766	1,164
Cash flows from investing activities		
Additions to property, plant and equipment	(1,954)	(2,488)
Purchases of investments in unconsolidated affiliates	(29)	(148)
Cash paid for acquisitions, net of cash acquired	(1,078)	45
Net proceeds from the sale of assets and investments	1,370	1,596
Increase in restricted cash	(137)	(86)
Increase in notes receivable from unconsolidated affiliates	(42)	(194)
Other	—	11
Cash used in continuing operations	(1,870)	(1,264)
Cash provided by (used in) discontinued operations	399	(124)
Net cash used in investing activities	(1,471)	(1,388)
Cash flows from financing activities		
Net repayments under short-term debt and credit facilities	(250)	(1,087)
Repayment of notes payable	(3)	(109)
Payments to retire long-term debt and other financing obligations	(2,091)	(1,687)
Net proceeds from the issuance of long-term debt and other financing obligations	3,433	4,287
Dividends paid to common stockholders	(178)	(340)
Net payments to minority interest holders	—	(128)
Change in notes payable to unconsolidated affiliates	(56)	(507)
Payments to redeem preferred interests of consolidated subsidiaries	(1,177)	(350)
Issuances of common stock	—	1,051
Contributions from (distributions to) discontinued operations	401	(655)
Other	79	—
Cash provided by continuing operations	158	475
Cash provided by (used in) discontinued operations	(401)	304
Net cash provided by (used in) financing activities	(243)	779
Increase in cash and cash equivalents	52	555
Less increase in cash and cash equivalents related to discontinued operations	—	10
Increase in cash and cash equivalents from continuing operations	52	545
Cash and cash equivalents		
Beginning of period	1,591	1,148
End of period	$ 1,643	$ 1,693

See accompanying notes.

EL PASO CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)
(Unaudited)

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
Net income (loss)	$(146)	$ (69)	$(1,728)	$ 269
Foreign currency translation adjustments	6	(30)	123	(3)
Unrealized net gains (losses) from cash flow hedging activity				
Unrealized mark-to-market earnings (losses) arising during period (net of income taxes of $49 and $68 in 2003 and $23 and $237 in 2002)	110	(53)	(103)	(399)
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $26 and $85 in 2003 and $3 and $86 in 2002)	44	5	137	(164)
Other comprehensive income (loss)	160	(78)	157	(566)
Comprehensive income (loss)	$ 14	$(147)	$(1,571)	$(297)

See accompanying notes.

EL PASO CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the United States Securities and Exchange Commission. Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by generally accepted accounting principles. You should read it along with our Current Report on Form 8-K dated September 23, 2003 (which updated the financial statement information originally presented in our 2002 Form 10-K to reclassify our petroleum markets business as a discontinued operation), which includes a summary of our significant accounting policies and other disclosures. The financial statements as of September 30, 2003, and for the quarters and nine months ended September 30, 2003 and 2002, are unaudited. We derived the balance sheet as of December 31, 2002, from the audited balance sheet filed in our Current Report on Form 8-K dated September 23, 2003. In our opinion, we have made all adjustments which are of a normal, recurring nature to fairly present our interim period results. Due to the seasonal nature of our businesses, information for interim periods may not be indicative of our results of operations for the entire year. Our results for all periods presented have been reclassified to reflect our petroleum and coal mining operations as discontinued operations. In addition, prior period information presented in these financial statements includes reclassifications which were made to conform to the current period presentation. These reclassifications had no effect on our previously reported net income or stockholders' equity.

2. Summary of Significant Events and Accounting Policies

Significant Events

Liquidity Update

In early 2003, following actions taken by rating agencies to downgrade the credit ratings of our company and many of the largest participants in our industry, we announced a plan to address the business challenges and liquidity needs of our company. These initiatives, broadly referred to as our 2003 Operational and Financial Plan, were based upon five key points. The five key points were:

- Preserve and enhance the value of our core businesses;
- Divest non-core businesses quickly, but prudently;
- Strengthen and simplify our balance sheet, while at the same time maximizing liquidity;
- Aggressively pursue additional cost reductions; and
- Work diligently to resolve regulatory and litigation matters.

To date in 2003, our major accomplishments regarding these business objectives have been as follows:

- We concentrated our capital investment in our core Pipelines, Production and Field Services segments such that 91 percent of total capital expenditures have been made in these businesses in the first nine months of 2003;
- We completed or announced sales of assets and investments of approximately $3.1 billion (see Note 4);
- We entered into a new $3 billion revolving credit facility that matures in June 2005 and completed financing transactions of approximately $3.8 billion ($3.6 billion as of September 30, 2003) (see Note 16);

- We retired approximately $5.8 billion of maturing debt and other obligations ($4.7 billion as of September 30, 2003), including:
  - the retirement of long-term debt of $2.9 billion ($2.2 billion as of September 30, 2003);
  - the net repayment of $650 million of outstanding amounts under our $3 billion revolving credit facility ($250 million as of September 30, 2003);
  - the repayment of $980 million of obligations under our Trinity River financing arrangement;
  - the redemption of $197 million of obligations under our Clydesdale financing arrangement, also restructuring that transaction as a term loan that will mature in equal quarterly payments through 2005 (see Notes 3 and 17); and
  - the contribution of $1 billion to the Limestone Electron Trust, which used the proceeds to repay $1 billion of its notes, and the purchase and consolidation of the third party equity interests in our Gemstone and Chaparral power investments (see Note 3);
- We refinanced a $1.2 billion two-year term loan issued in March 2003 in connection with the restructuring of our Trinity River financing arrangement to eliminate the amortization requirements of that loan in 2004 and 2005;
- We identified an estimated $445 million of cost savings and business efficiencies to be realized by the end of 2004;
- We executed definitive settlement agreements in June 2003, which substantially resolved our principal exposure relating to the Western Energy crisis and raised funds of $347 million to satisfy a portion of our obligation through the issuance of senior unsecured notes of El Paso Natural Gas Company (EPNG) in July 2003 (see Notes 6 and 18);
- We initiated a tender offer in October 2003 to exchange common stock and cash for our outstanding equity security units which would, if 100 percent of the units were tendered, result in a reduction of up to $575 million in our outstanding debt balances, an increase in stockholders' equity of up to approximately $475 million and a reduction of cash of up to approximately $112 million (see Note 16); and
- We initiated a program to supplement our capital spending on natural gas and oil properties by an additional $350 million.

We believe the accomplishments to date demonstrate our ability to address our liquidity issues and simplify and improve our capital structure. However, a number of factors could influence the timing and ultimate outcome of these efforts, including our ability to raise cash from asset sales, which may be impacted by our ability to locate potential buyers in a timely fashion and obtain a reasonable price or by competing asset sale programs by our competitors, oil and natural gas prices, conditions in the debt and equity markets, the timely receipt of necessary third party and governmental approvals and other factors.

Our plans and objectives for the year are discussed more fully in our Current Report on Form 8-K dated September 23, 2003.

Significant Accounting Policies

Our accounting policies are consistent with those discussed in our Current Report on Form 8-K dated September 23, 2003, except as follows:

Accounting for Asset Retirement Obligations. On January 1, 2003, we adopted Statement of Financial Accounting Standards (SFAS) No. 143, *Accounting for Asset Retirement Obligations*. SFAS No. 143 requires that we record a liability for retirement and removal costs of long-lived assets used in our business. This liability is recorded at its estimated fair value, with a corresponding increase to property, plant and equipment. This increase in property, plant and equipment is then depreciated over the remaining useful life of the long-lived asset to which that liability relates. An ongoing expense is also recognized for changes in the value of the liability as a result of the passage of time, which we also record in depreciation, depletion and amortization expense in our income statement. In the first quarter of 2003, we recorded a charge as a cumulative effect of accounting change of approximately $22 million, net of income taxes, related to our adoption of SFAS No. 143. We also recorded property, plant and equipment of $188 million and asset retirement obligations of $222 million as of January 1, 2003. Our asset retirement obligations are associated with our natural gas and oil wells and related infrastructure in our Production segment and our natural gas storage wells in our Pipelines segment. We have obligations to plug wells when production on those wells is exhausted, and we abandon them. We currently forecast that these obligations will be met at various times, generally over the next 10 years, based on the expected productive lives of the wells and the estimated timing of plugging and abandoning those wells. The net asset retirement liability as of January 1, 2003 and September 30, 2003, reported in other current and non-current liabilities in our balance sheet, and the changes in the net liability for the nine months ended September 30, 2003, were as follows (in millions):

Liability at January 1, 2003	$222
Liabilities settled in 2003	(44)
Accretion expense in 2003	13
Liabilities incurred in 2003	1
Changes in estimate	8
Net liability at September 30, 2003	$200

Our changes in estimate represent changes to the expected amount and timing of payments to settle our asset retirement obligations. These changes primarily result from obtaining new information about the timing of our obligations to plug our natural gas and oil wells and the costs to do so. Had we adopted SFAS No. 143 as of January 1, 2002, our current and non-current retirement liabilities on that date would have been approximately $200 million and our income from continuing operations and net income for the quarter and nine months ended September 30, 2002, would have been lower by $3 million and $10 million. Basic and diluted earnings per share for the quarter and nine months ended September 30, 2002, would not have been materially affected.

Accounting for Costs Associated with Exit or Disposal Activities. On January 1, 2003, we adopted SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*. SFAS No. 146 requires that we recognize costs associated with exit or disposal activities when they are incurred rather than when we commit to an exit or disposal plan. We applied the provisions of SFAS No. 146 in accounting for restructuring costs we incurred during 2003 (see Note 5). As we continue to evaluate our business activities and seek additional cost savings, we expect to incur additional charges that will be evaluated under this accounting standard.

Amendment of Statement 133 on Derivative Instruments and Hedging Activities. In April 2003, the Financial Accounting Standards Board (FASB) issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities.* This statement amends SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* to incorporate several interpretations of the Derivatives Implementation Group (DIG), and also makes several modifications to the definition of a derivative as it was defined in SFAS No. 133. SFAS No. 149 affects contracts entered into or modified after June 30, 2003. There was no initial financial statement impact of adopting this standard, although the FASB and DIG continue to deliberate on the application of the standard to certain derivative contracts, such as power capacity contracts, which may impact our financial statements in the future.

Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity. In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity.* This statement provides guidance on the classification of financial instruments as equity, as liabilities, or as both liabilities and equity. In particular, the standard requires that we classify all mandatorily redeemable securities as liabilities in the balance sheet. We adopted the provisions of SFAS No. 150 on July 1, 2003, and reclassified $625 million of our Capital Trust I and

Coastal Finance I preferred interests from preferred interests of consolidated subsidiaries to long-term financing obligations in our balance sheet. We also began classifying dividends accrued on these preferred interests as interest and debt expense in our income statement after July 1, 2003. For the quarter and nine months ended September 30, 2003, total dividends were $10 million and $30 million. The third quarter of 2003 dividends of $10 million were recorded in interest expense in our income statement. The first and second quarter of 2003 dividends of $20 million were recorded as distributions on preferred interests in our income statement.

Goodwill. Our goodwill as of December 31, 2002 and September 30, 2003, and the changes in goodwill for the nine months ended September 30, 2003, were as follows (in millions):

	Pipelines	Production	Field Services	Merchant Energy	Corporate & Other	Total
Balances as of December 31, 2002	$413	$62	$483	$ 45	$ 163	$1,166
Impairments of goodwill	—	—	—	—	(163)	(163)
Dispositions of goodwill	—	—	—	(42)	—	(42)
Other changes	—	10	(4)	—	—	6
Balances as of September 30, 2003	$413	$72	$479	$ 3	$ —	$ 967

During 2003, we impaired $163 million of goodwill related to our telecommunications business in our corporate segment and disposed of $42 million in goodwill primarily related to the sale of our financial services businesses in our Merchant Energy segment.

Accounting for Guarantees. On January 1, 2003, we adopted Financial Accounting Standards Board Interpretation (FIN) No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others*. FIN No. 45 requires that we record a liability for all guarantees, including financial performance and fair value guarantees, issued after December 31, 2002, at fair value when they are issued. There was no initial financial statement impact of adopting this standard.

Stock-Based Compensation. We account for our stock-based compensation plans using the provisions of Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees,* and its related interpretations. Had we accounted for our stock option grants using SFAS No. 123, *Accounting for Stock-Based Compensation,* rather than APB No. 25, the income and per share impacts of stock-based compensation on our financial statements would have been different. The following tables show the impact on net income (loss) and earnings (losses) per share had we applied SFAS No. 123:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In millions)			
Net income (loss), as reported	$ (146)	$ (69)	$(1,728)	$ 269
Deduct: Total stock-based employee compensation determined under fair value based method for all awards, net of related tax effects	22	25	37	101
Pro forma net income (loss)	$ (168)	$ (94)	$(1,765)	$ 168
Earnings (losses) per share:				
Basic, as reported	$(0.24)	$(0.12)	$ (2.90)	$0.49
Basic, pro forma	$(0.28)	$(0.16)	$ (2.96)	$0.31
Diluted, as reported	$(0.24)	$(0.12)	$ (2.90)	$0.49
Diluted, pro forma	$(0.28)	$(0.16)	$ (2.96)	$0.31

Accounting for Regulated Operations. Our interstate natural gas pipelines and storage operations are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) in accordance with the Natural Gas Act of 1938 and Natural Gas Policy Act of 1978. Of our regulated pipelines, four follow the regulatory accounting principles prescribed under SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, while three discontinued its application in 1996. As a result of recent changes in our competitive environment and operating cost structures, we continue to assess the applicability of the provisions of SFAS No. 71 to our financial statements. The outcome of this evaluation could result in the restoration of our application of this accounting in some of our regulated systems or the discontinuance of this accounting in others. We expect to complete our current evaluation of the applicability of SFAS No. 71 by the end of the year. For a discussion of differences in accounting for regulated operations, see our Current Report on Form 8-K dated September 23, 2003.

3. Acquisitions and Consolidations

Acquisitions

During the second quarter of 2003, we acquired and began consolidating the third party interests in our Chaparral and Gemstone investments, which we historically accounted for as investments in unconsolidated affiliates. Each of these acquisitions is discussed below.

Chaparral. As discussed more completely in our Current Report on Form 8-K dated September 23, 2003, we entered into our Chaparral investment in 1999 to expand our domestic power generation business. Chaparral owns or has interests in 34 power plants in the United States that have a total generating capacity of 3,470 megawatts (based on Chaparral's interest in the plants). These plants are primarily concentrated in the Northeast and Western United States. Chaparral also owns several companies that own long-term derivative power agreements.

As of December 31, 2002, we owned 20 percent of Chaparral, and the remaining 80 percent was owned by Limestone Electron Trust (Limestone). We acquired Limestone's 80 percent interest in Chaparral during 2003 in two transactions. First, in March 2003, we acquired an additional 70 percent economic interest in Chaparral when we invested $1 billion in Limestone. Limestone used these proceeds to retire notes that were previously guaranteed by us. Although we increased our economic interest in Chaparral with this investment in Limestone, we did not obtain any additional voting rights in Limestone or Chaparral so we continued to account for our investment in Chaparral using the equity method of accounting. In May 2003, we paid $175 million to acquire the remaining third party interest in Limestone, and all of Limestone's and Chaparral's remaining voting rights. Upon this acquisition, we began consolidating Chaparral's assets and liabilities. In addition, since we acquired Chaparral in multiple transactions (also referred to as a step acquisition), we reflected Chaparral's results of operations in our income statement as though we acquired it on January 1, 2003. Although this did not change our net income for the previously reported first quarter of 2003, it did impact the individual components of our income statement by increasing our revenues by $76 million, operating expenses by $80 million, earnings (losses) from unconsolidated affiliates by $55 million, interest expense by $67 million and decreasing distributions on preferred interests in subsidiaries by $18 million and other income (expense) by $2 million. Had we acquired Chaparral effective January 1, 2002, the net increases (decreases) to our income statement for the periods ended September 30, 2002, would have been as follows:

	Quarter Ended September 30, 2002	Nine Months Ended September 30, 2002
	(In millions)	
Revenues	$ 46	$ 135
Operating income	$ (16)	$ (40)
Net income	$ (7)	$ 18
Basic and diluted earnings per share	$(0.01)	$ 0.03

The $175 million we paid to acquire the remaining 10 percent interest in Limestone along with the remaining voting rights of Limestone and Chaparral, was negotiated based, in large part, on the terms of the original Chaparral agreements. Under those terms, we had the option to either provide for a payment to the third party equity holder in exchange for their remaining interests, or allow the third party equity holders to liquidate the assets of Chaparral, the proceeds of which would first be applied to the payment of the agreed amount to them. If we had elected to allow the third party equity holders to exercise their liquidation rights, Limestone would have controlled the liquidation process and would not necessarily have been motivated to achieve the maximum value for the assets. In order to protect our interests, maximize the recoverable value of the assets and obtain the flexibility to manage the assets of Chaparral, regardless of whether these assets were to be ultimately sold or held and used in our ongoing business, we chose to redeem the third party equity holder's interests for the agreed upon amount.

During the first quarter of 2003, as a result of our additional investment in Limestone, coupled with a number of developments including a general decline in power prices, declines in our own credit ratings as well as those of our counterparties, adverse developments at several of Chaparral's projects, our announced exit from the power contract restructuring business and generally weaker economic conditions in the unregulated power industry, we evaluated whether the carrying value of our investment in Chaparral was less than its fair value. We also evaluated whether any declines that resulted from our analysis would be considered temporary (expected to turn around within the next nine to twelve months). Based on our analysis, we determined that the fair value of Chaparral (based on its discounted expected net cash flows) was less than our carrying value of the investment. As a result, we recorded an impairment of our investment in Chaparral of $207 million, before income taxes, during the quarter ended March 31, 2003.

The following table presents our initial allocation of the purchase price of Chaparral to its assets and liabilities prior to its consolidation and prior to the elimination of intercompany transactions. This allocation reflects the allocation of (i) our purchase price of $1,175 million; (ii) the carrying value of our initial investment of $252 million; and (iii) our first quarter 2003 impairment of $207 million (in millions):

Total assets	
Current assets	$ 312
Assets from price risk management activities, current	190
Investments in unconsolidated affiliates	1,347
Property, plant and equipment, net	561
Assets from price risk management activities, non-current	1,085
Other assets	451
Total assets	3,946
Total liabilities	
Current liabilities	906
Liabilities from price risk management activities, current	19
Long-term debt, less current maturities	1,415[(1)]
Liabilities from price risk management activities, non-current	34
Other liabilities	352
Total liabilities	2,726
Net assets	$ 1,220

[(1)] This debt is recourse only to the project, contract or plant to which it relates.

Our initial allocation of the purchase price was based on preliminary valuations performed by an independent third party consultant. These preliminary valuations were derived using discounted cash flow analysis and other valuation methods. In addition, as part of our asset sale program, we are in the process of obtaining bids from potential buyers for some of the assets we acquired. We expect to finalize our purchase price allocation once we receive the final valuation report from our consultant and have evaluated the bids we have received. We believe we will complete our purchase price allocation by the end of 2003.

Gemstone. As discussed more completely in our Current Report on Form 8-K dated September 23, 2003, we entered into the Gemstone investment in 2001 to finance five major power plants in Brazil. Gemstone had investments in three power projects (Macae, Porto Velho and Araucaria) that had a total generating capacity of 1,788 megawatts (based on Gemstone's interest in the plants). Gemstone also owned a preferred interest in two of our consolidated power projects, Rio Negro and Manaus. In January 2003, the third party equity investor in Gemstone, Rabobank, notified us that it planned to remove us as the manager of Gemstone. Instead of being removed, we elected to buy Rabobank's interest in Gemstone for approximately $50 million in April 2003. Gemstone's results of operations have been included in our consolidated financial statements since April 1, 2003. Although our net income and basic and diluted earnings per share for the nine months ended September 30, 2003 would not have been affected, our revenues and operating income would have been higher by $58 million and $41 million had we acquired Gemstone effective January 1, 2003. Had the acquisition been effective January 1, 2002, our net income and our basic and diluted earnings per share would have been unaffected, but our revenues and operating income would have been higher by $56 million and $38 million for the quarter ended September 30, 2002, and $123 million and $90 million for the nine months ended September 30, 2002.

Our initial allocation of the $50 million purchase price to the assets acquired and liabilities assumed upon our consolidation of Gemstone in April 2003 was as follows (in millions):

Fair value of assets acquired	
Note and interest receivable	$ 122
Investments in unconsolidated affiliates	892
Other assets	3
Total assets	1,017
Fair value of liabilities assumed	
Note and interest payable	967
Total liabilities	967
Net assets acquired	$ 50

Our initial allocation of the purchase price was based on preliminary valuations performed by an independent third party consultant. These preliminary valuations were derived using discounted cash flow analysis and other valuation methods. We expect to finalize our purchase price allocation once we receive the final valuation report from our consultant, which we anticipate will be completed by the end of 2003.

As mentioned above, prior to the acquisition, we recorded our investments in Chaparral and Gemstone as investments in unconsolidated affiliates. We also had other balances, including loans and notes with Chaparral and Gemstone, which were eliminated upon consolidation. As a result, the overall impact on our consolidated balance sheet from acquiring these investments was different than the individual assets and liabilities acquired. The overall impact of these acquisitions on our consolidated balance sheet was an increase in our consolidated assets of $2.1 billion, an increase in our consolidated liabilities of approximately $2.4 billion, including an increase in our consolidated debt of approximately $2.2 billion, and a reduction of our preferred interests in consolidated subsidiaries of approximately $0.3 billion.

Consolidations

During the second quarter of 2003, we amended several financing and other agreements in connection with our new $3 billion revolving credit agreement (see Note 16). These amendments were completed to accomplish several objectives, including (i) simplifying our capital structure by eliminating several "off-balance sheet" obligations and replacing them with direct obligations, and (ii) strengthening the overall collateral package available to our financial lenders. These amendments are discussed below.

Lakeside. We amended an operating lease agreement at our Lakeside telecommunications facility to add a guarantee benefiting the party who had invested in the lessor and to allow the third party and certain lenders to share in the collateral package that was provided to the banks under our new $3 billion revolving credit facility. This guarantee reduced the investor's risk of loss of its investment, resulting in our controlling the lessor. As a result, we consolidated the lessor in the second quarter of 2003. The consolidation of Lakeside resulted in an increase in our property, plant and equipment of approximately $275 million and an increase in our long-term debt of approximately $275 million. Additionally, upon its consolidation, we recorded an asset impairment charge of approximately $127 million representing the difference between the facility's estimated fair value and the residual value guarantee under the lease. Prior to its consolidation, this difference was being periodically expensed as part of operating lease expense over the term of the lease.

Aruba. We amended an operating lease at our Aruba facility to provide a full guarantee to the parties who invested in the lessor and to allow the third party and certain lenders to share in the collateral package that was provided to the banks under our new $3 billion revolving credit facility. This guarantee reduced the investor's risk of loss of its investment, resulting in our controlling the lessor. As a result, we consolidated the lessor during the second quarter of 2003, increasing our total property, plant and equipment by $370 million (prior to an impairment charge we recorded on these assets of $50 million) and increasing our long-term debt by $370 million. As a result of our intent to exit substantially all of our petroleum markets operations, these leased assets and associated debt were reclassified as discontinued operations.

Clydesdale. In 2003, we modified our Clydesdale financing arrangement to convert a third party investor's (Mustang Investors, L.L.C.) preferred ownership interest in one of our consolidated subsidiaries into a term loan that matures in equal quarterly installments through 2005. We also acquired a $10 million preferred interest in Mustang and guaranteed all of Mustang's equity holder's obligations. As a result, we were required to consolidate Mustang in the second quarter of 2003 which increased our long-term debt by $743 million and decreased our preferred interests of consolidated subsidiaries by $753 million. The $10 million preferred interest we acquired in Mustang was eliminated upon its consolidation (see Notes 16 and 17).

4. Divestitures

During 2003, we completed or announced the sale of a number of assets and investments in each of our business segments. The gains and losses on these sales and any asset impairments recorded on these assets, investments and operations are discussed in Notes 8, 11 and 21.

Segment	Proceeds (In millions)	Significant Asset and Investment Divestitures
Completed as of September 30, 2003		
Pipelines	$ 82	• Panhandle gathering system located in Texas • Equity interest in Alliance pipeline and related assets • Helium processing operations in Oklahoma • Sulfur extraction facility • Horsham pipeline in Australia
Production	740	• Natural gas and oil properties located in western Canada, Texas, Louisiana, New Mexico, Oklahoma and the Gulf of Mexico • Drilling rigs
Field Services	153	• Gathering systems located in Wyoming • Midstream assets in the north Louisiana and Mid-Continent regions
Merchant Energy	377	• Equity interest in the CE Generation L.L.C. power investment (including the rights to an interest in a geothermal development project) • Mt. Carmel power plant • Equity interest in the Kladno power project • Enerplus Global Energy Management Company and its financial operations • EnCap funds management business and related investments • CAPSA/CAPEX investments in Argentina • Mohawk River Funding I, L.L.C.

Segment	Proceeds (In millions)	Significant Asset and Investment Divestitures
Corporate and Other	36	• Aircraft
Total continuing operations	1,388[1]	
Discontinued operations	599	• Coal reserves and properties in West Virginia, Virginia and Kentucky • Corpus Christi refinery • Florida petroleum terminals and tug and barge operations • Louisiana lease crude business • Petroleum asphalt operations
Total	$1,987	

[1] Excludes $18 million of costs incurred in preparing assets for disposal, returns of invested capital and cash transferred with assets sold.

Segment	Proceeds[1] (In millions)	Significant Asset and Investment Divestitures
Announced to date		
Pipelines	$ 63	• Equity interest in the Portland Natural Gas transmission system • Equity interest in gas storage facilities
Field Services	267	• 9.9 percent interest in the general partner of GulfTerra Energy Partners, L.L.C.[2] • Series B preference units in GulfTerra Energy Partners, L.P.[2] • Common units in GulfTerra Energy Partners, L.P.[2]
Merchant Energy	455	• East Coast Power, L.L.C.[3] • Central Costañera
Corporate and Other	25	• Harbortown development
Total continuing operations	810	
Discontinued operations	305	• Eagle Point refinery and related pipeline assets[4] • Nitrogen plant • Texas lease crude business[2] • Pipeline and terminal in the Philippines
Total	$1,115	

[1] Amounts on sales that have been announced or are under contract for sale are estimates, subject to customary regulatory approvals, final sale negotiations and other conditions.

[2] These sales were completed in October 2003.

[3] This sale was completed in October 2003 and $70 million of the proceeds were withheld pending the resolution of regulatory matters discussed further in Note 18.

[4] We have entered into a non-binding letter of intent to sell these assets.

Each period, we evaluate our potential asset sales to determine if any meet the criteria as held for sale or as discontinued operations under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. To the extent that all of the criteria of SFAS No. 144 are met, we classify an asset as held for sale or, if appropriate, discontinued operations. For example, our Board of Directors (or a designated subcommittee of our Board) is required to approve asset dispositions greater than specified thresholds. Unless specific approval is received by our Board (or a designated subcommittee) by the end of a given reporting period to commit to a plan to sell an asset, we would not classify it as held for sale or discontinued operations in that reporting period even if it is management's stated intent to sell the asset. As of December 31, 2002, we had $31 million of long-lived assets classified as held for sale and reflected in current assets in our balance sheet, all of which had been sold as of September 30, 2003. As of September 30, 2003, we had $111 million of long-lived assets classified as held for sale and reflected in current assets in our balance sheet. We also had approximately $1.6 billion of assets classified as discontinued operations as of September 30, 2003 (see Note 11).

We continue to evaluate assets we may sell in the future, and have announced that we intend to pursue the divestiture of our telecommunications business and domestic power assets. These activities are ongoing, and we have not entered into any definitive agreements. Furthermore, we are not certain what form these possible divestitures may take (e.g. outright sale or joint venture arrangement). As specific assets are identified for divestiture, we will be required to record them at the lower of fair value or historical cost. This may require us to assess them for possible impairment. The amounts of these impairment charges, if any, will generally be based on estimates of the expected fair value of the assets as determined by market data obtained through the divestiture process or by assessing the probability-weighted cash flows of the asset. For a discussion of impairment charges incurred on our long-lived assets, see Note 8; for impairments on discontinued operations, see Note 11; and for impairments on our investments in unconsolidated affiliates, see Note 21.

As of September 30, 2002, we had completed the following asset sales:

Segment	Proceeds (In millions)	Significant Asset and Investment Divestitures
Pipelines	$ 112	• Natural gas and oil production properties in Texas, Kansas and Oklahoma and their related contracts
Production	772	• Natural gas and oil properties located in Texas and Colorado
Field Services	817	• Texas and New Mexico midstream assets[1] • Dragon Trail processing plant
Total continuing operations	1,701[2]	
Discontinued operations	31	• A petroleum products terminal
Total	$1,732	

[1] Net proceeds from this sale were approximately $556 million in cash, common units of GulfTerra with a fair value of $6 million and the partnership's interest in the Prince tension leg platform including its nine percent overriding royalty interest in the Prince production field with a combined fair value of $190 million.

[2] Excludes $105 million of costs incurred in preparing assets for disposal, returns of invested capital and cash transferred with the assets sold.

5. Restructuring Charges

For the quarter and nine months ended September 30, 2003, we recognized restructuring costs totaling $14 million and $114 million. These costs were incurred as part of our ongoing liquidity enhancement and cost reduction efforts. Of this amount, $10 million and $66 million related to employee severance costs from reductions in our work force, of which approximately $51 million had been paid as of September 30, 2003. Through September 30, 2003, we had eliminated approximately 2,600 full-time positions, including approximately 1,400 full-time positions related to our discontinued operations. Employee severance costs included severance payments and costs for pension benefits settled and curtailed under existing benefit plans. For the quarter and nine months ended September 30, 2003, we also recorded $1 million and $10 million of employee severance costs related to our discontinued operations, substantially all of which had been paid as of September 30, 2003. During the first quarter of 2003, we also recognized charges of approximately $44 million associated with our liquefied natural gas (LNG) business following our February 2003 announcement to minimize our involvement in that business. This charge related to amounts paid for canceling our option to charter a fifth ship to transport LNG from supply areas to domestic and international market centers and to restructure the remaining charter agreements. We recorded all restructuring costs as operation and maintenance expense in our income statement, and these charges impacted the results in all of our business segments.

For the quarter and nine months ended September 30, 2002, we incurred $1 million and $64 million of restructuring charges. During 2002, we completed an employee restructuring across all of our operating segments which resulted in the elimination of approximately 808 full-time positions, including those employees related to our discontinued operations. We incurred and paid $23 million of employee severance and termination costs. Employee severance costs included severance payments and costs for pension benefits settled and curtailed under existing benefit plans. We also incurred fees of $40 million to eliminate the stock price and credit rating triggers related to our Gemstone and Chaparral investments. These restructuring charges were reflected as operation and maintenance expense in our income statement.

6. Western Energy Settlement

In June 2003, we entered into two definitive agreements (referred to as the Western Energy Settlement) with a number of public and private claimants, including the states of California, Washington, Oregon and Nevada, to resolve the principal litigation, claims and regulatory proceedings against us and our subsidiaries relating to the sale or delivery of natural gas and electricity from September 1996 to the date of the settlement. Subject to court and regulatory approvals, the settlement will include payments of cash, the issuance of common stock and the reduction in prices under a power supply contract.

These definitive settlement agreements modified an agreement in principle reached on March 20, 2003, as discussed in our Current Report on Form 8-K dated September 23, 2003, and resulted in an additional obligation and a pretax charge of $123 million during the second quarter of 2003. The charge was primarily a result of changes in the timing of settlement payments and changes in the value of the common stock to be issued in connection with the definitive settlement agreements. During the third quarter of 2003, we recorded a benefit of approximately $20 million due to changes in our stock price, resulting in a net charge for the nine months ended September 30, 2003, of $103 million. This net charge was in addition to accretion expense on the originally recorded discounted Western Energy Settlement obligation and other charges included as part of operation and maintenance expense during 2003. For the quarter and nine months ended September 30, 2003, these accretion and other charges were approximately $12 million and $55 million. As of September 30, 2003, $616 million of the total Western Energy Settlement obligation of $1,035 million was reflected as a current liability. The current portion includes a $193 million obligation to issue approximately 26.4 million shares of our common stock. The stock obligation will continue to impact our income statement, either positively or negatively, based on changes in our stock price until the settling parties elect to have the shares issued on their behalf. As of September 30, 2003, $10 million of the total obligation had been satisfied. Future payments will be reflected in our cash flows from operations. In addition, in July 2003, EPNG, our subsidiary, issued $355 million of senior notes, the net proceeds from which will be placed in an escrow account (once established) to be used to satisfy a portion of the overall obligation. For a further discussion of the Western Energy Settlement, see Note 18.

As further described in Note 18, upon final approval of the settlement agreements, we will be required to provide collateral for the $45 million per year, 20-year obligation in the form of natural gas and oil reserves, other assets to be agreed upon, cash and/or letters of credit. The initial collateral requirement is estimated to be between $455 million and $592 million depending on the type of collateral posted.

7. Ceiling Test Charges

Under the full cost method of accounting for natural gas and oil properties, we perform quarterly ceiling tests to determine whether the carrying value of natural gas and oil properties exceeds the present value of future net revenues, discounted at 10 percent, plus the lower of cost or fair market value of unproved properties, net of related income tax effects.

For the quarter and nine months ended September 30, 2003, we recorded a ceiling test charge of approximately $2 million primarily related to our Turkish full cost pool. For the nine months ended September 30, 2002, we recorded ceiling test charges of $267 million, of which $33 million was charged during the first quarter and $234 million during the second quarter. The 2002 charges include $226 million for our Canadian full cost pool, $24 million for our Turkish full cost pool, $10 million for our Brazilian full cost pool and $7 million for Australia and other international production operations. Our ceiling test charges were based upon the daily posted natural gas and oil prices at the end of each period, adjusted for oilfield or natural gas gathering hub and wellhead price differences, as appropriate. The 2002 charge for our Canadian full cost pool primarily resulted from a low daily posted price for natural gas at the end of the second quarter of 2002.

We use financial instruments to hedge against the volatility of natural gas and oil prices. The impact of these hedges was considered in determining our ceiling test charges and will be factored into future ceiling test calculations. The charges for our international cost pools would not have changed had the impact of these hedges not been included in calculating these ceiling test charges since we do not significantly hedge our international production activities.

8. Gain (Loss) on Long-Lived Assets

Our gain (loss) on long-lived assets consists of net realized gains and losses on sales of long-lived assets and impairments of long-lived assets, and was as follows:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In millions)			
Net realized gain (loss)	$(10)	$(3)	$ 6	$24
Asset impairments[1]				
Merchant Energy				
LNG assets	(5)	—	(34)	—
Power assets	(29)	—	(29)	—
Other	(10)	—	(10)	—
Production				
Non-full cost pool Canadian assets	—	—	(14)	—
Corporate				
Telecommunications assets	—	—	(396)	—
Total asset impairments	(44)	—	(483)	—
Gain (loss) on long-lived assets	$(54)	$(3)	$(477)	$24

(1) These amounts exclude approximately $1.3 billion of asset impairments for the nine months ended September 30, 2003, related to our petroleum markets operations that were reclassified as discontinued operations.

Net Realized Gain (Loss)

Our 2003 net realized gains (losses) were primarily related to the sales of Mohawk River Funding I in our Merchant Energy segment, the north Louisiana and Mid-Continent midstream assets in our Field Services segment, the Table Rock sulfur extraction facility in our Pipelines segment, non-full cost pool assets in our Production segment and the sales of assets in our Corporate segment. Our 2002 net realized gains (losses) were primarily related to the sales of expansion rights in our Pipelines segment, non-full cost pool assets in our Production segment and the sale of the Dragon Trail processing plant in our Field Services segment.

Asset Impairments

We are required to test assets for possible impairment whenever events or changes in circumstances indicate that the carrying amount of these assets may not be fully recoverable. One event that triggers this test is the expectation that it is more likely than not that we will sell or dispose of the asset before the end of its estimated useful life. Based on our intent to dispose of a number of our assets, we tested those assets for recoverability during the first nine months of 2003 and recorded the charges indicated in the table above. Our corporate telecommunications charge includes an impairment of our investment in the wholesale metropolitan transport services, primarily in Texas, of $269 million (including a writedown of goodwill of $163 million) and an impairment of our Lakeside Technology Center facility of $127 million based on probability-weighted scenarios of what the asset could be sold for in the current market. Our Merchant Energy charges were primarily a result of our plan to reduce our involvement in the LNG business and our power assets, including our turbines classified in long-term assets (see Note 15). For additional asset impairments on our discontinued operations and investments in unconsolidated affiliates, see Notes 11 and 21.

9. Other Expenses

Other expenses for the nine months ended September 30, 2003, were $129 million. These amounts include foreign currency losses of $73 million primarily on our Euro-denominated debt and a $37 million loss on the early extinguishment of our $1.2 billion bridge loan (see Note 16).

Other expenses for the quarter and nine months ended September 30, 2002, were $14 million and $277 million. For the nine months ended September 30, 2002, we incurred foreign currency losses of $45 million resulting from the impact of foreign currency fluctuations on our Euro-denominated debt, a $56 million impairment of our investment in the Costañera power plant, a cost-based investment in Argentina, and a $90 million contract termination fee paid by our Eagle Point Cogeneration facility (in our global power division of our Merchant Energy segment) to our Eagle Point refinery (in the petroleum markets division classified as discontinued operations). This payment was eliminated in consolidation since the income associated with the petroleum markets division is reflected in discontinued operations while the power division's expense is included in Merchant Energy's operating results. Other expenses also included $55 million of minority interest in our consolidated subsidiaries.

10. Income Taxes

Income taxes included in our income (loss) from continuing operations for the periods ended September 30, 2003 and 2002 were as follows:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	**2002**	**2003**	**2002**
	(In millions, except rates)			
Income taxes	$15	$16	$(463)	$120
Effective tax rate	(18)%	40%	47%	32%

For the nine months ended September 30, our effective tax rates were different than the statutory rate of 35 percent due to the following:

	2003	**2002**
	(Percentages)	
Statutory federal rate	35	35
Increase (decrease)		
State income tax, net of federal income tax benefit	(1)	(2)
Foreign income taxed at different rates	3	1
Abandonment of foreign investments	10	—
Earnings from unconsolidated affiliates where we anticipate receiving dividends	2	(1)
Minority interest preferred dividends	(1)	—
Other	(1)	(1)
Effective tax rate	47	32

During the quarters and nine months ended September 30, 2003 and 2002, we experienced a number of events that have impacted our overall effective tax rate on continuing operations. These events included the treatment of our coal and petroleum markets operations as discontinued operations (in which income taxes are apportioned between continuing and discontinued operations) and the abandonment of several foreign investments. These events, coupled with relatively low pretax income in continuing operations, have caused, and may continue to cause, variations in our effective tax rate.

11. Discontinued Operations

Petroleum Markets Operations

In June 2003, our Board of Directors authorized the sale of substantially all of our petroleum markets operations, including our Aruba refinery, our Unilube blending operations, our domestic and international terminalling facilities and our petrochemical and chemical plants. The Board's actions were in addition to previous actions approving the sales of our Eagle Point refinery, our asphalt business, our Florida terminal, tug and barge business and our lease crude operations. Based on our intent to dispose of these operations, we were required to adjust these assets to their estimated fair value. As a result, we recognized pre-tax charges during the first and second quarters of 2003 totaling $1,366 million related to our petroleum markets assets, which included $929 million related to our Aruba refinery and $252 million related to the impairment of our Eagle Point refinery. See Note 3 for a discussion of this lease. These impairments were based on a comparison of the carrying value of our petroleum markets assets to their estimated fair value. Our fair value estimates were based on preliminary market data obtained through the early stages of the sales process and an analysis of expected discounted cash flows. The magnitude of these charges was impacted by a number of factors, including the nature of the assets to be sold, and our established time frame for completing the sales, among other factors.

In the second quarter of 2003, we entered into a product offtake agreement with Vitol S.A. Inc. (Vitol) for the sale of a number of the products produced at our Aruba refinery. As a result of this contract, Vitol became the single largest customer of our Aruba refinery, purchasing approximately 75 percent of the products produced at that plant. The agreement is for one year with two one-year extensions at Vitol's option. We have the right to terminate the agreement when the refinery is sold.

Coal Mining Operations

In the latter part of 2002 and the first quarter of 2003, we sold our coal mining operations. These operations consisted of fifteen active underground and two surface mines located in Kentucky, Virginia and West Virginia. Following the authorization of the sale by our Board of Directors, we recorded impairment charges of $37 million and $185 million in our loss from discontinued operations during the third quarter and the nine months ended September 30, 2002.

Our petroleum markets operations and our coal mining operations were historically included in our Merchant Energy segment, and are classified as discontinued operations in our financial statements for all of the historical periods presented. All of the assets and liabilities of the remaining discontinued businesses are classified as other current assets and liabilities as of September 30, 2003. The summarized financial results and financial position data of our discontinued operations were as follows:

	Petroleum	Coal Mining (In millions)	Total
Operating Results			
Quarter Ended September 30, 2003			
Revenues	$ 917	$ —	$ 917
Costs and expenses	(963)	(1)	(964)
Gain (loss) on long-lived assets	8	(8)	—
Other expense	(2)	—	(2)
Interest and debt expense	(4)	—	(4)
Loss before income taxes	(44)	(9)	(53)
Income taxes	(4)	—	(4)
Loss from discontinued operations, net of income taxes	$ (40)	$ (9)	$ (49)
Quarter Ended September 30, 2002			
Revenues	$ 1,033	$ 75	$ 1,108
Costs and expenses	(1,145)	(95)	(1,240)
Gain (loss) on long-lived assets	3	(37)	(34)
Other income	21	—	21
Loss before income taxes	(88)	(57)	(145)
Income taxes	(31)	(21)	(52)
Loss from discontinued operations, net of income taxes	$ (57)	$ (36)	$ (93)
Nine Months Ended September 30, 2003			
Revenues	$ 4,621	$ 27	$ 4,648
Costs and expenses	(4,730)	(22)	(4,752)
Loss on long-lived assets	(1,278)	(11)	(1,289)
Other income (expenses)	(16)	1	(15)
Interest and debt expense	(8)	—	(8)
Loss before income taxes	(1,411)	(5)	(1,416)
Income taxes	(230)	1	(229)
Loss from discontinued operations, net of income taxes	$(1,181)	$ (6)	$(1,187)

	Petroleum	Coal Mining (In millions)	Total
Operating Results			
Nine Months Ended September 30, 2002			
Revenues	$ 3,095	$ 243	$ 3,338
Costs and expenses	(3,243)	(259)	(3,502)
Gain (loss) on long-lived assets	4	(185)	(181)
Other income	115	6	121
Interest and debt expense	(13)	—	(13)
Loss before income taxes	(42)	(195)	(237)
Income taxes	(15)	(73)	(88)
Loss from discontinued operations, net of income taxes	$ (27)	$(122)	$ (149)
Financial Position Data			
September 30, 2003			
Assets of discontinued operations			
Accounts and notes receivables	$ 226	$ —	$ 226
Inventory	441	—	441
Other current assets	97	—	97
Property, plant and equipment, net	678	—	678
Other non-current assets	133	—	133
Total assets	$ 1,575	$ —	$ 1,575
Liabilities of discontinued operations			
Accounts payable	$ 209	$ —	$ 209
Other current liabilities	132	—	132
Notes payable	370	—	370
Environmental remediation reserve	44	—	44
Total liabilities	$ 755	$ —	$ 755
December 31, 2002			
Assets of discontinued operations			
Accounts and notes receivables	$ 1,229	$ 29	$ 1,258
Inventory	636	14	650
Other current assets	79	1	80
Property, plant and equipment, net	1,950	46	1,996
Other non-current assets	65	16	81
Total assets	$ 3,959	$ 106	$ 4,065
Liabilities of discontinued operations			
Accounts payable	$ 1,153	$ 20	$ 1,173
Other current liabilities	180	5	185
Environmental remediation reserve	86	15	101
Other non-current liabilities	1	—	1
Total liabilities	$ 1,420	$ 40	$ 1,460

12. Cumulative Effect of Accounting Changes

On January 1, 2003, we adopted SFAS No. 143. As a result, we recorded a cumulative effect of an accounting change of approximately $22 million, net of income taxes (see Note 2).

On January 1, 2002, we adopted SFAS No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets.* As a result of our adoption of these standards on January 1, 2002, we stopped amortizing goodwill, and recognized a pretax and after-tax gain of $154 million related to the write-off of negative goodwill as a cumulative effect of an accounting change in our income statement.

In the second quarter of 2002, we also adopted DIG Issue No. C-16, *Scope Exceptions: Applying the Normal Purchases and Sales Exception to Contracts that Combine a Forward Contract and Purchased Option Contract.* One of our unconsolidated affiliates, the Midland Cogeneration Venture Limited Partnership, recognized a gain on a fuel supply contract upon adoption of this new rule, and we recorded a gain of $14 million, net of income taxes, as a cumulative effect of an accounting change in our income statement for our proportionate share of this gain.

13. Earnings Per Share

We calculated basic and diluted earnings per common share amounts as follows for the periods ended September 30:

	2003		2002	
	Basic	Diluted	Basic	Diluted
	(In millions, except per common share amounts)			
Quarter Ended September 30,				
Income (loss) from continuing operations	$ (97)	$ (97)	$ 24	$ 24
Discontinued operations, net of income taxes	(49)	(49)	(93)	(93)
Adjusted net loss	$ (146)	$ (146)	$ (69)	$ (69)
Average common shares outstanding	596	596	586	586
Earnings per common share				
Income (loss) from continuing operations	$ (0.16)	$ (0.16)	$ 0.04	$ 0.04
Discontinued operations, net of income taxes	(0.08)	(0.08)	(0.16)	(0.16)
Adjusted net loss	$ (0.24)	$ (0.24)	$(0.12)	$(0.12)
Nine Months Ended September 30,				
Income (loss) from continuing operations	$ (519)	$ (519)	$ 250	$ 250
Discontinued operations, net of income taxes	(1,187)	(1,187)	(149)	(149)
Cumulative effect of accounting changes, net of income taxes	(22)	(22)	168	168
Adjusted net income (loss)	$(1,728)	$(1,728)	$ 269	$ 269
Average common shares outstanding	596	596	548	548
Effect of dilutive securities				
Stock options	—	—	—	1
Average common shares outstanding	596	596	548	549
Earnings per common share				
Income (loss) from continuing operations	$ (0.87)	$ (0.87)	$ 0.46	$ 0.46
Discontinued operations, net of income taxes	(1.99)	(1.99)	(0.27)	(0.27)
Cumulative effect of accounting changes, net of income taxes	(0.04)	(0.04)	0.30	0.30
Adjusted net income (loss)	$ (2.90)	$ (2.90)	$ 0.49	$ 0.49

For the quarter and nine months ended September 30, 2003, there were a total of 42 million of potentially dilutive securities excluded from the determination of average common shares outstanding because we had net losses in these periods. For the quarter and nine months ended September 30, 2002, a total of 16 million shares of potentially dilutive securities was excluded based on our income levels. The excluded securities included stock options, restricted stock, equity security units, shares we are obligated to issue at the direction of the settling claimants under our Western Energy Settlement, trust preferred securities and convertible debentures.

14. Financial Instruments and Price Risk Management Activities

The following table summarizes the carrying value of our price risk management assets and liabilities as of September 30, 2003 and December 31, 2002:

	September 30, 2003	December 31, 2002
	(In millions)	
Net assets (liabilities)		
Energy contracts		
Trading contracts[1][2]	$ (78)	$ (45)
Non-trading contracts[2]		
Derivatives designated as hedges	(536)	(500)
Other derivatives	1,954	959
Total energy contracts	1,340	414
Interest rate and foreign currency contracts	77	22
Net assets from price risk management activities[3]	$1,417	$ 436

(1) Trading contracts are derivative contracts that historically have been entered into for purposes of generating a profit or benefiting from movements in market prices.

(2) Included in our trading and non-trading contracts at both September 30, 2003 and December 31, 2002 are $165 million and $123 million of intercompany derivative positions, that eliminate in consolidation, and have no impact on our consolidated price risk management activities.

(3) Net assets from price risk management activities include current and non-current assets and current and non-current liabilities from price risk management activities on the balance sheet.

As of September 30, 2003, other derivatives include $1,957 million of derivative contracts primarily related to power restructuring activities, $1,010 million of which relates to contracts we acquired in connection with our acquisition of Chaparral in the second quarter of 2003 and $947 million associated with our power restructuring activities at our Eagle Point Cogeneration and our Capitol District Energy Center Cogeneration Associates facilities. As of December 31, 2002, other derivatives include $968 million of derivative contracts associated with our power restructuring activities at our Eagle Point Cogeneration and our Capitol District Energy Center Cogeneration Associates facilities. For a further discussion of our Chaparral acquisition, see Note 3, and for a further discussion of our power restructuring activities, see our Current Report on Form 8-K dated September 23, 2003. The remaining balances in other derivatives includes unrealized losses of $3 million and $9 million as of September 30, 2003 and December 31, 2002, that relate to derivative positions that no longer qualify as cash flow hedges under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, because they were designated as hedges of anticipated future production on natural gas and oil properties that were sold during 2002.

In September 2003, we entered into several cross-currency fair value hedge transactions which effectively hedged the currency risk on a portion of our Euro-denominated debt through 2009. Collectively, these transactions swap €250 million of our fixed rate debt for approximately $275 million of floating rate debt at a weighted average rate of LIBOR plus 3.6%. In October and November 2003, we entered into several additional cross-currency fair value hedge transactions which effectively hedged the currency risk on a portion of our Euro denominated debt through 2009. Collectively, these transactions swap €100 million of our fixed rate debt for approximately $115 million of floating rate debt at a weighted average rate of LIBOR plus 4.11%. Also in October 2003, we entered into several fair value hedge transactions which effectively converted the fixed interest rate of 7.875% on $200 million of our debt to a weighted average rate of LIBOR plus 4.14% through 2012.

15. Inventory

	September 30, 2003	December 31, 2002
	(In millions)	
Current		
Materials and supplies and other	$163	$174
Natural gas liquids and natural gas in storage	40	78
Total current inventory	203	252
Non-current		
Dark fiber	5	5
Turbines	119	222
Total non-current inventory[1]	124	227
Total inventory	$327	$479

(1) We recorded these amounts as other non-current assets in our balance sheet. In September 2003, we negotiated an expected settlement under which we will transfer our ownership rights and obligations related to $100 million of our power turbine inventories, resulting in a write-down of $22 million of this inventory at September 30, 2003.

16. Debt and Other Credit Facilities

	September 30, 2003	December 31, 2002
	(In millions)	
Short-term financing obligations, including current maturities	$ 1,047	$ 2,075
Notes payable to affiliates	9	390
Long-term financing obligations	22,524[1]	16,106
Total debt obligations	$23,580	$18,571

Our debt and other credit facilities consist of both short and long-term borrowings and notes with our affiliated companies. During the first nine months of 2003, we entered into a new $3 billion revolving credit facility, acquired and consolidated a number of entities with existing debt, refinanced shorter-term obligations with longer-term borrowings and redeemed and eliminated preferred interests in our subsidiaries. A summary of our actions is as follows (in millions):

Debt obligations as of December 31, 2002	$18,571
Acquisitions and consolidations:	
Clydesdale restructuring	743
Gemstone acquisition[2][3]	1,013
Chaparral acquisition[3]	1,565
Bank refinancings:	
Lakeside lease	275
Principal amounts borrowed[4]	4,050
Repayments/retirements of principal[4]	(2,989)
Reclassifications of preferred interests as long-term financing obligations	625
Elimination of affiliate obligations	(326)
Other	53
Total debt obligations as of September 30, 2003	$23,580

(1) Does not include $370 million of long-term debt related to our Aruba refinery that is classified as part of our discontinued operations.

(2) This amount includes $75 million related to Macae which was consolidated as a consequence of our acquisition of Gemstone.

(3) This is a non-recourse project financing or non-recourse debt related to our power contract restructuring.

(4) Includes $500 million of borrowings and $750 million of repayments under our revolving credit agreements.

As discussed further in Note 17, our Clydesdale and Trinity River financings were restructured in 2003 resulting in their reclassification from preferred interests of consolidated subsidiaries to long-term debt. The Trinity River financing was redeemed with a portion of the proceeds from borrowings in 2003, specifically the $1.2 billion two-year term loan issued in March 2003, which was then refinanced with the $1.2 billion 10 year loan issued in May 2003. The Clydesdale financing was converted into a term loan maturing in equal quarterly installments through 2005. The balance of the term loan was $521 million as of September 30, 2003. In November 2003, we made additional payments of $107 million on this term loan. Additionally, we reclassified $625 million of our mandatory redeemable preferred securities of Coastal Finance I and Capital Trust I as a result of the adoption of SFAS No. 150 (see Notes 2 and 17).

Short-Term Debt and Credit Facilities

At December 31, 2002, our weighted average interest rate on our short-term credit facilities was 2.69%. We had the following short-term borrowings and other financing obligations:

	September 30, 2003	December 31, 2002
	(In millions)	
Current maturities of long-term debt and other financing obligations	$1,047	$ 575
Short-term credit facilities	—	1,500
	$1,047	$2,075

Credit Facilities

In April 2003, we entered into a new $3 billion revolving credit facility, with a $1.5 billion letter of credit sublimit, which matures on June 30, 2005. Our $3 billion revolving credit facility has a borrowing cost of LIBOR plus 350 basis points, letter of credit fees of 350 basis points and commitment fees of 75 basis points on unused amounts of the facility. This facility replaced our previous $3 billion revolving credit facility. Approximately $1 billion of our other financing arrangements (including the leases discussed in Notes 3 and 11, letters of credit and other facilities) were also amended to conform the provisions of those obligations to our $3 billion revolving credit facility. The $3 billion revolving credit facility and those other financing arrangements are secured by our equity in EPNG, Tennessee Gas Pipeline Company (TGP), ANR Pipeline Company (ANR), Wyoming Interstate Company Ltd. (WIC), ANR Storage Company, Southern Gas Storage Company and our Series A and Series C units in GulfTerra. The $3 billion revolving credit facility and other financing arrangements are also collateralized by our equity in the companies that own the assets that collateralize our Clydesdale financing arrangement. For a discussion of Clydesdale, see Notes 3 and 17.

As of September 30, 2003, there were $1.3 billion of borrowings outstanding and $1.0 billion of letters of credit issued under the $3 billion revolving credit facility, all of which was borrowed by or issued on behalf of us. Amounts outstanding under the $3 billion revolving credit facility as of September 30, 2003, were classified as non-current in our balance sheet, based on the maturity date which is June 30, 2005. Subsequent to September 30, 2003, we repaid an additional $400 million under our revolving credit facility. In addition, in October 2003, we liquidated a portion of the collateral that supports the revolver and related financing arrangements. The proceeds from the liquidation will be used to reduce commitments and repay amounts outstanding under the $3 billion revolving credit facility and related financing arrangements. As a result, there will be a $17 million reduction of the borrowing availability under our $3 billion revolving credit facility.

We also maintained a $1 billion revolving credit facility, which expired on August 4, 2003. EPNG and TGP were also borrowers under this facility.

The availability of borrowings under our $3 billion revolving credit facilities and other borrowing agreements is subject to conditions, which we currently meet. These conditions include compliance with the financial covenants and ratios required by those agreements, absence of default under the agreements, and continued accuracy of the representations and warranties contained in the agreements.

Long-Term Debt Obligations

During 2003, we have entered into, consolidated and retired several debt financing obligations:

Date	Company	Type	Interest Rate	Principal	Net Proceeds[1]	Due Date
				(In millions)		
Issuances						
March	El Paso[2]	Two-year term loan	LIBOR + 4.25%	$1,200	$1,149	2004-2005
March	SNG	Senior notes	8.875%	400	385	2010
March	ANR	Senior notes	8.875%	300	288	2010
May	El Paso Production Holding[3]	Senior notes	7.75%	1,200	1,169	2013
June	Macae[4]	Notes	Various	95	95	2008
July	EPNG	Senior notes	7.625%	355	347	2010
	Issuances through September 30, 2003			3,550	3,433	
October	Macae[4]	Term loan	Floating rate	200	200	2007
				$3,750	$3,633	
Acquisitions, Consolidations and Reclassifications						
April	Lakeside	Term loan	LIBOR + 3.5%	$ 275	$ 275	2006
April	Gemstone	Notes	7.71%	950	938	2004
	Macae[4][5]	Loan	Floating rate	75	75	2007
April	Clydesdale	Term loan	Various	743	743	2005
May	Chaparral[4]	Notes and loans	Various	1,671	1,565	Various
September	Capital Trust I	Preferred securities	4.75%	325	325	2028
September	Coastal Finance I	Preferred securities	8.375%	300	300	2038
				$4,339	$4,221	

Date	Company	Type	Interest Rate	Principal	Net Retirements
				(In millions)	
Retirements[6]					
January-September	Various	Long-term debt	Various	$ 136	136
February	El Paso CGP	Long-term debt	4.49%	240	240
May	Clydesdale	Term loan	Variable	100	100
May	El Paso[3]	Two-year term loan	LIBOR + 4.25%	1,200	1,191
July	El Paso CGP	Note	Floating rate	200	200
August	El Paso CGP	Senior debentures	9.75%	102	102
August	Clydesdale	Term loan	Variable	122	122
September	Mohawk River Funding I[7]	Note	7.09%	139	139
	Retirements through September 30, 2003			2,239	2,230
October	East Coast Power[8]	Senior secured note	Various	571	571
November	Clydesdale	Term loan	Variable	107	107
				$2,917	$2,908

(1) Net proceeds were primarily used to repay maturing long-term debt, redeem preferred interests of consolidated subsidiaries, repay short-term borrowings and other financing obligations and for other general corporate and investment purposes.

(2) The proceeds from the two-year term loan were used to redeem our Trinity River financing.

(3) Net proceeds were used to repay the $1.2 billion LIBOR based two-year term loan.

(4) This is a non-recourse project financing or non-recourse debt related to our power contract restructuring.

(5) This non-recourse project debt was consolidated as a consequence of our acquisition of Gemstone.

(6) Amount excludes net repayments of $250 million through September 30, 2003, and additional net repayments of $400 million as of October 31, 2003, related to our $3 billion revolving credit facility which is classified as long-term debt based on its maturity date of June 30, 2005.

(7) This debt related to Mohawk River Funding I, L.L.C. was eliminated through the sale of this entity.

(8) This debt related to East Coast Power, L.L.C. was eliminated through the sale of this entity.

Other

In October 2003, we initiated a tender offer to exchange our 11.5 million, 9% equity security units (consisting of a senior note and a stock purchase contract) for our common stock and cash. For each unit tendered, the holder will receive 2.5063 shares of common stock and cash in the amount of $9.70 per equity security unit. The exchange offer is conditioned upon the valid tender of at least 50 percent of the equity security units, or 5.75 million equity security units, which condition may be waived by us at our sole discretion. If 100 percent of the units are tendered, our debt obligations would be reduced by up to $575 million.

Restrictive Covenants

As part of our new $3 billion revolving credit facility, several of our significant covenants changed. Our ratio of debt to capitalization (as defined in the new revolving credit facility) cannot exceed 75 percent, instead of the previous maximum of 70 percent (as was defined in the prior credit facility agreement). For purposes of this calculation, we are allowed to add back to equity non-cash impairments of long-lived assets and exclude the impact of accumulated other comprehensive income, among other items. Additionally, in determining debt under the agreements, we are allowed to exclude certain non-recourse project financings, among other items. The covenant relating to subsidiary debt was removed. Also, EPNG, TGP, ANR, and upon the maturity of the Clydesdale financing transaction, Colorado Interstate Gas Company (CIG) cannot incur incremental debt if the incurrence of this incremental debt would cause their debt to EBITDA ratio (as defined in the new $3 billion revolving credit facility agreement) for that particular company to exceed 5 to 1. Additionally, the proceeds from the issuance of debt by the pipeline company borrowers can only be used for maintenance and expansion capital expenditures or investments in other FERC-regulated assets, to fund working capital requirements, or to refinance existing debt. As of September 30, 2003, we were in compliance with these covenants.

17. Preferred Interests of Consolidated Subsidiaries

Summarized below are our actions during 2003 related to our preferred interests of consolidated subsidiaries (in millions):

Balance as of December 31, 2002	$ 3,255
Redemption of Trinity River	(980)
Refinancing and redemptions of Clydesdale	(950)
Elimination of Gemstone minority interest	(300)
Reclassification of Capital Trust I and Coastal Finance I[1]	(625)
Balance as of September 30, 2003	$ 400

[1] These reclassifications were a result of our adoption of SFAS No. 150. See Note 2 for a discussion of our adoption of this accounting standard.

Trinity River. In 1999, we entered into the Trinity River financing arrangement to generate funds for investment and general operating purposes. As of December 31, 2002, approximately $980 million was outstanding under this arrangement. In the first quarter of 2003, we redeemed the entire $980 million of the outstanding preferred interests under the arrangement with a portion of the proceeds from the issuance of a $1.2 billion two-year term loan (see Note 16).

Clydesdale. In 2000, we entered into the Clydesdale financing arrangement to generate funds for investment and general operating purposes. As of December 31, 2002, approximately $950 million was outstanding under this arrangement. During 2003, we retired approximately $197 million of the third-party member interests in Clydesdale, and on April 16, 2003, we restructured the Clydesdale financing arrangement whereby the remaining unredeemed preferred member interests of $753 million were converted to a term loan guaranteed by us. Beginning in May 2003, the term loan is being amortized in equal quarterly amounts of $100 million through 2005. The term loan remains collateralized by the assets that historically supported the Clydesdale transaction, consisting of a production payment from us, various natural gas and oil properties and our equity in CIG, and is guaranteed by us. We also purchased $10 million of preferred equity of the third party investor, Mustang Investors, L.L.C., which, when coupled with our guarantee, resulted in the consolidation of Mustang in the second quarter of 2003. The consolidation of Mustang resulted in an increase in our long-term debt of approximately $743 million and a reduction in our preferred interests of consolidated subsidiaries of approximately $753 million.

Gemstone. As of December 31, 2002, Gemstone owned $300 million in preferred securities in two of our consolidated subsidiaries. In the second quarter of 2003, we acquired a 100 percent interest in the holder of these preferred interests and began consolidating this equity holder. As a result of this consolidation, we eliminated this minority interest (see Note 3).

Capital Trust I. In March 1998, we formed El Paso Energy Capital Trust I, a wholly owned subsidiary, to generate funds for investment and general operating purposes. During the third quarter of 2003, the outstanding amount of this preferred interest was reclassified as a long-term financing obligation on our balance sheet as a result of the adoption of SFAS No. 150 (see Notes 2 and 16).

Coastal Finance I. In May 1998, we formed Coastal Finance I, an indirect wholly owned business trust, to generate funds for investment and general operating purposes. During the third quarter of 2003, the outstanding amount of this preferred interest was reclassified as a long-term financing obligation on our balance sheet as a result of the adoption of SFAS No. 150 (see Notes 2 and 16).

18. Commitments and Contingencies

Legal Proceedings

Western Energy Settlement. On June 26, 2003, we announced that we had executed definitive settlement agreements to resolve the principal litigation and claims against us and our subsidiaries relating to the sale or delivery of natural gas and/or electricity to or in the Western United States. Parties to the settlement agreements include private class action litigants in California; the governor and lieutenant governor of California; the attorneys general of California, Washington, Oregon and Nevada; the California Public Utilities Commission (CPUC); the California Electricity Oversight Board; the California Department of Water Resources; Pacific Gas and Electric Company (PG&E), Southern California Edison Company, five California municipalities and six non-class private plaintiffs. For a discussion of the charges taken in connection with the Western Energy Settlement, see Note 6.

These definitive settlements were in addition to a structural settlement announced earlier in June 2003 where we agreed to provide structural relief to the settling parties. In the structural settlement, we agreed to do the following:

- Subject to the conditions in the settlement, provide 3.29 Bcf/d of primary firm pipeline capacity on our EPNG system to California delivery points during a five year period from the date of settlement, and not add any firm incremental load to our EPNG system that would prevent it from satisfying its obligation to provide this capacity;
- Construct a new $173 million, 320 MMcf/d, Line 2000 Power-Up expansion project, and forgo recovery of the cost of service of this expansion until EPNG's next rate case before the FERC;
- Clarify the rights of Northern California shippers to recall some of EPNG's system capacity (Block II capacity) to serve markets in PG&E's service area; and
- With limited exceptions, bar any of our affiliated companies from obtaining additional firm capacity on our EPNG pipeline system during a five year period from the effective date of the settlement.

In connection with this structural settlement, a Stipulated Judgment will be filed with the United States District Court for the Central District of California. This Stipulated Judgment will provide for the enforcement of some of the obligations contained in the structural settlement.

In the definitive settlement agreements announced on June 26, 2003, we agreed to the following terms.

- We admitted to no wrongdoing;
- We will make cash payments totaling $95.5 million for the benefit of the parties to the definitive settlement agreements subsequent to the signing of these agreements. This amount represents the

originally announced $102 million cash payment less credits for amounts that have been paid to other settling parties;

- We agreed to pay amounts equal to the proceeds from the issuance of approximately 26.4 million shares of our common stock on behalf of the settling parties. If this issuance is completed prior to final approval of the settlement agreements, the proceeds from any sale will be deposited into an escrow account for the benefit of the settling parties until final approval is received;

- We will eliminate the originally announced 20-year obligation to pay $22 million per year in cash by depositing $250 million in escrow for the benefit of the settling parties within 180 days of the signing of the definitive settlement agreements; this prepayment eliminates any collateral that might have been required on the $22 million per year payment over the next 20 years;

- We will pay $45 million in cash per year in semi-annual payments over a 20-year period rather than deliver natural gas as originally contemplated. This long-term payment obligation is a direct obligation of El Paso Corporation and El Paso Merchant Energy, L.P. (EPME) and will be guaranteed by our subsidiary, EPNG. Upon final approval of the settlement agreements, we will be required to provide collateral for this obligation in the form of oil and gas reserves, other assets (to be agreed upon) or cash and letters of credit. The initial collateral requirement is estimated to be between $455 million and $592 million depending on the type of collateral posted; and

- EPME will receive reduced payments due under a power supply transaction with the California Department of Water Resources by a total of $125 million, pro rated on a monthly basis over the remaining 30 month term of the transaction. The difference between the current payments and the reduced payments will be placed into escrow for the benefit of the settling parties on a monthly basis as deliveries are made under the transaction until final approval of the Master Settlement Agreement. At that time, the actual payments to EPME for delivered power will be at the reduced amounts.

The definitive settlement agreements are subject to approval by the California Superior Court for San Diego County and the structural settlement is subject to the approval by the FERC. In June 2003, in anticipation of the execution of the definitive settlement agreements, El Paso, the CPUC, PG&E, Southern California Edison Company, and the City of Los Angeles filed the structural settlement described above with the FERC in resolution of specific proceedings before that agency. The structural settlement was protested by EPNG's east of California shippers and other shippers requested clarification and/or modification of the settlement. EPNG and the other settling parties have responded to these protests and requests for clarification and/or modification and have urged the FERC to approve the structural settlement as filed. We currently expect final approval of these settlement agreements in early 2004.

California Lawsuits. We and several of our subsidiaries have been named as defendants in fifteen purported class action, municipal or individual lawsuits, filed in California state courts. These suits contend that our entities acted improperly to limit the construction of new pipeline capacity to California and/or to manipulate the price of natural gas sold into the California marketplace. Specifically, the plaintiffs argue that our conduct violates California's antitrust statute (Cartwright Act), constitutes unfair and unlawful business practices prohibited by California statutes, and amounts to a violation of California's common law restrictions against monopolization. In general, the plaintiffs in these cases are seeking (i) declaratory and injunctive relief regarding allegedly anticompetitive actions, (ii) restitution, including treble damages, (iii) disgorgement of profits, (iv) prejudgment and postjudgment interest, (v) costs of prosecuting the actions and (vi) attorneys' fees. All fifteen cases have been consolidated before a single judge, under two omnibus complaints. All of the class action and municipal lawsuits and all but one of the individual lawsuits will be resolved upon approval of the Western Energy Settlement. As to the remaining individual lawsuit, on May 8, 2003, a settlement agreement between the plaintiffs and defendants in that case became effective and resolved all disputes between the parties in return for a single payment by us. Pursuant to the settlement, the plaintiffs' action was dismissed with prejudice.

In November 2002, a lawsuit titled *Gus M. Bustamante v. The McGraw-Hill Companies* was filed in the Superior Court of California, County of Los Angeles by several individuals, including Lt. Governor

Bustamante acting as a private citizen, against us, our subsidiaries EPNG, EPME, and El Paso Tennessee Pipeline Co. (EPTP), as well as numerous other unrelated entities, alleging the creation of artificially high natural gas index prices via the reporting of false price and volume information. This purported class action on behalf of California consumers alleges various unfair business practices and seeks restitution, disgorgement of profits, compensatory and punitive damages, and civil fines. This lawsuit will be resolved upon approval of the Western Energy Settlement.

In September 2001, we received a civil document subpoena from the California Attorney General, seeking information said to be relevant to the department's ongoing investigation into the high electricity prices in California. We have cooperated in responding to the Attorney General's discovery requests. This proceeding will be resolved upon approval of the Western Energy Settlement.

In May 2002, two lawsuits challenging the validity of long-term power contracts entered into by the California Department of Water Resources in early 2001 were filed in California state court against 26 separate companies, including our subsidiary EPME. In general, the plaintiffs allege unfair business practices and seek restitution damages and an injunction against the enforcement of the contract provisions. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

In January 2003, a lawsuit titled *IMC Chemicals v. EPME, et al.* was filed in California state court against us, EPNG and EPME. The suit arose out of a gas supply contract between IMC Chemicals (IMCC) and EPME and sought to void the Gas Purchase Agreement between IMCC and EPME for gas purchases until December 2003. IMCC contended that EPME and its affiliates manipulated market prices for natural gas and, as part of that manipulation, induced IMCC to enter into the contract. In furtherance of its attempt to void the contract, IMCC repeated the allegations and claims of the California lawsuits described above. EPME intends to enforce the terms of the contract and counterclaim for contract damages. El Paso Corporation was dismissed from the case for lack of personal jurisdiction on September 9, 2003.

Other Energy Market Lawsuits. In February 2003, the state of Nevada and two individuals filed a class action lawsuit in Nevada state court naming us and a number of our subsidiaries and affiliates as defendants. The allegations are similar to those in the California cases. The suit seeks monetary damages and other relief under Nevada antitrust and consumer protection laws. This lawsuit will be resolved upon approval of the Western Energy Settlement.

A purported class action lawsuit was filed in federal court in New York City in December 2002 alleging that El Paso, EPME, EPNG, and other defendants manipulated California's natural gas market by manipulating the spot market of gas traded on the NYMEX. Our costs and legal exposure related to this lawsuit are not currently determinable.

Two purported class action lawsuits were filed in federal court in New York City in August 2003 and October 2003 alleging that El Paso, EPME and other defendants manipulated the price of natural gas futures and option contracts traded on the NYMEX. Our costs and legal exposure related to these lawsuits are not currently determinable.

In March 2003, the State of Arizona sued us, EPNG, EPME and other unrelated entities on behalf of Arizona consumers. The suit alleges that the defendants conspired to artificially inflate prices of natural gas and electricity during 2000 and 2001. Making allegations similar to those alleged in the California cases, the suit seeks relief similar to the California cases, but under Arizona antitrust and consumer fraud statutes. Our costs and legal exposure related to this lawsuit are not currently determinable.

In April 2003, Sierra Pacific Resources and its subsidiary, Nevada Power Company filed a lawsuit titled *Sierra Pacific Resources et al. v. El Paso Corporation et. al.,* against us, EPNG, EPTP, EPME and several other non-El Paso defendants. The complaint alleges that the defendants conspired to manipulate supplies and prices of natural gas in the California-Arizona border market from 1996 through 2001. The allegations are similar to those raised in the several cases that are the subject of the Western Energy Settlement described above. The plaintiffs allege that they entered into contracts at inappropriately high prices and hedging transactions because of the alleged manipulated prices. They allege that the defendants' activities constituted (1) violations of the Sherman Act, California antitrust statutes and the Nevada Unfair Trade Practices Act;

(2) fraud; (3) both a conspiracy to violate and a violation of Nevada's RICO Act; (4) a violation of the federal RICO statute; and (5) a civil conspiracy. The complaint seeks unspecified actual damages from all the defendants, and requests that such damages be trebled. Our costs and legal exposure related to this lawsuit are not currently determinable.

On April 28, 2003, a class action lawsuit titled *Jerry Egger, et al. v. Dynegy, Inc.,* was filed in California state court. It specifically names us and 19 other non-El Paso companies as defendants and alleges a conspiracy to manipulate electricity prices to consumers in nine Western states. The complaint seeks damages on behalf of the electricity end-users in eight of the states, Oregon, Washington, Utah, Nevada, Idaho, New Mexico, Arizona and Montana. The allegations assert the defendants violated the California antitrust statute (the Cartwright Act) and committed unfair business practices in violation of the California Business Code. The complaint seeks actual and treble damages in an unspecified amount, restitution and pre- and post-judgment interest. Our costs and legal exposure related to this lawsuit are not currently determinable.

Shareholder Class Action Suits. Beginning in July 2002, twelve purported shareholder class action lawsuits alleging violations of federal securities laws have been filed against us and several of our former officers. Eleven of these lawsuits are now consolidated in federal court in Houston before a single judge. The twelfth lawsuit was dismissed in light of similar claims being asserted in the consolidated suits in Houston. The lawsuits generally challenge the accuracy or completeness of press releases and other public statements made during 2001 and 2002. Two shareholder derivative actions have also been filed which generally allege the same claims as those made in the consolidated shareholder class action lawsuits. One was filed in federal court in Houston in August 2002, has been consolidated with the shareholder class actions pending in Houston, and has been stayed. The second shareholder derivative lawsuit, filed in Delaware State Court in October 2002, generally alleges the same claims as those made in the consolidated shareholder class action lawsuit and also has been stayed. Two other shareholder derivative lawsuits are now consolidated in state court in Houston. Both generally allege that manipulation of California gas supply and gas prices exposed us to claims of antitrust conspiracy, FERC penalties and erosion of share value. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

ERISA Class Action Suit. In December 2002, a purported class action lawsuit was filed in federal court in Houston alleging generally that our direct and indirect communications with participants in the El Paso Corporation Retirement Savings Plan included misrepresentations and omissions that caused members of the class to hold and maintain investments in El Paso stock in violation of the Employee Retirement Income Security Act (ERISA). Our costs and legal exposure related to this lawsuit are not currently determinable.

SEC Investigation. On October 6, 2003, we announced that the SEC had authorized the Staff of the Fort Worth Regional Office to conduct an investigation of certain aspects of our periodic reports filed with the SEC. The investigation appears to be focused principally on our power plant contract restructurings and the related disclosures and accounting treatment for the restructured power contracts, including in particular the Eagle Point restructuring transaction completed in 2002. We are cooperating with the SEC investigation.

Carlsbad. In August 2000, a main transmission line owned and operated by EPNG ruptured at the crossing of the Pecos River near Carlsbad, New Mexico. Twelve individuals at the site were fatally injured. On June 20, 2001, the U.S. Department of Transportation's Office of Pipeline Safety issued a Notice of Probable Violation and Proposed Civil Penalty to EPNG. The Notice alleged five violations of DOT regulations, proposed fines totaling $2.5 million and proposed corrective actions. EPNG has fully accrued for these fines. The alleged five probable violations of the regulations of the Department of Transportation's Office of Pipeline Safety are: (1) failure to develop an adequate internal corrosion control program, with an associated proposed fine of $500,000; (2) failure to investigate and minimize internal corrosion, with an associated proposed fine of $1,000,000; (3) failure to conduct continuing surveillance on its pipelines and consider, and respond appropriately to, unusual operating and maintenance conditions, with an associated proposed fine of $500,000; (4) failure to follow company procedures relating to investigating pipeline failures and thereby to minimize the chance of recurrence, with an associated proposed fine of $500,000; and (5) failure to maintain elevation profile drawings, with an associated proposed fine of $25,000. In October 2001, EPNG filed a response with the Office of Pipeline Safety disputing each of the alleged violations.

After a public hearing conducted by the National Transportation Safety Board (NTSB) on its investigation into the Carlsbad rupture, the NTSB published its final report in April, 2003. The NTSB stated that it had determined that the probable cause of the August 19, 2000 rupture was a significant reduction in pipe wall thickness due to severe internal corrosion, which occurred because EPNG's corrosion control program "failed to prevent, detect, or control internal corrosion" in the pipeline. The NTSB also determined that ineffective federal preaccident inspections contributed to the accident by not identifying deficiencies in EPNG's internal corrosion control program.

On November 1, 2002, EPNG received a federal grand jury subpoena for documents related to the Carlsbad rupture. EPNG is cooperating with this investigation.

A number of personal injury and wrongful death lawsuits were filed against EPNG in connection with the rupture. All of these lawsuits have been settled, with settlement payments fully covered by insurance. In connection with the settlement of the cases, EPNG contributed $10 million to a charitable foundation as a memorial to the families involved. The contribution was not covered by insurance.

Parties to four of the settled lawsuits have since filed an additional lawsuit titled *Diane Heady et al. v. EPEC and EPNG* in Harris County, Texas on November 20, 2002, seeking an additional $85 million based upon their interpretation of earlier settlement agreements. Parties to another of the settled lawsuits have filed an additional lawsuit titled *In the Matter of the Appointment of Jennifer Smith* in Eddy County, New Mexico on May 7, 2003, seeking an additional $86 million based upon their interpretation of earlier settlement agreements. The Jennifer Smith case was settled with the settlement payment fully covered by insurance. In addition, a lawsuit entitled *Baldonado et. al. v. EPNG* was filed on June 30, 2003 in state court in Eddy County, New Mexico on behalf of 23 firemen and EMS personnel who responded to the fire and who allegedly have suffered psychological trauma. EPNG filed a motion to dismiss the *Baldonado* lawsuit which is pending before the court. Our costs and legal exposure related to the *Heady* and *Baldonado* lawsuits are not currently determinable, however we believe these matters will be fully covered by insurance.

Grynberg. In 1997, a number of our subsidiaries were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties. The plaintiff in this case seeks royalties that he contends the government should have received had the volume and heating value of natural gas produced from royalty properties been differently measured, analyzed, calculated and reported, together with interest, treble damages, civil penalties, expenses and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. These matters have been consolidated for pretrial purposes (In re: Natural Gas Royalties *Qui Tam* Litigation, U.S. District Court for the District of Wyoming, filed June 1997). In May 2001, the court denied the defendants' motions to dismiss. Discovery is proceeding. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Will Price (formerly Quinque). A number of our subsidiaries were named as defendants in *Quinque Operating Company, et al. v. Gas Pipelines and Their Predecessors, et al.*, filed in 1999 in the District Court of Stevens County, Kansas. Quinque has been dropped as a plaintiff and Will Price has been added. This class action complaint alleges that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands. The plaintiff in this case seeks certification of a nationwide class of natural gas working interest owners and natural gas royalty owners to recover royalties that the plaintiff contends these owners should have received had the volume and heating value of natural gas produced from their properties been differently measured, analyzed, calculated and reported, together with prejudgment and postjudgment interest, punitive damages, treble damages, attorneys' fees, costs and expenses, and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. Plaintiffs' motion for class certification was denied on April 10, 2003. Plaintiffs' motion to file another amended petition to narrow the proposed class to royalty owners in wells in Kansas, Wyoming and Colorado was granted on July 28, 2003. Our costs and legal exposure related to this lawsuit are not currently determinable.

MTBE. In compliance with the 1990 amendments to the Clean Air Act, we use the gasoline additive, methyl tertiary-butyl ether (MTBE), in some of our gasoline. We also produce, buy, sell and distribute MTBE. A number of lawsuits have been filed throughout the U.S. regarding MTBE's potential impact on water supplies. We are currently one of several defendants in ten such lawsuits in New York, one in New Hampshire, one in Massachusetts, three in Connecticut and one in Illinois. The plaintiffs generally seek remediation of their groundwater and prevention of future contamination and a variety of compensatory damages as well as punitive damages, attorney's fees, and court costs. In the case filed in Illinois, certification of a national plaintiff's class of certain water providers is requested. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

In addition to the above matters, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings that arise in the ordinary course of our business.

For each of our outstanding legal matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. As of September 30, 2003, we had approximately $1,143 million accrued for all outstanding legal matters, of which $1,035 million related to our Western Energy matters. Approximately $5 million of the accrual was related to our discontinued operations.

Environmental Matters

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of September 30, 2003, we had accrued approximately $429 million, including approximately $418 million for expected remediation costs at current and former operated sites and associated onsite, offsite and groundwater technical studies, and approximately $12 million for related environmental legal costs, which we anticipate incurring through 2027. Approximately $50 million of the accrual was related to our discontinued operations.

Our reserve estimates range from approximately $418 million to approximately $618 million. Our accrual represents a combination of two estimation methodologies. First, where the most likely outcome can be reasonably estimated, that cost has been accrued ($98 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($320 million to $520 million) and the lower end of the range has been accrued. By type of site, our reserves are based on the following estimates of reasonably possible outcomes.

	September 30, 2003	
Sites	**Low**	**High**
	(In millions)	
Operating	$182	$258
Non-operating	204	317
Superfund	32	43

Below is a reconciliation of our accrued liability as of September 30, 2003 (in millions):

Balance as of January 1, 2003	$498
Additions/adjustments for remediation activities	(18)
Payments for remediation activities	(52)
Other changes, net	1
Balance as of September 30, 2003	$429

In addition, we expect to make capital expenditures for environmental matters of approximately $289 million in the aggregate for the years 2003 through 2008. These expenditures primarily relate to compliance with clean air regulations. For the remainder of 2003, we estimate that our total remediation expenditures will be approximately $20 million.

Internal PCB Remediation Project. Since 1988, TGP, our subsidiary, has been engaged in an internal project to identify and address the presence of polychlorinated biphenyls (PCBs) and other substances, including those on the Environmental Protection Agency's (EPA) List of Hazardous Substances (HSL), at compressor stations and other facilities it operates. While conducting this project, TGP has been in frequent contact with federal and state regulatory agencies, both through informal negotiation and formal entry of consent orders. TGP executed a consent order in 1994 with the EPA, governing the remediation of the relevant compressor stations, and is working with the EPA and the relevant states regarding those remediation activities. TGP is also working with the Pennsylvania and New York environmental agencies regarding remediation and post-remediation activities at its Pennsylvania and New York stations. In May 2003 we finalized a new estimate of the cost to complete the PCB/HSL Project. Over the years there have been developments that impacted various individual components, but our ability to estimate a more likely outcome for the total project has not been possible until recently. The new estimate identified a $31 million reduction in our estimated cost to complete the project.

Kentucky PCB Project. In November 1988, the Kentucky environmental agency filed a complaint in a Kentucky state court alleging that TGP discharged pollutants into the waters of the state and disposed of PCBs without a permit. The agency sought an injunction against future discharges, an order to remediate or remove PCBs and a civil penalty. TGP entered into interim agreed orders with the agency to resolve many of the issues raised in the complaint. The relevant Kentucky compressor stations are being remediated under a 1994 consent order with the EPA. Despite TGP's remediation efforts, the agency may raise additional technical issues or seek additional remediation work in the future.

PCB Cost Recoveries. In May 1995, following negotiations with its customers, TGP filed an agreement with the FERC that established a mechanism for recovering a substantial portion of the environmental costs identified in its internal remediation project. The agreement, which was approved by the FERC in November 1995, provided for a PCB surcharge on firm and interruptible customers' rates to pay for eligible remediation costs, with these surcharges to be collected over a defined collection period. TGP has twice received approval from the FERC to extend the collection period, which is now currently set to expire in June 2004. The agreement also provided for bi-annual audits of eligible costs. As of September 30, 2003, TGP had pre-collected PCB costs by approximately $117 million. This pre-collected amount will be reduced by future eligible costs incurred for the remainder of the remediation project. TGP is required, to the extent actual expenditures are less than the amounts collected, to refund to its customers the difference, plus carry charges incurred up to the date of the refunds. As of September 30, 2003, TGP has recorded a regulatory liability (included in other non-current liabilities on its balance sheet) of $85 million for future refund obligations. This obligation increased by $25 million in the second quarter due to the reduction of our accrual of estimated future PCB remediation and legal costs discussed above.

Coastal Eagle Point. Our Coastal Eagle Point Oil Company received several Administrative Orders and Notices of Civil Administrative Penalty Assessment from the New Jersey Department of Environmental Protection. The Orders allege noncompliance with the New Jersey Air Pollution Control Act (the Act) pertaining to excess emissions reported since 1998 by our Eagle Point refinery in Westville, New Jersey. On February 24, 2003, EPA Region 2 issued a Compliance Order alleging violations that included failure to monitor all components and failure to timely repair leaking components. The alleged violations were identified during a 1999 EPA audit of the Leak Detection and Repair program. Our Eagle Point refinery resolved the claims of the United States and the State of New Jersey in a Consent Decree on September 30, 2003, pursuant to the EPA's refinery enforcement initiative. We agreed to pay a civil penalty of $1.25 million to the United States and $1.25 million to New Jersey. We will contribute $1.0 million to an environmentally beneficial project near the refinery. Our Eagle Point refinery will invest an estimated $3 to $7 million to upgrade the plant's environmental controls by 2008. This settlement is subject to public comment and court approval.

CERCLA Matters. We have received notice that we could be designated, or have been asked for information to determine whether we could be designated, as a Potentially Responsible Party (PRP) with respect to 62 active sites under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) or state equivalents. We have sought to resolve our liability as a PRP at these sites through indemnification by third parties and settlements which provide for payment of our allocable share of remediation costs. As of September 30, 2003, we have estimated our share of the remediation costs at these sites to be between $32 million and $43 million. Since the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and because in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal CERCLA statute is joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in estimating our liabilities. Accruals for these issues are included in the previously indicated estimates for Superfund sites.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws and regulations and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties relating to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our current reserves are adequate.

Rates and Regulatory Matters

Wholesale Power Customers' Complaints. In late 2001 and 2002, several wholesale power customers filed complaints with the FERC against EPME and other wholesale power marketers. The complaints are listed below. The primary customers are: Nevada Power Co. and Sierra Pacific Power Co. (NPSP), PacifiCorp, City of Burbank, the California Public Utilities Commission and the California Electricity Oversight Board (CPUC/CEOB). In these complaints, the customers have asked the FERC to reform the contracts they entered into with EPME and other wholesale power marketers on the grounds that they involve rates and terms that are "unjust and unreasonable" or "contrary to" the public interest within the meaning of the Federal Power Act (FPA). In the NPSP complaint, the ALJ issued an initial decision concluding that the contracts at issue should not be modified, and the complaints should be dismissed. In the CPUC/CEOB matter, the ALJ issued an initial decision finding the public interest standard applies to the contract at issue, which finding is consistent with the initial decision of the ALJ in the NPSP case. In the PacifiCorp matter, the ALJ issued an initial decision concluding that the complaint filed by PacifiCorp against EPME (and other respondents) should be dismissed with prejudice. The ALJ's decisions were upheld by FERC on June 26, 2003. The City of Burbank and EPME reached a settlement of this case which was approved by the city council on May 27, 2003. The complaint was voluntarily withdrawn from the FERC. The CPUC/CEOB matter will be fully resolved upon approval and finalization of the Western Energy Settlement. NPSP has petitioned for review of the FERC decision.

CPUC Complaint Proceeding. In April 2000, the CPUC filed a complaint under Section 5 of the Natural Gas Act (NGA) with the FERC alleging that the sale of approximately 1.2 Bcf/d of capacity by EPNG to EPME, both of whom are our wholly owned subsidiaries, raised issues of market power and violation of FERC's marketing affiliate regulations and asked that the contracts be voided. In the spring and summer of 2001, two hearings were held before an ALJ to address the market power issue and the affiliate issue. In October 2001, the ALJ issued an initial decision on the two issues, finding that the record did not support a finding that either EPNG or EPME had exercised market power but finding that EPNG had violated FERC's marketing affiliate rule.

Also in October 2001, the FERC's Office of Market Oversight and Enforcement filed comments stating that the record at the hearings was inadequate to conclude that EPNG had complied with FERC regulations in the transportation of gas to California. In December 2001, the FERC remanded the proceeding to the ALJ for a supplemental hearing on the availability of capacity at EPNG's California delivery points. On September 23, 2002, the ALJ issued his initial decision, again finding that there was no evidence that EPME had exercised market power during the period at issue to drive up California gas prices and therefore recommending that the complaint against EPME be dismissed. However, the ALJ found that EPNG had withheld at least 345 MMcf/d of capacity (and perhaps as much as 696 MMcf/d) from the California market during the period from November 1, 2000 through March 31, 2001. The ALJ found that this alleged withholding violated EPNG's certificate obligations and was an exercise of market power that increased the gas price to California markets. He therefore recommended that the FERC initiate penalty procedures against EPNG. The FERC has taken no actions in this proceeding on the ALJ's findings. This proceeding will be resolved upon approval and finalization of the Western Energy Settlement.

Systemwide Capacity Allocation Proceeding. In July 2001, several of EPNG's contract demand (CD) customers filed a complaint against EPNG at the FERC claiming, among other things, that EPNG's full requirements (FR) contracts (contracts with no volumetric limitations) should be converted to CD contracts and that EPNG should be required to expand its system and give demand charge credits to CD customers when EPNG is unable to meet its full contract demands. Also in July 2001, several of EPNG's FR customers filed a complaint alleging that EPNG had violated the NGA and its contractual obligations by not expanding its system, at its cost, to meet their increased requirements. Earlier, KN Marketing, L.P. filed a complaint at the FERC alleging that EPNG had oversubscribed its firm mainline capacity from the San Juan Basin to the East End of its system. In the May 31, 2002 order discussed below, the FERC addressed these complaints. As a result of the FERC's orders in these proceedings, FR shippers were required to convert to CD service on September 1, 2003.

On May 31, 2002, the FERC issued an order that required (i) FR service, for all FR customers except small volume customers, be converted to CD service; (ii) firm customers be assigned specific receipt point rights in lieu of system-wide receipt point rights; (iii) reservation charge credits be given to all firm customers for failure to schedule confirmed volumes except in cases of force majeure; (iv) no new firm contracts be executed until EPNG has demonstrated there is adequate capacity on the system; and (v) a process be implemented to allow CD customers to turn back capacity for acquisition by FR customers, in which process EPNG would remain revenue neutral. The order also stated that the FERC expected EPNG to file for certificate authority to add compression to its Line 2000 to increase its system capacity by 320 MMcf/d without cost coverage until its next rate case (i.e., January 1, 2006), as EPNG had previously informed the FERC it was willing to do. On July 1, 2002, EPNG and other parties filed for clarification and/or rehearing of the May 31 order.

Following the May 31 order, the FERC issued several additional orders in this proceeding that, among other things, required EPNG to allocate substantial volumes of existing and proposed pipeline capacity to its converting FR shippers at their current aggregate reservation charges, and set the rates that EPNG could charge for backhaul service from its California delivery points for existing and new shippers.

On July 9, 2003, the FERC issued a rehearing order in this case. In that order, the FERC found that EPNG had not violated its certificates, its contractual obligations, including its obligations under the 1996 Rate Settlement (discussed below), or its tariff provisions as a result of the capacity allocations that have occurred on the system since the 1996 Rate Settlement. In addition, the FERC found that EPNG had correctly stated the capacity that is available on a firm basis for allocation among its shippers and that it had properly allocated that capacity. On a prospective basis, the FERC ordered EPNG to set aside a pool of 110 MMcf/d of capacity for use by the converting FR shippers until the first phase of the Line 2000 Power-Up (discussed below) goes into service (estimated to be February 2004, after which the pool of capacity will be reduced to 50 MMcf/d until the second phase of the Power-Up is in service in mid-2004), and to pay full reservation charge credits when it is unable to schedule gas that has been nominated and confirmed by its firm shippers. In cases of force majeure events, EPNG will limit the amount of its reservation charge credits to the return and associated tax portion of its rates. The rehearing order also lifted the ban established in the May 31 order on the resale of firm capacity that comes back to EPNG, subject only to the 110/50 MMcf/d of capacity that must be maintained in a pool for the converting FR shippers until the first two phases of the Line 2000 Power-Up are in service.

On July 18, 2003, the FR shippers filed an appeal of the July 9 order with the D.C. Circuit (*Arizona Corporation Comm'n, et al. v. FERC*, No. 03-1206) and subsequently sought a stay of the FERC's orders. The stay was denied by the Court. Other parties have filed appeals of the FERC's orders and all such appeals have been consolidated. The final outcome of these appeals cannot be predicted with certainty.

On August 29, 2003, the FERC issued a further order in this matter that, among other things, authorized our converted FR shippers to relocate the delivery points associated with the California turn back capacity they would receive under the May 31 order from California to their traditional east of California delivery points. EPNG sought rehearing of that order because it does not have adequate transfer capacity between its Northern and Southern mainlines to allow it to comply with the order unless it allocates its limited North/South capacity among its shippers. EPNG's converted FR shippers requested that the FERC initiate an enforcement investigation based on EPNG's position. EPNG has opposed the request. In the August 29 order, FERC also directed that a technical conference be held to address various concerns expressed by EPNG's shippers. That conference was held on September 24, 2003 and EPNG filed its comments on that conference with the FERC. On October 20, 2003, EPNG and the converted FR Shippers filed an uncontested settlement that if approved by the FERC, will resolve all issues regarding the administration of the 110 MMcf/d capacity pool.

On October 29, 2003, EPNG's east of California shippers filed a complaint against it with the FERC claiming that it had not properly implemented the FERC's orders in the Capacity Allocation Case with respect to its provision of backhaul transportation service from the California border and requesting that the FERC issue an order requiring it to properly implement such service. EPNG will respond to the complaint.

Rate Settlement. EPNG's current rate settlement establishes its base rates through December 31, 2005. Under the settlement, EPNG's base rates began escalating annually in 1998 for inflation. EPNG has the right to increase or decrease its base rates if changes in laws or regulations result in increased or decreased costs in excess of $10 million a year. In addition, all of EPNG's settling customers participate in risk sharing provisions. Under these provisions, EPNG received cash payments in total of $295 million for a portion of the risk EPNG assumed from capacity relinquishments by its customers (primarily capacity turned back to it by Southern California Gas Company and Pacific Gas and Electric Company which represented approximately one-third of the capacity of EPNG's system) during 1996 and 1997. The cash EPNG received was deferred, and EPNG recognizes this amount in revenues ratably over the risk sharing period. As of September 30, 2003, EPNG had unearned risk sharing revenues of approximately $8 million and had $3 million remaining to be collected from customers under this provision. Amounts received for relinquished capacity sold to customers, above certain dollar levels specified in EPNG's rate settlement, obligate it to refund a portion of the excess to customers. Under this provision, EPNG refunded a total of $46 million of 2002 revenues to customers during 2002 and the first quarter of 2003. During 2003, EPNG established an additional refund obligation of $30 million of which $14 million has been refunded to customers as of September 30, 2003. Both the risk and revenue sharing provisions of the rate settlement will terminate at the end of 2003.

Line 2000 Project. In July 2000, EPNG applied with the FERC for a certificate of public convenience and necessity for its Line 2000 project, which was designed to replace old compression on the system with a converted oil pipeline, resulting in no increase in system capacity. In response to demand conditions on its system, however, EPNG filed in March 2001 to amend its application to convert the project to an expansion project of 230 MMcf/d. In May 2001, the FERC authorized the amended Line 2000 project. EPNG placed the line in service in November 2002 at a capital cost of $189 million. The cost of the Line 2000 conversion will not be included in EPNG's rates until its next rate case, which will be effective on January 1, 2006.

In October 2002, pursuant to the FERC's orders in the systemwide capacity allocation proceeding, EPNG filed with the FERC for a certificate of public convenience and necessity to add compression to its Line 2000 project to increase the capacity of that line by an additional 320 MMcf/d at an estimated capital cost of approximately $173 million for all phases. On June 4, 2003, the FERC issued an order approving EPNG's certificate application. Requests for rehearing of the June 4 order are pending at the FERC. The project is currently under construction and Phase I should be placed in service during the first quarter of 2004.

Marketing Affiliate NOPR. In September 2001, the FERC issued a Notice of Proposed Rulemaking (NOPR) proposing to apply the standards of conduct governing the relationship between interstate pipelines and marketing affiliates to all energy affiliates. The proposed regulations, if adopted by the FERC, would dictate how all our energy affiliates conduct business and interact with our interstate pipelines. We have filed comments with the FERC addressing our concerns with the proposed rules, participated in a public conference and filed additional comments. At this time, we cannot predict the outcome of the NOPR, but adoption of the regulations in their proposed form would, at a minimum, place additional administrative and operational burdens on us.

Negotiated Rate Policy. In July 2002, the FERC issued a Notice of Inquiry (NOI) that sought comments regarding its 1996 policy of permitting pipelines to enter into negotiated rate transactions. We have entered into those transactions over the years, and the FERC is now reviewing whether negotiated rates should be capped, whether or not the "recourse rate" (a cost-of-service based rate) continues to safeguard against a pipeline exercising market power and other issues related to negotiated rate programs. El Paso's pipelines and others filed comments on the NOI.

In July 2003, the FERC issued an order that prospectively prohibits pipelines from negotiating rates based upon natural gas commodity price indices and imposes certain new filing requirements to ensure the transparency of negotiated rate transactions. Requests for rehearing were filed on August 25, 2003 and remain pending. We do not expect that the order on rehearing will have a material effect on us.

Cash Management Rule. On October 23, 2003, the FERC approved a rule that requires a FERC-regulated entity to file its cash management agreement with the FERC, maintain records of transactions involving its participation in the cash management program, compute its proprietary capital ratio quarterly based on criteria established by the FERC, and notify the FERC 45 days after the end of a calendar quarter whether its proprietary capital ratio falls below 30 percent and subsequently when its proprietary capital ratio returns to or exceeds 30 percent. In the rule, the FERC stated that the requirements imposed by the rule are not in the nature of a regulation governing participation in cash management programs and that the rule does not dictate the content or terms for participating in a cash management program. Although the rule is subject to rehearing, we do not believe an order on rehearing will have a material effect on us.

On September 10, 2003, the Office of Executive Director of Regulatory Audits completed an industry-wide audit of the FERC Form 2 related to cash management. The audit included EPNG and Mojave Pipeline Company. The audit did not identify any instances of non-compliance with the FERC's reporting and recording requirements but recommended that both EPNG and Mojave revise and update their existing cash management agreements with El Paso. EPNG, Mojave and our other pipelines are in the process of reviewing and revising their cash management agreements pursuant to this recommendation.

Pipeline Safety Notice of Proposed Rulemaking. In January 2003, the U.S. Department of Transportation issued a NOPR proposing to establish a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the notice refers to as "high consequence areas." The proposed rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002, a new bill signed into law in December 2002. Comments on the NOPR were filed on April 30, 2003. Although we cannot predict the outcome of this rulemaking, we do not expect the order to have a material effect on us.

FERC Inquiry. On February 26, 2003, we received a letter from the Office of the Chief Accountant at the FERC requesting details of our announcement of 2003 asset sales and plans for our subsidiaries, SNG and ANR, to issue a combined $700 million of long-term notes. The letter requested that we explain how we intended to use the proceeds from the issuance of the notes and if the notes were to be included in SNG's and ANR's capital structure for rate-setting purposes. Our response to the FERC was filed on March 12, 2003. On April 2, 2003, we received an additional request for information, to which we fully responded on April 15, 2003.

Western Trading Strategies. EPME, our subsidiary, responded on May 22, 2002, to the FERC's May 8, 2002 request in Docket No. PA-02-2, seeking statements of admission or denial with respect to trading strategies designed to manipulate western power markets. EPME provided an affidavit stating that it had not engaged in these trading strategies. On July 10, 2003, EPME filed a follow-up letter at the request of the Office of Market Oversight and Investigation further explaining a March 26, 2003 data response in this proceeding wherein EPME denied any physical withholding of power by its generating units into the California ISO or Cal PX markets. On August 1, 2003, the FERC staff issued an initial report on physical withholding of electric generation in the California markets. The report notified EPME that its generating unit, San Joaquin Cogen Ltd., was no longer the subject of further investigation.

Wash Trade Inquiries. In May 2002, the FERC issued data requests in Docket PA-02-2, including requests for statements of admission or denial with respect to so-called "wash" or "round trip" trades in western power and gas markets. In May and June 2002, EPME responded, denying that it had conducted any wash or round trip trades (i.e., simultaneous, prearranged trades entered into for the purpose of artificially inflating trading volumes or revenues, or manipulating prices).

In June 2002, we received an informal inquiry from the SEC regarding the issue of round trip trades. Although we do not believe any round trip trades occurred, we submitted data to the SEC in July 2002. In July 2002, we received a federal grand jury subpoena for documents concerning so-called round trip or wash trades. We have complied with these requests.

Price Reporting to Indices. On October 22, 2002, the FERC issued a data request in Docket PA-02-2 to all of the largest North American gas marketers, including EPME, regarding price reporting of transactional data to the energy trade press. We also received similar requests from the Commodities Futures Trading Commission (CFTC), and the U.S. Attorney. We engaged an outside firm to investigate the matters raised in the data request. EPME has provided information regarding its price reporting to indices to the FERC, the CFTC, and to the U.S. Attorney in response to their requests. The information provided indicates inaccurate prices were reported to the trade publications. However, EPME has no evidence that these reported prices to the publications resulted in any unrepresentative price index in any pricing publication. On March 26, 2003, we announced a settlement between EPME and CFTC of the price reporting matter providing for the payment by EPME of a civil monetary penalty of $20 million, $10 million of which was paid in the second quarter of 2003 and $10 million of which is payable within three years, without admitting or denying the findings made in the CFTC order implementing the agreement. On April 30, 2003, in a new docket PA03-7, the FERC issued an Order Directing Submission of Information with Respect to Internal Processes for Reporting Trading Data, directing marketing companies, including EPME, to show that they have corrected their internal processes for reporting trading data to the trade press, or that they no longer sell natural gas at wholesale. The order required the named companies to file within 45 days of the order, to respond to the following questions 1) that employees who participated in manipulations have been disciplined; 2) that the company has a code of conduct in place for reporting price information; 3) that respondent confirm that all trade data reporting is done by an entity within the company that does not have a financial interest in the published index; and 4) the company is cooperating with any government agency investigation in past price reporting practices. EPME filed an affidavit on June 13, 2003, asserting that its Code of Conduct prohibits the submission of false data and that EPME no longer reports data to the trade press. The FERC accepted the affidavit as being in compliance with its order.

Refunds Pricing. On August 13, 2002, the FERC issued a Notice Requesting Comment on Method for Determining Natural Gas Prices for Purposes of Calculating Refunds in ongoing California refund proceedings dealing with sales of electric power in which some of our companies are involved. Referencing a Staff Report also issued on August 13, 2002, the FERC requested comments on whether it should change the method for determining the delivered cost of natural gas in calculating the mitigated market-clearing price in the refund proceeding and, if so, what method should be used. Comments were filed on October 15, 2002. On December 12, 2002, the ALJ issued an Initial Decision, setting forth preliminary calculations of amounts owed. In the aggregate, the ALJ found that $3 billion is owed to natural gas suppliers, offset by an aggregate refund of $1.2 billion associated with prices charged in excess of the mitigated market clearing prices. The FERC issued its order on the Initial Decision on March 26, 2003. The FERC largely adopted the proposed findings of the ALJ in the Initial Decision, which for the most part approved the methodology used in calculating refund liabilities. However, the FERC Commissioners adopted the FERC Staff's findings and recommendations put forth in this refund proceeding, and changed the method for calculating the mitigated market clearing price to use published prices from the production basins, plus fully allocated transport costs, instead of published California border gas prices. The methodology could increase the refund liability. EPME filed a request for rehearing of the March 26, 2003 Order, which was denied in October 2003. Upon the finalization and approval of the Western Energy Settlement, claims by many of the claimants in this proceeding for credits against amounts due EPME will be resolved; however, the specific amount of the adjustment is indeterminable at this time. We cannot predict the final outcome of this matter.

FERC Order to Show Cause EL03-187. EPME is included as a respondent to an Order to Show Cause (OSC) issued by the FERC June 25, 2003. The OSC concerns alleged gaming and/or anomalous market behavior through the use of partnerships, alliances or other arrangements and directed submission of information. The main thrust of the Order is to address partnership and alliance relationships between Enron and other entities. The Order also addresses other alleged gaming partnerships or alliances among other parties. It is in this "other" category that EPME is identified. In its response to the OSC, EPME stated that the alleged partnership is a "parking" transaction with Public Service Company of New Mexico which EPME entered into for legitimate business purposes. On October 3, 2003 the FERC staff filed a motion to dismiss EPME from this proceeding. In light of the FERC staff's motion to dismiss EPME from this proceeding, on November 4, 2003, the Chief Administrative Law Judge of the FERC issued an order stating that EPME is not subject to the litigation process in this proceeding, pending action by the FERC Commissioners on the FERC staff's motion to dismiss EPME.

Australia. In May 2003, Western Australia regulators issued a final rate decision at lower than expected levels for the Dampier to Bunbury pipeline owned by EPIC Energy Australia Trust (EPIC), in which we have a 33 percent ownership interest. During the fourth quarter of 2002, the unfavorable regulatory environment and unanticipated cash requirements made it apparent that a cash equity infusion would be required to refinance the debt of EPIC Energy (WA) Nominees Pty. Ltd. that matures and is payable in full during 2003. Given the other demands on our liquidity, we concluded that we would not contribute any further equity into our EPIC Western Australian investment. As a result, we recognized an impairment of $153 million related to this investment in 2002. At September 30, 2003, our remaining investment in EPIC was approximately $53 million.

Southwestern Bell Proceeding. We are engaged in proceedings with Southwestern Bell involving disputes regarding our telecommunications interconnection agreement in our metropolitan transport business. In August 2002, we received a favorable ruling from the administrative law judge in Phase 1 of the proceedings. In September 2003, after receiving comments from the parties, the TPUC issued an interim order that largely upheld the favorable ruling from the administrative law judge, except with regard to our ability to access Southwestern Bell's network to interconnect with other carriers. The interim order will not become final until the language set forth in the interconnect agreement is consistent with the Triennial Review order of the Federal Communications Commission (FCC) as described below.

FCC Triennial Review. In this proceeding, the FCC, pursuant to its Congressional mandate, reexamined the entire list of UNEs, including high capacity loops and transport and dark fiber, to determine if any should be removed or qualified. The FCC may either eliminate or set more stringent offering guidelines for some of the existing UNE's. Any ruling that seriously impairs El Paso Global Networks' (EPGN) ability to access these UNEs would significantly affect its current business model. An order was issued by the FCC on August 21, 2003 validating several important issues to the EPGN activities and plans, such as access to dark fiber loops and transport as UNEs, access to network information, and splicing of dark fiber. The FCC also affirmed that UNEs may be used to provide wholesale services to other telecommunication carries. The Order has been appealed.

FCC Broadband Docket. The FCC has issued a Notice of Proposed Rule Making (NPRM) for Broadband Service and asked for general comments on a vast array of issues. The NPRM indicates that the FCC is inclined to declare high-speed, DSL internet access service as an information service. This would allow Incumbent Local Exchange Carriers (ILECs) to stop leasing their DSL internet service to third party competitors for resale to customers. ILECs have also submitted proposals that would effectively deregulate all optical level and high-speed copper based services. If the FCC adopted the NPRM proposal, the results would critically affect EPGN's business. EPGN filed initial comments, in conjunction with other ILEC's. EPGN also filed joint reply comments on July 3, 2002, stressing both the illegality of the proposed finding and the national security implications. Certain ILECs are advocating the position that all high capacity copper and fiber lines should be found to be "information services" in the same way that cable modems are listed by the FCC, thereby exempting the ILECs from having to lease their lines to EPGN. The Court of Appeals for the Ninth Circuit, on October 9, 2003, reversed the FCC decision that cable modems are purely information services with no telecommunications service component. No decision is expected in 2003.

While the outcome of our outstanding legal matters, environmental matters, and rates and regulatory matters cannot be predicted with certainty, based on current information and our existing accruals, we do not expect the ultimate resolution of these matters to have a material adverse effect on our financial position, operating results or cash flows. However, it is possible that new information or future developments could require us to reassess our potential exposure related to these matters. It is possible that these matters could impact our debt rating and credit rating. Further, for environmental matters, it is possible that other developments, such as increasingly strict environmental laws and regulations and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As new information regarding our outstanding legal matters, environmental matters and rates and regulatory matters becomes available, or relevant developments occur, we will review our accruals and make any appropriate adjustments. The impact of these changes may have a material effect on our results of operations, our financial position, and our cash flows in the periods these events occur.

Other

Enron Bankruptcy. In December 2001, Enron Corp. and a number of its subsidiaries, including Enron North America Corp. and Enron Power Marketing, Inc., (EPMI) filed for Chapter 11 bankruptcy protection in the United States Bankruptcy Court for the Southern District of New York. We had contracts with Enron North America, Enron Power Marketing and other Enron subsidiaries for, among other things, the transportation of natural gas and natural gas liquids and the trading of physical natural gas, power, petroleum and financial derivatives.

Our Merchant Energy positions were governed under a master International Swap Dealers Association, Inc. agreement, various master natural gas agreements, a master power purchase and sale agreement, and other commodity agreements. We terminated most of these trading-related contracts, which we believe was proper and in accordance with the terms of these contracts. In October 2002, we filed proofs of claim for our domestic trading positions against Enron's trading entities in an amount totaling approximately $318 million. Also in October 2002, our European trading business asserted $20 million in claims against Enron Capital and Trade Resources Limited which is subject to proceedings in the United Kingdom. In addition, Enron now asserts that El Paso Merchant Energy-Petroleum Company (EPMPC), as successor by merger to Coastal States Trading, Inc., our subsidiary, owes it approximately $3 million related to certain terminated petroleum contracts. EPMPC disputes this assertion due to contractual setoff rights. After considering the cash margins Enron deposited with us as well as the reserves we have established, our overall Merchant Energy exposure to Enron is $21 million, which is classified as current accounts and notes receivable. We believe our reserves are adequate based on offers received to purchase the claims, and on the price at which we sold a portion of Merchant Energy's claims to a third party. Merchant Energy's exposure estimate is also consistent with the projected distributions reflected in the disclosure statements recently filed by Enron in its bankruptcy proceedings.

In February 2003, Merchant Energy received a letter from EPMI demanding payment under a March 2001 Power Purchase and Sale Agreement (Agreement) of approximately $46 million. Merchant Energy responded to the February 2003 demand letter denying that any sums were due EPMI under the Agreement. In addition, EPMI has demanded this sum based on an August 2, 2001 guaranty agreement. EPMI has now filed a lawsuit against Merchant Energy and El Paso in the United States Bankruptcy Court for the Southern District of New York seeking to collect these sums. We have denied liability. This lawsuit has been referred to mediation. If the court adopts Enron's methodology, it could result in a reduction or elimination of our claims against Enron Corp. and its subsidiaries described above.

In early May 2003, Enron Broadband Services, Inc. filed a notice of rejection with respect to an agreement granting El Paso Networks, L.L.C. the right to use certain dark fiber in the Denver area. El Paso Networks objected to the notice of rejection. Enron Broadband Services withdrew its notice of rejection without waiving its rights to reject the contract in the future.

In addition, various Enron subsidiaries had transportation contracts on several of our pipeline systems. Most of these transportation contracts have now been rejected, and our pipeline subsidiaries have filed proofs of claim totaling approximately $137 million. EPNG filed the largest proof of claim in the amount of approximately $128 million, which included $18 million for amounts due for services provided through the date the contracts were rejected and $110 million for damage claims arising from the rejection of its transportation contracts. We have fully reserved for the amounts due through the date the contracts were rejected, and we have not recognized any amounts under these contracts since the rejection date.

NRG. NRG Power Marketing Inc. (NRG) filed for Chapter 11 bankruptcy protection in the United States Bankruptcy Court for the Southern District of New York. EPME had power trading contracts with NRG and additional financial derivative contracts, which were terminated as a result of NRG's bankruptcy filing. We believe our termination of these contracts was proper and in accordance with the contract terms. EPME determined that its aggregated claim, after it asserted any setoff rights, would be approximately $26 million. EPME filed the claim based on damages calculated under the various trading agreements with NRG. Xcel Energy, Inc., NRG's parent, guaranteed $12 million of the debt, and subsequently paid the guaranteed amount to EPME. Accordingly, the net claim filed by EPME in the bankruptcy case was approximately $14 million. The court approved a settlement agreement between EPME and NRG providing for a payment to EPME of $13 million. We are fully reserved for the difference between the net claim filed and the settlement amount.

US Gen. USGen New England, Inc. (USGen) filed for Chapter 11 bankruptcy protection in the United States Court for the District of Maryland in July 2003. Our subsidiary, Mohawk River Funding, III, L.L.C. (MRF III) had a power purchase agreement with USGen that terminated automatically as a result of the bankruptcy filing. We are in the process of evaluating our damages and calculating our claim amount as a result of the termination. Although we have not finalized our claim amount, we believe that we are adequately reserved for amounts we may not ultimately recover on the claims against USGen.

Mirant. Mirant Corporation and several affiliates, including its trading affiliate Mirant Americas Energy Marketing, L.P., filed for Chapter 11 bankruptcy protection in the United States Bankruptcy Court for the Northern District of Texas, Fort Worth Division on July 14, 2003. EPME immediately terminated its Master Netting Agreement with Mirant Americas Energy Marketing, L.P. EPME believes the damages owed to Mirant under the Master Netting Agreement are $37 million, and provided its calculations to Mirant. Mirant claimed that EPME defaulted under the terms of the Master Netting Agreement because the calculations were not commercially reasonable. Mirant asserts that the damages should be $106 million. The parties are currently preparing to arbitrate the issue. EPME believes the liability accrued will be sufficient to provide for its obligations. Additionally, a subsidiary of Mirant owes us approximately $42 million in installment payments in connection with its purchase from us of the Pasco, Florida and the West Georgia power plants in 2001. Although we may not have the right to offset these receivables against amounts owed Mirant Americas Energy Marketing, L.P., we believe that we are adequately reserved for amounts we may not ultimately recover on the claims against Mirant. Other El Paso entities have agreements in place with various Mirant entities that are impacted by the bankruptcy filings. We do not believe we have a material exposure as a result of these bankruptcy filings.

We continue to actively monitor the creditworthiness of our counterparties in the energy sector, many of whom have experienced financial distress since the collapse of Enron. Although we have not experienced significant losses due to the bankruptcies of our counterparties to date, should there be further bankruptcies and material contracts with our various subsidiaries are not assumed by other counterparties, it could have a material adverse effect on our financial position, operating results or cash flows.

Cogeneration Facilities. On May 2, 2003, the FERC issued an Order Initiating Investigation into Enron Corporation's ownership of East Coast Power, LLC, which owned three cogeneration facilities. The three facilities are: Cogen Technologies Linden Venture, L.P. (Linden), Camden Cogen L.P. (Camden) and Cogen Technologies NJ Venture (Bayonne). The FERC is investigating whether Enron's ownership of the facilities violated restrictions contained in the Public Utility Regulatory Policies Act of 1978 (PURPA) that prohibit an electric utility from owning more than 50 percent of a Qualifying Facility (QF). The FERC asserts that Enron was an electric utility at the time of its ownership as a consequence of its merger with Portland General. We currently believe that from February 1999 to August 1999, Enron owned less than 50 percent of the interests in the facilities due to its partnership with the California Public Employees Retirement System and other third party ownership interests. We currently own all of the equity in Camden and Bayonne and until October 15, 2003, we owned 79.2 percent of the indirect equity in Linden and Enron indirectly owned a 1 percent non-voting preferred interest in Linden. Chaparral acquired 49 percent of the interests in the facilities in August 1999 and the remaining interests in February 2001. If the FERC finds that Enron's ownership of the facilities violated the ownership restrictions contained in PURPA, it may seek to redetermine applicable rates that the QFs were entitled to charge their customers and order refunds for the period of non-compliance or to impose other penalties within its authority. A settlement was filed in connection with these proceedings in October 2003 and discovery has been suspended. The settlement is subject to approval by the FERC and finds that the prior ownership of Camden, Bayonne and Linden did not violate PURPA. A decision by FERC is currently expected in the fourth quarter of 2003. In October 2003, we sold all of our interest in the Linden facility to an affiliate of The Goldman Sachs Group, Inc. for approximately $450 million adjusted for distributions after January 1, 2003. Of this amount, Goldman retained $70 million of the purchase price pending the FERC's decision related to Linden. On October 24, 2003, the presiding administrative law judge certified the settlement. We expect the FERC to approve the settlement in the fourth quarter, at which time we believe these proceeds will be released.

Broadwing Arbitration. In June 2000, EPGN entered into an agreement with Broadwing Communications Services (Broadwing) to construct and maintain a fiber optic telecommunications system from Houston, Texas to Los Angeles, California. In May 2002, EPGN terminated its agreements with Broadwing due to Broadwing's failure to meet its contractual obligations. Broadwing disputed EPGN's right to terminate the agreements. Subsequently, EPGN filed a demand for arbitration and named its arbitrator. We have also sought and obtained injunctive relief to require Broadwing to perform maintenance activity and prohibit it from removing materials or equipment purchased for the project. If it is determined that we properly terminated the contract, Broadwing is required to return all money paid by us which is $62 million and transfer all of the work completed to date free and clear of any liens. We have entered into settlement discussions with Broadwing to attempt to resolve this dispute. In the fourth quarter of 2002, EPGN wrote down the value of this long-haul route by $104 million, leaving a remaining investment of $4 million.

Economic Conditions of Brazil. We own and have investments in power, pipeline and production projects in Brazil with an aggregate exposure, including financial guarantees, of approximately $1.8 billion. During 2002, Brazil experienced a significant decline in its financial markets due largely to concerns over the refinancing of its foreign debt and the presidential elections which were completed in late November 2002. These concerns contributed to significantly higher interest rates on local debt for the government and private sectors, significantly decreased the availability of funds from lenders outside of Brazil and decreased the amount of foreign investment in the country. These factors contributed to a downgrade of Brazil's foreign currency debt rating and a 26 percent devaluation of the local currency against the U.S. dollar since the beginning of 2002. The International Monetary Fund (IMF) announced in the fourth quarter of 2002 a

$30 billion loan package for Brazil and Brazil has met the specified fiscal targets set by the IMF for 2003. In addition, Brazil's President or other government representatives may impose or attempt to impose changes that could affect our business, including imposing price controls on electricity and fuels, attempting to force renegotiation of power purchase agreements (PPA's) which are indexed to the U.S. dollar, or attempting to impose other concessions. These developments have delayed and may continue to delay the implementation of project financings planned and underway in Brazil although we have raised $370 million of non-recourse debt on our Macae project through October 2003. We currently believe that the economic difficulties in Brazil will not have a material adverse effect on our investment in the country, but we continue to monitor the economic situation and potential changes in governmental policy, and are working with the state-controlled utilities in Brazil that are counterparties under our projects' PPA's to attempt to maintain the economic returns we anticipated when we made our investments. Future developments in Brazil, including forced renegotiations of our existing PPA's or changes in our assumptions related to PPA's where we are seeking extension, may cause us to reassess our exposure and potentially record impairments in the future. Some of the specific difficulties we are experiencing in Brazil are discussed below.

We own a 60 percent interest in a 484-megawatt gas-fired power project known as the Araucaria project, located near Curitiba, Brazil. The project company in which we have an ownership interest has a 20-year PPA with Copel, a regional utility. Copel is approximately 60 percent owned by the State of Parana. After the 2002 elections in Brazil, the new Governor of the State of Parana publicly characterized the Araucaria project as unfavorable to Copel and the State of Parana and promised a full review of the transaction. Subsequent to this announcement, Copel informed us that they would not pay capacity payments due under the PPA pending that review. Previous payments made under the PPA were made with a reservation of rights with respect to the enforceability of the contract. After meetings with the government as well as new management at Copel to discuss Copel's obligations under the PPA, we were unable to come to a satisfactory resolution of the current issues under the PPA, and we have initiated enforcement of our remedies under the contract, including filing an arbitration proceeding under the International Chamber of Commerce rules in Paris. Copel has filed suit in the Brazilian courts, seeking a declaration that the arbitration clause in the PPA is null and void. If we do not prevail in the arbitral proceeding, or are not otherwise able to enforce our remedies under the contract, we could be required to impair our investment in the project. Our losses would be limited to our investment. Our investment in the Araucaria project was $179 million at September 30, 2003.

We own two projects located in Manaus, Brazil. The first project is a 238-megawatt fuel-oil fired plant known as the Manaus Project with a net book value of plant equipment of $105 million at September 30, 2003 and the second project is a 158-megawatt fuel-oil fired plant known as the Rio Negro Project with a net book value of plant equipment of $109 million at September 30, 2003. The Manaus Project's PPA currently expires in January 2005 and the Rio Negro Project's PPA currently expires in January 2006. In the first quarter of 2003, we began experiencing delays in payment from the purchaser of our power, Manaus Energia S.A. Manaus Energia is an indirect wholly owned subsidiary of Centrais Electricas Brasileiras S. (Eletrobras), a Brazilian federal utility holding company. As of September 30, 2003, our total accounts receivable on these projects is $35 million. In addition, we have filed a lawsuit in the Brazilian courts against Manaus Energia on the Rio Negro Project regarding a tariff dispute related to power sales from 1999 to 2001 and have an additional long-term receivable of $32 million which is a subject of this lawsuit. In meetings with Manaus Energia in the second quarter of 2003, Manaus Energia expressed their desire to renegotiate the current PPAs and have informed us that they view the Manaus Project's PPA as having expired in January 2003, even though a letter agreement executed in May 2002 extended this contract until January 2005. We are continuing negotiations with Manaus Energia in efforts to correct the current payment default issues, to reaffirm the legal standing of the current PPA, and to renegotiate the PPAs to extend their terms. If we are unsuccessful in reaching an agreement with Manaus Energia regarding compliance with the existing contract terms or are unable to reach an agreement on long-term contract extensions on acceptable terms, we may be required to impair these projects. Our impairment charge would be limited to the amount of the net book value of the plant equipment and the amounts of accounts receivable discussed above as of September 30, 2003.

We own a 50 percent interest in a 409-megawatt dual-fuel-fired power project known as the Porto Velho Project, located in Porto Velho, Brazil. The Porto Velho Project sells power to Centrais Electricas do Norte de

Brasil S.A. (Eletronorte), a wholly owned subsidiary of Eletrobras. The Porto Velho Project has two PPA's. The first PPA has a term of ten years and relates to the first 64-megawatt phase of the project. The second PPA has a term of twenty years and relates to the second 345-megawatt phase of the project (the Phase 2 PPA). We have reached an agreement with the operating management of Eletronorte relating to the Phase 2 PPA, but the senior management of Eletronorte has yet to approve the agreement and delays in getting the amendment approved are continuing. We will continue to monitor this situation, and any possibility of having to renegotiate the Porto Velho Project's PPA's. If we do not obtain approval of the PPA's and are forced to renegotiate the prices, we could be required to impair our investment in the project. Our losses would be limited to our investment, which was $289 million at September 30, 2003, including guarantees we issued related to the construction of the project.

Economic Conditions in the Dominican Republic. Recent developments in the economic and financial situation in the Dominican Republic have led to a devaluation of the Dominican peso of approximately 53 percent against the U.S. dollar during 2003 (through September 30, 2003) and an increase in the local inflation rate of approximately 25 percent for the same period. A stand-by agreement with the IMF received final approval of the IMF Board in August. The Dominican government maintains that the accord could lead to approximately $1.2 billion in disbursements from multilaterals over the next 24 months and will serve to restore consumer and investor confidence in the banking system and economic policy framework, stabilize the exchange rate and avoid a liquidity crisis. An initial disbursement of funds was made in August 2003, but further disbursements are pending approval by the IMF.

We have investments in power projects in the Dominican Republic with an aggregate exposure of approximately $100 million. We own a 48.33 percent interest in a 67 megawatt heavy fuel oil fired power project known as the CEPP project. We also own a 24.99 percent interest in a 513 megawatt power generating complex known as Itabo. As a consequence of economic conditions described above, and due to their inability to pass through higher energy prices to their consumers, the local distribution companies that purchase the electrical output of these facilities have been delinquent in their payments to CEPP and Itabo, as well as the other generating facilities in the Dominican Republic since April 2003. The failure to pay generators has resulted in the inability of the generators to purchase fuel required for the production of energy which has caused significant energy shortfalls in the country. We currently believe that the economic difficulties in the Dominican Republic will not have a material adverse effect on our investments, but we will continue to monitor those conditions and are working with the government and the local distribution companies to resolve these issues.

Meizhou Wan Power Project. We own a 25 percent equity interest in a 734-megawatt, coal-fired power generating project, Meizhou Wan Generating, located in Fuzhou, People's Republic of China. Our investment in the project was $56 million at September 30, 2003, and we have also issued $34 million in guarantees and letters of credit for equity support and debt service reserves for the project. The project debt is collateralized only by the project's assets and is non-recourse to us. The project declared that it was ready for commercial operations in August 2001; however, the provincial government, who also buys all power generated from the project, has not accepted the project for commercial operations. In October 2002, we reached an interim agreement to allow the plant to operate and sell power at reduced rates until March 2003 while a long-term resolution to existing and past contract terms is negotiated. In March 2003, a letter was forwarded to the Province requesting that the interim agreement be extended until such time that a long term agreement can be reached. Although the Province has indicated that it will continue to pay the tariff provided for under the Interim Agreement until the new long term tariff is signed, we received a proposal from the Province in June 2003 for new rates that are slightly lower than those in our interim agreement. The price the project currently receives from the sale of power in the interim agreement is expected to be sufficient to provide for the operating costs and debt service of the project, but does not provide for a return on investment to the project's owners. We are also seeking to obtain local financing which will allow us to restructure the project debt on more favorable terms, and achieve a lower cost structure for the project. If we are unsuccessful in our ability to reach a long-term agreement with the provincial government at rates sufficient to recover our investment or refinance our debt on more favorable terms, we may be required to write-down the value of our investment.

Milford Power Project. We own a 95 percent equity interest in a 540-megawatt power plant construction project located in Milford, Connecticut. The project has been financed through equity contributions, construction financing from lenders that is recourse only to the project and through a construction management services agreement that we funded. This project has experienced significant construction delays, primarily associated with technological difficulties with its turbines, including the inability to operate on both gas and fuel oil, or to operate at its designed capacity as specified in the construction contract. In October 2001, we entered into a construction management services agreement providing additional funding through October 1, 2002. The construction contractor failed to complete construction of the plant prior to October 1, 2002, in accordance with the terms and specifications of the construction contract. As a result, the project was in default under its construction lending agreement. On October 25, 2002, we entered into a standstill agreement with the construction lending banks that expired on December 2, 2002. On March 4, 2003, we provided a notice to Milford declaring an event of default under the fuel supply agreement between us and Milford due to non-payment by Milford. On March 6, 2003, Milford received a notice from its lenders stating that the lenders intended to commence foreclosure on the project in accordance with the lending agreement within 30 days. As a result of the default under the construction lending agreement, we evaluated our investment and recorded an impairment charge of $17 million. In April 2003, El Paso's Board of Directors authorized Milford to enter into settlement negotiations with the lenders to the facility. Based upon the ongoing negotiations with the lenders and the Board's authorization to settle these issues, we recorded an additional charge during the first quarter of 2003 of approximately $86 million. These charges consisted of advances to Milford and other estimated liabilities related to the project. On September 10, 2003 we entered into an agreement with the Milford lenders and agreed to their takeover of our interest in the Milford project upon the satisfaction of certain conditions. In return for a payment of $10 million by us, the Milford lenders agreed, effective immediately, to allow us to terminate a fuel purchase agreement that we have with Milford thereby ending our obligation to provide additional security in the form of $73 million in fuel subordination. In return for an additional payment of $7 million by us, the Milford lenders agreed to the termination of various other agreements to be replaced by a single new agreement. This agreement is subject to receiving all approvals, including that of FERC. Simultaneously on September 10, 2003, Milford entered into a settlement with its construction contractor pursuant to which the contractor shall pay $18 million in delayed liquidated damages, forego $5 million in additional payments, and provide a $10 million credit to be applied to future operating services as well as post a letter of credit for $17 million as security for specified obligations. The settlement agreement became effective on October 20, 2003.

Berkshire Power Project. We own a 56.4 percent direct equity interest in a 261-megawatt power plant located in Massachusetts. The construction contractor failed to deliver a plant capable of operating on both gas and fuel oil, or capable of operating at its designed capacity. Berkshire negotiated a settlement with the contractor with respect to its failure to deliver the project in accordance with guaranteed specifications. Berkshire agreed to settle its claims against the contractor in exchange for $6 million to be applied to future operating services and the contractors agreement to perform plant upgrades at no charge. During the third quarter of 2002, the project lenders asserted that Berkshire was in default on its loan agreement. Berkshire is in the process of negotiating with its lenders to resolve disputed contract terms. Failure to reach a satisfactory resolution in these matters could have a material adverse effect on the value of our investment in the project. At September 30, 2003, we had an investment in Berkshire of $4 million, receivables from Berkshire of $30 million and derivative contracts with Berkshire of $11 million associated with a subordinated fuel agreement and a fuel management agreement. The ultimate resolution of these issues will be considered in the determination of whether any of these investments in and receivables from Berkshire will be impaired in the future.

Duke. Our subsidiary, SNG, owns a 50 percent equity investment in Citrus Corp. On March 7, 2003, Citrus Trading Corp. (CTC), a direct subsidiary of Citrus, filed suit against Duke Energy LNG Sales, Inc. titled *Citrus Trading Corp. v. Duke Energy LNG Sales, Inc.* in the District Court of Harris County, Texas seeking damages for breach of a gas supply contract pursuant to which CTC was entitled to purchase, through August 2005, up to 30.4 billion cubic feet per year of regasified LNG. On April 14, 2003, Duke forwarded to CTC a letter purporting to terminate the gas supply contract effective April 16, 2003, due to the alleged failure of CTC to increase the amount of an outstanding letter of credit backstopping its purchase obligations. On April 16, 2003, Duke filed an answer to the complaint, stating that (1) CTC had triggered the early termination of the gas supply agreement by allegedly failing to provide an adequate letter of credit to Duke; (2) CTC had breached the gas supply contract by allegedly violating certain use restrictions that required volumes equivalent to those purchased by CTC from Duke to be sold by CTC into the power generation market in the state of Florida; and (3) Duke was partially excused from performance under the gas supply agreement by reason of an alleged loss of supply of LNG on January 15, 2002 and would be fully excused from providing replacement gas upon the earlier of (i) 730 days or (ii) the incurrence of replacement costs equal to $60 million, escalated by the GNP implicit price deflator commencing January 1990 (approximately $79 million as of December 31, 2002). On April 29, 2003, Duke removed the pending litigation to federal court, based on the existence of foreign arbitration with its supplier of LNG, Sonatrading Amsterdam B.V., which had allegedly repudiated its supply contract as of January 27, 2003. On May 1, 2003, CTC notified Duke that it was in default under the gas supply contract, demanding cover damages for alternate supplies obtained by CTC beginning April 17, 2003. On May 23, 2003, CTC filed a motion to remand the case back to state court. On June 2, 2003, CTC gave notice of early termination to Duke in preparation for the subsequent filing of an amended petition for monetary damages. On July 31, 2003, the federal court remanded this case back to state court. On August 18, 2003, Duke filed a third-party petition against Sonatrading, its Algerian LNG supplier. CTC opposed the petition since, even in the event of a failure to receive supplies from Algeria, Duke was required to furnish supplies to CTC for a stated period of time. On October 6, 2003, the court ruled that, although Duke may attempt to get service on Sonatrading, Duke's claim against its supplier will be tried separately (and thus not delay or otherwise impact this case). Also on October 6, 2003, CTC filed an amended petition against Duke seeking termination damages of $187 million. We do not expect the ultimate resolution of this matter to have a material adverse effect on our financial position, operating results or cash flows.

Cases

The California cases discussed above are five filed in the Superior Court of Los Angeles County *(Continental Forge Company, et al v. Southern California Gas Company, et al,* filed September 25, 2000*; *Berg v. Southern California Gas Company, et al,* filed December 18, 2000*; *County of Los Angeles v. Southern California Gas Company, et al,* filed January 8, 2002*; *The City of Los Angeles, et al v. Southern California Gas Company, et al* and *The City of Long Beach, et al v. Southern California Gas Company, et al,* both filed March 20, 2001*); two filed in the Superior Court of San Diego County *(John W.H.K. Phillip v. El Paso Merchant Energy;* and *John Phillip v. El Paso Merchant Energy,* both filed December 13, 2000*); and two filed in the Superior Court of San Francisco County *(Sweetie's et al v. El Paso Corporation, et al,* filed March 22, 2001*; and *California Dairies, Inc., et al v. El Paso Corporation, et al,* filed May 21, 2001); and one filed in the Superior Court of the State of California, County of Alameda *(Dry Creek Corporation v. El Paso Natural Gas Company, et al,* filed December 10, 2001*); and five filed in the Superior Court of Los Angeles County *(The City of San Bernardino v. Southern California Gas Company, et al; The City of Vernon v. Southern California Gas Company; The City of Upland v. Southern California Gas Company, et al; Edgington Oil Company v. Southern California Gas Company, et al; World Oil Corporation, et al. v. Southern California Gas Company, et al,* filed December 27, 2002*). The two long-term power contract lawsuits are *James M. Millar v. Allegheny Energy Supply Company, et al.* filed May 13, 2002 in the Superior Court, San Francisco County, California and *Tom McClintock et al. v. Vikram Budhrajaetal* filed May 1, 2002 in the Superior Court, Los Angeles County, California. The cases referenced in Other Energy Market Lawsuits are: *The State of Nevada, et al. v. El Paso Corporation, El Paso Natural Gas Company, El Paso Merchant Energy Company, et al.* filed November 2002 in the District Court for Clark County, Nevada*; *Henry W. Perlman, et al. v. San Diego Gas & Electric et al.* filed December 2002, in the United States District Court, Southern District of New York; *Cornerstone Propane Partners, L.P. v. Reliant Energy Services, et al.* filed August 2003 in the United States District Court, Southern District of New York; *Robert E. Callégracey v. American Electric Power Company, Inc. et al.* filed October 2003 in the United States District Court, Southern District of New York; *State of Arizona v El Paso Corporation, El Paso Natural Gas Company, El Paso Merchant*

*Cases to be dismissed upon finalization and approval of the Western Energy Settlement.

Energy Company, et al. filed March 10, 2003 in the Superior Court, Maricopa County, Arizona; *Sierra Pacific Resources et. al. v. El Paso Corporation et. al.,* filed April 21, 2003 in the United States District Court for the District of Nevada; and *Jerry Egger, et. al. v. Dynegy, Inc.,* filed April 28, 2003 in the Superior Court for the County of San Diego, California.

The purported shareholder class actions filed in the U.S. District Court for the Southern District of Texas, Houston Division, are: *Marvin Goldfarb, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed July 18, 2002; *Residuary Estate Mollie Nussbacher, Adele Brody Life Tenant, et al v. El Paso Corporation, William Wise, and H. Brent Austin,* filed July 25, 2002; *George S. Johnson, et al v. El Paso Corporation, William Wise, and H. Brent Austin,* filed July 29, 2002; *Renneck Wilson, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 1, 2002; and *Sandra Joan Malin Revocable Trust, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 1, 2002; *Lee S. Shalov, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 15, 2002; *Paul C. Scott, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 22, 2002; *Brenda Greenblatt, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 23, 2002; *Stefanie Beck, et al v. El Paso Corporation, William Wise, and H. Brent Austin,* filed August 23, 2002; *J. Wayne Knowles, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed September 13, 2002; *The Ezra Charitable Trust, et al v. El Paso Corporation, William Wise, Rodney D. Erskine and H. Brent Austin,* filed October 4, 2002. The purported shareholder action filed in the Southern District of New York is *IRA F.B.O. Michael Conner et al v. El Paso Corporation, William Wise, H. Brent Austin, Jeffrey Beason, Ralph Eads, D. Dwight Scott, Credit Suisse First Boston, J.P. Morgan Securities,* filed October 25, 2002.

The shareholder derivative actions filed in Houston are *Grunet Realty Corp. v. William A. Wise, Byron Allumbaugh, John Bissell, Juan Carlos Braniff, James Gibbons, Anthony Hall Jr., Ronald Kuehn Jr., J. Carleton MacNeil Jr., Thomas McDade, Malcolm Wallop, Joe Wyatt and Dwight Scott,* filed August 22, 2002. The consolidated shareholder derivative action filed in Houston is *John Gebhart and Marilyn Clark v. El Paso Natural Gas, El Paso Merchant Energy, Byron Allumbaugh, John Bissell, Juan Carlos Braniff, James Gibbons, Anthony Hall Jr., Ronald Kuehn, Jr., J. Carleton MacNeil, Jr., Thomas McDade, Malcolm Wallop, William Wise, Joe Wyatt, Ralph Eads, Brent Austin and John Somerhalder* filed in November 2002. The shareholder derivative lawsuit filed in Delaware is *Stephen Brudno et al v. William A. Wise et al* filed in October 2002.

The ERISA Class Action Suit is *William H. Lewis III v. El Paso Corporation, H. Brent Austin and unknown fiduciary defendants 1-100.*

The MTBE cases discussed above and filed in New York are: *County of Suffolk and Suffolk County Water Authority v. Amerada Hess Corp., et al.,* filed on October 9, 2002, in the Supreme Court of the State of New York, County of Suffolk, and the following eight cases filed on September 30, 2003 in the Supreme Court of the State of New York, County of New York: *County of Nassau v. Amerada Hess, et al., Village of Mineola, Inc. and Water Dept. of the Village of Mineola v. Atlantic Richfield, et al., West Hempstead Water District v. Atlantic Richfield Co., et al., Carle Place Water District v. Atlantic Richfield Co., et al., Town of Southampton v. Atlantic Richfield Co., et al., Village of Hempstead v. Atlantic Richfield Co., et al., Town of East Hampton v. Atlantic Richfield Co., et al.,* and *Westbury Water District v. Atlantic Richfield Co., et al.* The tenth case *Water Authority of Western Nassau v. Atlantic Richfield Co., et al.,* was filed on October 1, 2003 in the Supreme Court of the State of New York, County of New York.

The MTBE case filed in New Hampshire is *State of New Hampshire v. Amerada Hess Corp. et al.,* filed in New Hampshire Superior Court, County of Merrimack, on September 30, 2003.

The MTBE case filed in Massachusetts is *Brimfield Housing Authority (Brimfield, MA), et al. v. Amerada Hess Corporation, et al.,* filed in Massachusetts Superior Court, County of Suffolk, on September 30, 2003.

The three MTBE cases filed in Connecticut are *Childhood Memories v. Amerada Hess Corporation, et al.,* filed in Connecticut Superior Court, Judicial District of Litchfield, on September 30, 2003, *Columbia Board of Education, Horace Porter School v. Amerada Hess Corporation, et al.,* filed in Connecticut Superior Court, Judicial District of Tolland, on September 30, 2003, and *Canton Board of Education, Cherry Brook School v. Amerada Hess Corporation, et al.,* filed in Connecticut Superior Court, Judicial District of Hartford, on September 30, 2003.

The MTBE case filed in Illinois is *Village of East Alton, Individually and on behalf of all others similarly situated v. Amerada Hess Corporation, et al.,* filed in the Circuit Court, Third Judicial Circuit, Madison County, Illinois, on September 30, 2003.

The customer complaints filed at the FERC against EPME and other wholesale power marketers are: *Nevada Power Company and Sierra Pacific Power Company vs. El Paso Merchant Energy, L.P.; California Public Utilities Commission vs. Sellers of Long-Term Contracts to the California Department of Water and California Electricity Oversight Board vs. PacifiCorp vs. El Paso Merchant Energy, L.P., and City of Burbank, California vs. Calpine Energy Services, L.P., Duke Energy Trading and Marketing, LLC, El Paso Merchant Energy*.

Commitments and Purchase Obligations

During 2003, we entered into purchase obligations to acquire pipe and other equipment that will be used in our Cheyenne Plains Pipeline project. Our total commitment is approximately $96 million and will be paid during 2004.

19. Capital Stock

On October 30, 2003, we declared a quarterly dividend of $0.04 per share on our common stock payable on January 5, 2004, to stockholders of record on December 5, 2003. During the quarter and nine months ended September 30, 2003, we paid dividends of $24 million and $178 million to common stockholders. In addition, El Paso Tennessee Pipeline Co., our subsidiary, paid dividends of approximately $6 million and $19 million on its Series A cumulative preferred stock, which is 8¼% per annum (2.0625% per quarter).

20. Segment Information

We segregate our business activities into four operating segments: Pipelines, Production, Field Services and Merchant Energy. These segments are strategic business units that provide a variety of energy products and services. They are managed separately as each business unit requires different technology, operational and marketing strategies. We reclassified our historical coal mining operation in the second quarter of 2002 and our petroleum and chemical operations in the second quarter of 2003 from our Merchant Energy segment to discontinued operations in our financial statements. Merchant Energy's operating results for all periods presented reflect this change.

We use earnings before interest expense and income taxes (EBIT) to assess the operating results and effectiveness of our business segments. We define EBIT as net income (loss) adjusted for (i) items that do not impact our income (loss) from continuing operations, such as extraordinary items, discontinued operations and the impact of accounting changes, (ii) income taxes, (iii) interest and debt expense and (iv) distributions on preferred interests of consolidated subsidiaries. Our business operations consist of both consolidated businesses as well as substantial investments in unconsolidated affiliates. We believe EBIT, which includes the results of both these consolidated and unconsolidated operations, is useful to our investors because it allows them to more effectively evaluate the performance of all of our businesses and investments. Also, we exclude interest and debt expense and distributions on preferred interests of consolidated subsidiaries so that investors may evaluate our operating results without regard to our financing methods or capital structure. EBIT may not be comparable to measures used by other companies and should not be used as a substitute for net income or other performance measures such as operating income or operating cash flow. The reconciliations of EBIT to income (loss) from continuing operations are presented below:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In millions)			
Total EBIT	$ 400	$ 420	$ 413	$1,440
Interest and debt expense	(474)	(343)	(1,350)	(950)
Distributions on preferred interests of consolidated subsidiaries	(8)	(37)	(45)	(120)
Income taxes	(15)	(16)	463	(120)
Income (loss) from continuing operations	$ (97)	$ 24	$ (519)	$ 250

The following tables reflect our segment results as of and for the periods ended September 30 (in millions):

	Quarter Ended September 30,					
	Pipelines	Production	Field Services	Merchant Energy	Corporate & Other[1]	Total
2003						
Revenues from external customers	$572	$ (49)[2]	$229	$ 709	$ 19	$1,480
Intersegment revenues	26	459[2]	97	(472)	(51)	59[3]
Operation and maintenance[4]	177	96	29	168	1	471
Depreciation, depletion and amortization	95	181	7	32	13	328
Ceiling test charges	—	2	—	—	—	2
(Gain) loss on long-lived assets	(1)	(1)	2	56	(2)	54
Western Energy Settlement	(20)	—	—	—	—	(20)
Operating income (loss)	267	101	(8)	(70)	(18)	272
Earnings from unconsolidated affiliates	28	1	41	8	1	79
Other income	6	1	—	25	17	49
EBIT	$301	$ 103	$ 33	$ (37)	$ —	$ 400
2002						
Revenues from external customers	$553	$ 80[2]	$386	$ 562	$(165)	$1,416
Intersegment revenues	58	419[2]	165	(509)	147	280[3]
Operation and maintenance[4]	197	97	44	126	(1)	463
Depreciation, depletion and amortization	94	181	11	11	19	316
Loss on long-lived assets	2	—	1	—	—	3
Operating income (loss)	259	179	20	(132)	(16)	310
Earnings (losses) from unconsolidated affiliates	39	2	(30)	48	(1)	58
Other income (expense)	4	(2)	(1)	1	50	52
EBIT	$302	$ 179	$(11)	$ (83)	$ 33	$ 420

(1) Includes our Corporate and telecommunication activities and eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We record an intersegment revenue elimination, which is the only elimination included in the "Other" column, to remove intersegment transactions.

(2) Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production. A loss occurs when hedged prices are lower than market prices and a gain occurs when hedged prices are higher than market prices. Intersegment revenues represent sales to our marketing affiliate EPME, which is responsible for marketing our production.

(3) Relates to intercompany activities between our continuing operating segments and our discontinued petroleum markets operations.

(4) Includes restructuring charges in connection with our ongoing liquidity enhancement and cost saving efforts (see Note 5).

	Nine Months Ended September 30,					
	Pipelines	Production	Field Services	Merchant Energy	Corporate & Other[1]	Total
2003						
Revenues from external customers	$1,882	$ (129)[2]	$885	$ 2,263	$ 40	$4,941
Intersegment revenues	89	1,626[2]	377	(1,740)	(150)	202[3]
Operation and maintenance[4]	532	276	100	601	24	1,533
Depreciation, depletion and amortization	291	586	25	92	55	1,049
Ceiling test charges	—	2	—	—	—	2
(Gain) loss on long-lived assets	(9)	8	(2)	75	405	477
Western Energy Settlement	126	—	—	(25)	2	103
Operating income (loss)	763	500	(24)	(373)	(487)	379
Earnings (losses) from unconsolidated affiliates	96	11	31	(108)	1	31
Other income (expense)	16	4	(1)	69	(85)	3
EBIT	$ 875	$ 515	$ 6	$ (412)	$(571)	$ 413
2002						
Revenues from external customers	$1,769	$ 391[2]	$923	$ 3,036	$ 34	$6,153
Intersegment revenues	176	1,218[2]	669	(1,642)	(141)	280[3]
Operation and maintenance[4]	567	286	143	438	42	1,476
Depreciation, depletion and amortization	280	581	45	43	51	1,000
Ceiling test charges	—	267	—	—	—	267
(Gain) on long-lived assets	(12)	(2)	(9)	—	(1)	(24)
Operating income (loss)	893	359	94	332	(87)	1,591
Earnings (losses) from unconsolidated affiliates	110	5	2	(153)	—	(36)
Other income (expense)	21	(2)	(2)	(169)	37	(115)
EBIT	$1,024	$ 362	$ 94	$ 10	$ (50)	$1,440

(1) Includes our Corporate and telecommunication activities and eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We record an intersegment revenue elimination, which is the only elimination included in the "Other" column, to remove intersegment transactions. Losses reflected in our Corporate activities include approximately $396 million related to the impairment of our telecommunication business in the second quarter of 2003, inclusive of a write-down of goodwill of $163 million. See Note 8 for an additional discussion of this impairment.

(2) Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production. A loss occurs when hedged prices are lower than market prices and a gain occurs when hedged prices are higher than market prices. Intersegment revenues represent sales to our marketing affiliate EPME, which is responsible for marketing our production.

(3) Relates to intercompany activities between our continuing operating segments and our discontinued petroleum markets operations.

(4) Includes restructuring charges in connection with our ongoing liquidity enhancement and cost saving efforts (see Note 5).

Total assets by segment are presented below:

	September 30, 2003	December 31, 2002
	(In millions)	
Pipelines	$15,476	$14,802
Production	8,110	8,057
Field Services	2,425	2,680
Merchant Energy	11,624	12,349
Total segment assets	37,635	37,888
Corporate and other	3,466	4,271
Discontinued operations	1,575	4,065
Total consolidated assets	$42,676	$46,224

21. Investments in Unconsolidated Affiliates and Related Party Transactions

We hold investments in affiliates which we account for using the equity method of accounting. During the second quarter of 2003, we consolidated two of our larger equity investments, Chaparral and Gemstone. See Note 3 for a further discussion of these transactions. Summarized financial information of our proportionate share of unconsolidated affiliates below includes affiliates in which we hold an interest of 50 percent or less, and affiliates in which we hold a greater than 50 percent interest. Our proportional share of the net income of the unconsolidated affiliates in which we hold a greater than 50 percent interest was $1 million and $7 million for the quarters ended, and $6 million and $21 million for the nine months ended September 30, 2003 and 2002.

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In millions)			
Operating results data:				
Operating revenues	$717	$654	$2,340	$1,614
Operating expenses	503	449	1,579	1,056
Income from continuing operations	102	113	404	274
Net income	102	114	404	275

Our income statement reflects our earnings (losses) from unconsolidated affiliates. This amount includes income or losses directly attributable to the net income or loss of our equity investments as well as impairments and other adjustments to income we record as follows:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In millions)			
Proportional share of income of investees	$102	$ 113	$ 404	$ 274
Impairments:				
Dauphin Island/Mobile Bay	—	—	(80)	—
Chaparral(1)	—	—	(207)	—
Milford power facility(2)	(2)	—	(88)	—
CAPSA/CAPEX/Agua del Cajon(3)	—	—	—	(286)
Cogen Technologies Linden Venture, LP(4)	(22)	—	(22)	—
Aux Sable natural gas liquids plant	—	(47)	—	(47)
Gain on sale of CAPSA/CAPEX	—	—	24	—
Gain on issuances by GulfTerra of its common units	3	—	15	—
Other	(2)	(8)	(15)	23
Earnings (losses) from unconsolidated affiliates	$ 79	$ 58	$ 31	$ (36)

(1) This impairment resulted from other than temporary declines in the investment's fair value based on developments in our power business and the power industry (see Note 3).

(2) This impairment resulted from a write-off of notes receivable and accruals on contracts due to ongoing difficulty at the project level.
(3) This impairment resulted from weak economic conditions in Argentina.
(4) The impairment results from the anticipated loss from the sale of East Coast Power, L.L.C.

We enter into a number of transactions with our unconsolidated affiliates in the ordinary course of conducting our business. The following table shows revenues, income and expenses incurred between us and our unconsolidated affiliates:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In millions)			
Operating revenue	$89	$(20)	$213	$151
Other revenue — management fees	5	47	11	139
Cost of sales	29	41	91	106
Reimbursement for operating expenses	34	44	103	135
Other income	2	4	7	12
Interest income	2	4	8	21
Interest expense	—	10	3	35

Chaparral and Gemstone

As of December 31, 2002, we held equity investments in Chaparral and Gemstone. During the second quarter of 2003, we acquired the remaining third party equity interests and all of the voting rights in both of these entities and began consolidating them in our consolidated financial statements. The following tables summarize our overall investments in Chaparral and Gemstone as of December 31, 2002. For the impact of these consolidations on our financial results, see Note 3.

	Chaparral	Gemstone
	(In millions)	
Equity investment	$ 256	$ 663
Credit facilities receivable	377	25
Notes receivable	323	—
Debt securities payable	(79)	(122)
Contingent interest promissory notes payable	(173)	—
Total net investment	$ 704	$ 566

GulfTerra Energy Partners

A subsidiary in our Field Services segment serves as the general partner of GulfTerra, a master limited partnership that has limited partnership units that trade on the New York Stock Exchange.

As of September 30, 2003, we owned 11,674,245 of the partnership's common units, the one percent general partner interest, all of the Series B preference units and all of its Series C units. During 2003, we contributed approximately $2 million of our Series B preference units to GulfTerra in order for us to maintain our one percent general partner interest as a result of three common units offerings completed by GulfTerra.

In October 2003, we sold 9.9 percent of the one percent general partner interest of GulfTerra to Goldman Sachs for $88 million. In addition, GulfTerra redeemed all of the Series B preference units that we owned for $156 million. Finally, as part of the overall transaction, GulfTerra released us from our obligation to repurchase the Chaco processing facility and we contributed communications assets to GulfTerra. Prior to the transaction, we would have been obligated to repurchase the facility for approximately $77 million in 2021. As part of the approval process, we retained an independent financial advisor who provided us with a fairness opinion related to these transactions. We also retained an independent third party consultant to assist us in determining the value of the general partner interest sold to Goldman Sachs. Based on preliminary valuations performed by this consultant, we estimate that we will recognize a gain on these transactions in excess of

$100 million in the fourth quarter of 2003. We expect to finalize this estimate once we receive the final valuation report from our consultant in the fourth quarter of 2003.

Also in October 2003, we sold 590,000 of the partnership's common units that we owned for approximately $23 million. Following these transactions, we own the remaining 90.1 percent of the general partner interest, 19.0 percent of the partnership's common units and all of GulfTerra's Series C units.

Our segments also conduct transactions in the ordinary course of business with GulfTerra, including sales of natural gas and operational services. Below is the summary of our transactions with GulfTerra.

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In millions)			
Revenues received from GulfTerra				
Pipelines	$ —	$ —	$ —	$ 1
Production	—	—	—	2
Field Services	—	—	5	—
Merchant Energy	6	3	22	14
	$ 6	$ 3	$ 27	$ 17
Expenses paid to GulfTerra				
Production	$ 3	$ 3	$ 7	$ 7
Field Services	14	25	56	64
Merchant Energy	8	26	27	62
	$ 25	$ 54	$ 90	$133
Reimbursements received from GulfTerra				
Field Services	$ 22	$ 15	$ 68	$ 38

For a further discussion of our relationships with GulfTerra, see our Current Report on Form 8-K dated September 23, 2003.

22. New Accounting Pronouncements Issued But Not Yet Adopted

As of September 30, 2003, there were several accounting standards and interpretations that had been issued, but not yet adopted by us. Below is a discussion of the more significant standards that could impact us.

Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51

In January 2003, the FASB issued FIN No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51*. This interpretation defines a variable interest entity as a legal entity whose equity owners do not have sufficient equity at risk and/or a controlling financial interest in the entity. This standard requires a company to consolidate a variable interest entity if it is allocated a majority of the entity's losses and/or returns, including fees paid by the entity. On October 9, 2003, the FASB issued FASB Staff Position, FSP FIN No. 46-6, *Effective Date of FASB Interpretation No. 46, Consolidation of Variable Interest Entities*. This staff position deferred our required adoption date of FIN No. 46 to the fourth quarter of 2003.

Upon adoption of this standard, we will be required to consolidate the preferred equity holder of one of our consolidated subsidiaries, Coastal Securities Company Limited. The impact of this consolidation will be an increase in long-term debt and a decrease in preferred interests in consolidated subsidiaries by $100 million. We will also be required to consolidate Rondonia Power Company, an equity investment that holds our Porto Velho power project in Brazil. The impact of this consolidation will be an increase in property, plant and equipment of approximately $244 million, an increase to other current and non-current assets of approximately $30 million and a decrease in notes receivable from affiliates by approximately $274 million. We also continue to evaluate our other joint venture and financing arrangements to assess the impact, if any, of FIN No. 46 on those arrangements.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The information contained in Item 2 updates, and you should read it in conjunction with, information disclosed in our Current Report on Form 8-K dated September 23, 2003, and the financial statements and notes presented in Item 1 of this Form 10-Q.

Overview

In early 2003, following actions taken by rating agencies to downgrade the credit ratings of our company and many of the largest participants in our industry, we announced a plan to address the business challenges and liquidity needs of our company. These initiatives, broadly referred to as our 2003 Operational and Financial Plan, were based upon five key points. The five key points were:

- Preserve and enhance the value of our core businesses;
- Divest non-core businesses quickly, but prudently;
- Strengthen and simplify our balance sheet, while at the same time maximizing liquidity;
- Aggressively pursue additional cost reductions; and
- Work diligently to resolve regulatory and litigation matters.

To date in 2003, our major accomplishments regarding these business objectives have been as follows:

- We concentrated our capital investment in our core Pipelines, Production and Field Services segments such that 91 percent of total capital expenditures have been made in these businesses in the first nine months of 2003;
- We completed or announced sales of assets and investments of approximately $3.1 billion;
- We entered into a new $3 billion revolving credit facility that matures in June 2005 and completed financing transactions of approximately $3.8 billion ($3.6 billion as of September 30, 2003);
- We retired approximately $5.8 billion of maturing debt and other obligations ($4.7 billion as of September 30, 2003), including:
  - the retirement of long-term debt of $2.9 billion ($2.2 billion as of September 30, 2003);
  - the net repayment of $650 million of outstanding amounts under our $3 billion revolving credit facility ($250 million as of September 30, 2003);
  - the repayment of $980 million of obligations under our Trinity River financing arrangement;
  - the redemption of $197 million of obligations under our Clydesdale financing arrangement, also restructuring that transaction as a term loan that will amortize over the next two years; and
  - the contribution of $1 billion to the Limestone Electron Trust, which used the proceeds to repay $1 billion of its notes and the purchase and consolidation of the third party equity interests in our Gemstone and Chaparral power investments;
- We refinanced a $1.2 billion two-year term loan issued in March 2003 in connection with the restructuring of our Trinity River financing arrangement to eliminate the amortization requirements of that loan in 2004 and 2005;
- We identified an estimated $445 million of costs savings and business efficiencies to be realized by the end of 2004;
- We executed definitive settlement agreements in June 2003, which substantially resolved our principal exposure relating to the Western Energy crisis and raised funds of $347 million to satisfy a portion of our obligation through the issuance of senior unsecured notes of EPNG in July 2003;

- We initiated a tender offer in October 2003 to exchange common stock and cash for our outstanding equity security units which would, if 100 percent of the units were tendered, result in a reduction of up to $575 million in our outstanding debt balances, an increase in stockholders' equity of up to approximately $475 million and a reduction of cash of up to approximately $112 million; and
- We initiated a program to supplement our capital spending on natural gas and oil properties by an additional $350 million.

Liquidity and Capital Resources

Overview of Cash Flow Activities for the Nine Months Ended September 30, 2003

For the nine months ended September 30, 2003 and 2002, our cash flows are summarized as follows:

	2003	2002
	(In millions)	
Cash flows from continuing operating activities		
Net income (loss)	$(1,728)	$ 269
Non-cash income adjustments	2,895	1,206
Cash flows before working and non-working capital changes	1,167	1,475
Working capital changes	584	192
Non-working capital changes and other	13	(333)
Cash flows from continuing operating activities	1,764	1,334
Cash flows from continuing investing activities	(1,870)	(1,264)
Cash flows from continuing financing activities	158	475
Discontinued operations		
Cash flows from operating activities	2	(170)
Cash flows from investing activities	399	(124)
Cash flows from financing activities	(401)	304
Increase in cash and cash equivalents related to discontinued operations	—	10
Change in cash	52	555
Less increase in cash and cash equivalents related to discontinued operations	—	10
Increase in cash and cash equivalents from continuing operations	$ 52	$ 545

During the nine months ended September 30, 2003, our cash and cash equivalents increased by approximately $52 million to approximately $1.6 billion. We generated cash from several sources, including from our principal continuing operations as well as through our discontinued operations, sales of assets and issuances of long-term debt. We used a major portion of that cash to fund our capital expenditures, purchase additional investments in subsidiaries and redeem preferred interests of minority interest holders. Overall, our cash sources and uses are summarized as follows (in billions):

Cash inflows	
Cash flows from continuing operations (before working and non-working capital changes)	$1.2
Working capital and non-working capital changes	0.6
Net proceeds from the sale of assets and investments	1.4
Net proceeds from the issuance of long-term debt	3.4
Borrowings under revolving credit facility	0.5
Net discontinued operations activity	0.4
Total cash inflows	7.5
Cash outflows	
Additions to property, plant and equipment	2.0
Net cash paid to acquire Chaparral and Gemstone	1.1
Payments to redeem preferred interests of consolidated subsidiaries	1.2
Payments to retire long-term debt	2.1
Payments on revolving credit facilities	0.7
Dividends paid to common stockholders	0.2
Other	0.1
Total cash outflows	7.4
Net increase in cash	$0.1

As of October 31, 2003, we had available cash on hand and borrowing capacity under our revolving credit facility totaling $2.7 billion. A more detailed analysis of our cash flows from operating, investing and financing activities follows.

Cash From Continuing Operating Activities

Overall, cash generated from continuing operating activities was $1.8 billion for the first nine months of 2003 versus $1.3 billion in the same period of 2002. We have generated approximately $1.2 billion in cash from operations (net income from continuing operations adjusted for non-cash income items) in the first nine months of 2003 before working capital and non-working capital changes, as compared to $1.5 billion in 2002. The decline in 2003 was primarily a result of the impact on cash of sales of operating assets during both 2002 and 2003 and the effects of lower capital spending in our Production segment. Working capital sources were $0.6 billion in 2003 as compared to $0.2 billion in 2002. During 2002, we used a significant amount of working capital due to increases in natural gas prices and the resulting changes in margins outstanding against our hedged natural gas production. Since the beginning of 2003, volatility in natural gas prices has caused the amounts that we are required to post as collateral for margin calls and other credit requirements to be at approximately the same level as those requirements at the beginning of the year, despite an overall reduction in the number of contracts requiring collateral. However, we recovered cash in 2003 by substituting letters of credit under our new revolving credit facilities for actual cash on deposit, and as a result, our 2003 margin activity has been a source of cash of approximately $0.4 billion.

Cash From Continuing Investing Activities

Net cash used in our continuing investing activities was $1.9 billion for the nine months ended September 30, 2003. Our investing activities consisted primarily of capital expenditures and additional investments, primarily in Chaparral and Gemstone as follows (in billions):

Production exploration, development and acquisition expenditures	$1.3
Pipeline expansion, maintenance and integrity projects	0.5
Net cash paid to acquire Chaparral and Gemstone	1.1
Other (primarily power projects)	0.1
Total capital expenditures and additional investments	$3.0

Cash received from our investing activities includes $1.4 billion from the sale of assets and investments, including the sale of natural gas and oil properties located in western Canada, Texas, Louisiana, New Mexico, Oklahoma and the Gulf of Mexico for $0.7 billion, the sale of an equity investment in CE Generation for $0.2 billion and the sale of other pipeline, power and processing assets of $0.5 billion.

Cash From Continuing Financing Activities

Net cash provided by our continuing financing activities was $0.2 billion for the nine months ended September 30, 2003. Cash provided from our financing activities included the net proceeds from the issuance of long-term debt of $3.4 billion, $0.4 billion of cash contributed by our discontinued operations and other financing activities of $0.1 billion. Cash used in our financing activities included net repayments of $0.2 billion on revolving credit facilities and $2.1 billion of payments made to retire third party long-term debt. We also paid $1.2 billion to fully redeem our Trinity River preferred securities and partially redeem our Clydesdale preferred securities and paid dividends to common stockholders of $0.2 billion.

Cash from Discontinued Operations

During the first nine months of 2003, our discontinued operations generated $0.4 billion of cash through sales of inventories at our refineries and asset sales which raised $0.5 billion, offset by capital expenditures of $0.1 billion. These net cash inflows were distributed to our continuing operations.

Financing and Commitments

Our Current Report on Form 8-K dated September 23, 2003, includes a detailed discussion of our liquidity, financing activities, contractual obligations and commercial commitments. The information presented below updates, and you should read it in conjunction with, the information disclosed in that Form 8-K.

During the first nine months of 2003, we completed a number of actions intended to simplify our financial and capital structure, refinance shorter term obligations and reduce guarantees and other "off-balance sheet" obligations, replacing them with direct financial obligations. These actions included entering into a new $3 billion revolving credit facility, acquiring and consolidating a number of entities with existing debt, refinancing shorter-term obligations with longer-term borrowings and redeeming and eliminating preferred interests in our subsidiaries as follows (in millions):

Short-term financing obligations, including current maturities	$ 2,075
Notes payable to affiliates	390
Long-term financing obligations	16,106
Securities of subsidiaries	3,420
Total debt and securities of subsidiaries as of December 31, 2002	21,991
Acquisitions and consolidations:	
Chaparral and Gemstone[(1)(2)]	2,578
Operating leases and refinanced securities of subsidiaries	1,018
Elimination of affiliated obligations	(326)
Principal amounts borrowed[(3)]	4,050
Repayments/retirements of principal[(3)]	(2,989)
Reclassifications of preferred interests as long-term financing obligations[(4)]	625
Redemptions and eliminations of securities of subsidiaries	(2,955)
Other	53
Total debt and securities of subsidiaries as of September 30, 2003	$24,045[(5)]

(1) This is a non-recourse project financing or contract debt.

(2) This amount includes $75 million related to Macae which was consolidated as a consequence of our acquisition of Gemstone.

(3) Includes $500 million of borrowings and $750 million of repayments under our revolving credit agreements.

(4) Relates to our adoption of SFAS No. 150. See Item 1, Notes 2, 16 and 17.

(5) Does not include $370 million of long-term debt related to our Aruba refinery that is classified as part of our discontinued operations.

Our financing activities are discussed in greater detail below:

Short-Term Debt and Credit Facilities

At December 31, 2002, our weighted average interest rate on our short-term credit facilities was 2.69%. We had the following short-term borrowings and other financing obligations:

	September 30, 2003	December 31, 2002
	(In millions)	
Current maturities of long-term debt and other financing obligations	$1,047	$ 575
Short-term credit facilities	—	1,500
	$1,047	$2,075

Credit Facilities

In April 2003, we entered into a new $3 billion revolving credit facility, with a $1.5 billion letter of credit sublimit, which matures on June 30, 2005. Our $3 billion revolving credit facility has a borrowing cost of LIBOR plus 350 basis points, letter of credit fees of 350 basis points and commitment fees of 75 basis points on unused amounts of the facility. This facility replaced our previous $3 billion revolving credit facility. Approximately $1 billion of our other financing arrangements (including the leases discussed in Item 1, Notes 3 and 11, letters of credit and other facilities) were also amended to conform the provisions of those obligations to our $3 billion revolving credit facility. The $3 billion revolving credit facility and those other financing arrangements are secured by our equity in EPNG, TGP, ANR, WIC, ANR Storage Company, Southern Gas Storage Company and our Series A and Series C units in GulfTerra. The $3 billion revolving credit facility and other financing arrangements are also collateralized by our equity in the companies that own the assets that collateralize our Clydesdale financing arrangement. For a discussion of Clydesdale, see Item 1, Notes 3 and 17.

As part of our new $3 billion revolving credit facility, several of our significant covenants changed. Our ratio of debt to capitalization (as defined in the new revolving credit facility) cannot exceed 75 percent, instead of the previous maximum of 70 percent (as was defined in the prior credit facility agreement). For purposes of this calculation, we are allowed to add back to equity non-cash impairments of long-lived assets and exclude the impact of accumulated other comprehensive income, among other items. Additionally, in determining debt under the agreements, we are allowed to exclude certain non-recourse project financings, among other items. The covenant relating to subsidiary debt was removed. Also, EPNG, TGP, ANR, and upon the maturity of the Clydesdale financing transaction, CIG cannot incur incremental debt if the incurrence of this incremental debt would cause their debt to EBITDA ratio (as defined in the new revolving credit facility agreement) for that particular company to exceed 5 to 1. Additionally, the proceeds from the issuance of debt by the pipeline company borrowers can only be used for maintenance and expansion capital expenditures or investments in other FERC-regulated assets, to fund working capital requirements, or to refinance existing debt. As of September 30, 2003, we were in compliance with these covenants.

As of September 30, 2003, there were $1.3 billion of borrowings outstanding and $1.0 billion of letters of credit issued under the $3 billion revolving credit facility, all of which was borrowed by or issued on behalf of us. Amounts outstanding under the $3 billion revolving credit facility as of September 30, 2003, were classified as non-current in our balance sheet, based on the maturity date which is June 30, 2005. Subsequent to September 30, 2003, we repaid an additional $400 million under our revolving credit facility. In addition, in October 2003, we liquidated a portion of the collateral that supports the revolver and related financing arrangements. The proceeds from the liquidation will be used to reduce commitments and repay amounts outstanding under the $3 billion revolving credit facility and related financing arrangements. As a result, there will be a $17 million reduction of the borrowing availability under our $3 billion revolving credit facility.

We also maintained a $1 billion revolving credit facility, which expired on August 4, 2003. EPNG and TGP were also borrowers under this facility.

The availability of borrowings under our $3 billion revolving credit facilities and other borrowing agreements is subject to conditions, which we currently meet. These conditions include compliance with the financial covenants and ratios required by those agreements, absence of default under the agreements, and continued accuracy of the representations and warranties contained in the agreements.

Other

In October 2003, we initiated a tender offer to exchange our 11.5 million, 9% equity security units (consisting of a senior note and a stock purchase contract) for our common stock and cash. For each unit tendered, the holder will receive 2.5063 shares of common stock and cash in the amount of $9.70 per equity security unit. The exchange offer is conditioned upon the valid tender of at least 50 percent of the equity security units, or 5.75 million equity security units, which condition may be waived by us at our sole discretion. If 100 percent of the units are tendered, our debt obligations would be reduced by up to $575 million.

Long-Term Debt Obligations

During 2003, we have entered into, consolidated and retired several debt financing obligations:

Date	Company	Type	Interest Rate	Principal	Net Proceeds[1]	Due Date
				(In millions)		
Issuances						
March	El Paso[2]	Two-year term loan	LIBOR + 4.25%	$1,200	$1,149	2004-2005
March	SNG	Senior notes	8.875%	400	385	2010
March	ANR	Senior notes	8.875%	300	288	2010
May	El Paso Production Holding[3]	Senior notes	7.75%	1,200	1,169	2013
June	Macae[4]	Notes	Various	95	95	2008
July	EPNG	Senior notes	7.625%	355	347	2010
	Issuances through September 30, 2003			3,550	3,433	
October	Macae[4]	Term loan	Floating rate	200	200	2007
				$3,750	$3,633	
Acquisitions, Consolidations and Reclassifications						
April	Lakeside	Term loan	LIBOR + 3.5%	$ 275	$ 275	2006
April	Gemstone	Notes	7.71%	950	938	2004
	Macae[4][5]	Loan	Floating rate	75	75	2007
April	Clydesdale	Term loan	Various	743	743	2005
May	Chaparral[4]	Notes and loans	Various	1,671	1,565	Various
September	Capital Trust I	Preferred securities	4.75%	325	325	2028
September	Coastal Finance I	Preferred securities	8.375%	300	300	2038
				$4,339	$4,221	

Date	Company	Type	Interest Rate	Principal	Net Retirements
				(In millions)	
Retirements[6]					
January-September	Various	Long-term debt	Various	$ 136	136
February	El Paso CGP	Long-term debt	4.49%	240	240
May	Clydesdale	Term loan	Variable	100	100
May	El Paso[2]	Two-year term loan	LIBOR + 4.25%	1,200	1,191
July	El Paso CGP	Note	Floating rate	200	200
August	El Paso CGP	Senior debentures	9.75%	102	102
August	Clydesdale	Term loan	Variable	122	122
September	Mohawk River Funding I[7]	Note	7.09%	139	139
	Retirements through September 30, 2003			2,239	2,230
October	East Coast Power[8]	Senior secured note	Various	571	571
November	Clydesdale	Term loan	Variable	107	107
				$2,917	$2,908

(1) Net proceeds were primarily used to repay maturing long-term debt, redeem preferred interests of consolidated subsidiaries, repay short-term borrowings and other financing obligations and for other general corporate and investment purposes.
(2) The proceeds from the two-year term loan were used to redeem our Trinity River financing.
(3) Net proceeds were used to repay the $1.2 billion LIBOR based two-year term loan.
(4) This is a non-recourse project financing or non-recourse debt related to our power contract restructuring.
(5) This non-recourse project debt was consolidated as a consequence of our acquisition of Gemstone.
(6) Amount excludes net repayments of $250 million through September 30, 2003, and additional net repayments of $400 million as of October 31, 2003, related to our $3 billion revolving credit facility which is classified as long-term debt based on its maturity date of June 30, 2005.
(7) This debt related to Mohawk River Funding I, L.L.C. was eliminated through the sale of this entity.
(8) This debt related to East Coast Power, L.L.C. was eliminated through the sale of this entity.

Notes Payable to Affiliates

Our notes payable to unconsolidated affiliates as of September 30, 2003, were $9 million versus $390 million as of December 31, 2002. The decrease was primarily due to retirements of $45 million of

Chaparral debt securities in the first quarter of 2003 and the consolidation of $123 million of Gemstone and $203 million of Chaparral debt securities in the second quarter of 2003.

Minority Interests and Preferred Interests of Consolidated Subsidiaries

The total amount outstanding for securities of subsidiaries and preferred stock of consolidated subsidiaries was $0.5 billion at September 30, 2003, versus $3.4 billion at December 31, 2002. The decrease was due to the retirements of $980 million of Trinity River preferred interests and $197 million of preferred member interests in Clydesdale in 2003. Additionally, we retired an additional $753 million of Clydesdale preferred member interests, converting it into a loan that matures in equal quarterly installments through 2005. We also eliminated the entire $300 million of Gemstone's minority member interest following our acquisition and consolidation of Gemstone and reclassified $625 million of our Capital Trust I and Coastal Finance I consolidated trusts as long-term financing obligations related to our adoption of SFAS No. 150. See Item 1, Notes 2, 16 and 17 for a further discussion of preferred interests of our consolidated subsidiaries.

Letters of Credit

We enter into letters of credit in the ordinary course of our operating activities. As of September 30, 2003, we had outstanding letters of credit of approximately $1.2 billion (including $131 million related to our discontinued petroleum markets operations) compared to $852 million (including $170 million related to our discontinued petroleum markets operations) as of December 31, 2002. The increase was primarily due to issuing letters of credit under our revolving credit facilities in lieu of cash to support our petroleum and trading businesses. Of the outstanding letters of credit, $148 million was supported with cash collateral.

Segment Results

We use earnings before interest expense and income taxes (EBIT) to assess the operating results and effectiveness of our business segments. We define EBIT as net income (loss) adjusted for (i) items that do not impact our income (loss) from continuing operations, such as extraordinary items, discontinued operations and the impact of accounting changes, (ii) income taxes, (iii) interest and debt expense and (iv) distributions on preferred interests of consolidated subsidiaries. Our business operations consist of both consolidated businesses as well as substantial investments in unconsolidated affiliates. We believe EBIT, which includes the results of both these consolidated and unconsolidated operations, is useful to our investors because it allows them to more effectively evaluate the performance of all of our businesses and investments. Also, we exclude interest and debt expense and distributions on preferred interests of consolidated subsidiaries so that investors may evaluate our operating results without regard to our financing methods or capital structure. EBIT may not be comparable to measures used by other companies and should not be used as a substitute for net income or other performance measures such as operating income or operating cash flow. The following is a reconciliation of our operating income to our EBIT and our EBIT to our net income (loss) for the periods ended September 30:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In millions)			
Operating revenues	$ 1,539	$ 1,696	$ 5,143	$ 6,433
Operating expenses	(1,267)	(1,386)	(4,764)	(4,842)
Operating income	272	310	379	1,591
Earnings (losses) from unconsolidated affiliates	79	58	31	(36)
Other income (expense)	49	52	3	(115)
EBIT	400	420	413	1,440
Interest and debt expense	(474)	(343)	(1,350)	(950)
Distributions on preferred interests of consolidated subsidiaries	(8)	(37)	(45)	(120)
Income taxes	(15)	(16)	463	(120)
Income (loss) from continuing operations	(97)	24	(519)	250
Discontinued operations, net of income taxes	(49)	(93)	(1,187)	(149)
Cumulative effect of accounting changes, net of income taxes	—	—	(22)	168
Net income (loss)	$ (146)	$ (69)	$(1,728)	$ 269

Overview of Results of Operations

Below are our results of operations (as measured by EBIT) by segment. Our four operating segments — Pipelines, Production, Field Services and Merchant Energy — provide a variety of energy products and services. They are managed separately as each business unit requires different technology, operational and marketing strategies. We reclassified our historical coal mining operation in the second quarter of 2002 and our petroleum and chemical operations in the second quarter of 2003 from our Merchant Energy segment to discontinued operations in our financial statements. Merchant Energy's results for all periods presented reflect this change. For a further discussion of charges and other income and expense items impacting the results below, see Item 1, Notes 2 through 9 and 21.

EBIT by Segment	Quarter Ended September 30, 2003	Quarter Ended September 30, 2002	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
	(In millions)			
Pipelines	$ 301	$ 302	$ 875	$ 1,024
Production	103	179	515	362
Field Services	33	(11)	6	94
Merchant Energy	(37)	(83)	(412)	10
Segment EBIT	400	387	984	1,490
Corporate and other	—	33	(571)	(50)
Consolidated EBIT	$ 400	$ 420	$ 413	$ 1,440

Pipelines

Our Pipelines segment owns and operates our interstate transmission businesses. For a further discussion of the business activities of our Pipelines segment, see our Current Report on Form 8-K dated September 23, 2003. Results of our Pipelines segment operations were as follows for the periods ended September 30:

Pipelines Segment Results	Quarter Ended September 30, 2003	Quarter Ended September 30, 2002	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
	(In millions, except volume amounts)			
Operating revenues	$ 598	$ 611	$ 1,971	$ 1,945
Operating expenses	(331)	(352)	(1,208)	(1,052)
Operating income	267	259	763	893
Other income	34	43	112	131
EBIT	$ 301	$ 302	$ 875	$ 1,024
Throughput volumes (BBtu/d)[1]				
TGP	3,960	4,472	4,732	4,498
EPNG and MPC	4,198	4,069	4,064	4,106
ANR	3,586	3,637	4,284	4,137
CIG and WIC	2,639	2,613	2,724	2,679
SNG	1,890	1,982	2,117	2,114
Equity investments (our ownership share)	2,526	2,735	2,533	2,565
Total throughput	18,799	19,508	20,454	20,099

(1) Throughput volumes for the quarter and nine months ended September 30, 2002, exclude 199 BBtu/d and 210 BBtu/d related to our equity investment in the Alliance pipeline system which was sold in November 2002 and March 2003. Throughput volumes also exclude volumes transported between entities within the Pipelines segment. Prior period volumes have been restated to reflect current year presentation which includes billable transportation throughput volume for storage injection and withdrawal.

Third Quarter 2003 Compared to Third Quarter 2002

Operating revenues for the quarter ended September 30, 2003, were $13 million lower than the same period in 2002. The decrease was due to a $14 million favorable resolution of measurement issues at a processing plant serving the TGP system in 2002, $8 million from lower natural gas recovered in excess of amounts used in operations and $6 million due to capacity contracts that have expired which EPNG is prohibited from remarketing due to various FERC orders in EPNG's systemwide capacity allocation proceeding. For a further discussion of these orders, see Item 1, Note 18. These decreases were offset by $15 million from higher revenues due to completed system expansions and new transportation contracts.

Operating expenses for the quarter ended September 30, 2003, were $21 million lower than the same period in 2002 primarily due to the revaluation of the stock portion of the Western Energy Settlement of $20 million. For a further discussion of the settlement see Item 1, Note 6.

Other income for the quarter ended September 30, 2003, was $9 million lower than the same period in 2002 primarily due to lower equity earnings of $6 million resulting from the sale of our interests in the Alliance pipeline system completed in the first quarter of 2003 and $4 million from our investment in Citrus.

Nine Months Ended 2003 Compared to Nine Months Ended 2002

Operating revenues for the nine months ended September 30, 2003, were $26 million higher than the same period in 2002. The increase was due to higher revenues of $33 million due to completed system expansions and new transportation contracts, $32 million from higher volumes and prices on natural gas recovered in excess of amounts used in operations, $25 million from increased transportation revenues due to higher throughput in 2003 as a result of colder winter weather, $17 million from higher realized prices in 2003 on the resale of natural gas purchased from the Dakota gasification facility which was partially offset by $5 million from lower gas resales due to a FERC approved buyout of the Dakota gas purchase contract effective August 1, 2003, $13 million from higher sales under natural gas purchase contracts and a $9 million increase in liquid revenues resulting from higher liquid prices. These increases were offset by $48 million from lower revenues due to CIG's sale of the Panhandle field and other production properties in July 2002, a $34 million revenue reduction from capacity contracts that have expired which EPNG is prohibited from remarketing due to various FERC orders and $18 million from the favorable resolution of measurement issues at a processing plant serving the TGP system in 2002.

Operating expenses for the nine months ended September 30, 2003, were $156 million higher than the same period in 2002. The increase was primarily due to $138 million from charges related to EPNG's portion of the Western Energy Settlement. Also contributing to the increase were $16 million from higher prices on natural gas purchased at the Dakota gasification facility along with the impact of the FERC approved gas purchase contract buyout of $6 million which was partially offset by $5 million from lower gas purchases following the termination of the Dakota contract, $22 million of lower general and administrative costs in 2002 versus 2003, an $11 million gain on the sale of pipeline expansion rights in February 2002, $8 million from higher system supply purchases in 2003 resulting from higher prices and volumes in 2003, and $7 million from higher depreciation due to a revision in depreciation expense for a TGP facility that is being depreciated at an incremental rate of 6.67% per year instead of the general system rate of 1.62% per year. These increases were offset by a $27 million decrease in operating costs due to CIG's sale of its Panhandle field and other production properties, $22 million from lower environmental remediation and legal costs and a $12 million decrease due to bad debt expense recorded in 2002 related to the bankruptcy of Enron Corp.

Other income for the nine months ended September 30, 2003, was $19 million lower than the same period in 2002. The decrease was due to $16 million from lower equity earnings due to the sale of our interest in the Alliance pipeline system completed in the first quarter of 2003 and $11 million from the favorable resolution of uncertainties in 2002 associated with the sale of our interests in the Iroquois and Empire State pipeline systems and Gulfstream pipeline project in 2001. These decreases were offset by $11 million from a higher allowance for equity funds used during construction in 2003.

Production

Our Production segment conducts our natural gas and oil exploration and production activities. Our operating results are driven by a variety of factors including the ability to locate and develop economic natural gas and oil reserves, extract those reserves with minimal production costs, sell the products at attractive prices and operate at a low total cost level.

Since December 31, 2001, we have sold over 2.5 Tcfe of proved reserves in multiple sales transactions with various third parties. The cumulative amount of the reserves sold represented over 38 percent of our year end 2001 total reserve base, and generated total cash proceeds of approximately $2.0 billion. These sales were conducted as part of our overall efforts to reduce debt and improve our liquidity position. These sales, which included proved developed producing reserves, combined with normal production declines, mechanical failures on certain producing wells and higher finding and development costs, have resulted in our total equivalent production levels declining each quarter since the first quarter of 2002. For the first nine months of 2003, our total equivalent production has declined approximately 122 Bcfe or 27 percent as compared to the same period in 2002. Future trends in production will be dependent upon the amount of capital allocated to our Production segment, the level of success in our drilling programs and any future sales activities relating to our proved reserves.

As further described in our Current Report on Form 8-K dated September 23, 2003, Production has historically engaged in hedging activities on its natural gas and oil production to stabilize cash flows and to reduce the risk of downward commodity price movements on its sales. As of September 30, 2003, we have hedged approximately 54 million MMBtu's of our remaining anticipated natural gas production for 2003 at a NYMEX Henry Hub price of $3.38 per MMBtu before regional price differentials and transportation costs.

Our depletion rate is determined under the full cost method of accounting. We expect a higher depletion rate in future periods as a result of higher finding and development costs experienced this year, coupled with a lower reserve base due to the asset sales mentioned above. For the fourth quarter of 2003, we expect our domestic unit of production depletion rate to be approximately $1.84 per Mcfe.

For 2003, we expect to spend $1.4 billion on capital expenditures. During the nine months ended September 30, 2003, we spent approximately $1.2 billion on capital expenditures. In October 2003, we entered into agreements with a wholly owned subsidiary of Lehman Brothers (Lehman), an investment bank, and a wholly owned subsidiary of Nabors Industries Ltd. (Nabors) that will collectively result in an additional $350 million of drilling activity over the next nine to 12 months. Lehman will contribute 50 percent of an estimated $500 million total cost to develop two specified packages of wells in exchange for a 50 percent net profits interest (cash proceeds available after royalties and operating costs have been paid), and Nabors will contribute 20 percent in exchange for a 20 percent net profits interest in such packages of wells. Once a specified payout is achieved, Lehman's and Nabors' net profits interests will convert to an overriding royalty interest in the wells for the remainder of the wells' productive lives. We will contribute the remaining 30 percent of the $500 million of capital as part of our existing 2003 and 2004 capital budget. Under the terms of the agreements, all parties have a right to cease further investment with 30 days notice.

As of January 1, 2003, our reserve estimates were prepared internally by our Production segment and reviewed by Huddleston & Co., Inc. During the fourth quarter of 2003, we appointed Ryder Scott Co. as our primary reservoir engineer.

Results of our Production segment operations were as follows for the periods ended September 30:

Production Segment Results	Quarter Ended September 30, 2003	Quarter Ended September 30, 2002	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
	(In millions, except volumes and prices)			
Operating revenues:				
Natural gas	$ 332	$ 403	$ 1,237	$ 1,324
Oil, condensate and liquids	72	92	246	289
Other	6	4	14	(4)
Total operating revenues	410	499	1,497	1,609
Transportation and net product costs	(20)	(29)	(75)	(84)
Total operating margin	390	470	1,422	1,525
Operating expenses(1)	(289)	(291)	(922)	(1,166)
Operating income	101	179	500	359
Other income	2	—	15	3
EBIT	$ 103	$ 179	$ 515	$ 362
Volumes and prices				
Natural gas				
Volumes (MMcf)	80,426	120,092	279,026	373,378
Average realized prices with hedges ($/Mcf)(2)	$ 4.13	$ 3.36	$ 4.43	$ 3.54
Average realized prices without hedges ($/Mcf)(2)	$ 5.04	$ 3.08	$ 5.74	$ 2.91
Average transportation costs ($/Mcf)	$ 0.18	$ 0.15	$ 0.21	$ 0.17
Oil, condensate and liquids				
Volumes (MBbls)	2,891	3,986	9,259	13,940
Average realized prices with hedges ($/Bbl)(2)	$ 24.94	$ 23.17	$ 26.63	$ 20.75
Average realized prices without hedges ($/Bbl)(2)	$ 25.53	$ 23.91	$ 27.33	$ 20.67
Average transportation costs ($/Bbl)	$ 1.12	$ 0.98	$ 1.02	$ 0.91

(1) Includes production costs, depletion, depreciation and amortization, ceiling test charges, asset impairments, gain and loss on long-lived assets, general and administrative expenses and severance and other taxes.

(2) Prices are stated before transportation costs.

Third Quarter 2003 Compared to Third Quarter 2002

Operating revenues for the quarter ended September 30, 2003, were $89 million lower than the same period in 2002. Our natural gas revenues, including the impact of hedges, were $71 million lower in the third quarter of 2003. Our 2003 natural gas production volumes decreased by 33 percent, resulting in a $133 million decrease in revenues versus the same period in 2002. Realized natural gas prices rose in 2003 by 23 percent, resulting in a $62 million increase in revenues when compared to the same period in 2002. The overall decline in natural gas volumes was due to the sales of production properties in New Mexico, Oklahoma, Utah, offshore Gulf of Mexico and western Canada as well as normal production declines and mechanical failures in certain producing wells. Our oil, condensate and liquids revenues, including the impact of hedges, were $20 million lower in the third quarter of 2003. Our 2003 oil, condensate and liquids volumes decreased by 27 percent, resulting in a $25 million decrease in revenues versus the same period in 2002. Realized oil, condensate and liquids prices rose in 2003 by 8 percent, resulting in a $5 million increase in revenues when compared to the same period in 2002. The declines in volumes were primarily due to the property sales, production declines and mechanical failures mentioned above.

Transportation and net product costs for the quarter ended September 30, 2003, were $9 million lower than the same period in 2002 primarily due to a lower percentage of gas volumes subject to transportation fees and lower fees incurred in 2003 to meet minimum payments on pipeline agreements.

Operating expenses for the quarter ended September 30, 2003, were $2 million lower than the same period in 2002 primarily due to lower oilfield service costs of $4 million, as a result of asset dispositions which reduced labor and production processing fees, and lower severance and other taxes of $2 million. Partially offsetting these decreases were higher general and administrative costs of $3 million. While overall depletion expense remained level, there was a $53 million increase due to higher depreciation, depletion and amortization (DD&A) rates in 2003 and costs of $4 million related to the accretion of our liability for asset retirement obligations in 2003, offset by a $57 million decrease due to lower production volumes in 2003. The higher depletion rate resulted from increased finding and development costs coupled with a lower reserve base due to asset sales.

Nine Months Ended 2003 Compared to Nine Months Ended 2002

Operating revenues for the nine months ended September 30, 2003, were $112 million lower than the same period in 2002. Our natural gas revenues, including the impact of hedges, were $87 million lower in 2003. Our 2003 natural gas production volumes decreased by 25 percent, resulting in a $334 million decrease in revenues versus the same period in 2002. Realized natural gas prices rose in 2003 by 25 percent, resulting in a $247 million increase in revenues when compared to the same period in 2002. The decline in natural gas volumes was due to sales of production properties in Colorado, New Mexico, Oklahoma, Utah, Texas, offshore Gulf of Mexico, and western Canada as well as normal production declines and mechanical failures on certain producing wells. Our oil, condensate and liquids revenues, including the impact of hedges, were $43 million lower in 2003. Our 2003 oil, condensate and liquids volumes decreased by 34 percent, resulting in a $97 million decrease in revenues versus the same period in 2002. Realized oil, condensate and liquids prices rose in 2003 by 28 percent, resulting in a $54 million increase in revenues when compared to the same period in 2002. The declines in volumes were primarily due to the property sales, production declines and mechanical failures mentioned above. Partially offsetting the decrease in revenues was a positive mark-to-market adjustment of $16 million in 2003 compared to 2002 related to hedges of anticipated future production that no longer qualified for hedge accounting when we sold those properties in March 2002.

Transportation and net product costs for the nine months ended September 30, 2003, were $9 million lower than the same period in 2002 primarily due to a lower percentage of gas volumes subject to transportation fees.

Operating expenses for the nine months ended September 30, 2003 were $244 million lower than the same period in 2002 primarily due to a 2002 non-cash full cost ceiling test charge of $267 million for our international properties in Canada, Turkey, Brazil and Australia. Also contributing to the decrease were lower oilfield service costs in 2003 of $38 million, primarily due to asset dispositions which resulted in lower labor and production processing fees, and a $5 million gain in 2003 on the sales of non-full cost pool assets. Partially offsetting these decreases was higher depletion expense of $5 million, consisting of a $143 million increase due to higher DD&A rates in 2003 and costs of $14 million related to the accretion of our liability for asset retirement obligations, partially offset by a $152 million decrease due to lower production volumes in 2003. The higher depletion rate in 2003 resulted from increased finding and development costs coupled with a lower reserve base due to asset sales. Also offsetting these decreases were higher general and administrative costs of $24 million in 2003, higher severance and other taxes of $16 million in 2003, intangible asset impairments of $14 million in 2003 on non-full cost assets in Canada and employee severance costs of $4 million in 2003. The increase in severance taxes was primarily due to tax credits taken in 2002 for qualified natural gas wells.

Other income for the nine months ended September 30, 2003, was $12 million higher than in 2002 primarily due to higher earnings in 2003 from Pescada, an equity investment in Brazil.

Field Services

Our Field Services segment conducts our midstream activities. A subsidiary in our Field Services segment serves as the general partner of GulfTerra and owns the one percent general partner interest. In October 2003, we sold 9.9 percent of our interest in the general partner to Goldman Sachs. We continue to own the remaining 90.1 percent interest in the general partner. In addition, GulfTerra redeemed all of the Series B preference units that we owned and released us from our obligation to repurchase the Chaco gathering facility in exchange for our contribution of communications assets to GulfTerra. Total proceeds from this transaction were $244 million. Also in October 2003, we sold 590,000 of the partnership's common units that we owned for $23 million. For a further discussion of these transactions, see Item 1, Note 21. Our ownership in the partnership's common units decreased from 26.5 percent as of December 31, 2002 to 23.1 percent as of September 30, 2003 as a result of common unit offerings by GulfTerra during the second and third quarters of 2003, and it further decreased as a result of October 2003 unit offerings by GulfTerra and our sale of 590,000 common units. As a result, in addition to our general partner interest, we currently own, through various subsidiaries, 19.0 percent of the partnership's common units and all of its Series C units.

We recognize earnings and receive cash from the partnership in several ways, including through a share of the partnership's cash distributions and through our ownership of limited, preferred and general partner interests. We also receive management fees pursuant to an agreement to provide various operational and administrative services to the partnership. These management fees have increased as a result of GulfTerra's asset acquisitions in 2002. We expect these fees will continue to increase as additional services are provided. In addition, we are reimbursed for other costs paid directly by us on the partnership's behalf. During the quarter and nine months ended September 30, 2003, we received approximately $22 million and $68 million related to expenses incurred on behalf of the partnership. During the quarter and nine months ended September 30, 2002, we received approximately $15 million and $38 million related to expenses incurred. Our earnings and cash distributions received from GulfTerra were as follows:

	Quarter Ended September 30, 2003		Nine Months Ended September 30, 2003	
	Earnings Recognized	Cash Received	Earnings Recognized	Cash Received
	(In millions)			
General partner's share of distributions[1]	$18	$18	$ 49	$49
Proportionate share of income available to common unit holders[1]	7	8	18	24
Series B preference units[1]	4	—[1][2]	12	—[2]
Series C units	8	8	17	22
Gain on issuance by GulfTerra of its common units	3	—	15	—
	$40	$34	$111	$95

[1] Our earnings and distributions will be reduced proportionately due to the sale of 9.9 percent of our interest in the general partner and our sale of 590,000 of the partnership's common units. Additionally, due to the redemption of our Series B units in October 2003, we will no longer receive earnings on these units.

[2] The partnership was not obligated to pay cash distributions on these units until 2010.

In the second quarter of 2003, we sold our midstream assets in the Mid-Continent and north Louisiana regions. Our Mid-Continent assets primarily included our Greenwood, Hugoton, Keyes and Mocane natural gas gathering systems, our Sturgis, Mocane and Lakin processing plants and our processing arrangements at three additional processing plants. Our north Louisiana assets primarily included our Dubach processing plant and Gulf States interstate natural gas transmission system. These assets generated EBIT of approximately $10 million during the year ended December 31, 2002. Our remaining assets now consist primarily of our investment in GulfTerra and processing facilities in the south Texas, south Louisiana and Rocky Mountain regions.

As a result of our asset sales and the resulting decline in our gathering and processing activities, our EBIT has decreased significantly. However, the increases in earnings from our interests in GulfTerra have partially offset these decreases primarily because some of the assets were sold to GulfTerra. For a further discussion of the business activities of our Field Services segment, see our Current Report on Form 8-K dated September 23, 2003. Results of our Field Services segment operations were as follows for the periods ended September 30:

Field Services Segment Results	Quarter Ended September 30, 2003	Quarter Ended September 30, 2002	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
	(In millions, except volumes and prices)			
Gathering, transportation and processing gross margins[1]	$ 33	$ 80	$ 109	$ 289
Operating expenses	(41)	(60)	(133)	(195)
Operating income (loss)	(8)	20	(24)	94
Other income (expense)[2]	41	(31)	30	—
EBIT	$ 33	$ (11)	$ 6	$ 94
Volumes and prices				
Gathering and transportation				
Volumes (BBtu/d)	190	2,209	402	3,422
Prices ($/MMBtu)	$ 0.15	$ 0.19	$ 0.19	$ 0.17
Processing				
Volumes (inlet BBtu/d)	3,017	3,883	3,174	3,984
Prices ($/MMBtu)	$ 0.10	$ 0.11	$ 0.10	$ 0.11

(1) Gross margins consist of operating revenues less cost of products sold. We believe this measurement is more meaningful for analyzing our Field Services operating results because commodity costs play such a significant role in the determination of profit from our midstream activities.

(2) Includes equity earnings from our investment in GulfTerra.

Third Quarter 2003 Compared to Third Quarter 2002

Total gross margins for the quarter ended September 30, 2003, were $47 million lower than the same period in 2002 primarily as a result of our asset sales in 2002 and 2003, the most significant of these being the sales of our San Juan Basin assets in November 2002 and our Mid-Continent and north Louisiana midstream assets in the second quarter of 2003. The sales of these assets decreased gathering margins by $31 million and processing margins by $10 million. Processing margins also decreased $4 million in the third quarter of 2003 primarily due to higher natural gas prices relative to NGL prices, which reduced our margin per unit processed and caused us to minimize the amount of NGLs that were extracted by our natural gas processing facilities in Texas.

Operating expenses for the quarter ended September 30, 2003, were $19 million lower than the same period in 2002 primarily due to the asset sales discussed above, resulting in lower operating costs of $9 million and lower depreciation expense of $4 million. Also contributing to the decrease were lower operating expenses as a result of cost reductions of $6 million and higher fees received of $4 million from GulfTerra for administrative and other services to operate their assets. The increase in fees received was a direct result of GulfTerra's asset acquisitions in 2002. These decreases were partially offset by an additional legal reserve of $3 million in 2003 and $5 million of additional costs related to higher maintenance requirements.

Other income for the quarter ended September 30, 2003, was $72 million higher than the same period in 2002 primarily due to increased earnings of $23 million from our investment in GulfTerra, as well as a loss of $47 million recorded in September 2002 related to the sale of our investment in the Aux Sable natural gas liquids plant.

Nine Months Ended 2003 Compared to Nine Months Ended 2002

Total gross margins for the nine months ended September 30, 2003, were $180 million lower than the same period in 2002 primarily as a result of our asset sales in 2002 and 2003, the most significant of these being the sales of our Texas and New Mexico assets in April 2002, our San Juan Basin assets in November 2002, and our Mid-Continent and north Louisiana midstream assets in the second quarter of 2003. The sales of these assets decreased gathering margins by $122 million and processing margins by $26 million. Processing margins also decreased $13 million in the first nine months of 2003 primarily due to higher natural gas prices relative to NGL prices, which reduced our margin per unit processed and caused us to minimize the amount of NGLs that were extracted by our natural gas processing facilities in Texas. Gathering margins were also lower in 2003 by $13 million due to the favorable resolutions of fuel, rate and volume matters in the first quarter of 2002.

Operating expenses for the nine months ended September 30, 2003, were $62 million lower than the same period in 2002 primarily due to the asset sales discussed above, resulting in lower operating costs of $37 million and lower depreciation expense of $21 million. Also contributing to the decrease in operating expenses were a net gain of $14 million from the sale of our Mid-Continent and north Louisiana midstream assets in the second quarter of 2003 and higher fees received of $14 million from GulfTerra to provide administrative and other services to operate their assets. The increase in fees received was a direct result of GulfTerra's asset acquisitions in 2002. In addition, our 2002 cost reduction plan, initiated mid-2002, resulted in $10 million of lower operating costs in 2003. These decreases were partially offset by a $10 million gain in the second quarter of 2002 from the sale of our Dragon Trail processing plant, an increase in general and administrative costs of $8 million in 2003, $10 million of purchase price adjustments in 2003 to gains from asset sales during 2002, an additional legal reserve of $6 million in 2003 and $5 million related to higher maintenance requirements.

Other income for the nine months ended September 30, 2003, was $30 million higher than the same period in 2002 due to increased earnings of $60 million from our investment in GulfTerra, as well as a loss of $47 million recorded in September 2002 related to the sale of our investment in the Aux Sable natural gas liquids plant. Partially offsetting the increase was $80 million in impairment charges on our Dauphin Island Gathering Partners and Mobile Bay Processing Partners investments. The impairment was recorded based on an expected loss from the anticipated sale of our interests in these investments.

Merchant Energy

Our Merchant Energy segment consists of three divisions: global power, energy trading and other. Historically, our Merchant Energy segment also included our petroleum markets division, but in June 2003, our Board of Directors approved the sale of substantially all of these operations. As a result, the petroleum markets division was reclassified as discontinued operations for all periods presented. For a further discussion of our petroleum markets operations, see Item 1, Note 11. The petroleum markets division previously included our LNG business activities and equity earnings on a gas processing plant and investments in several crude oil pipelines. These operations are now included in the "Other" division in the tables below. Merchant Energy's operating results and an analysis of those results for the periods ended September 30 are presented below:

	Division				Total Merchant Energy Segment
Merchant Energy Segment Results	Global Power	Energy Trading	Other	Eliminations	
	(In millions)				
Third Quarter 2003					
Gross margin[1]	$ 247	$ (33)	$ (4)	$(15)	$ 195
Operating expenses	(219)	(47)	(14)	15	(265)
Operating income (loss)	28	(80)	(18)	—	(70)
Other income (expense)	41	(3)	(5)	—	33
EBIT	$ 69	$ (83)	$ (23)	$ —	$ (37)

Merchant Energy Segment Results	Division: Global Power	Division: Energy Trading	Division: Other	Division: Eliminations	Total Merchant Energy Segment
			(In millions)		
Third Quarter 2002					
Gross margin[1]	$ 157	$(160)	$ 24	$ (8)	$ 13
Operating expenses	(112)	(36)	(5)	8	(145)
Operating income (loss)	45	(196)	19	—	(132)
Other income (expense)	53	(4)	—	—	49
EBIT	$ 98	$(200)	$ 19	$ —	$ (83)
Nine Months Ended 2003					
Gross margin[1]	$ 693	$(230)	$ (8)	$(54)	$ 401
Operating expenses	(591)	(129)	(108)	54	(774)
Operating income (loss)	102	(359)	(116)	—	(373)
Other income (expense)	(34)	10	(15)	—	(39)
EBIT	$ 68	$(349)	$(131)	$ —	$(412)
Nine Months Ended 2002					
Gross margin[1]	$ 991	$(181)	$ 58	$(32)	$ 836
Operating expenses	(399)	(115)	(22)	32	(504)
Operating income (loss)	592	(296)	36	—	332
Other income (expense)	(331)	9	—	—	(322)
EBIT	$ 261	$(287)	$ 36	$ —	$ 10

(1) Gross margin for our global power division consists of revenues from our power plants and the initial net gains and losses incurred in connection with the restructuring of power contracts, as well as the subsequent revenues, cost of electricity purchases and changes in fair value of those contracts. The cost of fuel used in the power generation process is included in operating expenses. Gross margin for our energy trading division and other division consists of revenues from commodity trading and origination activities less the costs of commodities sold, including changes in the fair value of our derivative contracts.

Global Power

Our global power division includes the ownership and operation of domestic and international power generating facilities, including consolidated plants and equity investments. Our Current Report on Form 8-K dated September 23, 2003, includes a description of the various power activities included in global power.

Our domestic operations primarily include contracted operations, merchant operations and the results of our power restructuring business. Our contracted operations include our power plants that have dedicated power contracts with customers. The results of our contracted operations include the income related to the generation of power to meet long-term power commitments to electric utilities. Typically, the fixed price long-term sales contracts and the fixed price long-term fuel contracts in these operations are recorded on an accrual basis. However, some of our contracted operations have derivative fuel supply contracts that are subject to mark-to-market changes. Therefore, the operating results from our contracted operations may vary from period to period due to changes in the fair value of the these derivative fuel supply contracts.

Our merchant operations include power plants that serve their customers during peak periods without dedicated power contracts. The results of our merchant operations include income related to the generation of power for sale into the open market. Generally, the merchant power plants operate when the price of power in a market exceeds the variable costs of generating power. Many of our merchant operations have contractual obligations, such as transportation capacity contracts, that represent fixed costs for the plant. Our ability to recover the fixed operating costs depends on electricity demand and the volume of power generated as well as the margins that can be realized.

In 2003, our power restructuring business includes the results of managing our existing restructured power contracts. In 2002, our results include the impact of the power contract restructurings transactions that we completed in 2002, in addition to the results of managing these contracts. As a result of our credit downgrade and economic changes in the power market, we are no longer pursuing additional power contract restructuring activities. On an ongoing basis, the results of our power restructuring business will primarily consist of the physical sales and purchases of electricity as well as changes in fair value of the derivative contracts from period to period, including accretion of the discounted value as well as changes in commodity prices and discount rates. Changes in the discount rate used to calculate the fair value of our derivatives can significantly impact our earnings. See Item 3, Quantitative and Qualitative Disclosures About Market Risk.

Because of changes in our business strategy, we are pursuing the sale of our domestic power operations. The future results in our domestic power operations will be impacted by the timing of the potential sales of our power assets and the related operating results from those facilities.

Our international operations primarily include contracted plants and pipelines located primarily in Brazil, Latin America, Asia, Mexico and Europe. For a description of the political and foreign risks and related contingencies that affect our international facilities, see Item 1, Note 18.

Results of our global power division were as follows:

Global Power Division Results	Quarter Ended September 30, 2003	Quarter Ended September 30, 2002	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
	(In millions)			
Gross margin	$ 247	$ 157	$ 693	$ 991
Operating expenses	(219)	(112)	(591)	(399)
Operating income	28	45	102	592
Other income (expense)	41	53	(34)	(331)
EBIT	$ 69	$ 98	$ 68	$ 261

In the second quarter of 2003, we acquired the remaining interests in our Chaparral and Gemstone investments. For a discussion of the acquisition of Chaparral and Gemstone, see Item 1, Note 3. Upon the acquisitions of these remaining interests, we consolidated these investments, which had been previously reported using the equity method of accounting. This change in accounting for our Chaparral and Gemstone investments created significant variances in our gross margin, operating expenses and other income (expense) when comparing the quarter and nine months ended September 30, 2003 to the same periods in 2002. Additionally, we completed significant power restructurings in 2002, which created significant variances in our gross margin and operating expenses from 2003 to 2002. Finally, impairments and sales of some of our power assets and investments in 2002 and 2003 also caused significant variances in our operating expenses from 2003 to 2002. The following table and discussion provides an analysis of the performance within our domestic and international power operations, which is our basis for evaluating the performance of our global power business. We believe that our evaluation at the EBIT level is an effective way of managing overall performance due to the differing nature of each of the power activities described above and because our global operations include both equity and consolidated investments. The EBIT for our global power division, segregated between our domestic and international power operations, was as follows:

Global Power Division Results	Quarter Ended September 30, 2003	Quarter Ended September 30, 2002	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
	(In millions)			
Domestic power operations	$ 4	$ 66	$(109)	$ 491
International power operations	79	49	221	(165)
Other[(1)]	(14)	(17)	(44)	(65)
EBIT	$ 69	$ 98	$ 68	$ 261

(1) Other consists of the indirect general and administrative costs associated with our domestic and international operations, including legal, finance, and engineering costs. Direct general and administrative expenses of our domestic and international operations are included in EBIT of those operations.

Third Quarter 2003 Compared to Third Quarter 2002

Our domestic operations, which consist of both contracted and merchant operations as well as our power restructuring activities, generated EBIT during the quarter ended September 30, 2003, of $4 million compared to $66 million during the quarter ended September 30, 2002. The $62 million decrease in domestic operations EBIT was primarily attributable to a $69 million decrease in EBIT from our domestic operations other than our Chaparral operations offset by a $7 million increase in EBIT from Chaparral.

The $69 million decrease in the EBIT of our domestic operations other than Chaparral included a $22 million charge associated with an expected settlement involving two turbines included in our inventory, which will eliminate a future cash obligation of $78 million. Also contributing to the decrease was a $13 million loss on one of our equity investments that experienced a decrease in the fair value of its derivative fuel supply contracts and $12 million of decreased equity earnings due to the sale of our investment in CE Generation in early 2003. The remaining decrease relates to our decision not to operate our merchant plants since electricity demands and margins were lower, making it uneconomical to run the plants, as well as mechanical difficulties with one of the turbines at our Eagle Point merchant facility in 2003.

The $7 million increase in EBIT attributable to our Chaparral operations includes a $92 million increase in EBIT related to our investment in Chaparral primarily due to our increased ownership and consolidation of Chaparral, offset by a $46 million decrease in our management fees earned from Chaparral that we received in 2002 but not in 2003, and $39 million of impairments and losses related to the sales of some of the Chaparral power assets in 2003. The $39 million of impairments include a $29 million impairment of our East Coast Power facility generated by its sale completed in October 2003, and a $10 million loss on the sale of Mohawk River Funding I, one of our power restructuring entities.

For the quarter ended September 30, 2003, EBIT from our international operations was $30 million higher than the same period in 2002, which was primarily due to $15 million of interest expense and foreign taxes that was recorded in EBIT through equity earnings before the consolidation of Gemstone in 2003 but which was excluded from EBIT following the consolidation. We also benefited from an increase in EBIT of $23 million primarily from two Brazilian power plants that increased their generating capacity in 2003. These increases were offset by $6 million of legal fees related to arbitration proceedings on two of our Asian equity investments in 2003.

For the quarter ended September 30, 2003, our other global power operations' indirect general and administrative costs decreased by $3 million compared to the same period in 2002, primarily due to support personnel reductions resulting from the sales of power plants during 2002 and 2003 and a reduction of our business development activities as we pursue the sale of our domestic power operations.

Nine Months Ended 2003 Compared to Nine Months Ended 2002

For the nine months ended September 30, 2003, our domestic operations generated an EBIT loss of $109 million compared to EBIT earnings of $491 million for the same period in 2002. The $600 million decrease in EBIT was primarily attributable to a $188 million decrease in EBIT from Chaparral and a $412 million decrease in EBIT from our domestic operations other than Chaparral.

The $188 million decrease in EBIT attributable to Chaparral includes $246 million of impairments and losses related to the sales of some of the Chaparral power assets in 2003. Of the $246 million, $207 million of the charges was attributable to an impairment of our Chaparral investment, $29 million is associated with the sale of our East Coast Power facility which closed in October 2003, and $10 million relates to a loss on the sale of Mohawk River Funding I, one of our power restructuring entities. We also experienced a $139 million decrease in our management fees earned from Chaparral that we received in 2002 but not in 2003. Offsetting these decreases was a $197 million increase in earnings related to our investment in Chaparral primarily due to our increased ownership and consolidation of Chaparral.

We also experienced a net $412 million decrease in the EBIT of our domestic operations other than Chaparral, which included an $88 million impairment associated with our Milford power project and a $22 million charge associated with an expected settlement involving two turbines included in our inventory that will eliminate a future cash obligation of $78 million. Also contributing to the decrease was $331 million of net gains related to our power restructurings in 2002 on our Eagle Point Cogeneration and Mount Carmel power plants, which includes an $80 million loss on a power supply agreement that we entered into with our energy trading division in the first quarter of 2002 associated with the Eagle Point Cogeneration power contract restructuring transaction and a $90 million contract termination fee we paid in 2002 to our petroleum division associated with the termination of a steam contract between our Eagle Point Cogeneration facility and the Eagle Point refinery (which is included in our petroleum markets division reflected in discontinued operations). For a further description of our 2002 power contract restructurings, see our Current Report on Form 8-K dated September 23, 2003. Also contributing to the decrease were lower equity earnings of $16 million due to the sale of our investment in CE Generation in early 2003. Partially offsetting these decreases were $63 million of increases in the fair value of our power restructuring contracts primarily resulting from income accretion for nine months in 2003 compared to less than nine months in 2002, on contracts restructured in the first quarter of 2002. The remaining decrease relates primarily to our decision not to operate our merchant plants since electricity demands and margins were lower, making it uneconomical to run the plants, as well as mechanical difficulties with one of the turbines of our Eagle Point merchant facility in 2003.

For the nine months ended September 30, 2003, our international operations generated EBIT earnings of $221 million compared to an EBIT loss of $165 million for the same period in 2002. Our 2002 EBIT loss includes a $342 million impairment of our Argentina investments and a turbine forfeiture fee of $19 million related to a project that was cancelled offset by a $77 million gain from the termination of a power purchase agreement at our Nejapa power facility. The remaining increase in EBIT of $102 million includes a $24 million gain on the sale of our Argentina investment in 2003, $23 million of interest expense and foreign taxes that were recorded in EBIT through equity earnings before the consolidation of Gemstone in 2003, which was excluded from EBIT following the consolidation of Gemstone, a $61 million increase in EBIT primarily from two Brazilian power plants that increased their generating capacity in 2003 and a $12 million reduction in Brazil's direct general and administrative costs due to personnel reductions resulting from completion of construction activities on our power plants. These EBIT increases were offset by $12 million of legal fees related to arbitration proceedings on two of our Asian equity investments in 2003.

Our other global power operations' indirect general and administrative costs decreased by $21 million compared to the same period in 2002, primarily due to support personnel reductions resulting from the sales of power plants during 2002 and 2003 and a reduction of our business development activities as we pursue the sale of our domestic power operations.

Energy Trading

In November 2002, we announced that we would exit the trading business due to the increasing and volatile cash demands inherent in that business, which were magnified by our credit downgrade. In late 2002, we began liquidating approximately 40,000 transactions in our trading portfolio, of which approximately 21,000 transactions remained as of September 30, 2003. We anticipate that we will liquidate approximately 9,000 transactions in the fourth quarter of 2003 and approximately 5,000 transactions in 2004 under existing contractual terms, resulting in an anticipated 7,000 transactions remaining as of December 31, 2004. We define a transaction as all of the settlements required by a contract within a calendar year (e.g. a contract that extends five years is counted as five transactions).

Despite our intention to liquidate our trading portfolio by the end of 2004, we may retain certain contracts because (i) they are either uneconomical to sell or terminate in the current environment due to their contractual terms or credit concerns of the counterparty, (ii) a sale would require an acceleration of cash demands, or (iii) they represent hedges associated with activities reflected in other segments of our business including our Production segment and our global power division. We have taken different strategies to liquidate or retain these transactions to achieve the most favorable economic results for us. Changes to our liquidation strategy may impact the cash flow and the financial results of the energy trading division.

Our trading portfolio is grouped into categories, as described below, that include contracts with third parties and affiliates that require physical delivery of a commodity or financial settlement. Each category may include transactions that are accounted for differently depending on whether they are derivative or non-derivative contracts. Derivative contracts are recorded on our balance sheet at their fair value with changes to the fair value recorded in our income statement. Non-derivative contracts are recorded on an accrual basis, which means the associated income or expense is recognized when the underlying commodities or services are delivered or received, and the fair value of the contracts is not carried on our balance sheet as price risk management activities.

Our natural gas contracts include long-term obligations to deliver natural gas to power plants. We currently have seven significant physical natural gas contracts with power plants. These contracts have various expiration dates ranging from 2007 to 2028, with obligations under individual contracts ranging from 30,000 MMBtu/d to 142,000 MMBtu/d. Also included in our natural gas portfolio are other contracts that we use to manage the risk associated with our long-term supply obligations. Our natural gas contracts include both derivative and non-derivative contracts.

Our power contracts include long-term obligations to provide power to our power contract restructuring affiliates. We currently have four power supply contracts related to our power contract restructuring business, with the largest of these being for approximately 1.7 MMWh per year extending through 2016. We also have other contracts that require the physical delivery of power or are used to manage the risk associated with our obligations to supply power. Substantially all of our power contracts are accounted for as derivatives. The results of our affiliated contracts are eliminated in consolidation.

We have tolling arrangements that provide us with the right to require a counterparty to convert natural gas into electricity. Under these arrangements, we supply the natural gas used in the underlying power plants and sell the electricity produced by the power plant. In exchange for this right, we pay a monthly fixed fee and a variable fee based on the quantity of electricity produced. We currently have two unaffiliated physical tolling contracts, both of which are accounted for as derivatives with the largest of these being in the Midwest having a contractual expiration date of 2019 and annual capacity charges of approximately $30 million. Changes in the fair value of these derivatives may significantly impact our gross margins on a quarterly basis and historically we have seen high volatility in the relationship between the natural gas and power prices that impact this contract. We also have other physical and financial positions that are impacted by changes in the relationship between natural gas and electricity prices.

We have long-term natural gas transportation contracts that give us the right to transport natural gas using pipeline capacity for a fixed demand charge plus variable transportation costs. Our natural gas transportation contracts have contractual expiration dates through 2028. Through September 30, 2003, we have sold transportation capacity equal to 2.5 Bcf/d of the 4.4 Bcf/d that existed at the end of 2002. Of our remaining 1.9 Bcf/d of capacity as of September 30, 2003, we are retaining 1.5 Bcf/d to meet our gas supply commitments and we are actively attempting to market 0.4 Bcf/d to third parties. In the third quarter of 2003, we incurred approximately $41 million of gross demand charges on transportation contracts and we have utilized approximately 65 percent of the available capacity through delivery to customers or release. Demand charges for transportation services are recognized on an accrual basis as they are incurred. Depending on natural gas prices at different locations, we may be able to recover some of these demand charges through the margin earned on purchasing and selling natural gas using these transportation services, but we cannot be assured that we will be able to recover all of these demand charges in the future. Our ability to utilize our transportation capacity is dependent on various factors including the difference in natural gas prices at receipt and delivery locations along the pipeline system and the amount of capital required to support credit demands from our gas suppliers.

Similar to the transportation contracts described above, we also have natural gas storage contracts that give us the ability to store natural gas in various locations. We are actively attempting to release all of our storage capacity. Through September 30, 2003, we have liquidated storage capacity equal to 105 Bcf of the 125 Bcf that existed at the end of 2002. We currently control storage capacity totaling 20 Bcf as of

September 30, 2003 with contractual terms that currently extend through 2007. We incurred $4 million of gross storage demand charges during the third quarter of 2003.

We have executed financial contracts, primarily fixed for floating swaps that effectively hedge 350 Bcf of our Production segment's anticipated natural gas sales through 2007. These derivatives do not impact the trading division's operating results since we have offsetting positions with our Production segment. However, our third party counterparties require us to provide collateral equal to the fair value of these hedges, effectively prepaying the anticipated settlement amount. The $442 million of the collateral we have posted for these positions is included in margin and other deposits on energy trading activities in our balance sheet and will be returned to us as these transactions are settled.

As we pursue the liquidation of our portfolio, the value we ultimately receive in settlement of these derivative contracts may be less than our estimates of fair value. Additionally, we have non-derivative contracts that are not recorded on our balance sheet, which, if sold, could result in an acceleration of the recognition of gains or losses on these contracts.

During 2003, our trading business continued to operate in a challenging environment with reduced liquidity, lower credit standing of participants and a general decline in the number of trading counterparties. Additionally, in the fourth quarter of 2002, we implemented new accounting rules (EITF Issue No. 02-3, *Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities*) that impacted the values of our portfolios starting in the fourth quarter of 2002. Many contracts which were accounted for as derivative contracts in 2002 are accounted for as non-derivative, accrual-based contracts in 2003. All of these factors reduce the comparability of our operating results between periods. Results of our energy trading division were as follows:

	Quarter Ended September 30,		Nine Months Ended September 30,	
Energy Trading Division Results	**2003**	**2002**	**2003**	**2002**
	(In millions)			
Gross margin	$(33)	$(160)	$(230)	$(181)
Operating expenses	(47)	(36)	(129)	(115)
Operating loss	(80)	(196)	(359)	(296)
Other income (expense)	(3)	(4)	10	9
EBIT	$(83)	$(200)	$(349)	$(287)

Third Quarter 2003 Compared to Third Quarter 2002

For the quarter ended September 30, 2003, gross margin improved by $127 million compared to the same period in 2002. We incurred a $33 million loss in gross margin in 2003, which includes a $21 million loss related to settlements of non-derivative contracts primarily related to our natural gas transportation demand charges and a $12 million loss resulting from gains or losses on early settlements of contracts and net changes in the fair value of derivative positions. For the quarter ended September 30, 2002, we incurred a $160 million loss in gross margin, which primarily resulted from a decrease in the fair value on our transportation and storage contracts, which were recorded at fair value in 2002 and on an accrual basis in 2003. This decrease in fair value in 2002 resulted from a continued decline in volatility, decreased liquidity in the marketplace and our decision to manage our portfolio to increase cash flow. These losses were partially offset by an increase of $22 million in the value of our net trading price risk management assets and receivables resulting from the improved credit of several of our counterparties in the third quarter of 2002.

Operating expenses for the quarter ended September 30, 2003, were $11 million higher than in the same period in 2002. This increase relates primarily to $10 million of restructuring costs incurred in 2003 related to the closing of our London office, which is comprised of a $6 million charge to fund the deficit of our United Kingdom pension plan upon its termination and a $4 million provision for the London office's remaining lease obligation through June 2006, net of a sublease arrangement. Also contributing to this increase was $11 million of accretion expense related to our California settlement obligation recognized in 2003 and a

$7 million increase in depreciation expense resulting from a decrease in the economic life of our fixed assets. These increases were offset by a $8 million decrease in personnel costs due to the reduction in the number of employees and $5 million of bad debt expense recorded in the third quarter of 2002 related to the Enron bankruptcy.

Nine Months Ended 2003 Compared to Nine Months Ended 2002

For the nine months ended September 30, 2003, gross margin decreased by $49 million compared to the same period in 2002. We incurred a $230 million loss in gross margin in 2003, which includes a $38 million loss on settlement of non-derivative contracts primarily related to our natural gas transportation demand charges that we were unable to recover through release or utilization, $47 million of net losses on early termination of contracts and a $145 million loss resulting primarily from a decline in the fair value of our natural gas derivative positions during 2003. This decline resulted primarily from an increase in the basis differentials of natural gas prices, primarily in the northeastern United States and decreasing trading volumes as a result of our decision to exit the trading portfolio. For the nine months ended September 30, 2002, we incurred a $181 million loss in gross margin, which primarily resulted from a decrease in the fair value on our derivative transportation and storage contracts. This decrease in fair value resulted from a continued decline in volatility, decreased liquidity in the marketplace and our decision to manage our portfolio to increase cash flow. These losses were partially offset by an increase of $22 million in the value of our net trading price risk management assets and receivables resulting from the improved credit of several of our counterparties in the third quarter of 2002.

Operating expenses for the nine months ended September 30, 2003, were $14 million higher than in the same period in 2002. This increase relates primarily to a $17 million of expenses incurred in connection with our California settlement obligation, which includes $36 million of accretion expense recognized on the obligation, $6 million of legal and other costs related to the resolution of the California lawsuit, offset by a $25 million reduction in our accrual of our obligation as a result of the finalization of a definitive agreement which changed the timing of the estimated payments. Also contributing to this increase was $10 million of restructuring costs incurred in the third quarter of 2003 related to closing of our London office, including a $6 million charge required to fund the deficit of our United Kingdom pension plan upon termination of the plan and a $4 million provision for the London office's remaining lease obligation through June 2006, net of a sublease arrangement. Also contributing to the increase was a $15 million increase in depreciation expense resulting from the acceleration of the depreciation of assets of the trading division upon the decision to exit trading thus resulting in a shorter economic life. These increases were offset by a $20 million decrease in personnel costs due to the reduction in the number of employees and $5 million of bad debt expense recorded in the third quarter of 2002 related to the Enron bankruptcy.

Other

This division includes our LNG business and the results of operations of our equity investment in a gas processing plant and our investment in several crude pipelines. Historically, our LNG business included supply agreements, terminal capacity arrangements, the development of regasification technology (the Energy Bridge project) and options to charter ships to supply LNG to domestic and international market centers. In 2003, we announced our intent to reduce our involvement in the LNG business and have incurred charges in 2003 to reduce our involvement and future exposure under our ship chartering arrangements. We are currently pursuing the sale of the supply and terminal capacity arrangements which include derivative and nonderivative contracts. In November 2003, we entered into an agreement to assign to a third party our Elba Island LNG contracts and our capacity rights at the Elba Island LNG terminal. We expect to complete this transaction in December 2003, subject to conditions precedent and customary approvals.

Results of our other division were as follows for the periods ended September 30:

Other Division Results	Quarter Ended September 30, 2003	Quarter Ended September 30, 2002	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
	(In millions)			
Gross margin	$ (4)	$24	$ (8)	$ 58
Operating expenses	(14)	(5)	(108)	(22)
Operating income (loss)	(18)	19	(116)	36
Other expense	(5)	—	(15)	—
EBIT	$(23)	$19	$(131)	$ 36

Third Quarter 2003 Compared to Third Quarter 2002

For the quarter ended September 30, 2003, we incurred a $4 million net decrease in the fair value of our derivative LNG supply contracts. For the quarter ended September 30, 2002, we had a $25 million increase in the fair value of our Snøhvit derivative LNG contract. This contract was subsequently sold in the fourth quarter of 2002.

For the quarter of 2003, operating expenses increased by $9 million compared to the same period in 2002 primarily due to a $10 million impairment of a crude oil pipeline in 2003 due to a decline in the expected reserves of a crude oil field from which the pipeline is used to transport crude oil to a common gathering point.

Other expense for the quarter ended September 30, 2003 was $5 million higher than the same period in 2002. The increase was primarily due to $4 million of bad debt expense recorded in 2003 related to disputed interest income on advances we have incurred in connection with our Elba Island terminal facility that we do not expect will be collected.

Nine Months Ended 2003 Compared to Nine Months Ended 2002

For the nine months ended September 30, 2003, we incurred a gross margin loss of $8 million attributable to net decreases in the fair value of our derivative LNG contracts. For the nine months ended September 30, 2002, we incurred a $58 million gross margin gain, which was primarily the result of a $59 million gain in 2002 to record the initial fair value of our Snøhvit LNG contract and a $25 million increase in the fair value of that contract through the end of the third quarter of 2002. The Snøhvit contract was sold in the fourth quarter of 2002. The gains in 2002 from the Snøhvit contract were offset by a $26 million net decrease in the fair value of our other LNG derivative contracts in 2002.

Operating expenses for the nine months ended September 30, 2003 were $86 million higher than the same period in 2002. The increase was primarily due to impairments and other charges we incurred in 2003 in connection with our decision to reduce our involvement in the LNG business, including the development of onshore and offshore terminaling activity. The onshore business included the development of various LNG terminals for which we had asset impairments of $9 million in 2003. The offshore business included the development of the Energy Bridge technology for which we had $25 million in asset impairments of a regasification testing facility and $44 million in ship charter cancellation costs in 2003. Also contributing to the increase was a $10 million impairment of a crude oil pipeline in 2003 due to a decline in the expected reserves of a crude oil field from which the pipeline is used to transport crude oil to a common gathering point. Offsetting these increases were lower general and administrative expenses of $8 million related to our reduced involvement in our LNG business.

Other expense for the nine months ended September 30, 2003, was $15 million higher than the same period in 2002. The increase was primarily due to a $10 million charge in 2003 associated with one of our onshore LNG terminals that, we no longer anticipate utilizing and $5 million lower equity earnings from our investment in the Javelina gas processing plant in 2003 due to an increase in feedstock costs as a result of higher natural gas prices.

Fair Value of Price Risk Management Contracts

The following table details the net estimated fair value of our derivative energy contracts (both trading and non-trading) by year of maturity and valuation methodology as of September 30, 2003. We classify as trading activities those derivative price risk management activities that we enter into with the objective of generating profits or benefiting from exposure to shifts or changes in market prices, and the effects of these contracts are included in our trading division and other division's operating results. All other derivative-related activities, including those related to power restructuring and hedging activities, are classified as non-trading price risk management activities, and the financial effects of these contracts are included in our global power division and Production segment's operations.

Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity 6 to 10 Years	Maturity Beyond 10 Years	Total Fair Value
			(In millions)			
Trading contracts						
Exchange-traded positions[1]	$(118)	$ 2	$ 46	$ 3	$ —	$ (67)
Non-exchange traded positions[2]	58	116	(69)	(96)	(20)	(11)
Total trading contracts, net	(60)	118	(23)	(93)	(20)	(78)
Non-trading contracts[3]						
Non-exchange traded positions[2]	15	161	385	703	154	1,418
Total energy contracts	$ (45)	$279	$362	$610	$134	$1,340

(1) Exchange-traded positions are traded on active exchanges such as the New York Mercantile Exchange, International Petroleum Exchange and London Clearinghouse.

(2) Non-exchange traded positions include those positions that are valued based on exchange prices, third party pricing data and valuation techniques that incorporate specific contractual terms, statistical and simulation analysis and present value concepts.

(3) Non-trading contracts include derivatives from our power contract restructuring activities of $1,957 million, and derivatives related to our natural gas and oil producing activities of $(539) million. Earnings related to our natural gas and oil producing derivative activities are included in our Production segment results.

A reconciliation of these trading and non-trading activities for the period ended September 30, 2003, is as follows:

	Trading	Non-Trading	Total Commodity Based
		(In millions)	
Fair value of contracts outstanding at December 31, 2002	$(45)	$ 459	$ 414
Fair value of contract settlements during the period	102	(9)	93
Change in fair value of contracts	(51)	(254)	(305)
Initial fair value of contracts consolidated as a result of Chaparral acquisition	—	1,222	1,222
Option premiums received, net	(84)	—	(84)
Net change in contracts outstanding during the period	(33)	959	926
Fair value of contracts outstanding at September 30, 2003	$(78)	$1,418	$1,340

During the second quarter of 2003, we acquired derivative contracts with a fair value of approximately $1.2 billion as of the acquisition date, in conjunction with our acquisition of Chaparral. The majority of the value of the derivative contracts acquired are for power purchase agreements and power supply agreements related to power restructuring activities conducted at Chaparral. The changes in the fair value of our power restructuring derivatives can be significantly impacted by changes in interest rates. See Item 3, Quantitative and Qualitative Disclosures About Market Risk, for a sensitivity analysis of the impact of a 10 percent change in interest rates on our power restructuring contracts. The fair value of contract settlements includes physical or financial settlement terminations due to counterparty bankruptcies and the sale of derivative contracts through early termination or through the sale of consolidated subsidiaries that own derivative contracts.

Corporate and Other

Corporate and other operations include general and administrative functions as well as the operations of our telecommunications and other miscellaneous businesses. For the quarter ended September 30, 2003, operating results were breakeven, compared to income of $33 million during the same period in 2002. During 2002, we recognized a $21 million gain on the early extinguishment of debt and $20 million of income from the favorable resolution of a non-operating contingent obligation in the third quarter of 2002.

Corporate and other expenses for the nine months ended September 30, 2003, were $571 million, compared to $50 million during the same period in 2002. In the second quarter of 2003, we recorded impairment charges of approximately $396 million in our telecommunications business, including a write-down of goodwill of $163 million. Also, we recognized a $37 million loss on the early retirement of our $1.2 billion bridge loan in 2003 and a $21 million gain on the early extinguishment of debt in 2002. In addition, we recorded $73 million of foreign currency losses in 2003 versus $45 million of foreign currency losses in 2002 on our Euro-denominated debt, and $20 million of income from the favorable resolution of non-operating contingent obligations in the third quarter of 2002. Partially offsetting these increases were lower business restructuring costs in the Corporate area in 2003 compared to those costs incurred in 2002.

Interest and Debt Expense

Interest and debt expense for the quarter and nine months ended September 30, 2003, was $131 million and $400 million higher than the same periods in 2002. Below is an analysis of our interest expense for the periods ended September 30:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In millions)			
Long-term debt, including current maturities	$431	$325	$1,217	$855
Revolving credit facilities	36	3	91	10
Commercial paper	—	3	—	25
Other interest	15	20	61	85
Capitalized interest	(8)	(8)	(19)	(25)
Total interest and debt expense	$474	$343	$1,350	$950

Third Quarter 2003 Compared to Third Quarter 2002

Interest expense on long-term debt for the quarter ended September 30, 2003, was $106 million higher than the same period in 2002. The increase was due to higher average debt balances. During 2003, our long-term debt increased by approximately $6.1 billion from debt issuances and acquisitions and consolidations of companies with debt, which increased our interest on long-term debt by approximately $122 million. Of this increase, $48 million related to issuances of new debt or changes in rates on existing debt, while $74 million related to debt consolidated or acquired by us. In addition, we experienced $10 million of interest due to the reclassification of $625 million of preferred securities as long-term financial obligations in the third quarter as a result of the adoption of a new accounting standard SFAS No. 150. See Note 2 for a discussion of this accounting change. Also contributing to the increase was $3 million of additional interest related to various debt issuances during 2002 that were outstanding during all of 2003. Partially offsetting these increases was the retirement of approximately $1.4 billion of long-term debt during 2002 and 2003 with an average effective interest rate of 6.90%, reducing interest expense by approximately $24 million.

Interest expense on revolving credit facilities for the quarter ended September 30, 2003, was $33 million higher than the same period in 2002 due to higher average borrowings under these facilities in December 2002 and in 2003. Our average revolving credit balances, which were based on daily ending balances, were approximately $1.5 billion, with an average interest rate of 4.64% during 2003.

Interest expense on commercial paper for the quarter ended September 30, 2003, was $3 million lower than the same period in 2002 due to the discontinuation of commercial paper activities in 2003 following our credit rating downgrades.

Other interest for the quarter ended September 30, 2003, was $5 million lower than the same period in 2002 primarily due to a $3 million decrease in interest resulting from the retirement of other financing obligations.

Nine Months Ended 2003 Compared to Nine Months Ended 2002

Interest expense on long-term debt for the nine months ended September 30, 2003, was $362 million higher than the same period in 2002. The increase was due to higher average debt balances. Long-term debt increased in 2003 by approximately $7.3 billion (including $1.2 billion of bridge loan that was paid in May 2003), which increased interest by approximately $301 million. Of this increase, $109 million related to issuances of new debt or changes in rates on existing debt, while $192 million related to debt consolidated or acquired by us. Also contributing to the increase was $125 million of additional interest related to debt issuances during 2002 that were outstanding during the first nine months of 2003 and an increase of $10 million due to the reclassification of $625 million of preferred securities as a result of the adoption of SFAS No. 150. Partially offsetting these increases was the retirement of approximately $2.0 billion of long-term debt during 2002 and 2003 with an average effective interest rate of 6.61%, decreasing interest expense by approximately $67 million.

Interest expense on revolving credit facilities for the nine months ended September 30, 2003, was $81 million higher than the same period in 2002 due to higher borrowings under these facilities in 2003. Our average revolving credit balances, which were based on daily ending balances, were approximately $1.7 billion, with an average interest rate of 3.88% during 2003.

Interest expense on commercial paper for the nine months ended September 30, 2003, was $25 million lower than the same period in 2002 due to the discontinuation of commercial paper activities in 2003.

Other interest for the nine months ended September 30, 2003, was $24 million lower than the same period in 2002. The decrease was primarily due to a $12 million reduction in affiliated interest expense on notes we had with Chaparral and Gemstone which were eliminated as a result of the consolidation of these investments in the second quarter of 2003, a $12 million decrease resulting from the retirement of other financing obligations and a $4 million decrease due to the reduction in our power and trading activities in 2003. These decreases were partially offset by a $7 million increase as a result of the write-off of unamortized financing costs due to retirement of the Trinity River financing arrangement in 2003.

Capitalized interest for the nine months ended September 30, 2003, was $6 million lower than the same period in 2002 primarily due to lower average interest rates in 2003 than in 2002.

Distributions on Preferred Interests of Consolidated Subsidiaries

Distributions on preferred interests of consolidated subsidiaries for the quarter and nine months ended September 30, 2003, were $29 million and $75 million lower than the same periods in 2002 primarily due to the redemptions or elimination in 2002 and 2003 of a number of our preferred interests in consolidated subsidiaries, including those related to the Gemstone, El Paso Oil & Gas Associates, Coastal Limited Ventures, El Paso Oil & Gas Resources, Trinity River, Clydesdale and El Paso Energy Capital Trust IV financing transactions and due to the reclassification of our Capital Trust I and Coastal Finance I mandatorily redeemable preferred securities to long-term financing obligations as a result of the adoption of SFAS No. 150. The decreases were also due to lower interest rates in 2003. Most of our preferred distributions are based on variable short-term rates, which were lower on average in 2003 than the same periods in 2002.

Income Taxes

Income taxes from continuing operations and our effective tax rates for the periods ended September 30 were as follows:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In millions, except for rates)			
Income taxes	$15	$16	$(463)	$120
Effective tax rate	(18)%	40%	47%	32%

Our effective tax rates were different than the statutory tax rate of 35 percent in 2003 primarily due to:

- state income taxes, net of federal income tax benefit;
- foreign income taxed at different rates;
- abandonment of foreign investments;
- earnings from unconsolidated affiliates where we anticipate receiving dividends; and
- minority interest preferred dividends.

Our effective tax rates were different than the statutory tax rate of 35 percent in 2002 primarily due to:

- state income taxes, net of federal income tax benefit;
- foreign income taxed at different rates; and
- earnings from unconsolidated affiliates where we anticipate receiving dividends.

During the quarters and nine months ended September 30, 2003 and 2002, we experienced a number of events that have impacted our overall effective tax rate on continuing operations. These events included the treatment of our coal and petroleum markets operations as discontinued operations (in which income taxes are apportioned between continuing and discontinued operations) and the abandonment of several foreign investments for tax purposes. These events, coupled with relatively low pretax income in continuing operations, have caused, and may continue to cause, variations in our effective tax rate.

For a further discussion of our effective tax rates, see Item 1, Note 10.

Discontinued Operations

During the nine months ended September 30, 2003, our after-tax loss from discontinued operations was $1,187 million. During this period, we recorded pre-tax charges of $1,366 million related to impairments of long-lived assets and investments triggered by our decision to sell substantially all of our petroleum markets business, approximately $929 million of which related to the impairment of our Aruba refinery and approximately $252 million of which related to the impairment of our Eagle Point refinery.

We also incurred $23 million of net losses on our refinery operations during the nine months ended September 30, 2003 which included losses from our Aruba refinery of $73 million and earnings from our Eagle Point refinery of $55 million. The Aruba refinery losses primarily related to lower throughput due to a significant turnaround maintenance activities during the third quarter of 2003. We expect our Eagle Point refinery's volumes to be lower in the fourth quarter of 2003 due to scheduled turnaround maintenance activities.

The income tax benefit related to discontinued operations for the nine months ended September 30, 2003, was $229 million resulting in an effective tax rate for discontinued operations of 16 percent. This effective rate was different than the statutory rate of 35 percent primarily due to state income taxes and foreign income taxed at different rates.

In the second quarter of 2003, we entered into a product offtake agreement with Vitol S.A. Inc., for the sale of a number of the products produced at our Aruba refinery. As a result of this contract, Vitol became the single largest customer of our Aruba refinery, purchasing approximately 75 percent of the products produced at that plant. The agreement is for one year with two one-year extensions at Vitol's option. We have the right to terminate the agreement when the refinery is sold.

Commitments and Contingencies

See Item 1, Note 18, which is incorporated herein by reference.

New Accounting Pronouncements Issued But Not Yet Adopted

See Item 1, Note 22, which is incorporated herein by reference.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

We have made statements in this document that constitute forward-looking statements, as that term is defined in the Private Securities Litigation Reform Act of 1995. Forward-looking statements include information concerning possible or assumed future results of operations. The words "believe," "expect," "estimate," "anticipate" and similar expressions will generally identify forward-looking statements. These statements may relate to information or assumptions about:

- earnings per share;
- capital and other expenditures;
- dividends;
- financing plans;
- capital structure;
- liquidity and cash flow;
- credit ratings;
- pending legal proceedings, claims and governmental proceedings, including environmental matters;
- future economic performance;
- operating income;
- management's plans; and
- goals and objectives for future operations.

Forward-looking statements are subject to risks and uncertainties. While we believe the assumptions or bases underlying the forward-looking statements are reasonable and are made in good faith, we caution that assumed facts or bases almost always vary from the actual results, and these variances can be material, depending upon the circumstances. We cannot assure you that the statements of expectation or belief contained in the forward-looking statements will result or be achieved or accomplished. Important factors that could cause actual results to differ materially from estimates or projections contained in forward-looking statements are described in our Current Report on Form 8-K dated September 23, 2003.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

This information updates, and you should read it in conjunction with, information disclosed in our Current Report on Form 8-K dated September 23, 2003, in addition to the information presented in Item 1 and 2 of this Quarterly Report on Form 10-Q.

There are no material changes in our quantitative and qualitative disclosures about market risks from those reported in our Current Report on Form 8-K dated September 23, 2003, except as presented below:

Market Risk

We are exposed to a variety of market risks in the normal course of our business activities, including commodity price, foreign exchange and interest rate risks. We measure risks on the derivative and non-derivative contracts in our trading portfolio included in continuing operations and discontinued operations on a daily basis using a Value-at-Risk model. We measure our Value-at-Risk using a historical simulation technique, and we prepare it based on a confidence level of 95 percent and a one-day holding period. This Value-at-Risk was $7 million and $11 million as of September 30, 2003 and December 31, 2002, and represents our potential one-day unfavorable impact on the fair values of our trading contracts. As we liquidate our trading portfolio, our Value-at-Risk may vary from period to period.

Interest Rate Risk

As of September 30, 2003, included in our non-trading derivatives not designated as hedges (see Item 1, Note 14), we had $1.7 billion of third party long-term power purchase and power supply contracts. These contracts are associated with our power restructuring business and are valued using estimated future market power prices and a discount rate that considers the appropriate U.S. Treasury rate plus a credit spread specific to the contract's counterparty. We make adjustments to this discount rate when we believe that market changes in the rates result in changes in value that can be realized. Since September 30, 2002, in order to provide for market risk, we have not reflected the increase in value that would result from decreases in U.S. Treasury rates because we believe the resulting increase in the value of these non-trading derivatives could not be realized in a current transaction between willing parties. Had we reflected the actual U.S. Treasury yields as of September 30, 2003 in our valuation, the value of our third party non-trading derivatives would have been higher by approximately $143 million. To the extent there is commodity price risk associated with these derivative contracts, it is included in our Value-at-Risk calculation discussed above, but our exposure to changes in interest rates and credit spreads has not been included in our Value-at-Risk calculation since these risks are managed separately from the other derivative positions included in our Value-at-Risk model. As of September 30, 2003, a ten percent increase or decrease in the discount rate used to value these positions would result in a change in the fair value of these derivative contracts of $(58) million and $62 million.

Item 4. Controls and Procedures

Evaluation of Controls and Procedures. Under the supervision and with the participation of management, including our principal executive officer and principal financial officer, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures (Disclosure Controls) and internal controls over financial reporting (Internal Controls) as of the end of the period covered by this Quarterly Report pursuant to Rules 13a-15 and 15d-15 under the Securities Exchange Act of 1934 (Exchange Act).

Definition of Disclosure Controls and Internal Controls. Disclosure Controls are our controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified under the Exchange Act. Disclosure Controls include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure. Internal Controls are procedures which are designed with the objective of providing reasonable assurance that (1) our transactions are properly authorized; (2) our assets are safeguarded against unauthorized or improper use; and (3) our transactions are properly recorded and reported, all to permit the preparation of our financial statements in conformity with generally accepted accounting principles.

Limitations on the Effectiveness of Controls. El Paso's management, including the principal executive officer and principal financial officer, does not expect that our Disclosure Controls and Internal Controls will prevent all errors and all fraud. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events. Therefore, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our Disclosure Controls and Internal Controls are designed to provide such reasonable assurances of achieving our desired control objectives, and our principal executive officer and principal financial officer have concluded that our Disclosure Controls and Internal Controls are effective in achieving that level of reasonable assurance.

No Significant Changes in Internal Controls. We have sought to determine whether there were any "significant deficiencies" or "material weaknesses" in El Paso's Internal Controls, or whether the company had identified any acts of fraud involving personnel who have a significant role in El Paso's Internal Controls. This information was important both for the controls evaluation generally and because the principal executive officer and principal financial officer are required to disclose that information to our Board's Audit Committee and our independent auditors and to report on related matters in this section of the Quarterly Report. The principal executive officer and principal financial officer note that there has not been any change in Internal Controls during the period covered by this Quarterly Report that has materially affected, or is reasonably likely to materially affect, Internal Controls.

Effectiveness of Disclosure Controls. Based on the controls evaluation, our principal executive officer and principal financial officer have concluded that the Disclosure Controls are effective to ensure that material information relating to El Paso and its consolidated subsidiaries is made known to management, including the principal executive officer and principal financial officer, on a timely basis.

Officer Certifications. The certifications from the principal executive officer and principal financial officer required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included as Exhibits to this Quarterly Report.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Note 18, which is incorporated herein by reference.

Item 2. Changes in Securities and Use of Proceeds

None

Item 3. Defaults Upon Senior Securities

None.

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

None.

Item 5. Other Information

None.

Item 6. Exhibits and Reports on Form 8-K

a. Exhibits

Each exhibit identified below is filed as a part of this report. Exhibits not incorporated by reference to a prior filing are designated by an "*"; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a "+" represent management contracts or compensatory plans or arrangements.

Exhibit Number	Description
3.A	Amended and Restated Certificate of Incorporation effective as of August 11, 2003 (Exhibit 3.A to our 2003 Second Quarter Form 10-Q).
3.B	By-Laws effective as of July 31, 2003 (Exhibit 3.B to our 2003 Second Quarter Form 10-Q).
+10.N	Key Executive Severance Protection plan, Amended and Restated effective as of August 1, 1998 (Exhibit 10.O to our 1998 Third Quarter Form 10-Q); Amendment No. 1 effective as of February 7, 2001, to the Key Executive Severance Protection Plan (Exhibit 10.K.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective November 7, 2002, to the Key Executive Severance Protection Plan and Amendment No. 3 effective as of December 6, 2002, to the Key Executive Severance Protection Plan (Exhibit 10.N.1 to our 2002 Form 10-K).
*+10.N.1	Amendment No. 4 to the Key Executive Severance Protection Plan effective September 2, 2003, to the Key Executive Severance Protection Plan.
*+10.U	Letter Agreement dated July 15, 2003, between El Paso and Douglas L. Foshee.

Exhibit Number	Description
+10.Z	Severance Pay Plan Amended and Restated effective as of October 1, 2002; Supplement No. 1 to the Severance Pay Plan effective as of January 1, 2003; and Amendment No. 1 to Supplement No. 1 effective as of March 21, 2003 (Exhibit 10.Z to our 2003 First Quarter Form 10-Q, Commission File No. 1-14365); Amendment No. 2 to Supplement No. 1 to the Severance Pay Plan effective as of June 1, 2003 (Exhibit 10.Z.1 to our 2003 Second Quarter Form 10-Q).
*+10.Z.1	Amendment No. 3 to Supplement No. 1 to the Employee Severance Pay Plan effective as of September 2, 2003.
*12.1	Computation of Ratio of Earnings to Fixed Charges for the five years ended December 31, 2002 and the nine months ended September 30, 2003.
*31.A	Certification of Chief Executive Officer pursuant to § 302 of the Sarbanes-Oxley Act of 2002.
*31.B	Certification of Chief Financial Officer pursuant to § 302 of the Sarbanes-Oxley Act of 2002.
*32.A	Certification of Chief Executive Officer pursuant to 18 U.S.C. § 1350 as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002.
*32.B	Certification of Chief Financial Officer pursuant to 18 U.S.C. § 1350 as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002.

Undertaking

We hereby undertake, pursuant to Regulation S-K, Item 601(b), paragraph (4)(iii), to furnish to the U.S. Securities and Exchange Commission, upon request, all constituent instruments defining the rights of holders of our long-term debt not filed herewith for the reason that the total amount of securities authorized under any of such instruments does not exceed 10 percent of our total consolidated assets.

b. Reports on Form 8-K

Date	Event Reported
July 9, 2003	Announced the execution of two definitive settlement agreements to resolve the principal litigation in connection with the Western Energy crisis and the taking of the final procedural step to ensure completion of these agreements.
July 14, 2003	Announced an update on the progress made under our 2003 Operational and Financial Plan.
July 16, 2003	Announced that Douglas L. Foshee was elected our President and Chief Executive officer.
July 30, 2003	Provided summarized financial information on our investment in Companias Asociadas Petroleras Sociedad Anonima (CAPSA).
September 23, 2003	Revised financial information presented in our Annual Report on Form 10-K for the year ended December 31, 2002, to segregate our petroleum markets business as a discontinued operation.

Date	Event Reported
October 3, 2003	Announced the sale of 9.9 percent stake in our general partner interest of GulfTerra Energy Partners, L.P.
October 7, 2003	Announced that the SEC had authorized an investigation into certain aspects of our periodic reports.
October 10, 2003	Announced drilling ventures with Lehman Brothers and Nabors Industries Ltd.
October 16, 2003	Announced the closing of our sale of East Coast Power, L.L.C.
October 20, 2003	Announced the sale of our 29.64 percent interest in the Portland Natural Gas Transmission System.
October 22, 2003	Filed the Computation of our Ratio of Earnings to Fixed Charges for the five years ended December 31, 2002 and for the quarters ended June 30, 2003 and 2002.

We also furnished information to the SEC on Current Reports on Form 8-K under Item 9, Regulation FD and Item 12, Results of Operation and Financial Condition. Current Reports on Form 8-K under Item 9 and Item 12 are not considered to be "filed" for purposes of Section 18 of the Securities and Exchange Act of 1934 and are not subject to the liabilities of that section, but are filed to provide full disclosure under Regulation FD.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EL PASO CORPORATION

Date: November 12, 2003

/s/ D. Dwight Scott

D. Dwight Scott
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)

Date: November 12, 2003

/s/ Jeffrey I. Beason

Jeffrey I. Beason
Senior Vice President and Controller
(Principal Accounting Officer)