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 June 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 August 11, 2003: 600,513,302

EL PASO CORPORATION

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

/d	= per day	MMBtu	= million British thermal units
Bbl	= barrels	Mcf	= thousand cubic feet
BBtu	= billion British thermal units	Mcfe	= thousand cubic feet of gas equivalents
Bcf	= billion cubic feet	MMcf	= million cubic feet
MBbls	= thousand barrels		

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 June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
Operating revenues	$ 1,679	$1,821	$ 3,604	$4,737
Operating expenses				
Cost of products and services	441	414	1,032	1,383
Operation and maintenance	493	497	1,049	1,013
Depreciation, depletion and amortization	361	334	721	684
Ceiling test charges	—	234	—	267
Loss (gain) on long-lived assets	401	(12)	423	(27)
Western Energy Settlement	123	—	123	—
Taxes, other than income taxes	71	58	149	136
	1,890	1,525	3,497	3,456
Operating income (loss)	(211)	296	107	1,281
Earnings (losses) from unconsolidated affiliates	86	133	(48)	(94)
Other income	45	59	83	96
Other expenses	(86)	(58)	(129)	(263)
Interest and debt expense	(463)	(304)	(876)	(607)
Distributions on preferred interests of consolidated subsidiaries	(16)	(43)	(37)	(83)
Income (loss) before income taxes	(645)	83	(900)	330
Income taxes	(373)	26	(478)	104
Income (loss) from continuing operations	(272)	57	(422)	226
Discontinued operations, net of income taxes	(916)	(116)	(1,138)	(56)
Cumulative effect of accounting changes, net of income taxes	—	14	(22)	168
Net income (loss)	$(1,188)	$ (45)	$(1,582)	$ 338
Basic earnings per common share				
Income (loss) from continuing operations	$ (0.45)	$ 0.11	$ (0.71)	$ 0.43
Discontinued operations, net of income taxes	(1.54)	(0.22)	(1.91)	(0.11)
Cumulative effect of accounting changes, net of income taxes	—	0.03	(0.04)	0.32
Net income (loss)	$ (1.99)	$(0.08)	$ (2.66)	$ 0.64
Diluted earnings per common share				
Income (loss) from continuing operations	$ (0.45)	$ 0.11	$ (0.71)	$ 0.43
Discontinued operations, net of income taxes	(1.54)	(0.22)	(1.91)	(0.11)
Cumulative effect of accounting changes, net of income taxes	—	0.03	(0.04)	0.32
Net income (loss)	$ (1.99)	$(0.08)	$ (2.66)	$ 0.64
Basic average common shares outstanding	596	530	595	529
Diluted average common shares outstanding	596	532	595	531
Dividends declared per common share	$ 0.04	$ 0.22	$ 0.08	$ 0.44

See accompanying notes.

EL PASO CORPORATION

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

	June 30, 2003	December 31, 2002
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,785	$ 1,591
Accounts and notes receivable		
Customers, net of allowance of $187 in 2003 and $176 in 2002	2,289	4,123
Affiliates	323	774
Other	389	451
Inventory	208	252
Assets from price risk management activities	950	1,007
Margin and other deposits on energy trading activities	924	1,003
Assets of discontinued operations	1,711	2,121
Other	839	602
Total current assets	9,418	11,924
Property, plant and equipment, at cost		
Pipelines	18,115	18,049
Natural gas and oil properties, at full cost	15,239	14,940
Power facilities	2,244	959
Gathering and processing systems	781	1,060
Other	1,033	768
	37,412	35,776
Less accumulated depreciation, depletion and amortization	14,522	14,045
Total property, plant and equipment, net	22,890	21,731
Other assets		
Investments in unconsolidated affiliates	5,096	4,891
Assets from price risk management activities	2,942	1,844
Goodwill and other intangible assets, net	1,276	1,367
Assets of discontinued operations	—	1,944
Other	2,695	2,523
	12,009	12,569
Total assets	$44,317	$46,224

See accompanying notes.

EL PASO CORPORATION

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

	June 30, 2003	December 31, 2002
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 1,713	$ 3,581
Affiliates	17	29
Other	519	742
Short-term financing obligations, including current maturities	947	2,075
Notes payable to affiliates	16	189
Liabilities from price risk management activities	971	1,041
Western Energy Settlement	609	100
Liabilities of discontinued operations	929	1,373
Accrued interest	354	324
Other	812	896
Total current liabilities	6,887	10,350
Debt		
Long-term financing obligations	22,491	16,106
Notes payable to affiliates	—	201
	22,491	16,307
Other		
Liabilities from price risk management activities	1,582	1,376
Deferred income taxes	2,966	3,576
Western Energy Settlement	436	799
Other	2,083	2,019
	7,067	7,770
Commitments and contingencies		
Securities of subsidiaries		
Preferred interests of consolidated subsidiaries	1,025	3,255
Minority interests of consolidated subsidiaries	65	165
	1,090	3,420
Stockholders' equity		
Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 605,387,708 shares in 2003 and 605,298,466 shares in 2002	1,816	1,816
Additional paid-in capital	4,429	4,444
Retained earnings	1,312	2,942
Accumulated other comprehensive loss	(532)	(529)
Treasury stock (at cost) 6,517,941 shares in 2003 and 5,730,042 shares in 2002	(221)	(201)
Unamortized compensation	(22)	(95)
Total stockholders' equity	6,782	8,377
Total liabilities and stockholders' equity	$44,317	$46,224

See accompanying notes.

EL PASO CORPORATION

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

	Six Months Ended June 30,	
	2003	2002
Cash flows from operating activities		
Net income (loss)	$(1,582)	$ 338
Less loss from discontinued operations, net of income taxes	(1,138)	(56)
Net income (loss) from continuing operations	(444)	394
Adjustments to reconcile net income (loss) to net cash from operating activities		
Depreciation, depletion and amortization	721	684
Ceiling test charges	—	267
Non-cash losses (gains) from trading and power activities	47	(527)
Loss (gain) on long-lived assets	423	(27)
Undistributed earnings of unconsolidated affiliates	76	266
Deferred income tax expense (benefit)	(507)	89
Cumulative effect of accounting changes	22	(168)
Western Energy Settlement	113	—
Other non-cash income items	355	198
Working capital changes	(85)	(397)
Non-working capital changes and other	203	(56)
Cash provided by continuing operations	924	723
Cash provided by (used in) discontinued operations	90	(196)
Net cash provided by operating activities	1,014	527
Cash flows from investing activities		
Additions to property, plant and equipment	(1,334)	(1,449)
Purchases of interests in equity investments	(24)	(108)
Cash paid for acquisitions, net of cash received	(1,078)	—
Net proceeds from the sale of assets and investments	1,270	1,365
Increase in restricted cash	(105)	(363)
Increase in notes receivable from unconsolidated affiliates	(79)	(214)
Other	25	48
Cash used in continuing operations	(1,325)	(721)
Cash provided by (used in) discontinued operations	329	(90)
Net cash used in investing activities	(996)	(811)
Cash flows from financing activities		
Net repayments under short-term debt and credit facilities	—	(558)
Payments to retire long-term debt and other financing obligations	(1,599)	(1,242)
Net proceeds from the issuance of long-term debt and other financing obligations	3,086	3,504
Dividends paid to common stockholders	(154)	(224)
Change in notes payable to unconsolidated affiliates	26	(324)
Payments to redeem preferred interests of consolidated subsidiaries	(1,177)	(54)
Issuances of common stock	—	1,022
Contributions from (distributions to) discontinued operations	419	(603)
Other	(6)	(8)
Cash provided by continuing operations	595	1,513
Cash provided by (used in) discontinued operations	(419)	296
Net cash provided by financing activities	176	1,809
Increase in cash and cash equivalents	194	1,525
Less increase in cash and cash equivalents related to discontinued operations	—	10
Increase in cash and cash equivalents from continuing operations	194	1,515
Cash and cash equivalents		
Beginning of period	1,591	1,148
End of period	$ 1,785	$ 2,663

See accompanying notes.

EL PASO CORPORATION

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
Net income (loss)	$(1,188)	$ (45)	$(1,582)	$ 338
Foreign currency translation adjustments	58	28	117	27
Unrealized net gains (losses) from cash flow hedging activity				
Unrealized mark-to-market losses arising during period (net of income taxes of $54 and $117 in 2003 and $79 and $214 in 2002)	(110)	(114)	(213)	(346)
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $27 and $59 in 2003 and $29 and $83 in 2002)	43	(74)	93	(169)
Other comprehensive loss	(9)	(160)	(3)	(488)
Comprehensive loss	$(1,197)	$(205)	$(1,585)	$(150)

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 2002 Annual Report on Form 10-K, which includes a summary of our significant accounting policies and other disclosures. The financial statements as of June 30, 2003, and for the quarters and six months ended June 30, 2003 and 2002, are unaudited. We derived the balance sheet as of December 31, 2002, from the audited balance sheet filed in our 2002 Form 10-K. 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 indicate the 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 have 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 maximizing liquidity;
- Aggressively pursue additional cost reductions in 2003 and beyond; and
- Work diligently to resolve regulatory and litigation matters.

So far in 2003, our major accomplishments regarding these five business objectives are as follows:

- Concentrating our capital investment in our core Pipelines, Production and Field Services segments such that 89 percent of total capital expenditures were made in these businesses in the first half of 2003;
- Completing or announcing sales of assets and investments of approximately $2.7 billion (see Note 4);
- Repaying approximately $4.2 billion of maturing debt and other obligations ($3.8 billion as of June 30, 2003), including:
  - Retiring long-term debt of $2.0 billion ($1.6 billion as of June 30, 2003);
  - Repaying $980 million of obligations under our Trinity River financing arrangement;
  - Redeeming $197 million of obligations under our Clydesdale financing arrangement and restructuring that transaction as a term loan that will amortize over the next two years (see Notes 3 and 17); and
  - Contributing $1 billion to the Limestone Electron Trust, which used the proceeds to repay $1 billion of its notes and purchasing the third party equity interests in our Gemstone and Chaparral power investments and consolidating those investments (see Note 3);

• Refinancing 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;

• Entering into a new $3 billion revolving credit facility that matures in June 2005 and completing financing transactions of approximately $3.6 billion ($3.2 billion as of June 30, 2003) (see Note 16);

• Identifying an estimated $445 million of cost savings and business efficiencies to be realized by the end of 2004; and

• Reaching definitive settlement agreements in June 2003, which substantially resolved our principal exposure relating to the western energy crisis and funding $347 million 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 believe the accomplishments achieved 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 our 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 2002 Form 10-K.

Significant Accounting Policies

Our accounting policies are consistent with those discussed in our 2002 Form 10-K, 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 non-current 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 June 30, 2003, reported in other non-current liabilities in our balance sheet, and the changes in the net liability for the six months ended June 30, 2003, were as follows (in millions):

Liability at January 1, 2003	$222
Liabilities settled in 2003	(43)
Accretion expense in 2003	9
Liabilities incurred in 2003	1
Changes in estimate	8
Net liability at June 30, 2003	$197

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 wells and the costs to do so. Had we adopted SFAS No. 143 as of January 1, 2002, our non-current retirement liabilities would have been approximately $200 million as of January 1, 2002, and our income from continuing operations and net income for the quarter and six months ended June 30, 2002, would have been lower by $3 million and $7 million. Basic and diluted earnings per share for the quarter and six months ended June 30, 2002, would not have been 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.

Goodwill and Other Intangible Assets

Our goodwill and other intangibles as of December 31, 2002 and June 30, 2003, and the changes in goodwill and other intangibles for the six months ended June 30, 2003 were as follows (in millions):

Balance, December 31, 2002	$1,367
Impairment of goodwill	(163)
Acquisition of intangibles	117
Other changes	(45)
Balance, June 30, 2003	$1,276

During 2003, we impaired $163 million of goodwill related to our telecommunications business in our corporate segment and acquired $117 million of intangible assets in connection with the acquisition of Chaparral in our Merchant Energy segment. Chaparral's intangible assets consisted of power purchase agreements with terms ranging from five to twenty years (see Notes 3 and 8).

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 guarantees, including financial performance and fair value guarantees, issued after December 31, 2002, at their 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 June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(In millions)			
Net income (loss), as reported	$(1,188)	$ (45)	$(1,582)	$ 338
Deduct: Total stock-based employee compensation determined under fair value based method for all awards, net of related tax effects	9	33	24	74
Pro forma net income (loss)	$(1,197)	$ (78)	$(1,606)	$ 264

	Quarter Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
Earnings (losses) per share:				
Basic, as reported	$ (1.99)	$(0.08)	$ (2.66)	$0.64
Basic, pro forma	$ (2.01)	$(0.15)	$ (2.70)	$0.50
Diluted, as reported	$ (1.99)	$(0.08)	$ (2.66)	$0.64
Diluted, pro forma	$ (2.01)	$(0.15)	$ (2.70)	$0.50

3. Acquisitions and Consolidations

Acquisitions

During the second quarter of 2003, we acquired 100 percent of the third party interests in our Chaparral and Gemstone investments, which have historically been accounted for as equity investments. With these acquisitions, we began consolidating these investments in our financial statements. Each of these acquisitions is discussed below.

Chaparral. As discussed more completely in our 2002 Form 10-K, 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 5,592 megawatts. These plants are primarily concentrated in the Northeast and Western United States. Chaparral also owns several companies that own and perform under long-term power agreements.

As of December 31, 2002, we owned 20 percent of Chaparral, and the remaining 80 percent was owned by Limestone Electron Trust. We acquired Limestone's 80 percent interest in Chaparral during 2003 in two transactions. First, in March 2003, we acquired an additional 70 percent interest in Chaparral when we purchased a $1 billion interest in Limestone. Limestone used these proceeds to retire notes that were previously guaranteed by us. Although we increased our economic interest in Chaparral with the purchase of this interest in Limestone, we did not obtain any additional voting rights in 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 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, other income (expense) by $53 million, interest expense by $67 million and distributions on preferred interests in subsidiaries by $18 million. Had we acquired Chaparral effective January 1, 2002, our revenues for the quarter and six months ended June 30, 2002, would have been higher by $48 million and $84 million, our operating income for the quarter and six months ended June 30, 2002, would have been lower by $35 million and $69 million, and our net income for the quarter and six months ended June 30, 2002, would have been lower by $28 million and $5 million. For the quarter and six months ended June 30, 2002, our basic and diluted earnings per share would have been lower by $0.06 and $0.01 per common share.

The $175 million we paid to acquire the remaining 10 percent interest in Limestone along with the remaining voting rights of Chaparral, was negotiated based, in large part, on the terms of the 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 are 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 counterparty credit ratings, the decline in our own credit ratings, adverse developments at several projects wholly or partially owned by Chaparral, our 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 (or 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 not sufficient to recover the carrying value of our 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 the total assets and liabilities of Chaparral prior to our consolidation and the elimination of intercompany transactions and reflects the allocation of our purchase price of $1,175 million, plus our initial investment of $252 million less our first quarter 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 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 when we receive the final valuation report from our consultant and have evaluated these bids. We believe this will be completed by the end of 2003.

Gemstone. As discussed more completely in our 2002 Form 10-K, 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. These plants have a total generating capacity of 1,788 megawatts. 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 out the third party investor for approximately $50 million in April 2003. The results of Gemstone's operations have been included in our consolidated financial statements beginning April 1, 2003. Had the acquisition been effective January 1, 2002, our revenues, operating income, and net income for the quarter and six months ended June 30, 2002, as well as the quarter ended March 31, 2003 would not have been significantly different, and basic and diluted earnings per share would have been unaffected.

The allocation of the fair value of $50 million to the assets acquired and liabilities assumed upon our consolidation of Gemstone in April 2003 is 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 will finalize our purchase price allocation when we receive the final valuation report from our consultant, which we anticipate will be by the end of the third quarter of 2003.

Prior to our acquisitions of Chaparral and Gemstone, we carried them as investments in unconsolidated affiliates and had other balances, including loans and notes with them. These balances were eliminated when we consolidated Chaparral and Gemstone. 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 impact of these acquisitions on our consolidated balance sheet was an increase in assets of $2.1 billion, an increase in liabilities of approximately $2.4 billion, including an increase in debt of approximately $2.2 billion, and a reduction of 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 simplifying our capital structure by eliminating several "off-balance sheet" obligations, replacing them with direct obligations, and strengthening the overall collateral package available to our financial lenders.

We amended an operating lease agreement at our Lakeside telecommunications facility to add a guarantee to 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, and therefore resulted in our controlling the lessor. As a consequence, we consolidated the lessor. The consolidation of Lakeside resulted in an increase in our property, plant and equipment of approximately $275 million and long-term debt of approximately $275 million. Additionally, upon the 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.

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, and therefore resulted in our controlling the lessor. As a result, we consolidated the lessor during the second quarter of 2003, increasing our total fixed assets by $370 million (prior to an impairment charge we recorded on these assets of $50 million) and long-term debt by $370 million. As a result of our intent to exit substantially all of our petroleum operations, these leased assets and associated debt were reclassified as discontinued operations.

We modified our Clydesdale financing arrangement to convert the third party investor's (Mustang Investors, L.L.C.) preferred ownership in one of our consolidated subsidiaries into a term loan that matures in equal quarterly installments through 2005. This change simplified our balance sheet and provided us with a fixed schedule of payments. We also acquired a $10 million preferred interest in Mustang and guaranteed all of Mustang's equity holder's obligations. As a result of this amendment, we were required to consolidate Mustang which increased our long-term debt by $743 million and decreased our preferred interests of consolidated subsidiaries by $753 million. Our $10 million preferred interest in Mustang was eliminated upon its consolidation (see Note 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 reflected below do not include any asset impairments we may have recognized at the time we decided to sell the asset or investment. See Notes 8, 11 and 21 for a discussion of impairments on long-lived assets, assets treated as discontinued operations and investments in unconsolidated affiliates.

Segment	Proceeds	Pre-tax Gain (Loss)	Significant Asset and Investment Divestitures
	(In millions)		
Completed as of June 30, 2003			
Pipelines	$ 63	$ 8	• Panhandle gathering system located in Texas • 2.1 percent equity interest in Alliance pipeline and related assets • Helium processing operations in Oklahoma • Sulfur extraction facility
Production	708	5	• Natural gas and oil properties located in western Canada, Colorado, Utah, Texas, New Mexico, Oklahoma and the Gulf of Mexico
Field Services	153	14	• Gathering systems located in Wyoming • Midstream assets in the north Louisiana and Mid-Continent regions
Merchant Energy	324	30	• 50 percent equity interest in CE Generation L.L.C. power investment (including the rights to a 50 percent interest in a geothermal development project) • Mt. Carmel power plant • Equity interest in Kladno power project • Enerplus Global Energy Management Company and its financial operations • CAPSA/CAPEX investments in Argentina
Corporate and Other	33	(11)	• Aircrafts
Continuing operations	1,281[1]	46[2]	
Discontinued operations	530	49	• 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
Total	$1,811	$ 95	

(1) Includes $11 million of net proceeds related to the working capital of the assets sold. Working capital is reflected in cash flows from operating activities rather than proceeds from asset sales.

(2) Of this gain, $16 million relates to sales of long-lived assets (included in gain or loss on long-lived assets), while $30 million relates to sales of investments (included in earnings or losses from unconsolidated affiliates).

Segment	Proceeds	Pre-tax Gain (Loss)	Significant Asset and Investment Divestitures
	(In millions)		
Announced to date[1]			
Production	$ 20	$ —	• Louisiana Minerals
Merchant Energy	486	(14)	• East Coast Power, LLC[2] • EnCap[3]
Corporate and Other	28	(1)	• Aircraft[3] • Harbortown development
Continuing operations	534	(15)	
Discontinued operations	332	10	• Petroleum asphalt operations and lease crude business[3] • Eagle Point refinery and related pipeline assets[4]
Total	$ 866	$ (5)	

(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) See Note 18 for a discussion of regulatory matters that could impact this sale.

(3) These sales were completed in July 2003.

(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*. The more significant criteria we evaluate are whether:

- Management, with the authority to approve the sale, commits to a plan to sell the asset;
- The asset is available for immediate sale in its present condition;
- An active program to locate a buyer and other actions required to complete the sale have been started; and
- The sale of the asset is probable and is expected to be completed within one year.

To the extent that all of these criteria as well as the other requirements 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 $64 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 June 30, 2003. We also had approximately $1.7 billion of assets classified as discontinued operations (see Note 11).

We continue to evaluate assets we may sell in the future. We have announced that we intend to pursue the sale of our telecommunications business and domestic power assets. These activities are in the early stages, 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 sale, 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 the 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 sales 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.

In February 2002, we sold CIG Trailblazer Gas Company, L.L.C., a company which owned pipeline expansion rights, to a third party. Our Pipelines segment recorded a gain on this sale of approximately $11 million.

In March 2002, we sold natural gas and oil properties located in east and south Texas. Net proceeds from these sales were approximately $500 million. We did not recognize a gain or loss on these sales because we apply the full cost method of accounting for our oil and natural gas operations (which requires that gains or losses on property sales are only recognized in certain circumstances).

In April 2002, we sold midstream assets for approximately $752 million to GulfTerra Energy Partners, L.P. (formerly known as El Paso Energy Partners, L.P.), a publicly traded master limited partnership of which our subsidiary serves as the general partner. 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. Because most of the assets had recently been acquired in a purchase transaction and accordingly had been recorded at fair value, no gain or loss was recognized on this sale.

In May and June 2002, we also completed sales of natural gas and oil properties, a natural gas gathering system and a natural gas plant. Net proceeds from these sales were approximately $325 million. We recognized a gain on long-lived assets of $10 million, $6 million after taxes, on the natural gas gathering system and the plant. Our 2002 net realized gains also included sales of non-full cost pool assets in our Production segment and gains and losses on other sales transactions.

5. Restructuring Charges

During 2003, we incurred restructuring charges in connection with our ongoing liquidity enhancement and cost saving efforts. For the quarter and six months ended June 30, 2003, we recognized restructuring costs totaling $31 million and $100 million. Of this amount, $31 million and $56 million related to employee severance costs from reductions in our work force. Through June 30, 2003, we have terminated approximately 1,860 full-time positions. Approximately $34 million of these severance costs had been paid as of June 30, 2003. We also recognized charges of approximately $44 million during the first quarter of 2003, 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 expenses in our income statement, and these charges impacted the results of all our business segments.

During the second quarter of 2002, we incurred $63 million of restructuring charges. In May 2002, we completed an employee restructuring across all of our operating segments which resulted in the termination of approximately 350 full-time positions. We incurred $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 settlement date. Subject to court and regulatory approvals, the settlement will include payments of cash, the issuance of common stock and the reduction in prices under two power supply contracts.

These definitive settlement agreements modified the agreement in principle reached on March 20, 2003, as discussed in our 2002 Form 10-K, and resulted in an additional obligation and a pre-tax 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. This charge was also in addition to accretion expense on the originally recorded discounted Western Energy Settlement obligation and other charges related to the settlement totaling $24 million, all of which were included as part of operation and maintenance expense during the second quarter of 2003. For the six months ended June 30, 2003, these accretion and other charges were approximately $43 million. As of June 30, 2003, $609 million of the total Western Energy Settlement obligation of $1,045 million was reflected as a current liability. The current portion includes a $213 million obligation to issue approximately 26.4 million shares of our common stock since we estimate the finalization of the settlement to occur within the next twelve months. 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 June 30, 2003, $10 million of the total obligation had been paid. 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 obligation. For a further discussion of the Western Energy Settlement, see Note 18.

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 will 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 six months ended June 30, 2003, our ceiling test charges were less than $1 million. For the six months ended June 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 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. These write-downs were based upon the daily posted natural gas and oil prices as of June 30, 2002, adjusted for oilfield or natural gas gathering hub and wellhead price differences, as appropriate. The 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, which was approximately $1.43 per MMBtu.

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 our 2002 ceiling test charges since we do not significantly hedge our international production activities.

8. (Loss) Gain on Long-Lived Assets

Our (loss) gain on long-lived assets from continuing operations 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 June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(In millions)			
Net realized gain	$ 20	$12	$ 16	$27
Asset impairments[1]	(421)	—	(439)	—
(Loss) gain on long-lived assets	$(401)	$12	$(423)	$27

[1] These amounts exclude approximately $987 million and $1.3 billion of asset impairments for the quarter and six months ended June 30, 2003, related to our petroleum operations that were reclassified as discontinued operations.

Net Realized Gain

Our 2003 net realized gains were primarily related to the sales of 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 were primarily related to the sales of pipeline 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 recoverability whenever events or changes in circumstances indicate that the carrying amount of these assets may not be fully recoverable. One triggering event 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 and second quarters of 2003. As a result of these assessments, we recognized impairment charges in our Corporate segment of approximately $396 million related to our telecommunications business. This 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. We also recognized impairments of $31 million in our Merchant Energy segment as a result of our plan to reduce our involvement in the LNG business and $14 million in our Production segment related to non-full cost assets in Canada. For additional asset impairments on our discontinued operations and investments in unconsolidated affiliates, see Note 11 and Note 21.

9. Other Expenses

Other expenses for the quarter and six months ended June 30, 2003, were $86 million and $129 million, including foreign currency losses of $33 million and $46 million resulting from the impact of foreign currency fluctuations on our Euro-denominated debt in the first and second quarters of 2003. In the second quarter of 2003, we also incurred a $37 million loss on the early extinguishment of our $1.2 billion bridge loan (see Note 16).

Other expenses for the quarter and six months ended June 30, 2002, were $58 million and $263 million, including foreign currency losses of $45 million resulting from the impact of foreign currency fluctuations on our Euro-denominated debt in the second quarter of 2002. Also included in other expenses were a $56 million impairment of our investment in the Costañera power plant, a cost-based investment in Argentina, and a $90 million steam contract termination fee paid to our Eagle Point refinery (in the petroleum division) by our Eagle Point Cogeneration facility (in our global power division of our Merchant Energy segment) in the first quarter of 2002. These amounts were eliminated in consolidation since the income associated with the petroleum division is reflected in discontinued operations while the power division's expense is included as part of our Merchant Energy's segment results. In the first quarter of 2002, other expenses also included $52 million of minority interest in our consolidated subsidiaries.

10. Income Taxes

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(In millions, except rates)			
Income taxes	$(373)	$26	$(478)	$104
Effective tax rate	58%	31%	53%	32%

For the six months ended June 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	(2)	(2)
Foreign income taxed at different rates	9	1
Abandonment of foreign investment	10	—
Earnings from unconsolidated affiliates where we anticipate receiving dividends	4	(1)
Minority interest preferred dividends	(3)	—
Other	—	(1)
Effective tax rate	53	32

11. Discontinued Operations

Petroleum Operations

In June 2003, our Board of Directors authorized the sale of substantially all of our petroleum 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 taken when they approved the sales of our Eagle Point refinery, our asphalt 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 a pre-tax charge of approximately $987 million during the second quarter of 2003 related to our petroleum and chemical assets, including a $50 million impairment charge related to the portion of the Aruba refinery we leased under an operating lease. See Note 3 for a discussion of this lease. Our second quarter charge was in addition to the $350 million pre-tax impairment charge recognized during the first quarter of 2003 when we announced our intent to sell our Eagle Point refinery and several chemical assets. These impairments were based on a comparison of the carrying value of the underlying 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 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 for the sale of a number of the products produced at our Aruba refinery. As a result of this contract, the buyer 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 the buyer'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 compared the carrying value of the underlying assets to our estimated sales proceeds, net of estimated selling costs, based on bids received in the sales process. Because this carrying value was higher than our estimated net sales proceeds, we recorded an impairment charge of $148 million in our total loss from discontinued operations in the second quarter of 2002.

Our petroleum operations and our coal mining operations, which were historically included in our Merchant Energy segment, have been reclassified as discontinued operations in our financial statements for all of the historical periods presented. We will also be required to reflect them as discontinued operations for all historical annual periods previously reported in our 2002 Form 10-K. In addition, we reclassified all of the assets and liabilities of our remaining petroleum markets business as of June 30, 2003 to other current assets and liabilities. The summarized financial results and financial position data of our discontinued operations were as follows:

	Petroleum	Coal Mining	Total
		(In millions)	
Operating Results			
Quarter Ended June 30, 2003			
Revenues	$ 1,525	$ —	$ 1,525
Costs and expenses	(1,623)	—	(1,623)
Loss on long-lived assets	(990)	—	(990)
Other expense	(21)	—	(21)
Interest and debt expense	(4)	—	(4)
Loss before income taxes	(1,113)	—	(1,113)
Income taxes	(197)	—	(197)
Loss from discontinued operations, net of income taxes	$ (916)	$ —	$ (916)
Quarter Ended June 30, 2002			
Revenues	$ 1,197	$ 101	$ 1,298
Costs and expenses	(1,261)	(68)	(1,329)
(Loss) gain on long-lived assets	2	(148)	(146)
Other income (expense)	(2)	6	4
Interest and debt expense	(10)	—	(10)
Loss before income taxes	(74)	(109)	(183)
Income taxes	(25)	(42)	(67)
Loss from discontinued operations, net of income taxes	$ (49)	$ (67)	$ (116)
Operating Results			
Six Months Ended June 30, 2003			
Revenues	$ 3,704	$ 27	$ 3,731
Costs and expenses	(3,767)	(21)	(3,788)
Loss on long-lived assets	(1,286)	(3)	(1,289)
Other income (expense)	(14)	1	(13)
Interest and debt expense	(4)	—	(4)
Income (loss) before income taxes	(1,367)	4	(1,363)
Income taxes	(226)	1	(225)
Income (loss) from discontinued operations, net of income taxes	$(1,141)	$ 3	$(1,138)

	Petroleum	Coal Mining	Total
		(In millions)	
Operating Results			
Six Months Ended June 30, 2002			
Revenues	$ 2,062	$ 168	$ 2,230
Costs and expenses	(2,099)	(164)	(2,263)
(Loss) gain on long-lived assets	2	(148)	(146)
Other income	94	6	100
Interest and debt expense	(13)	—	(13)
Income (loss) before income taxes	46	(138)	(92)
Income taxes	16	(52)	(36)
Income (loss) from discontinued operations, net of income taxes	$ 30	$ (86)	$ (56)
Financial Position Data			
June 30, 2003			
Assets of discontinued operations			
Accounts and notes receivables	$ 423	$ —	$ 423
Inventory	435	—	435
Other current assets	66	—	66
Property, plant and equipment, net	673	—	673
Other non-current assets	114	—	114
Total assets	$ 1,711	$ —	$ 1,711
Liabilities of discontinued operations			
Accounts payable	$ 394	$ —	$ 394
Other current liabilities	129	—	129
Notes payable	370	—	370
Environmental remediation reserve	36	—	36
Total liabilities	$ 929	$ —	$ 929
December 31, 2002			
Assets of discontinued operations			
Accounts and notes receivables	$1,229	$ 29	$1,258
Inventory	635	14	649
Other current assets	80	1	81
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	$1,154	$ 20	$1,174
Other current liabilities	180	5	185
Environmental remediation reserve	86	15	101
Other non-current liabilities	1	—	1
Total liabilities	$1,421	$ 40	$1,461

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 on 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 one 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 June 30:

	2003		2002	
	Basic	Diluted	Basic	Diluted
	(In millions, except per common share amounts)			
Quarter Ended June 30,				
Income (loss) from continuing operations	$ (272)	$ (272)	$ 57	$ 57
Discontinued operations, net of income taxes	(916)	(916)	(116)	(116)
Cumulative effect of accounting changes, net of income taxes	—	—	14	14
Adjusted net loss	$(1,188)	$(1,188)	$ (45)	$ (45)
Average common shares outstanding	596	596	530	530
Effect of dilutive securities				
Stock options				1
FELINE PRIDES[SM]				1
Average common shares outstanding	596	596	530	532
Earnings per common share				
Income (loss) from continuing operations	$ (0.45)	$ (0.45)	$ 0.11	$ 0.11
Discontinued operations, net of income taxes	(1.54)	(1.54)	(0.22)	(0.22)
Cumulative effect of accounting changes, net of income taxes	—	—	0.03	0.03
Adjusted net loss	$ (1.99)	$ (1.99)	$(0.08)	$(0.08)
Six Months Ended June 30,				
Income (loss) from continuing operations	$ (422)	$ (422)	$ 226	$ 226
Discontinued operations, net of income taxes	(1,138)	(1,138)	(56)	(56)
Cumulative effect of accounting changes, net of income taxes	(22)	(22)	168	168
Adjusted net income (loss)	$(1,582)	$(1,582)	$ 338	$ 338

	2003		2002	
	Basic	Diluted	Basic	Diluted
	(In millions, except per common share amounts)			
Average common shares outstanding	595	595	529	529
Effect of dilutive securities				
Stock options				1
FELINE PRIDES℠				1
Average common shares outstanding	595	595	529	531
Earnings per common share				
Income (loss) from continuing operations	$ (0.71)	$ (0.71)	$ 0.43	$ 0.43
Discontinued operations, net of income taxes	(1.91)	(1.91)	(0.11)	(0.11)
Cumulative effect of accounting changes, net of income taxes	(0.04)	(0.04)	0.32	0.32
Adjusted net income (loss)	$ (2.66)	$ (2.66)	$ 0.64	$ 0.64

For the quarter and six months ended June 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 six months ended June 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 June 30, 2003 and December 31, 2002:

	June 30, 2003	December 31, 2002
	(In millions)	
Net assets (liabilities)		
Energy contracts		
Trading contracts[(1)(2)]	$ (159)	$ (47)
Non-trading contracts[(2)]		
Derivatives designated as hedges	(747)	(500)
Other derivatives	2,189	959
Total energy contracts	1,283	412
Interest rate and foreign currency contracts	56	22
Net assets from price risk management activities[(3)]	$1,339	$ 434

(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 activities are $219 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 June 30, 2003, other derivatives include $2,199 million of derivative contracts primarily related to power restructuring activities, $1,239 million of which relates to contracts we acquired in connection with our acquisition of Chaparral in the second quarter of 2003 and $960 million 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 2002 Form 10-K. Because of the significant increase in our power contract restructuring positions as a result of our acquisition of Chaparral, our exposure has increased related to changes in the discount rates. These rates are used in the determination of the fair values of these positions. For a discussion of these interest rate risks, see Item 3, Quantitative and Qualitative Disclosures About Market Risk. The remaining balances in other derivatives, unrealized losses of $10 million and $9 million as of June 30, 2003 and December 31, 2002, 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.

15. Inventory

	June 30, 2003	December 31, 2002
	(In millions)	
Current		
Materials and supplies and other	$169	$174
Natural gas liquids and natural gas in storage	39	78
Total current inventory[1]	208	252
Non-current		
Dark fiber	5	5
Turbines	219	222
Total non-current inventory[2]	224	227
Total inventory	$432	$479

[1] As a result of our intent to dispose of our petroleum and chemical assets, inventory balances totaling $435 million and $635 million as of June 30, 2003 and December 31, 2002, have been reclassified as assets of discontinued operations (see Note 11).

[2] We recorded these amounts as other non-current assets in our balance sheet.

16. Debt and Other Credit Facilities

	June 30, 2003	December 31, 2002
	(In millions)	
Short-term financing obligations, including current maturities	$ 947	$ 2,075
Notes payable to affiliates	16	390
Long-term financing obligations	22,491	16,106
Total debt obligations	$23,454	$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 six 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, December 31, 2002	$18,571
Acquisitions and consolidations:	
Clydesdale restructuring	743
Gemstone acquisition	1,013
Chaparral acquisition	1,565[2]
Bank refinancings:	
Lakeside lease	275
Aruba lease[1]	—
Principal amounts borrowed[3]	3,695
Repayments of principal[3]	(2,108)
Elimination of affiliate obligations	(326)
Other	26
Total debt obligations, June 30, 2003	$23,454

(1) Included in liabilities of discontinued operations.

(2) This debt is project-related debt that is non-recourse to us.

(3) Includes $500 million of borrowings and 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 $3.7 billion of principal borrowings, specifically the $1.2 billion two-year term loan issued in March 2003.

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:

	June 30, 2003	December 31, 2002
	(In millions)	
Current maturities of long-term debt and other financing obligations	$ 947	$ 575
Short-term credit facilities	—	1,500
	$ 947	$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. This facility replaces our previous $3 billion 364-day revolving credit facility. In addition, approximately $1 billion of other financing arrangements (including the leases discussed in Notes 3 and 11, letters of credit and other facilities) were amended to conform our obligations to the new $3 billion revolving credit facility. Our $3 billion revolving credit facility and these 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 common and Series C units in GulfTerra. This 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. EPNG and TGP remain jointly and severally liable for any amounts outstanding under the new $3 billion revolving credit facility through August 19, 2003. Except for the following conditions, after that date EPNG and TGP will be liable only for the amounts they borrow under the $3 billion revolving credit facility. If, on August 19, 2003, (1) an event of default is continuing with respect to the $3 billion revolving credit facility or (2) we, or any of the subsidiary guarantors under the facility or any of the restricted subsidiaries (each as defined in the $3 billion revolving credit facility) are subject to a bankruptcy or similar proceeding, then EPNG and TGP will continue to be jointly and severally liable for any amounts outstanding under the $3 billion revolving credit facility until none of the events described in (1) or (2) above exists. As of August 11, 2003, none of these conditions existed. Once EPNG's and TGP's joint and several liabilities expire on August 19, 2003, there are no circumstances in which EPNG and TGP could again become liable under our $3 billion facility except for amounts borrowed by them under the $3 billion revolving credit facility.

The $3 billion revolving credit facility has a borrowing cost of LIBOR plus 350 basis points and letter of credit fees of 350 basis points. As of June 30, 2003, we had $1.5 billion outstanding and $1.1 billion of letters of credit issued under the $3 billion revolving credit facility. The amounts borrowed were classified as non-current in our balance sheet as of June 30, 2003.

We also maintained a $1 billion revolving credit facility, which expired on August 4, 2003. EPNG and TGP were also borrowers under this facility. As of June 30, 2003, no amounts were outstanding, and $132 million of letters of credit were issued. The $132 million of letters of credit expired or were reissued under the $3 billion revolving credit facility prior to August 4, 2003.

The availability of borrowings under our credit facilities and 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[2]	Senior notes	7.75%	1,200	1,169	2013
June	El Paso	Notes	Various	95	95	2008
	Issuances through June 30, 2003			3,195	3,086	
July	EPNG	Senior notes	7.625%	355	347	2010
				$3,550	$3,433	
Acquisitions and Consolidations						
April	Lakeside	Term loan	LIBOR + 3.5%	$ 275	$ 275	2006
April	Gemstone	Notes	7.71%	1,025	1,013	2004
April	Mustang Investor	Term loan	Various	743	743	2005
May	Chaparral[3]	Notes and loans	Various	1,671	1,565	Various
				$3,714	$3,596	

(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) Net proceeds from the May 2003 issuance were used to repay the $1.2 billion LIBOR based two-year term loan. The proceeds from the two-year term loan were used to repay our Trinity River financing.

(3) This debt is project-related debt that is non-recourse to us.

Date	Company	Type	Interest Rate	Principal	Net Payments
				(In millions)	
Retirements					
January-June	Various	Long-term debt	Various	$ 68	68
February	El Paso CGP	Long-term debt	4.49%	240	240
May	El Paso	Term loan	Variable	100	100
May	El Paso[(1)]	Two-year term loan	LIBOR + 4.25%	1,200	1,191
	Retirements through June 30, 2003			1,608	1,599
July	El Paso CGP	Note	Floating rate	200	200
August	El Paso CGP	Senior debentures	9.75%	102	102
August	El Paso	Term loan	Variable	100	100
				$2,010	$2,001

(1) Net proceeds from the May 2003 issuance were used to repay the $1.2 billion LIBOR based two-year term loan. The proceeds from the two-year term loan were used to repay our Trinity River financing.

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, 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 June 30, 2003, we were in compliance with these covenants.

17. Preferred Interests of Consolidated Subsidiaries

As further described below, we restructured our Trinity River and Clydesdale financing arrangements as well as eliminated the preferred interests in our subsidiaries held by Gemstone during 2003. A summary of our actions is as follows (in millions):

December 31, 2002	$3,255
Redemption of Trinity River	(980)
Refinancing and redemptions of Clydesdale	(950)
Elimination of Gemstone minority interest	(300)
June 30, 2003	$1,025

For a further discussion of our debt and credit facilities see Note 16.

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 the first quarter of 2003, we retired approximately $189 million of the third-party member interests in Clydesdale and an additional $8 million in April 2003. Also, 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. The new term loan amortizes in equal quarterly amounts of $100 million over the next two years. 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 the 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. As of June 30, 2003, the balance owed to third parties under the Clydesdale financing arrangement was $643 million. In August 2003, we made a quarterly principal payment of $100 million on this term loan.

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 100 percent 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).

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; 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 on June 4, 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 million 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 Federal Energy Regulatory Commission (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 was filed with the United States District Court for the Central District of California. This Stipulated Judgment provides 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 Master Settlement Agreement, 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 will 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 Public Utilities Commission of the State of California, PG&E, Southern California Edison Company, and the City of Los Angeles filed the structural settlement described above with the FERC in resolution of certain specific proceedings before that agency. The structural settlement was protested by EPNG's East of California shippers and certain 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 late 2003 or 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 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) attorney's fees. All fifteen cases have been consolidated before a single judge, under two omnibus complaints, one of which has been set for trial in September 2003. All of the class action and municipal lawsuits and all but one of the individual lawsuits will be resolved upon finalization and 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 plaintiff's 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 TGP, 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 finalization and 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 finalization and 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. These cases have been removed to federal court. 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 arises out of a gas supply contract between IMC Chemicals (IMCC) and EPME and seeks to void the Gas Purchase Agreement between IMCC and EPME for gas purchases until December 2003. IMCC contends 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 repeats the allegations and claims of the California lawsuits described above. EPME intends to enforce the terms of the contract and counterclaim for contract damages. A Motion to Stay the Proceedings Pending Arbitration was granted, and the parties are presently preparing for arbitration. Our costs and legal exposure are not currently determinable.

Other Energy Market Lawsuits. 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 finalization and approval of the Western Energy Settlement.

A purported class action suit 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.

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 factual allegations similar to those alleged in the California cases, the suit seeks relief similar to the California cases as well, 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. In the now-amended complaint, the lawsuit 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 suit 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 states in the West Coast Energy Market. 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-judgement 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 suits alleging violations of federal securities laws have been filed against us and several of our former officers. Eleven of these suits are now consolidated in federal court in Houston before a single judge. The suits generally challenge the accuracy or completeness of press releases and other public statements made during 2001 and 2002. The twelfth shareholder class action lawsuit was filed in federal court in New York City in October 2002 challenging the accuracy or completeness of our February 27, 2002 prospectus for an equity offering that was completed on June 21, 2002. It has since been dismissed, in light of similar claims being asserted in the consolidated suits in Houston. Four shareholder derivative actions have also been filed. One shareholder derivative lawsuit was filed in federal court in Houston in August 2002. This derivative action generally alleges the same claims as those made in the shareholder class action, has been consolidated with the shareholder class actions pending in Houston and has been stayed. A second shareholder derivative lawsuit was 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. A third shareholder derivative suit was filed in state court in Houston in March 2002, and a fourth shareholder derivative suit was filed in state court in Houston in November 2002. The third and fourth shareholder derivative suits both generally allege that manipulation of California gas supply and gas prices exposed El Paso 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.

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.

On February 11, 2003, the National Transportation Safety Board (NTSB) conducted a public hearing on its investigation into the Carlsbad rupture at which the NTSB adopted Findings, Conclusions and Recommendations based upon its investigation. In April 2003, the NTSB published its final report. 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 the grand jury.

A number of personal injury and wrongful death lawsuits were filed against EPNG in connection with the rupture. All of these suits 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 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 a 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 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 about 23 firemen and EMS personnel who responded to the fire and who allegedly have suffered psychological trauma. 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, attorney's 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 one such lawsuit in New York. The plaintiffs seek remediation of their groundwater and prevention of future contamination, compensatory damages for the costs of replacement water and for diminished property values, as well as punitive damages, attorney's fees, court costs, and, in some cases, future medical monitoring. Our costs and legal exposure related to this lawsuit 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 June 30, 2003, we had approximately $1,151 million accrued for all outstanding legal matters. Approximately $5 million of the accrual was related to discontinued petroleum 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 June 30, 2003, we had accrued approximately $431 million, including approximately $416 million for expected remediation costs at current and former operated sites and associated onsite, offsite and groundwater technical studies, and approximately $15 million for related environmental legal costs, which we anticipate incurring through 2027. Approximately $45 million of the accrual was related to the discontinued petroleum operations.

The high end of our reserve estimates was approximately $612 million and the low end was approximately $412 million. The estimate of $412 million represents a combination of two estimating methodologies. First, where the most likely outcome can be reasonably estimated, that cost has been accrued ($97 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($315 million to $515 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.

Sites	June 30, 2003 Low	June 30, 2003 High
	(In millions)	
Operating	$179	$254
Non-operating	203	316
Superfund	30	42

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

Balance as of January 1, 2003	$498
Additions/adjustments for remediation activities	(40)
Payments for remediation activities	(31)
Other changes, net	4
Balance as of June 30, 2003	$431

In addition, we expect to make capital expenditures for environmental matters of approximately $296 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 $43 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 the Pennsylvania and New York stations. In May 2003, TGP 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 TGP's 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 the costs to complete this project. Accruals for these issues are included in the previously indicated estimates for operating sites.

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. Accruals for these issues are included in the previously indicated estimates for operating sites.

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 costs under the PCB remediation project, 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 June 30, 2003, TGP has pre-collected PCB costs by approximately $117 million. The pre-collection 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 pre-collected, to refund to its customers the unused pre-collection amount, plus carrying charges incurred up to the date of the refunds. As of June 30, 2003, TGP has recorded a regulatory liability (included in other non-current liabilities on its balance sheet) of $83 million for future refund obligations. The obligation increased by $25 million in the second quarter due to the reduction of TGP's accrual of estimated future environmental remediation and legal costs.

Coastal Eagle Point. From May 1999 to March 2001, 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 (DEP). All of the assessments are related to alleged noncompliance with the New Jersey Air Pollution Control Act (The Act) pertaining to excess emissions from the first quarter 1998 through the fourth quarter 2000 reported by our Eagle Point refinery in Westville, New Jersey. The DEP has assessed penalties totaling approximately $1.3 million for these alleged violations. The DEP has indicated a willingness to accept a reduced penalty and a supplemental environmental project. Our Eagle Point refinery has been granted an administrative hearing on issues raised by the assessments. Subsequently, DEP assessed an additional $118,000 in penalties for alleged non-compliance with the act. On February 24, 2003, EPA Region 2 issued a Compliance Order based on a 1999 EPA inspection of the refinery's leak detection and repair (LDAR) program. Alleged violations include failure to monitor all components, and failure to timely repair leaking components. During an August 2000 follow-up inspection, the EPA confirmed our Eagle Point refinery had improved its implementation of the program. The Compliance Order requires documentation of compliance with the program. We met with the EPA and DEP in March 2003 to discuss the Order and the possibility for a global settlement pursuant to the EPA's refinery enforcement initiative. Global settlements involving other refiners have included civil penalties and addressed LDAR as well as new source review, the benzene standard, and the standard for combustion of refinery fuel gas. On April 25, 2003, our Eagle Point refinery sent a letter to the EPA committing to global settlement discussions, which are ongoing. Our Eagle Point refinery expects to resolve both the DEP assessments and the EPA refinery initiative issues.

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 63 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 June 30, 2003, we have estimated our share of the remediation costs at these sites to be between $30 million and $42 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 operating 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 matter, 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 counsel on May 27, 2003. The complaint was voluntarily withdrawn from the FERC. The CPUC/CEOB matter will be fully resolved upon finalization of the Western Energy Settlement. NPSP has petitioned for review of the FERC decision.

CPUC Complaint Proceeding. In April 2000, the California Public Utilities Commission 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 finalization and approval 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 it 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 to them by not expanding its system, at its cost, to meet their increased requirements.

On May 31, 2002, the FERC issued an order on the complaints in which it required that (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 their existing systemwide 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 existing CD customers to turn back capacity for acquisition by FR customers in which process EPNG would remain revenue neutral. These changes were to be made effective November 1, 2002. The order also stated that the FERC expected EPNG to file for certificate authority to add compression to 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 that it was willing to do. In July 2002, EPNG and other parties filed for clarification and/or rehearing of the May 31 order.

On September 20, 2002, the FERC issued an order postponing the effective date of the FR conversions until May 1, 2003 and requiring EPNG to allocate among FR customers (i) the 320 MMcf/d of capacity that will be available from the addition of compression to Line 2000, and (ii) any firm capacity under existing contracts that expired between May 31, 2002, and May 1, 2003. In total, EPNG's FR customers will pay only their current aggregate reservation charges for existing unsubscribed capacity, for the 230 MMcf/d of capacity made available in November 2002 by EPNG's Line 2000 project, for the 320 MMcf/d of capacity from the addition of compression to Line 2000, and for all capacity subject to contracts expiring before May 1, 2003. On April 14, 2003, the FERC issued an order resetting the implementation date to September 1, 2003.

In October 2002, EPNG filed tariff sheets in compliance with the September 20 order to implement a partial demand charge credit for the period November 1, 2002 to May 6, 2003, and to allow California delivery points to be used as secondary receipt points to the extent of its backhaul displacement capabilities. EPNG proposed both a reservation and a usage charge for this service. On December 26, 2002, the FERC issued an order (i) denying EPNG's request to charge existing CD customers a reservation rate for California receipt service for the remaining term of the settlement, *i.e.,* through December 31, 2005; (ii) allowing EPNG to charge its maximum IT rate for the service; (iii) approving EPNG's proposed usage rate for the service until its next rate case; and (iv) requiring it to make a showing that capacity is available for any new shippers utilizing this service.

On July 9, 2003, the FERC issued a rehearing order in the proceeding. The order denied rehearing of FERC's previous determination that FR contracts must be converted to CD contracts. The order also declined to postpone the September 1, 2003 implementation date for the conversion of the FR contracts and for the replacement of systemwide firm receipt rights with firm rights at specific receipt locations. In ruling on these issues, the FERC found that EPNG had not violated its certificates, its contractual obligations, including its obligations under the 1996 Settlement, or its tariff provisions as a result of the capacity allocations that have occurred on the system since the 1996 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 EPNG has allocated that capacity consistent with the requirements of the previous orders in the proceeding. On a prospective basis, the FERC ordered EPNG to remove the pro rata allocation provisions from its tariff, 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 and maintenance, EPNG will limit the amount of our reservation charge credits to the return and associated tax portion of its rates. The rehearing order also lifted the ban 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 two appeals of the July 9 order with the United States Court of Appeals for the D.C. Circuit (*Arizona Corp. Comm'n, et al. v. FERC,* Nos. 03-1206, *et al,*) and subsequently moved the Court for a stay of the September 1, 2003 conversion date. EPNG has intervened in the proceedings and will oppose the petitions. The Court denied the stay motion on August 6, 2003. The final outcome of these appeals cannot be predicted with certainty.

On August 8, 2003, a number of parties sought further clarification and/or rehearing of the FERC's July 2003 rehearing order. EPNG sought clarification of a companion order that addressed tariff sheets implementing the conversions. We cannot predict the final outcome of FERC's actions on those filings.

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 June 30, 2003, EPNG had unearned risk sharing revenues of approximately $16 million and had $6 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

$19 million. 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 May 31 and September 20 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.

Marketing Affiliate NOPR. In September 2001, the FERC issued a Notice of Proposed Rulemaking (NOPR). The NOPR proposes 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 modifications to its negotiated rate policy applicable to interstate natural gas pipelines. The new policy has two primary changes. First, the FERC will no longer permit the pricing of negotiated rates based on natural gas commodity price indices, although it will permit current contracts negotiated on that basis to continue until the end of the applicable contract period. Second, the FERC is imposing new filing requirements on pipelines to ensure the transparency of negotiated rate transactions.

Interim Rule on Cash Management. In August 2002, the FERC issued a NOPR proposing, *inter alia,* that all cash management or money pool arrangements between a FERC-regulated subsidiary and its non-FERC regulated parent be in writing and that, as a condition of participating in such an arrangement, the FERC-regulated entity maintain a minimum proprietary capital balance of 30 percent and both it and its parent maintain investment grade credit ratings. After receiving written comments and hearing industry participants' concerns at a public conference in September 2002, the FERC issued an Interim Rule on Cash Management on June 26, 2003, which did not adopt the proposed limitations on entry into or participating in cash management programs. Instead, the Interim Rule requires natural gas companies to maintain up-to-date documentation authorizing the establishment of the cash management program in which they participate and supporting all deposits into, borrowings and interest from, and interest expense paid to such program.

The Interim Rule also seeks comments on a proposed reporting requirement that a FERC-regulated entity file cash management agreements and any changes thereto within ten days and that it notify the Commission within five days when its proprietary capital ratio falls below 30 percent (i.e., its long-term debt-to-equity ratio rises above 70 percent) and when it subsequently returns to or exceeds 30 percent. We filed comments on the Interim Rule on August 7, 2003.

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. At this time, we cannot predict the outcome of this rulemaking.

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 SNG's and ANR's issuance of the notes and if the notes will be included in the two regulated companies' 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 OMOI further explaining a March 26, 2003 data response in this proceedings 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 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 Commodities Futures Trading Commission (CFTC), and to the U.S. Attorney in response to their requests. The information provided indicates inaccurate prices were reported to the trade publications. EPME has no evidence that the reporting to the publications resulted in any unrepresentative price index. 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 certain 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) 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. 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. Our initial review indicates that the alleged partnership is a "parking" transaction with Public Service Company of New Mexico (PNM) which EPME entered into for legitimate business purposes and will so advise the FERC when it responds to the OSC.

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 June 30, 2003, our remaining investment in EPIC was approximately $52 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. We currently anticipate a determination from the PUC of Texas on the administrative law judge's recommendation by the end of the third quarter of 2003. The PUC issued a draft order for comment in June. The draft order, if issued, would largely uphold 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. Despite the favorable ruling from the administrative law judge, the PUC retains the right to affirm or reject the award and any significant rejection of the award would negatively impact our metro transport business. An adverse resolution to the proceeding by the PUC would have a negative impact on our ongoing operations and prospects in this business.

FCC Triennial Review. In this proceeding, the FCC, pursuant to its Congressional mandate, is reexamining the entire list of Unbundled Network Elements (UNEs), including high capacity loops and transport and dark fiber, to determine if any should be removed or qualified. It is possible that the FCC may either eliminate or set more stringent offering guidelines for some of the existing UNE's. Although El Paso Global Networks (EPGN), formerly known as El Paso Communications Company, has no reason to assume that dark fiber or high capacity loops or transport may be eliminated, any ruling that seriously impairs its ability to access these UNEs would significantly affect its current business model. Further, the FCC has indicated that certain packet/switching technologies/services will not be unbundled. Such a holding, if so ordered, would increase rates on such routes. EPGN has filed comments and an order is expected before the end of the third quarter 2003. It is expected that most of the order will be 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", thereby exempting them from having to lease their lines to EPGN. We have opposed such a holding, which we believe would be unlawful. A decision is expected by the end of 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 also possible that these matters could impact our debt rating and credit rating. Further, for environmental matters, 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 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 on our cash flows in the period the event occurs.

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 NGL and the trading of physical natural gas, power, petroleum and financial derivatives.

Our Merchant Energy positions are 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 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 Coastal States Trading, Inc. (CSTI) owes it approximately $3 million related to certain terminated petroleum contracts. CSTI disputes this assertion. After considering the cash margins Enron has deposited with us as well as the reserves we have established, our overall Merchant Energy exposure to Enron is $29 million, which is classified as current accounts and notes receivable. We believe this amount is reasonable 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 consistent with the projected distributions reflected in the disclosure statements recently filed by Enron in its bankruptcy proceedings. As it currently stands, Enron's Plan of Reorganization, coupled with the partial claims sale, would result in Merchant Energy's receipt of approximately $30 million, assuming all of the filed claims are allowed and the proceeding described immediately below is resolved in our favor.

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 now made demand on us for 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. The first joint session with the mediator is currently anticipated to be in the fourth quarter of 2003. If the court adopts Enron's methodology, it could also result in a reduction of Merchant Energy's claims against Enron Capital and Trade Resources Limited described above.

In early May 2003, Enron Broadband Services, Inc. filed a notice of rejection with respect to an IRU agreement granting El Paso Networks, L.L.C. the right to use certain dark fiber in the Denver area. El Paso Networks is currently evaluating what actions it may want to take in response to the notice of rejection.

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. The September 20, 2002 order in the EPNG capacity allocation proceeding discussed in *Rates and Regulatory Matters* above prohibited EPNG from remarketing Enron capacity that was not remarketed prior to May 31, 2002. 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 EPME's 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 claims based on damages calculated under the various trading agreements with NRG. Xcel Energy, Inc. 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. EPME has entered into settlement negotiations with NRG, and subject to court approval, has agreed to settle the claim for approximately $13 million.

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 USGen's 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 15, 2003. EPME immediately terminated its Master Netting Agreement with Mirant Americas Energy Marketing, L.P. We are in the process of evaluating amounts owed to Mirant in accordance with the termination provisions of our Master Netting Agreement. Although we have not finalized these amounts, we believe the liability we have accrued will be sufficient to provide for our 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 do 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. Except as set forth above, we do not believe we have a material exposure as a result of the 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 interests in Camden and Bayonne and 79.2 percent of the indirect equity interests in Linden and Enron indirectly owns 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. We intervened in the proceeding before the FERC to protect our interests. While we do not believe resolution of this proceeding is a condition to closing, it is possible that this proceeding will delay the closing of our announced sale of our interests in East Coast Power. The schedule for the proceeding calls for hearings in November 2003 and a decision from the presiding Administrative Law Judge in February 2004. The decision of the Administrative Law Judge could then be appealed to the full Commission. We are engaged in discussions with the FERC trial staff and the other parties to the proceeding in an effort to resolve this matter without the need for a hearing.

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. The arbitration is scheduled for the fourth quarter of 2003. We have entered into settlement discussions with Broadwing to attempt to resolve this dispute. In the fourth quarter of 2002, we wrote down the value of this long-haul route by $104 million, leaving a total 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 Brazil's foreign debt and the presidential elections which were completed in late November 2002. These concerns have contributed to significantly higher interest rates on local debt for the government and private sectors, have significantly decreased the availability of funds from lenders outside of Brazil and have decreased the amount of foreign investment in the country. These factors have contributed to a downgrade of Brazil's foreign currency debt rating and a 24 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; however, the release of the majority of the money will depend on Brazil meeting specified fiscal targets set by the IMF in 2003. In addition, Brazil's President or other government representatives may impose or attempt to impose changes affecting 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. 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 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 recent 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 will 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. If we do not prevail in that 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 $178 million at June 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 $106 million at June 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 $110 million at June 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). Manaus Energia is an indirect wholly owned subsidiary of Centrais Electricas Brasileiras S. (Eletrobras), a Brazilian federal utility holding company. As of June 30, 2003 our total accounts receivable on these projects is $24 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 a 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 June 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. (Electronorte), 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 Porto Velho Project. The second PPA has a term of twenty years and relates to the second 345-megawatt phase of the Porto Velho Project (the Phase 2 PPA). We have recently 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 could occur. 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. Our investment in the Porto Velho project was $281 million at June 30, 2003, including guarantees we have 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 77 percent versus the U.S. dollar since January 2003 (through June 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 is expected to receive final approval of the IMF Board in August. The Dominican government maintains that the accord, which should hopefully lead to some $1.2 billion in disbursements from multilaterals over the next 24 months, will serve to restore consumer and investor confidence, stabilize the exchange rate and pave the way to economic recovery. The initial disbursement of the funds is not anticipated until early September of 2003.

We have investments in power projects in the Dominican Republic with an aggregate exposure, including financial guarantees, of approximately $104 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 $57 million at June 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. The lenders have not yet exercised this remedy. As a result of the default under the construction lending agreement, we evaluated our investment and recorded an impairment charge of $17 million while Chaparral recorded an impairment charge of $44 million in the fourth quarter of 2002. 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. We are in the process of finalizing negotiations with the lenders to settle these issues.

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 is negotiating with the contractor with respect to its failure to deliver the project in accordance with guaranteed specifications. 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 June 30, 2003, we had an investment in Berkshire of $7 million, receivables from Berkshire of $20 million and derivative contracts with Berkshire of $10 million associated with a subordinated fuel agreement and a fuel management agreement. Berkshire continues to discuss settlement opportunities with its construction contractor. 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 Corporation. 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 liquefied natural gas (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. The outcome of this litigation is not currently determinable. However, CTC subsequently invoiced Duke for cover damages arising from the terminated contract. On July 31, 2003, the federal court remanded this case back to state court. CTC plans to file its amended petition for monetary damages on August 19, 2003. 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; *State of Arizona v El Paso Corporation, El Paso Natural Gas Company, El Paso Merchant 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

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

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. *John Gebhart v. 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 William Wise,* filed March 2002; *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, Joe Wyatt and William Wise* 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 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*.

19. Capital Stock

On August 1, 2003, we declared a quarterly dividend of $0.04 per share on our common stock payable on October 6, 2003, to stockholders of record on September 5, 2003. During the quarter and six months ended June 30, 2003, we paid dividends of $24 million and $154 million to common stockholders. In addition, El Paso Tennessee Pipeline Co., our subsidiary, paid dividends of approximately $6 million and $12 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. 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. Our business operations consist of both consolidated businesses as well as substantial investments in unconsolidated affiliates. As a result, 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. This measurement may not be comparable to measurements 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 June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(In millions)			
Total EBIT	$(166)	$ 430	$ 13	$1,020
Interest and debt expense	(463)	(304)	(876)	(607)
Distributions on preferred interests of consolidated subsidiaries	(16)	(43)	(37)	(83)
Income taxes	373	(26)	478	(104)
Income (loss) from continuing operations	$(272)	$ 57	$(422)	$ 226

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

	Quarter Ended June 30,					
	Pipelines	Production	Field Services	Merchant Energy	Corporate & Other[1]	Total
2003						
Revenues from external customers	$588	$(171)[2]	$255	$ 922	$ 85	$1,679
Intersegment revenues	32	663[2]	123	(706)	(112)	—
Operation and maintenance[3]	179	90	40	179	5	493
Depreciation, depletion and amortization	101	200	8	33	19	361
Loss (gain) on long-lived assets	(8)	—	(5)	15	399	401
Western Energy Settlement	146	—	—	(25)	2	123
Operating income (loss)	$112	$ 164	$(16)	$ (46)	$(425)	$ (211)
Earnings (losses) from unconsolidated affiliates	25	4	(38)	95	—	86
Other income	8	—	—	29	8	45
Other expense	—	—	—	(2)	(84)	(86)
EBIT	$145	$ 168	$(54)	$ 76	$(501)	$ (166)
2002						
Revenues from external customers	$567	$ 156[2]	$263	$ 714[4]	$ 121	$1,821
Intersegment revenues	62	404[2]	238	(540)[4]	(164)	—
Operation and maintenance[3]	184	92	37	139	45	497
Depreciation, depletion and amortization	95	193	15	13	18	334
Ceiling test charges	—	234	—	—	—	234
Loss (gain) on long-lived assets	(2)	—	(10)	—	—	(12)
Operating income (loss)	$277	$ 5	$ 36	$ 36	$ (58)	$ 296
Earnings from unconsolidated affiliates	35	3	17	78	—	133
Other income	13	(1)	2	17	28	59
Other expense	(2)	—	(1)	(8)	(47)	(58)
EBIT	$323	$ 7	$ 54	$ 123	$ (77)	$ 430

(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. Intersegment revenues represent sales to our marketing affiliate EPME, which is responsible for marketing our production.

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

(4) Merchant Energy revenues were restated on July 1, 2002, due to the adoption of a consensus reached on Emerging Issues Task Force (EITF) Issue No. 02-3, *Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities*, which requires us to report all physical sales of energy commodities in our energy trading activities on a net basis as a component of revenues. See our 2002 Form 10-K regarding the adoption of EITF Issue No. 02-3.

	Six Months Ended June 30,					
	Pipelines	Production	Field Services	Merchant Energy	Corporate & Other[1]	Total
2003						
Revenues from external customers	$1,310	$ (80)[2]	$656	$ 1,555	$ 163	$3,604
Intersegment revenues	63	1,167[2]	280	(1,269)	(241)	—
Operation and maintenance[3]	355	180	71	420	23	1,049
Depreciation, depletion and amortization	196	405	18	60	42	721
Loss (gain) on long-lived assets	(8)	9	(4)	19	407	423
Western Energy Settlement	146	—	—	(25)	2	123
Operating income (loss)	$ 496	$ 399	$(16)	$ (303)	$(469)	$ 107
Earnings (losses) from unconsolidated affiliates	68	10	(10)	(116)	—	(48)
Other income	14	3	—	50	16	83
Other expense	(4)	—	(1)	(6)	(118)	(129)
EBIT	$ 574	$ 412	$(27)	$ (375)	$(571)	$ 13
2002						
Revenues from external customers	$1,216	$ 311[2]	$537	$ 2,474[4]	$ 199	$4,737
Intersegment revenues	118	799[2]	504	(1,133)[4]	(288)	—
Operation and maintenance[3]	370	189	99	311	44	1,013
Depreciation, depletion and amortization	186	400	34	32	32	684
Ceiling test charges	—	267	—	—	—	267
Loss (gain) on long-lived assets	(14)	(2)	(10)	—	(1)	(27)
Operating income (loss)	$ 634	$ 180	$ 74	$ 464	$ (71)	$1,281
Earnings (losses) from unconsolidated affiliates	71	3	32	(201)	1	(94)
Other income	19	—	2	37	38	96
Other expense	(2)	—	(3)	(207)	(51)	(263)
EBIT	$ 722	$ 183	$105	$ 93	$ (83)	$1,020

(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. Intersegment revenues represent sales to our marketing affiliate EPME, which is responsible for marketing our production.

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

(4) Merchant Energy revenues were restated on July 1, 2002, due to the adoption of a consensus reached on Emerging Issues Task Force (EITF) Issue No. 02-3, *Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities*, which requires us to report all physical sales of energy commodities in our energy trading activities on a net basis as a component of revenues. See our 2002 Form 10-K regarding the adoption of EITF Issue No. 02-3.

Total assets by segment are presented below:

	June 30, 2003	December 31, 2002
	(In millions)	
Pipelines	$15,018	$14,802
Production	8,071	8,057
Field Services	2,452	2,680
Merchant Energy	13,284	12,276
Corporate and other	3,781	4,344
Total segment assets	42,606	42,159
Discontinued operations	1,711	4,065
Total consolidated assets	$44,317	$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 greater than 50 percent interest. Our proportional share of the net income (loss) of the unconsolidated affiliates in which we hold a greater than 50 percent interest was $(2) million and $5 million for the quarters ended, and $5 million and $14 million for the six months ended June 30, 2003 and 2002.

	Quarter Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(In millions)			
Operating results data:				
Operating revenues	$768	$598	$1,623	$960
Operating expenses	515	392	1,076	607
Income from continuing operations	131	121	302	161
Net income	131	121	302	161

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 June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(In millions)			
Proportional share of income of investees	$131	$121	$ 302	$ 161
Impairments:				
Dauphin Island/Mobile Bay[1]	(80)	—	(80)	—
Chaparral[2]	—	—	(207)	—
Milford power facility[3]	—	—	(86)	—
CAPSA/CAPEX/Agua del Cajon[4]	—	—	—	(286)
Gain on sales of CAPSA/CAPEX	24	—	24	—
Gain on issuance of GulfTerra common units	12	—	12	—
Other	(1)	12	(13)	31
Earnings (losses) from unconsolidated affiliates	$ 86	$133	$ (48)	$ (94)

(1) The impairment results from the anticipated loss from the sale of our interests in these investments.
(2) 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).
(3) This impairment resulted from a write-off of notes receivable and accruals on contracts due to ongoing difficulty at the project level.
(4) This impairment resulted from weak economic conditions in Argentina.

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 for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(In millions)			
Operating revenue	$80	$113	$124	$171
Other revenue — management fees	4	46	6	92
Cost of sales	43	39	62	65
Reimbursement for operating expenses	33	52	69	91
Other income	2	5	5	8
Interest income	1	5	6	17
Interest expense	6	11	3	25

Chaparral and Gemstone

As of December 31, 2002, we held equity investments in both Chaparral and Gemstone. During the second quarter of 2003, we acquired the remaining third party equity interests 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[(1)]	25
Notes receivable	323	—
Debt securities payable	(79)	(122)
Contingent interest promissory notes payable	(173)	—
Total net investment	$ 704	$ 566

(1) These facilities earned interest at variable rates based on LIBOR. This rate was 1.8 percent at March 31, 2003 and 1.9 percent at December 31, 2002.

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.

We currently own 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 the Series C units. During the first half of 2003, we contributed approximately $2 million of our Series B preference units to GulfTerra. This contribution was made in order for us to maintain our one percent general partner interest as a result of three common unit offerings completed by the partnership.

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 June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(In millions)			
Revenues received from GulfTerra				
Pipelines	$ —	$ 1	$ —	$ 1
Production	—	1	—	2
Field Services	—	—	5	—
Merchant Energy	6	4	16	11
	$ 6	$ 6	$ 21	$ 14
Expenses paid to GulfTerra				
Production	$ 2	$ 2	$ 4	$ 4
Field Services	25	25	42	39
Merchant Energy	8	30	19	36
	$ 35	$ 57	$ 65	$ 79
Reimbursements received from GulfTerra				
Field Services	$ 22	$ 15	$ 46	$ 23

For a further discussion of our relationships with GulfTerra, see our 2002 Form 10-K.

22. New Accounting Pronouncements Issued But Not Yet Adopted

As of June 30, 2003, there were a number of 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.

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 the interpretations of the Derivatives Implementation Group (DIG), and also makes several minor modifications to the definition of a derivative as it was defined in SFAS No. 133. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003. We do not believe there will be any initial impact of adopting this standard.

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. The provisions of SFAS No. 150 are effective for all financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning July 1, 2003. Based on our preliminary assessment of the standard, we believe its provisions will require us to reclassify our Capital Trust I and Coastal Finance I preferred interests (both currently classified as preferred interests of consolidated subsidiaries) as liabilities beginning July 1, 2003. As of June 30, 2003, the Capital Trust I balance was $325 million and the Coastal Finance I balance was $300 million.

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. The provisions of FIN No. 46 are effective for all variable interest entities created after January 31, 2003, and are effective on July 1, 2003, for all variable interest entities created before January 31, 2003.

Upon adoption of this standard on July 1, 2003, 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 current assets of approximately $20 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 2002 Annual Report on Form 10-K 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 maximizing liquidity;
- Aggressively pursue additional cost reductions in 2003 and beyond; and
- Work diligently to resolve regulatory and litigation matters.

So far in 2003, our major accomplishments regarding these five business objectives are as follows:

- Concentrating our capital investment in our core Pipelines, Production and Field Services segments such that 89 percent of total capital expenditures were made in these businesses in the first half of 2003;
- Completing or announcing sales of assets and investments of approximately $2.7 billion;
- Repaying approximately $4.2 billion of maturing debt and other obligations ($3.8 billion as of June 30, 2003), including:
  - Retiring long-term debt of $2.0 billion ($1.6 billion as of June 30, 2003);
  - Repaying $980 million of obligations under our Trinity River financing arrangement;
  - Redeeming $197 million of obligations under our Clydesdale financing arrangement and restructuring that transaction as a term loan that will amortize over the next two years; and
  - Contributing $1 billion to the Limestone Electron Trust, which used the proceeds to repay $1 billion of its notes and purchasing the third party equity interests in our Gemstone and Chaparral power investments and consolidating those investments;
- Refinancing 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;
- Entering into a new $3 billion revolving credit facility that matures in June 2005 and completing financing transactions of approximately $3.6 billion ($3.2 billion as of June 30, 2003);
- Identifying an estimated $445 million of costs savings and business efficiencies to be realized by the end of 2004; and
- Reaching definitive settlement agreements in June 2003, which substantially resolved our principal exposure relating to the western energy crisis and funding $347 million of our obligation through the issuance of senior unsecured notes of El Paso Natural Gas Company in July 2003.

Liquidity and Capital Resources

Overview of Cash Flow Activities for the Six Months Ended June 30, 2003

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

	2003	2002
	(In millions)	
Cash flows from continuing operating activities		
Net income (loss)	$ (444)	$ 394
Non-cash income adjustments	1,250	782
Cash flows before working and non-working capital changes	806	1,176
Working capital changes	(85)	(397)
Non-working capital changes and other	203	(56)
Cash flows from continuing operating activities	924	723
Cash flows from continuing investing activities	(1,325)	(721)
Cash flows from continuing financing activities	595	1,513
Discontinued operations		
Cash flows from operating activities	90	(196)
Cash flows from investing activities	329	(90)
Cash flows from financing activities	(419)	296
Increase in cash and cash equivalents related to discontinued operations	—	10
Change in cash	194	1,525
Less increase in cash and cash equivalents related to discontinued operations	—	10
Increase in cash and cash equivalents from continuing operations	$ 194	$1,515

During the six months ended June 30, 2003, our cash and cash equivalents increased by approximately $0.2 billion to approximately $1.8 billion. We generated cash from several sources, including cash flows from our principal continuing as well as discontinued operations, sales of assets and issuances of long-term debt. We used a major portion of that cash to fund our capital expenditures, to purchase additional investments in subsidiaries and to redeem preferred interests of minority interest holders. Overall, our cash sources and uses were summarized as follows (in billions):

Cash inflows	
Cash flows from continuing operations (before working and non-working capital changes)	$ 0.8
Working capital and non-working capital changes	0.1
Net proceeds from the sale of assets and investments	1.3
Net proceeds from the issuance of long-term debt	3.1
Borrowings under revolving credit facility	0.5
Net discontinued operations activity	0.4
Other	0.1
Total cash inflows	6.3
Cash outflows	
Additions to property, plant and equipment	1.3
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	1.6
Payments on short-term revolving credit facilities	0.5
Dividends paid to common stockholders	0.2
Other	0.2
Total cash outflows	6.1
Net increase in cash	$ 0.2

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 for the six months ended June 30, 2003, was $0.9 billion versus $0.7 billion in the same period of 2002. We generated approximately $0.8 billion in cash from operations (net income from continuing operations adjusted for non-cash income items) in 2003 before working capital and non-working capital changes, as compared to $1.2 billion in 2002. The decline in 2003 was primarily a result of asset sales during both 2002 and 2003. Working capital uses were $0.1 billion in 2003 as compared to a use of cash of $0.4 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. So far in 2003, we have experienced higher margin calls due to continued increases in gas prices and collateral demands on us due to the reduction in our credit ratings, offset by recoveries of collateral through the use of letters of credit under our new revolving credit facilities. As a result, our 2003 margin activity has been relatively flat.

Cash From Continuing Investing Activities

Net cash used in our continuing investing activities was $1.3 billion for the six months ended June 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	$0.9
Pipeline expansion, maintenance and integrity projects	0.3
Net cash paid to acquire Chaparral and Gemstone	1.1
Other (primarily power projects)	0.1
Total capital expenditures and additional investments	$2.4

Cash received from our investing activities includes $1.3 billion from the sale of assets and investments, including the sale of natural gas and oil properties located in western Canada, 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 $0.4 billion.

Cash From Continuing Financing Activities

Net cash provided by our continuing financing activities was $0.6 billion for the six months ended June 30, 2003. Cash provided from our financing activities included the net proceeds from the issuance of long-term debt of $3.1 billion, $0.4 billion of cash contributed by our discontinued operations and other financing activities of $0.1 billion. Cash used by our financing activities included payments made to retire third party long-term debt of $1.6 billion. We also paid $1.2 billion to fully redeem the Trinity River preferred securities and partially redeem Clydesdale preferred securities previously issued by our subsidiaries and paid dividends of $0.2 billion to common stockholders.

Cash from Discontinued Operations

During the first six months of 2003, our discontinued operations generated $0.4 billion of cash which were distributed to our continuing operations. Operating cash flow was approximately $0.1 billion, which was generated primarily through sales of inventories at our refineries. Cash from investing activities was $0.3 billion which was generated through asset sales of $0.4 billion, offset by capital expenditures of $0.1 billion.

Financing and Commitments

Our 2002 Form 10-K 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 our 2002 Form 10-K.

During the first six months of 2003, we completed a number of actions intended to simplify our financial and capital structure, refinance shorter term obligations and eliminate guarantees and other "off-balance sheet" obligations and replace 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, December 31, 2002	21,991
Acquisitions and consolidations:	
Chaparral and Gemstone	2,578
Operating leases and refinanced securities of subsidiaries	1,018
Elimination of affiliated obligations	(326)
Principal amounts borrowed	3,695
Repayments of principal	(2,108)
Redemptions and eliminations of securities of subsidiaries	(2,330)
Other	26
Total debt and securities of subsidiaries, June 30, 2003	$24,544

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:

	June 30, 2003	December 31, 2002
	(In millions)	
Current maturities of long-term debt and other financing obligations	$947	$ 575
Short-term credit facilities	—	1,500
	$947	$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. This facility replaces our previous $3 billion 364-day revolving credit facility. In addition, approximately $1 billion of other financing arrangements (including the leases as discussed in Item 1, Notes 3 and 11, letters of credit and other facilities) were amended to conform our obligations to the new $3 billion revolving credit facility. Our $3 billion revolving credit facility and these other financing arrangements are secured by our equity in EPNG, TGP, ANR, WIC, ANR Storage Company, Southern Gas Storage Company and our common and Series C units in GulfTerra. This 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. EPNG and TGP remain jointly and severally liable for any amounts outstanding under the new $3 billion revolving credit facility through August 19, 2003. Except for the following conditions, after that date

EPNG and TGP will be liable only for the amounts they borrow under the $3 billion revolving credit facility. If, on August 19, 2003, (1) an event of default is continuing with respect to the $3 billion revolving credit facility or (2) we, or any of the subsidiary guarantors under the facility or any of our restricted subsidiaries (each as defined in the $3 billion revolving credit facility) are subject to a bankruptcy or similar proceeding, then EPNG and TGP will continue to be jointly and severally liable for any amounts outstanding under the $3 billion revolving credit facility until none of the events described in (1) or (2) above exists. As of August 11, 2003, none of these conditions existed. Once EPNG's and TGP's joint and several liabilities expire on August 19, 2003, there are no circumstances in which EPNG and TGP could again become liable under our $3 billion facility except for amounts borrowed by them under the $3 billion revolving credit facility.

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 June 30, 2003, we were in compliance with these covenants.

The $3 billion revolving credit facility has a borrowing cost of LIBOR plus 350 basis points and letter of credit fees of 350 basis points. As of June 30, 2003, we had $1.5 billion outstanding and $1.1 billion of letters of credit issued under the $3 billion revolving credit facility. The amounts borrowed were classified as non-current in our balance sheet as of June 30, 2003.

We also maintained a $1 billion revolving credit facility which expired on August 4, 2003. EPNG and TGP were also borrowers under this facility. As of June 30, 2003, no amounts were outstanding, and $132 million of letters of credit were issued. The $132 million of letters of credit expired or were reissued under the $3 billion revolving credit facility prior to August 4, 2003.

The availability of borrowings under our credit facilities and 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[(2)]	Senior notes	7.75%	1,200	1,169	2013
June	El Paso	Notes	Various	95	95	2008
	Issuances through June 30, 2003			3,195	3,086	
July	EPNG	Senior notes	7.625%	355	347	2010
				$3,550	$3,433	

(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) Net proceeds from the May 2003 issuance were used to repay the $1.2 billion LIBOR based two-year term loan. The proceeds from the two-year term loan were used to repay our Trinity River financing.

Date	Company	Type	Interest Rate	Principal	Net Proceeds[1]	Due Date
				(In millions)		
Acquisitions and Consolidations						
April	Lakeside	Term loan	LIBOR + 3.5%	$ 275	$ 275	2006
April	Gemstone	Notes	7.71%	1,025	1,013	2004
April	Mustang Investor	Term loan	Various	743	743	2005
May	Chaparral[3]	Notes and loans	Various	1,671	1,565	Various
				$3,714	$3,596	

Date	Company	Type	Interest Rate	Principal	Net Payments
				(In millions)	
Retirements					
January-June	Various	Long-term debt	Various	$ 68	68
February	El Paso CGP	Long-term debt	4.49%	240	240
May	El Paso	Term loan	Variable	100	100
May	El Paso[2]	Two-year term loan	LIBOR + 4.25%	1,200	1,191
	Retirements through June 30, 2003			1,608	1,599
July	El Paso CGP	Note	Floating rate	200	200
August	El Paso CGP	Senior debentures	9.75%	102	102
August	El Paso	Term loan	Variable	100	100
				$2,010	$2,001

(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) Net proceeds from the May 2003 issuance were used to repay the $1.2 billion LIBOR based two-year term loan. The proceeds from the two-year term loan were used to repay our Trinity River financing.

(3) This debt is project-related debt that is non-recourse to us.

Notes Payable to Affiliates

Our notes payable to unconsolidated affiliates as of June 30, 2003, were $16 million versus $390 million as of December 31, 2002. The decrease was primarily due to the consolidation of $122 million of Gemstone and $203 million of Chaparral debt securities in the second quarter of 2003. Also contributing to the decrease was the retirement of $45 million of Chapparal debt securities in the first quarter of 2003.

Minority and Preferred Interests of Consolidated Subsidiaries

The total amount outstanding for securities of subsidiaries and preferred stock of consolidated subsidiaries was $1.1 billion at June 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. In the second quarter of 2003, we retired an additional $753 million of Clydesdale preferred member interests, converting it into a loan that matures in equal installments through 2005, and also eliminated the entire $300 million of Gemstone's minority member interest following our acquisition and consolidation of Gemstone. See Item 1, Notes 3 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 June 30, 2003, we had outstanding letters of credit of approximately $1.5 billion and $852 million 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 business. Of the outstanding letters of credit, $146 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. We exclude interest and debt expenses 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. Our business operations consist of both consolidated businesses as well as substantial investments in unconsolidated affiliates. As a result, 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. This measurement may not be comparable to measurements 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 (loss) to our EBIT and our EBIT to our net income (loss) for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(In millions)			
Operating revenues	$ 1,679	$ 1,821	$ 3,604	$ 4,737
Operating expenses	(1,890)	(1,525)	(3,497)	(3,456)
Operating income (loss)	(211)	296	107	1,281
Earnings (losses) from unconsolidated affiliates	86	133	(48)	(94)
Other income	45	59	83	96
Other expenses	(86)	(58)	(129)	(263)
EBIT	(166)	430	13	1,020
Interest and debt expense	(463)	(304)	(876)	(607)
Distributions on preferred interests of consolidated subsidiaries	(16)	(43)	(37)	(83)
Income taxes	373	(26)	478	(104)
Income (loss) from continuing operations	(272)	57	(422)	226
Discontinued operations, net of income taxes	(916)	(116)	(1,138)	(56)
Cumulative effect of accounting changes, net of income taxes	—	14	(22)	168
Net income (loss)	$(1,188)	$ (45)	$(1,582)	$ 338

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 June 30, 2003	Quarter Ended June 30, 2002	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002
	(In millions)			
Pipelines	$ 145	$323	$ 574	$ 722
Production	168	7	412	183
Field Services	(54)	54	(27)	105
Merchant Energy	76	123	(375)	93
Segment EBIT	335	507	584	1,103
Corporate and other	(501)	(77)	(571)	(83)
Consolidated EBIT	$(166)	$430	$ 13	$1,020

Pipelines

Our Pipelines segment holds our interstate transmission businesses. For a further discussion of the business activities of our Pipelines segment, see our 2002 Form 10-K. Results of our Pipelines segment operations were as follows for the periods ended June 30:

Pipelines Segment Results	Quarter Ended June 30, 2003	Quarter Ended June 30, 2002	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002
	(In millions, except volume amounts)			
Operating revenues	$ 620	$ 629	$ 1,373	$ 1,334
Operating expenses	(508)	(352)	(877)	(700)
Operating income	112	277	496	634
Other income	33	46	78	88
EBIT	$ 145	$ 323	$ 574	$ 722
Throughput volumes (BBtu/d)[(1)]				
TGP	4,266	4,235	5,124	4,510
EPNG and MPC	3,925	4,046	3,997	4,124
ANR	3,826	3,744	4,639	4,390
CIG and WIC	2,602	2,576	2,767	2,713
SNG	2,016	1,992	2,232	2,180
Equity investments (our ownership share)	2,372	2,487	2,538	2,479
Total throughput	19,007	19,080	21,297	20,396

(1) Throughput volumes for the quarter and six months ended June 30, 2002, exclude 208 BBtu/d and 216 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.

Second Quarter 2003 Compared to Second Quarter 2002

Operating revenues for the quarter ended June 30, 2003, were $9 million lower than the same period in 2002. The decrease was primarily due to lower revenues of $27 million due to CIG's sale of the Panhandle field and other production properties in July 2002 and a decrease of $13 million due to capacity contracts that have expired which EPNG is prohibited from remarketing due to its September 20, 2002 FERC order. See Item 1, Note 18 for a further discussion of this order. These decreases were partially offset by the impact of higher prices in 2003 on natural gas recovered in excess of amounts used in operations of $12 million, increased transportation usage revenues of $8 million due to higher contract rates in 2003 and increased revenues of $11 million due to system expansion projects and new transportation contracts.

Operating expenses for the quarter ended June 30, 2003, were $156 million higher than the same period in 2002. The increase was primarily due to charges related to EPNG's portion of the Western Energy Settlement of $154 million (see Item 1, Notes 6 and 18 for a discussion of this settlement). Also contributing to the increase were lower corporate overhead allocations in 2002 versus 2003 of $27 million. These increases were offset by lower environmental and legal costs of $25 million in 2003 versus 2002 as a result of changes in our estimated future environmental remediation and legal costs and a $14 million reduction in operating costs due to CIG's sale of its Panhandle field and other production properties.

Other income for the quarter ended June 30, 2003, was $13 million lower than the same period in 2002. The decrease was due to lower equity earnings of $6 million due to the sale of our interests in the Alliance pipeline system completed in the first quarter of 2003, lower earnings of $5 million from our investment in Citrus and the favorable resolution of uncertainties associated with the 2002 sale of our interest in the Iroquois pipeline system of $4 million.

Six Months Ended 2003 Compared to Six Months Ended 2002

Operating revenues for the six months ended June 30, 2003, were $39 million higher than the same period in 2002. The increase was due to higher volumes and prices in 2003 on natural gas recovered in excess of amounts used in operations of $40 million, increased transportation revenues of $24 million due to higher throughput volumes in 2003 resulting from colder winter weather, increased revenues of $18 million due to system expansion projects and new transportation contracts, $14 million from higher realized prices in 2003 on the resale of natural gas purchased from the Dakota gasification facility and higher sales under natural gas purchase contracts of $11 million. These increases were offset primarily by lower revenues of $47 million due to CIG's sale of its Panhandle field and other production properties and a $28 million revenue reduction from capacity contracts that have expired which EPNG is prohibited from remarketing due to its FERC order.

Operating expenses for the six months ended June 30, 2003, were $177 million higher than the same period in 2002. The increase was primarily due to charges related to EPNG's portion of the Western Energy Settlement of $158 million. Also contributing to the increase were lower corporate overhead allocations in 2002 versus 2003 of $27 million, higher prices on natural gas purchased at the Dakota gasification facility of $13 million, higher fuel and system supply purchases in 2003 of $12 million resulting from higher prices and volumes and an $11 million gain on the sale of pipeline expansion rights in February 2002. These increases were offset primarily by a $26 million decrease in operating costs due to CIG's sale of its Panhandle field and other production properties, lower environmental remediation and legal costs of $24 million and a $12 million decrease due to bad debt expense recorded in 2002 related to the bankruptcy of Enron Corp.

Other income for the six months ended June 30, 2003, was $10 million lower than the same period in 2002. The decrease was due to lower equity earnings of $11 million due to the sale of our interest in the Alliance pipeline system completed in the first quarter of 2003, the favorable resolution of uncertainties in 2002 of $8 million associated with the sale of our interests in the Iroquois and Empire State pipeline systems and the Gulfstream pipeline project in 2001. The decreases were offset by higher equity earnings in 2003 from our investment in Citrus of $8 million.

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 the lowest total cost level possible.

As further described in our 2002 Form 10-K, 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 June 30, 2003, we have hedged approximately 108 million MMBtu's of our remaining anticipated natural gas production for 2003 at a NYMEX Henry Hub price of $3.45 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 in the first half of 2003, coupled with a lower reserve base due to asset sales. For the third quarter of 2003, we expect our domestic unit of production depletion rate to be approximately $1.76 per Mcfe.

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

Production Segment Results	Quarter Ended June 30, 2003	Quarter Ended June 30, 2002	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002
	(In millions, except volumes and prices)			
Operating Revenues:				
Natural gas	$ 415	$ 441	$ 905	$ 921
Oil, condensate and liquids	68	115	174	197
Other	9	4	8	(8)
Total operating revenues	492	560	1,087	1,110
Transportation and net product costs	(24)	(33)	(55)	(55)
Total operating margin	468	527	1,032	1,055
Operating expenses[1]	(304)	(522)	(633)	(875)
Operating income	164	5	399	180
Other income	4	2	13	3
EBIT	$ 168	$ 7	$ 412	$ 183
Volumes and prices				
Natural gas				
Volumes (MMcf)	96,857	120,020	198,600	253,286
Average realized prices with hedges ($/Mcf)[2]	$ 4.28	$ 3.67	$ 4.56	$ 3.64
Average realized prices without hedges ($/Mcf)[2]	$ 5.32	$ 3.39	$ 6.02	$ 2.83
Average transportation costs ($/Mcf)	$ 0.22	$ 0.22	$ 0.22	$ 0.19
Oil, condensate and liquids				
Volumes (MBbls)	2,644	4,966	6,368	9,954
Average realized prices with hedges ($/Bbl)[2]	$ 26.13	$ 23.05	$ 27.40	$ 19.79
Average realized prices without hedges ($/Bbl)[2]	$ 26.83	$ 22.90	$ 28.16	$ 19.39
Average transportation costs ($/Bbl)	$ 0.98	$ 0.91	$ 0.98	$ 0.89

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

(2) Prices are stated before transportation costs.

Second Quarter 2003 Compared to Second Quarter 2002

Operating revenues for the quarter ended June 30, 2003, were $68 million lower than the same period in 2002. Our natural gas revenues, including the impact of hedges, were $26 million lower in the second quarter of 2003. Our 2003 natural gas production volumes were lower by 19 percent, resulting in an $85 million decrease in revenues, from the same period in 2002. Realized natural gas prices rose in 2003 by 17 percent, resulting in a $59 million increase in revenues, when compared to the same period in 2002. The overall decline in natural gas volumes was due to sales of production properties in Colorado, New Mexico, Oklahoma, Utah, Texas 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 $47 million lower in the second quarter of 2003. Our 2003 oil, condensate and liquids volumes decreased by 46 percent, resulting in a $55 million decrease in revenues, from the same period in 2002. Realized oil, condensate and liquids prices rose in 2003 by 13 percent, resulting in an $8 million increase in revenues, when compared to the same period in 2002. The declines in volumes were primarily due to the property sales and production declines mentioned above.

Transportation and net product costs for the quarter ended June 30, 2003, were $9 million lower than the same period in 2002 primarily due to lower natural gas volumes subject to transportation fees.

Operating expenses for the quarter ended June 30, 2003, were $218 million lower than the same period in 2002 primarily due to a second quarter of 2002 non-cash full cost ceiling test charge of $234 million incurred primarily in our Canadian full cost pool. Also contributing to the decrease were lower oilfield service costs of $20 million primarily due to asset dispositions which resulted in lower labor and production processing fees and a $5 million gain on the sales of non-full cost pool assets. Partially offsetting these decreases were higher depletion expenses of $7 million, comprised of a $49 million increase due to higher depletion rates in 2003 and costs of $5 million related to the accretion of our liability for asset retirement obligations, partially offset by a $47 million decrease due to lower production volumes in 2003. The higher depletion rate resulted from higher capitalized costs in the full cost pool coupled with a lower reserve base. In addition, these decreases were offset by higher corporate overhead allocations of $16 million, higher severance and other taxes of $12 million in 2003 and intangible asset impairments of $5 million in 2003 related to non-full cost assets in Canada. The increase in severance taxes was primarily due to tax credits taken in 2002 for qualified natural gas wells.

Other income for the quarter ended June 30, 2003, was $2 million higher than the same period in 2002 primarily due to higher earnings in 2003 from Pescada, an equity investment in Brazil.

Six Months Ended 2003 Compared to Six Months Ended 2002

Operating revenues for the six months ended June 30, 2003, were $23 million lower than the same period in 2002. Our natural gas revenues, including the impact of hedges, were $16 million lower in 2003. Our 2003 natural gas production volumes were lower by 22 percent, resulting in a $199 million decrease in revenues, from the same period in 2002. Realized natural gas prices rose in 2003 by 25 percent, resulting in a $183 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 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 $23 million lower in 2003. Our 2003 oil, condensate and liquids volumes decreased by 36 percent, resulting in a $71 million decrease in revenues, from the same period in 2002. Realized oil, condensate and liquids prices rose in 2003 by 38 percent, resulting in a $48 million increase in revenues, when compared to the same period in 2002. The declines in volumes were primarily due to the property sales and production declines mentioned above. Partially offsetting the decrease was a higher mark-to-market loss of $15 million in 2002 compared to 2003 related to hedges of anticipated future production that no longer qualified for hedge accounting when we sold those properties in March 2002.

Operating expenses for the six months ended June 30, 2003, were $242 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 of $35 million primarily due to asset dispositions which resulted in lower labor and production processing fees and a $5 million gain on the sales of non-full cost pool assets. Partially offsetting the decreases were higher depletion expenses of $5 million, comprised of a $90 million increase due to higher depletion rates in 2003 and costs of $10 million related to the accretion of our liability for asset retirement obligations, partially offset by a $95 million decrease due to lower production volumes in 2003. The higher depletion rate resulted from higher capitalized costs in the full cost pool coupled with a lower reserve base. In addition, these decreases were offset by higher corporate overhead allocations of $21 million, higher severance and other taxes of $19 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 six months ended June 30, 2003, was $10 million higher than the same period in 2002 primarily due to higher earnings in 2003 from our Pescada investment.

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 a one percent general partner interest. In April 2003, we announced we may sell between five and ten percent of our one percent general partner interest. In addition to our general partner interest, we currently own, through various subsidiaries, 23.5 percent of the partnership's common units, all of its Series B preference units and all of its Series C units. We may also sell some of our common unit holdings, and 2,000,000 of our common units have been registered for possible sale. 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 are also reimbursed for costs we incur to provide various operational and administrative services to the partnership. In addition, we are reimbursed for other costs paid directly by us on the partnership's behalf. During the quarter and six months ended June 30, 2003, we were reimbursed approximately $22 million and $46 million for expenses incurred on behalf of the partnership. During the quarter and six months ended June 30, 2002, we were reimbursed approximately $15 million and $23 million for expenses incurred. Our earnings and cash from GulfTerra were as follows:

	Quarter Ended June 30, 2003		Six Months Ended June 30, 2003	
	Earnings Recognized	Cash Received	Earnings Recognized	Cash Received
	(In millions)			
General partner's share of distributions	$16	$16	$33	$31
Proportionate share of income available to common unit holders	6	8	9	16
Series B preference units	4	—[1]	8	—[1]
Series C units	4	7	9	14
Gain on issuance of GulfTerra common units	12	—	12	—
	$42	$31	$71	$61

[1] The partnership is 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 treating activities, our EBIT has decreased significantly. However, the increases in earnings from our interests in GulfTerra have partially offset this decrease in EBIT primarily because some of the assets were sold to the partnership. For a further discussion of the business activities of our Field Services segment, see our 2002 Form 10-K. Results of our Field Services segment operations were as follows for the periods ended June 30:

Field Services Segment Results	Quarter Ended June 30, 2003	Quarter Ended June 30, 2002	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002
	(In millions, except volumes and prices)			
Gathering, transportation and processing gross margins[1]	$ 29	$ 84	$ 76	$ 209
Operating expenses	(45)	(48)	(92)	(135)
Operating income (loss)	(16)	36	(16)	74
Other income (expense)[2]	(38)	18	(11)	31
EBIT	$ (54)	$ 54	$ (27)	$ 105
Volumes and prices				
Gathering and transportation				
Volumes (BBtu/d)	444	2,265	510	4,039
Prices ($/MMBtu)	$ 0.18	$ 0.20	$ 0.20	$ 0.17
Processing				
Volumes (inlet BBtu/d)	3,202	3,956	3,254	4,035
Prices ($/MMBtu)	$ 0.08	$ 0.11	$ 0.09	$ 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.

Second Quarter 2003 Compared to Second Quarter 2002

Total gross margins for the quarter ended June 30, 2003, were $55 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 sale of the San Juan Basin assets in November 2002. The sale of these assets decreased gathering margins by $28 million and processing margins by $4 million. Processing margins also decreased $7 million in the second quarter of 2003 largely 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 June 30, 2003, were $3 million lower than the same period in 2002 primarily due to the asset sales discussed above, resulting in lower operating costs of $8 million and lower depreciation expenses of $8 million. Also contributing to the decrease in operating expenses was 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 reimbursements of $4 million from GulfTerra for administrative and other services to operate their assets. The increase in reimbursements was a direct result of the additional assets that GulfTerra currently owns. 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 corporate overhead allocations of $10 million in 2003, $8 million of purchase price adjustments in 2003 to gains from asset sales during 2002 and an additional legal reserve of $5 million in 2003.

Other expense for the quarter ended June 30, 2003, included $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. Partially offsetting the impact of this impairment were increased earnings of $12 million from our investment in GulfTerra, as well as a $12 million gain resulting from GulfTerra's issuance of common units in the second quarter. As GulfTerra issues common units, we may recognize gains or losses to the extent our proportionate share of GulfTerra's equity increases or decreases.

Six Months Ended 2003 Compared to Six Months Ended 2002

Total gross margins for the six months ended June 30, 2003, were $133 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 sale of the Texas and New Mexico assets in April 2002 and the San Juan Basin assets in November 2002. The sale of these assets decreased gathering margins by $85 million and processing margins by $15 million. Processing margins also decreased $9 million in the first six months of 2003 largely 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 2002.

Operating expenses for the six months ended June 30, 2003, were $43 million lower than the same period in 2002 primarily due to the asset sales discussed above, resulting in lower operating costs of $29 million and lower depreciation expenses of $17 million. Also contributing to the decrease in operating expenses was 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 reimbursements of $10 million from GulfTerra to provide administrative and other services to operate their assets. The increase in reimbursements was a direct result of the additional assets that GulfTerra currently owns. In addition, our 2002 cost reduction plan, initiated mid-2002, resulted in $6 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 corporate overhead allocations of $10 million in 2003, $9 million of purchase price adjustments in 2003 to gains from asset sales during 2002 and an additional legal reserve of $5 million in 2003.

Other expense for the six months ended June 30, 2003, included $80 million in impairment charges on our Dauphin Island Gathering Partners and Mobile Bay Processing Partners investments. Partially offsetting the impact of this impairment were increased earnings of $26 million from our investment in GulfTerra, as well as a $12 million gain resulting from GulfTerra's issuance of common units in the second quarter as described above.

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 division. In June 2003, we announced that the Board of Directors had approved the sale of substantially all of our petroleum operations. As a result, the petroleum operations were reclassified as discontinued operations for all the historical periods presented. For a further discussion of our petroleum operations, see Item 1, Note 11. The petroleum division previously included our LNG business activities and equity earnings on a gas processing plant. These operations are now included in the "Other" division in the tables below. Below are Merchant Energy's operating results and an analysis of those results for the periods ended June 30:

Merchant Energy Segment Results	Division				Total Merchant Energy Segment
	Global Power	Energy Trading	Other	Eliminations	
	(In millions)				
Second Quarter 2003					
Gross margin	$ 255	$ (56)	$ (11)	$(18)	$ 170
Operating expenses	(177)	(31)	(26)	18	(216)
Operating income (loss)	78	(87)	(37)	—	(46)
Other income (expense)	116	7	(1)	—	122
EBIT	$ 194	$ (80)	$ (38)	$ —	$ 76
Second Quarter 2002					
Gross margin	$ 239	$ (89)	$ 60	$(12)	$ 198
Operating expenses	(131)	(36)	(7)	12	(162)
Operating income (loss)	108	(125)	53	—	36
Other income (expense)	94	(7)	—	—	87
EBIT	$ 202	$(132)	$ 53	$ —	$ 123
Six Months Ended 2003					
Gross margin	$ 433	$(197)	$ (4)	$(39)	$ 193
Operating expenses	(359)	(82)	(94)	39	(496)
Operating income (loss)	74	(279)	(98)	—	(303)
Other income (expense)	(75)	13	(10)	—	(72)
EBIT	$ (1)	$(266)	$(108)	$ —	$(375)
Six Months Ended 2002					
Gross margin	$ 834	$ (21)	$ 34	$(24)	$ 823
Operating expenses	(287)	(79)	(17)	24	(359)
Operating income (loss)	547	(100)	17	—	464
Other income (expense)	(384)	13	—	—	(371)
EBIT	$ 163	$ (87)	$ 17	$ —	$ 93

Global Power

Our global power division includes the ownership and operation of domestic and international power generating facilities. Our 2002 Form 10-K includes a description of the various power activities included in global power. Our global power division has undergone significant changes in 2002 and 2003 in our business strategies. For example, in 2002 we were involved in restructuring power contracts as more fully described in our 2002 Form 10-K. Due to a decline in our credit rating in late 2002 and early 2003, we no longer pursue those restructuring activities and are considering selling our domestic power operations.

Many of our domestic and international power projects have been held in Chaparral and Gemstone. During 2003, we obtained control of these two entities, acquiring the remaining third party equity interests and consolidating their operations. For a discussion of the acquisition of Chaparral and Gemstone, see Item 1 Note 3. In 2002, Chaparral and Gemstone were accounted for as unconsolidated equity investments. Because of the changes in our business strategies and differences in our accounting methods, the operating results of our power operations between 2003 and 2002 are not necessarily comparable.

Additionally, because of the substantial increase in our non-trading power restructuring derivative instruments that we acquired through Chaparral, we increased our exposure to changes in the fair value of these instruments. This exposure relates to changes in the underlying rates used to discount the expected cash flows associated with these contracts as more fully explained in Item 3, Quantitative and Qualitative Disclosures About Market Risk.

Results of our global power division were as follows for the periods ended June 30:

Global Power Division Results	Quarter Ended June 30, 2003	Quarter Ended June 30, 2002	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002
	(In millions)			
Gross margin	$ 255	$ 239	$ 433	$ 834
Operating expenses	(177)	(131)	(359)	(287)
Operating income	78	108	74	547
Other income (expense)	116	94	(75)	(384)
EBIT	$ 194	$ 202	$ (1)	$ 163

Second Quarter 2003 Compared to Second Quarter 2002

Gross margin consists of revenues from our power plants and the net results from our power restructuring activities. The cost of fuel in the power generation process is included in operating expenses. For the quarter ended June 30, 2003, our gross margin was $16 million higher than the same period in 2002. The increase was primarily due to $145 million of gross margins earned by power plants we consolidated in the second quarter of 2003 associated with the consolidation of Chaparral and Gemstone and an increase of $26 million due to increases in the fair values of our power restructuring contracts during 2003. These increases were partially offset by a $90 million gain recorded in 2002 on the termination of a power purchase agreement at our Nejapa power facility, lower power generation revenues of $27 million due to the partial shutdown of our Eagle Point Cogeneration facility during the first six months of 2003 for maintenance needed to convert the power plant to a merchant power plant and a $46 million management fee we received from Chaparral in the second quarter of 2002 that we did not receive in 2003.

Operating expenses for the quarter ended June 30, 2003, were $46 million higher than the same period in 2002. The increase was primarily due to $93 million of operating expenses incurred by power plants we consolidated in the second quarter of 2003 associated with the consolidation of Chaparral and Gemstone, partially offset by $16 million of decreased operating costs for power facilities converted to a merchant basis as a result of restructuring activities in 2002. In 2003, we also experienced $20 million of lower payroll expenses associated with our employee reductions.

Other income for the quarter ended June 30, 2003, was $22 million higher than the same period in 2002. This increase was primarily due to a gain on the sale of our CAPSA/CAPEX investments in Argentina for $24 million in 2003 and $13 million of minority interest expense recorded in 2002 associated with the termination of a power purchase agreement at our Nejapa power facility. These increases were partially offset by a net $7 million decrease in equity earnings due to the consolidation of Chaparral and Gemstone in the second quarter of 2003.

Six Months Ended 2003 Compared to Six Months Ended 2002

For the six months ended June 30, 2003, our gross margin was $401 million lower than the same period in 2002. The decrease was primarily due to power contract restructurings for our Eagle Point Cogeneration, Mount Carmel and Nejapa power plants that we completed in 2002, which contributed $562 million to our gross margin in 2002, including 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. The effects of this power supply agreement were eliminated from Merchant Energy's consolidated results. Contributing to the decrease in gross margin was a decrease of $63 million in 2003 power generation revenues primarily due to the partial shutdown of our Eagle Point Cogeneration facility during the first six months of 2003 for maintenance needed to convert the power plant to a merchant power plant. Also contributing to the decrease was $92 million in management fees we received from Chaparral in 2002 that we did not receive in 2003. Partially offsetting these decreases were $226 million of gross margins earned by power plants we consolidated in 2003 associated with the consolidation of Chaparral and Gemstone and increases in the fair values of our power restructuring contracts of $44 million during 2003.

Operating expenses for the six months ended June 30, 2003, were $72 million higher than the same period in 2002. The increase was primarily due to $178 million of operating expenses incurred by power plants we consolidated in 2003 associated with the consolidation of Chaparral and Gemstone, partially offset by $40 million of decreased operating costs resulting primarily from converting several of our power plants to merchant plants in conjunction with our power restructuring activities in 2002 and a $19 million turbine forfeiture fee paid in 2002 as plans for future construction of new power plants were reduced. Additionally, our payroll, and related employee costs were lower by $32 million due to a reduction in the number of employees.

Other expenses for the six months ended June 30, 2003, were $309 million lower than the same period in 2002. This decrease was primarily due to $342 million of impairment charges in 2002 on our Agua del Cajon, CAPSA/CAPEX and Costañera investments in Argentina, $13 million of minority interest expense recorded in 2002 associated with the termination of a power purchase agreement at our Nejapa power facility 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 division reflected in discontinued operations). Also contributing to the decrease in other expenses was a $130 million increase in equity earnings due to the consolidation of Chaparral and Gemstone in 2003 and a $24 million gain on the sale of our CAPSA/CAPEX investments in Argentina in 2003. The decrease in other expenses were primarily offset by a $207 million impairment we recorded on our Chaparral investment in 2003 and an additional $86 million loss on the impairment of notes from our Milford equity investment and loss accruals related to other associated contracts in 2003. Milford's losses are based on ongoing settlement negotiations related to this investment.

Energy Trading

In November 2002, we announced that we would exit the energy 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 actively liquidating our trading portfolio and anticipate that this effort will continue through 2004. Through June 30, 2003, we have liquidated approximately 15,000, or 38 percent of the total number of forward positions outstanding at December 31, 2002. We have also liquidated 97 Bcf of the 125 Bcf of natural gas storage rights and 2.5 Bcf/d of our 4.4 Bcf/d of transportation capacity that we owned in 2002. The remaining capacity will be liquidated as these capacity agreements expire or are sold. Some of our transportation capacity agreements are being utilized to serve customers and will not be actively marketed until the underlying transactions are terminated. We completed the liquidation of our European portfolio and expect to close that operation in the third quarter of 2003. We also liquidated miscellaneous activities including our interest rate and coal portfolios. We anticipate we will have 12,000 transactions remaining by the end of 2003, after normal settlements. Our portfolio may include transactions that benefit other segments of our business, which in future periods may be transferred to those segments. Our liquidation activities have and will continue to prevent comparability of our earnings on a period to period basis.

During the second quarter of 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, we implemented new accounting rules that impacted the values of our portfolios starting in the fourth quarter of 2002. All of these factors reduce the comparability of our operating results between periods.

Results of our energy trading division were as follows for the periods ended June 30:

Energy Trading Division Results	Quarter Ended June 30, 2003	Quarter Ended June 30, 2002	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002
	(In millions)			
Gross margin	$(56)	$ (89)	$(197)	$ (21)
Operating expenses	(31)	(36)	(82)	(79)
Operating loss	(87)	(125)	(279)	(100)
Other income (expense)	7	(7)	13	13
EBIT	$(80)	$(132)	$(266)	$ (87)

Second Quarter 2003 Compared to Second Quarter 2002

Gross margin consists of revenues from commodity trading and origination activities less the costs of commodities sold, including changes in the fair value of our energy trading portfolio. For the quarter ended June 30, 2003, gross margin increased by $33 million compared to the same period in 2002. We incurred an $89 million loss in gross margin during the second quarter of 2002, which primarily resulted from a decline in option valuations that decreased the fair value of our trading portfolio in 2002. We incurred a $56 million gross margin loss in the second quarter of 2003, which partially resulted from $6 million of net losses incurred on the early termination and liquidation of contracts in our trading portfolio. The remaining loss in 2003 resulted primarily from the fact that we experienced narrowing of the differential between gas and power prices that caused a decrease in the fair value of our power-related derivatives and transportation and storage demand charges we were unable to fully recover through the use of the capacity due to our focus on conserving working capital.

Operating expenses for the quarter ended June 30, 2003, were $5 million lower than the same period in 2002. This decrease was primarily the result of a $25 million net reduction in the accrual for the California settlement obligation as a result of the finalization of the definitive settlement agreement which encompasses changes in the timing of payment and a $4 million net decrease in personnel costs due to a reduction in the number of employees. These decreases in expenses were offset by increases, including $12 million of amortization of our debt discount on the California settlement obligation, $4 million of legal and other costs related to the resolution of the California lawsuits as described in Item 1, Notes 6 and 18 and $4 million as a result of accelerating the depreciation of the assets of the trading division upon the decision to exit trading thus resulting in a shorter economic life.

Other income for the quarter ended June 30, 2003, was $14 million higher than 2002, primarily as a result of lower overhead allocations in 2002 and $5 million of foreign exchange gains recognized in 2003 primarily due to the Canadian dollar strengthening against the U.S. dollar during the quarter.

Six Months Ended 2003 Compared to Six Months Ended 2002

For the six months ended June 30, 2003, gross margin was $176 million lower than the same period in 2002. We incurred a $197 million gross margin loss during the first six months of 2003, which partially resulted from $40 million of net losses incurred on the early termination and liquidation of our contracts in our trading portfolio. The remaining loss in 2003 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 business. We incurred a $21 million loss in gross margin during the first six months of 2002, which primarily resulted from a decline in the fair value of our trading portfolio in 2002, offset by an $80 million gain on a power supply agreement that we entered into with our global power division in the first quarter of 2002 associated with the Eagle Point Cogeneration restructuring transaction. The effects of this power supply agreement were eliminated from Merchant Energy's consolidated results.

Operating expenses for the six months ended June 30, 2003, were $3 million higher than the same period in 2002. In 2003, we recognized a net $5 million of costs related to the settlement of our California lawsuits as described in Item 1, Notes 6 and 18. This net increase in costs includes $24 million of debt amortization on our settlement obligation and $6 million of legal and other costs, offset by a $25 million reduction in our estimate of our expected obligation as a result of the execution of a definitive agreement which encompassed changes in the timing of payments. Depreciation expense increased by $8 million as a result of accelerating the depreciation of the assets of the trading division upon the decision to exit trading resulting in a shorter economic life, offset by $10 million net decrease in personnel costs due to a reduction in the number of employees.

Other income for the six months ended June 30, 2003, was at the same level as the previous year. While the impact was flat, we did experience foreign currency gains of approximately $7 million primarily due to the strengthening of the Canadian dollar against the U.S. dollar offset by a decrease in interest income due to the collection or termination of interest bearing assets.

Other

This division includes our LNG business and the results of operations of our equity investment in a gas processing plant. Historically, our LNG business included supply agreements, terminal capacity arrangements, the development of regassification 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. We are currently pursuing the sale of the supply and terminal capacity arrangements. Additionally, in the first quarter of 2003, we incurred charges of $44 million in connection with reducing future exposure under our ship chartering arrangements. In the second quarter 2003, we expensed $19 million of costs related to the testing facility used in the development of the regasification technology since we are not actively pursuing further technology development. Results of our other division were as follows for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
Other Division Results	**2003**	**2002**	**2003**	**2002**
		(In millions)		
Gross margin	$(11)	$60	$ (4)	$ 34
Operating expenses	(26)	(7)	(94)	(17)
Operating income (loss)	(37)	53	(98)	17
Other income (expense)	(1)	—	(10)	—
EBIT	$(38)	$53	$(108)	$ 17

Second Quarter 2003 Compared to Second Quarter 2002

Gross margin consists of revenues from LNG commodity trading and origination activities, less the costs of commodities sold. For the quarter ended June 30, 2003, our gross margin was $71 million lower than the same period in 2002. The decrease relates primarily to a gain of $59 million on the Snøhvit LNG contract in 2002. Also contributing to the decrease was a $12 million reduction in the fair value of our LNG supply contracts in 2003.

Operating expenses for the quarter ended June 30, 2003, were $19 million higher than the same period in 2002. The increase was primarily due to a $20 million impairment of our LNG assets in the second quarter of 2003 associated with Energy Bridge technology development costs previously capitalized that were no longer considered recoverable due to our reduced involvement in the LNG business.

Six Months Ended 2003 Compared to Six Months Ended 2002

For the six months ended June 30, 2003, our gross margin was $38 million lower than the same period in 2002. The decrease relates primarily to the $59 million gain on the Snøhvit LNG contract in 2002, partially offset by a $21 million decrease in the fair value of our remaining LNG supply contracts in 2003.

Operating expenses for the six months ended June 30, 2003, were $77 million higher than the same period in 2002. This increase included $55 million of ship charter cancellation costs incurred in 2003 associated with our reduced involvement in our LNG business and $5 million of employee severance costs. Also, contributing to the increase was a $20 million impairment of our LNG assets in the second quarter of 2003 associated with Energy Bridge technology development costs previously capitalized that were no longer considered recoverable due to our reduced involvement in the LNG business. Partially offsetting this increase was a decrease in outside consulting fees for 2003.

Other income for the six months ended June 30, 2003, was $10 million lower than the same period in 2002. The decrease was due primarily to a $10 million impairment of costs associated with one of our LNG terminals that we no longer anticipate using and a $3 million in equity losses from our joint venture in the Javelina gas processing facility.

Fair Value of Price Risk Management Contracts as of June 30, 2003

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 June 30, 2003. We have historically classified 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. All other derivative-related activities, including those related to power restructuring and hedging activities, have historically been classified as non-trading price risk management activities.

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]	$ (87)	$ 12	$ 75	$ 15	$ —	$ 15
Non-exchange traded positions[2]	(30)	40	(67)	(100)	(17)	(174)
Total trading contracts, net	(117)	52	8	(85)	(17)	(159)
Non-trading contracts[3]						
Non-exchange traded positions[2]	(65)	189	424	718	176	1,442
Total energy contracts	$(182)	$241	$432	$ 633	$159	$1,283

(1) Exchange-traded positions include positions that 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 energy contracts include derivatives from our power contract restructuring activities of $2,199 million, and derivatives related to our natural gas and oil producing activities of $(757) million. Earnings related to the natural gas and oil producing derivative activities are included in our Production segment results.

The income impacts of both our trading and non-trading price risk management activities are included in the divisions of our Merchant Energy segment and in our Production segment. A reconciliation of these trading and non-trading activities for the period ended June 30, 2003, is as follows:

	Trading	Non-Trading	Total Commodity Based
		(In millions)	
Fair value of contracts outstanding at December 31, 2002	$ (47)	$ 459	$ 412
Fair value of contract settlements during the period	44	199	243
Change in fair value of contracts	(64)	(438)	(502)
Fair value of contracts consolidated as a result of Chaparral acquisition	—	1,222	1,222
Option premiums received, net	(92)	—	(92)
Net change in contracts outstanding during the period	(112)	983	871
Fair value of contracts outstanding at June 30, 2003	$(159)	$1,442	$1,283

During the second quarter of 2003, we acquired derivative contracts with a fair value as of June 30, 2003, of approximately $1.2 billion, 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 these 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 related contracts.

Our trading portfolio is reflected at its estimated fair value, which is the amount at which the contracts in our portfolio could be bought or sold in a current transaction between willing buyers and sellers. However, the value we ultimately receive in settlement of our trading activities may be less than our estimates. As discussed above, we are actively liquidating our trading portfolio, which includes approximately 25,000 positions as of June 30, 2003. We believe the net realizable value of our trading portfolio, if liquidated in the timeframe set out in our exit plan, may be less than its currently estimated fair value. Our belief is based on recent transactions completed at values below estimated fair value and bids received on positions that were also below their fair value. Additionally, a portion of the transactions that we plan to liquidate is accounted for under the accrual method and is not recorded on our balance sheet.

Corporate and Other

Corporate and other expenses, which include general and administrative activities as well as the operations of our telecommunications and other miscellaneous businesses, for the quarter ended June 30, 2003, were $501 million, $424 million higher than the same period in 2002. In the second quarter of 2003, we recorded impairment charges of approximately $269 million in our telecommunications business, inclusive of a write-down of goodwill of $163 million due to our announced exit of this business and an impairment of our Lakeside Technology Center facility of $127 million due to the decline in the estimated fair value of that facility. The second quarter 2003 increase was also due to a $37 million loss on the early extinguishment of our $1.2 billion bridge loan. Partially offsetting these cost increases were $40 million of 2002 costs related to eliminating rating and stock-price triggers in our Gemstone and Chaparral investments.

Corporate and other expenses for the six months ended June 30, 2003, were $571 million, an increase of $488 million over those costs during the same period in 2002. These increases were due to the same reasons discussed in the second quarter analysis above, including impairment charges in our telecommunications business of $396 million, inclusive of a write-down of goodwill of $163 million, and the $37 million loss on our extinguishment of debt, along with $33 million of higher foreign currency losses on our Euro-denominated debt during 2003. Partially offsetting these increases were lower business restructuring costs in 2003, versus those costs incurred in 2002.

Interest and Debt Expense

Interest and debt expense for the quarter and six months ended June 30, 2003, was $159 million and $269 million higher than the same period in 2002. Below is an analysis of our interest expense for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(In millions)			
Long-term debt, including current maturities	$415	$267	$786	$530
Revolving credit facilities	35	6	55	7
Commercial paper	—	11	—	22
Other interest	18	28	46	65
Capitalized interest	(5)	(8)	(11)	(17)
Total interest expense	$463	$304	$876	$607

Second Quarter 2003 Compared to Second Quarter 2002

Interest expense on long-term debt for the quarter ended June 30, 2003, was $148 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 $6.9 billion from debt issuances and acquisitions and consolidations of companies with debt, which increased our interest on long-term debt by approximately $112 million. Also contributing to the increase was $54 million of additional interest related to various debt issuances during 2002 that were outstanding during 2003. Partially offsetting these increases was the retirement of approximately $1.3 billion of long-term debt during 2002 and 2003 with an average effective interest rate of 7.46%, decreasing interest expense by approximately $23 million.

Interest expense on revolving credit facilities for the quarter ended June 30, 2003, was $29 million higher than the same period in 2002 due to higher borrowings under the revolving credit facilities in December 2002 and 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 4.3% during 2003.

Interest expense on commercial paper for the quarter ended June 30, 2003, was $11 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 June 30, 2003, was $10 million lower than the same period in 2002. The decrease was primarily due to an $8 million decrease in interest resulting from the retirement of other financing obligations and a $3 million decrease due to the reduction in trading activities in 2003.

Capitalized interest for the quarter ended June 30, 2003, was $3 million lower than the same period in 2002 primarily due to lower interest rates in the second quarter of 2003 than in 2002.

Six Months Ended 2003 Compared to Six Months Ended 2002

Interest expense on long-term debt for the six months ended June 30, 2003, was $256 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 $6.9 billion, which increased interest by approximately $178 million. Also contributing to the increase was $122 million of additional interest related to debt issuances during 2002 that were outstanding during 2003. Partially offsetting these increases was the retirement of approximately $1.7 billion of long-term debt during 2002 and 2003 with an average effective interest rate of 6.99%, decreasing interest expense by approximately $45 million.

Interest expense on revolving credit facilities for the six months ended June 30, 2003, was $48 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 $1.8 billion, with an average interest rate of 3.5% during 2003.

Interest expense on commercial paper for the six months ended June 30, 2003, was $22 million lower than the same period in 2002 due to the discontinuation of commercial paper activities in 2003.

Other interest for the six months ended June 30, 2003, was $19 million lower than the same period in 2002. The decrease was primarily due to a $12 million decrease resulting from the retirement of our other financing obligations, a $7 million decrease due to the consolidation of Chaparral and Gemstone and a $9 million decrease due to the reduction in trading activities in 2003. These decreases were partially offset by a $7 million increase as a result of the write-off of unamortized costs due to retirement of the Trinity River financing arrangement in 2003.

Capitalized interest for the six months ended June 30, 2003, was $6 million lower than the same period in 2002 primarily due to lower 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 six months ended June 30, 2003, were $27 million and $46 million lower than the same periods in 2002 primarily due to the redemptions or elimination of over $2.2 million of preferred interests 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. The decreases were also due to lower interest rates in 2003 and the impact of the consolidation of Chaparral and Gemstone as a result of our acquisition of these investments. 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 June 30 were as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(In millions, except for rates)			
Income taxes	$(373)	$26	$(478)	$104
Effective tax rate	58%	31%	53%	32%

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

- state income taxes, net of federal income tax benefit;
- foreign income taxed at different rates;
- abandonment of foreign investment;
- 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 the following:

- 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.

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

Discontinued Operations

During the six months ended June 30, 2003, our after-tax loss from discontinued operations was $1,138 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 business, approximately $929 million of which related to the second quarter impairment of our Aruba refinery and approximately $252 million of which related to the first quarter impairment of our Eagle Point refinery.

We also incurred losses on our refinery operations during the second quarter of 2003 of $74 million which primarily related to lower pricing in the second quarter and lower crude throughput at our Aruba facility. Year to date operating results for our refineries were slightly positive at $5 million.

The income tax benefit related to discontinued operations for the six months ended June 30, 2003, was $226 million resulting in an effective tax rate for discontinued operations of 17 percent. This effective rate was different than the statutory rate of 35 percent primarily due to state income taxes and foreign income taxes at different rates.

In the second quarter of 2003, we entered into a product offtake agreement for the sale of a number of the products produced at our Aruba refinery. As a result of this contract, the buyer 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 the buyer'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 2002 Form 10-K.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

There are no material changes in our quantitative and qualitative disclosures about market risks from those reported in our 2002 Form 10-K, 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 our portfolio of commodity and energy-related contracts on a daily basis using a Value-at-Risk model. We measure our trading and hedging activities included in our non-trading portfolio's Value-at-Risk using the 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 $16 million and $11 million as of June 30, 2003 and December 31, 2002, and represents our potential one-day unfavorable impact on the fair values of our commodity and energy-related contracts. The $5 million increase in our portfolio Value-at-Risk was related to higher natural gas price volatility and our efforts in the first six months of 2003 to mitigate the cash flow impact of rising gas prices on our trading portfolio. As we liquidate our trading portfolio, our Value-at-Risk may vary more than in historical periods when we more actively managed our positions using Value-at-Risk. As a result, our Value-at-Risk could increase.

Interest Rate Risk

As of June 30, 2003, included in the $2.2 billion of our non-trading derivatives not designated as hedges, we had $1.2 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 specific counterparty credit spread. 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. While the commodity price risk associated with these derivative instruments has been incorporated into our Value-at-Risk model discussed above, our exposure to changes in interest rates and credit spreads has not been included in our Value-at-Risk since it is managed separately from our other derivative positions included in our Value-at-Risk model. As of June 30, 2003, a ten percent increase or decrease in the discount rate utilized would result in a change in the fair value of these derivative instruments of $(63) million and $66 million, respectively.

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

We held our annual meeting of stockholders on June 17, 2003. Proposals we presented for a stockholders' vote included the election of twelve directors, two amendments to our Certificate of Incorporation, ratification of the appointment of PricewaterhouseCoopers LLP as independent certified public accountants for the fiscal year 2003 and three stockholder proposals. Proposals were also presented by Selim Zilkha, a stockholder, which included the nomination for election of a nine director slate, three amendments to El Paso's By-laws and a proposal regarding the presentation of proposals at the annual meeting.

Each of the twelve incumbent directors nominated by El Paso was elected with the following voting results:

Nominee	For	Withheld
John M. Bissell	230,211,392	4,825,927
Juan Carlos Braniff	224,777,447	10,318,321
James L. Dunlap	230,368,109	4,727,659
Robert W. Goldman	230,398,308	4,697,430
Anthony W. Hall, Jr.	230,382,094	4,713,644
Ronald L. Kuehn, Jr.	230,003,212	5,092,526
J. Carleton MacNeil, Jr.	230,421,643	4,674,672
Thomas R. McDade	224,779,864	4,828,368
J. Michael Talbert	229,930,687	5,165,379
Malcolm Wallop	220,130,651	9,535,234
John Whitmire	231,890,432	3,205,913
Joe B. Wyatt	225,416,482	9,621,056

The Zilkha slate of directors received the following votes:

Nominee	For	Withheld
R. Gerald Bennett	197,431,145	5,466,974
C. Robert Black	196,410,411	6,546,734
Charles H. Bowman	197,436,059	5,462,886
Ronald J. Burns	197,427,286	5,471,410
Stephen D. Chesebro	197,325,344	5,573,322
Ted Earl Davis	197,491,257	5,465,032
John J. Murphy	202,930,257	5,455,915
John V. Singleton	197,469,153	5,429,513
Selim K. Zilkha	115,849,899	92,478,073

The appointment of PricewaterhouseCoopers LLP as El Paso's independent certified public accountants for the fiscal year 2003 was ratified with the following voting results:

	For	Against	Abstain
Proposal to ratify the appointment of PricewaterhouseCoopers LLP as independent certified public accountants	420,883,265	12,655,154	4,483,579

There were no broker non-votes for the ratification of PricewaterhouseCoopers LLP.

Two management proposals were presented for a stockholder vote. One proposal was to amend the Certificate of Incorporation to eliminate Article 12, and the other was to eliminate our Series A Junior Participating Preferred Stock.

	For	Against	Abstain
Proposal to amend our Certificate of Incorporation to eliminate Article 12, containing a "Fair Price" Provision	417,046,416	6,670,908	14,296,555
Proposal to amend our Certificate of Incorporation to eliminate our Series A Junior Participating Preferred Stock	427,713,129	4,340,952	5,959,802

Selim Zilkha presented four proposals including three amendments to El Paso's By-laws and one regarding the sequence for the presentation of proposals at the annual meeting with the following voting results:

	For	Against	Abstain
Zilkha proposal to amend By-laws to set the number of Directors at nine	207,660,208	216,357,665	14,004,120
Zilkha proposal to amend By-laws to delete the advance notice provisions applicable to Director nominations	100,597,097	323,043,772	14,343,237
Zilkha proposal to amend By-laws to repeal changes made after November 7, 2002	210,245,285	213,009,627	14,767,074
Zilkha proposal for sequence of presentation of proposals	237,235,654	180,656,328	23,121,896

Three proposals submitted by stockholders were presented for a stockholder vote. One proposal called for stockholder approval of a report on pay disparity, the second proposal called for stockholder approval of indexed options for senior executives and the third proposal called for stockholder approval regarding shareholder approval of any adoption of poison pills. The first and second stockholder proposals were not approved, and the third proposal was approved with the following voting results.

	For	Against	Abstain
Stockholder proposal regarding pay disparity report	100,807,243	311,486,535	15,682,076
Stockholder proposal regarding indexed options for senior executives	129,123,846	200,230,767	108,627,737
Stockholder proposal regarding stockholder approval of any adoption of a poison pill	323,358,885	107,143,140	7,519,826

Item 5. Other Information

On July 16, 2003, we announced that Douglas L. Foshee was elected our new President and Chief Executive Officer.

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.
*3.B	Bylaws effective as of July 31, 2003.
10.A	$3,000,00,000 Revolving Credit Agreement dated as of April 16, 2003 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company and ANR Pipeline Company, as Borrowers, the Lenders Party Thereto, and JPMorgan Chase Bank, as Administrative Agent, ABN Amro Bank N.V. and Citicorp North America, Inc., as Co-Document Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents, J.P. Morgan Securities Inc. and Citigroup Global Markets Inc., as Joint Bookrunners and Co-Lead Arrangers (Exhibit 99.1 to our Form 8-K filed April 18, 2003, Commission File No. 1-14365).
10.B	$1,000,000,000 Amended and Restated 3-Year Revolving Credit Agreement dated as of April 16, 2003 among El Paso Corporation, El Paso Natural Gas Company and Tennessee Gas Pipeline Company, as Borrowers, The Lenders Party Thereto, and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-document Agents, Bank of America, N.A., as Syndication Agent, J.P. Morgan Securities Inc. and Citigroup Global Markets Inc., as Joint Bookrunners and Co-Lead Arrangers (Exhibit 99.2 to our Form 8-K filed April 18, 2003, Commission File No. 1-14365).
10.C.	Security and Intercreditor Agreement dated as of April 16, 2003, among El Paso Corporation, the Persons Referred to therein as Pipeline Company Borrowers, the Persons Referred to therein as Grantors, Each of the Representative Agents, JPMorgan Chase Bank, as Credit Agreement Administrative Agent and JPMorgan Chase Bank, as Collateral Agent, Intercreditor Agent, and Depository Bank (Exhibit 99.3 to our Form 8-K filed April 18, 2003, Commission File No. 1-14365).
+10.I	1999 Omnibus Incentive Compensation Plan dated January 20, 1999 (Exhibit 10.1 to our Form S-8 filed May 20, 1999, File No. 333-78951); Amendment No. 1 effective as of February 7, 2001 to the 1999 Omnibus Incentive Compensation Plan (Exhibit 10.V.1 to our 2001 First Quarter Form 10-Q).
*+10.I.1	Amendment No. 2 to the 1999 Omnibus Incentive Compensation Plan effective as of May 1, 2003.

Exhibit Number	Description
+10.J	2001 Omnibus Incentive Compensation plan, effective as of January 29, 2001 (Exhibit 10.1 to our Form S-8 filed June 29, 2001, File No. 333-64236); Amendment No. 1 effective as of February 8, 2001 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2001 Form 10-K); Amendment No. 2 effective as of April 1, 2001 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2002 Form 10-K); Amendment No. 3 effective as of July 17, 2002 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2002 Second Quarter Form 10-Q).
*+10.J.1	Amendment No. 4 to the 2001 Omnibus Incentive Compensation Plan effective as of May 1, 2003.
+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).
*+10.Z.1	Amendment No. 2 to Supplement No. 1 to the Severance Pay Plan effective as of June 1, 2003.
+10.AA	El Paso Production Companies Long-Term Incentive Plan effective as of January 1, 2003 (Exhibit 10.AA to our 2003 First Quarter Form 10-Q, Commission File No. 1-14365).
*+10.AA.1	Amendment No. 1 to the El Paso Production Companies Long-Term Incentive Plan effective as of June 6, 2003.
10.DD.1	Amendment No. 2 dated April 30, 2003 to the $1,200,000,000 Senior Secured Interim Term Credit and Security Agreement dated as of March 13, 2003 (Exhibit 10.DD.1 to our 2003 First Quarter Form 10-Q, Commission File No. 1-14365).
10.GG	Amended and Restated Sponsor Subsidiary Credit Agreement dated April 16, 2003 among Noric Holdings, L.L.C. as borrower, and the Other Sponsor Subsidiaries Party as Co-Obligators, Mustang Investors, L.L.C., as Sponsor Subsidiary Lender, and Clydesdale Associates, L.P. as Subordinated Note Holder, and Wilmington Trust Company, as Sponsor Subsidiary Collateral Agent, and Citicorp North America, Inc. as Mustang Collateral Agent; Fifth Amended and Restated El Paso Agreement dated April 16, 2003 by El Paso Corporation, in favor of Mustang Investors, L.L.C. and the Other Indemnified Persons; Amended and Restated Guaranty Agreement dated as of April 16, 2003 made by El Paso Corporation, as Guarantor in favor of Each Sponsor Subsidiary, Noric, L.L.C., Noric, L.P. and each Controlled Business as Beneficiaries; Definitions Agreement dated as of April 16, 2003 among El Paso Corporation and Noric Holdings, L.L.C. and the Other Sponsor Subsidiaries Party thereto, Mustang Investors, L.L.C., and Clydesdale Associates, L.P. and the Other Parties Named therein (Exhibit 10.GG to our 2003 First Quarter Form 10-Q, Commission File No. 1-14365).

Exhibit Number	Description
*10.HH	Master Settlement Agreement dated as of June 24, 2003, by and between, on the one hand, El Paso Corporation, El Paso Natural Gas Company, and El Paso Merchant Energy, L.P.; and, on the other hand, the Attorney General of the State of California, the Governor of the State of California, the California Public Utilities Commission, the California Department of Water Resources, the California Energy Oversight Board, the Attorney General of the State of Washington, the Attorney General of the State of Oregon, the Attorney General of the State of Nevada, Pacific Gas & Electric Company, Southern California Edison Company, the City of Los Angeles, the City of Long Beach, and classes consisting of all individuals and entities in California that purchased natural gas and/or electricity for use and not for resale or generation of electricity for the purpose of resale, between September 1, 1996 and March 20, 2003, inclusive, represented by class representatives Continental Forge Company, Andrew Berg, Andrea Berg, Gerald J. Marcil, United Church Retirement Homes of Long Beach, Inc., doing business as Plymouth West, Long Beach Brethren Manor, Robert Lamond, Douglas Welch, Valerie Welch, William Patrick Bower, Thomas L. French, Frank Stella, Kathleen Stella, John Clement Molony, SierraPine, Ltd., John Frazee and Jennifer Frazee, John W.H.K. Phillip, and Cruz Bustamante.
*10.II	Joint Settlement Agreement submitted and entered into by El Paso Natural Gas Company, El Paso Merchant Energy Company, El Paso Merchant Energy-Gas, L.P., the Public Utilities Commission of the State of California, Pacific Gas & Electric Company, Southern California Edison Company and the City of Los Angeles.
*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
April 7, 2003	Announced that James L. Dunlap joined the El Paso Board effective as of April 7, 2003.
April 16, 2003	Announced the extension of maturity of El Paso's $3 billion revolving credit facility.
April 16, 2003	Announced the sale of East Coast Power, L.L.C. interests for $456 million.
April 18, 2003	Announced the refinancing and restructuring of our major bank facilities.
April 23, 2003	Filed the Computation of our Ratio of Earnings to Fixed Charges for the five years ended December 31, 2002.
April 23, 2003	Filed the slides on the progress of our Operational and Financial Plan presented at investor meetings.
April 24, 2003	Announced additional possible asset sales.
April 24, 2003	Announced sale of Mid-Continent and northern Louisiana midstream assets and the close of the sale of Enerplus Global Energy Management Company.
April 30, 2003	Announced execution of letter of intent to sell Eagle Point refinery and related pipeline assets.
May 13, 2003	Announced Executive Management changes.
June 5, 2003	Announced the filing with the FERC for approval of a Structural Settlement to resolve claims related to the Western Energy crisis.
June 5, 2003	Filed the Computation of our Ratio of Earnings to Fixed Charges for the five years ended December 31, 2002 and the quarter ended March 31, 2003 and 2002.
June 19, 2003	Announced the preliminary results of our 2003 Stockholder Meeting.
July 9, 2003	Announced the execution of two definitive settlement agreements to resolve 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 the 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).

We also furnished information to the SEC on Current Reports on Form 8-K under Item 9 and Item 12. 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.

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: August 14, 2003

/s/ D. Dwight Scott

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

Date: August 14, 2003

/s/ Jeffrey I. Beason

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