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 March 31, 2002

OR

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

For the transition period from to

Commission File Number 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 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 May 6, 2002: 532,727,453

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 March 31, 2002	Quarter Ended March 31, 2001
Operating revenues	$13,188	$17,762
Operating expenses		
Cost of products and services	11,025	15,697
Operation and maintenance	696	663
Merger-related costs	—	1,161
Asset impairments	342	—
Ceiling test charge	33	—
Depreciation, depletion and amortization	375	326
Taxes, other than income taxes	92	127
	12,563	17,974
Operating income (loss)	625	(212)
Other income		
Earnings from unconsolidated affiliates	61	100
Other, net	(2)	44
	59	144
Income (loss) before interest, income taxes and other charges	684	(68)
Interest and debt expense	307	295
Minority interest	40	62
Income taxes	108	(35)
	455	322
Income (loss) before extraordinary items and cumulative effect of accounting change	229	(390)
Extraordinary items, net of income taxes	—	(10)
Cumulative effect of accounting change, net of income taxes	154	—
Net income (loss)	$ 383	$ (400)
Basic earnings per common share		
Income (loss) before extraordinary items	$ 0.44	$ (0.78)
Extraordinary items, net of income taxes	—	(0.02)
Cumulative effect of accounting change, net of income taxes	0.29	—
Net income (loss)	$ 0.73	$ (0.80)
Diluted earnings per common share		
Income (loss) before extraordinary items	$ 0.43	$ (0.78)
Extraordinary items, net of income taxes	—	(0.02)
Cumulative effect of accounting change, net of income taxes	0.29	—
Net income (loss)	$ 0.72	$ (0.80)
Basic average common shares outstanding	527	502
Diluted average common shares outstanding	538	502
Dividends declared per common share	$ 0.22	$ 0.21

See accompanying notes.

EL PASO CORPORATION

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

	March 31, 2002	December 31, 2001
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,259	$ 1,139
Accounts and notes receivable, net		
Customer	5,240	5,074
Unconsolidated affiliates	1,186	911
Other	737	896
Inventory	1,011	825
Assets from price risk management activities	2,131	2,702
Other	1,280	1,112
Total current assets	12,844	12,659
Property, plant and equipment, at cost		
Pipelines	17,660	17,596
Natural gas and oil properties, at full cost	13,717	14,466
Gathering and processing systems	2,675	2,628
Refining, crude oil and chemical facilities	2,442	2,425
Power facilities	1,044	834
Other	1,022	1,021
	38,560	38,970
Less accumulated depreciation, depletion and amortization	14,256	14,379
Total property, plant and equipment, net	24,304	24,591
Other assets		
Investments in unconsolidated affiliates	4,889	5,297
Assets from price risk management activities	2,943	2,118
Other	3,577	3,506
	11,409	10,921
Total assets	$48,557	$48,171

See accompanying notes.

EL PASO CORPORATION

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

	March 31, 2002	December 31, 2001
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 5,252	$ 4,971
Unconsolidated affiliates	28	26
Other	855	959
Short-term borrowings and other financing obligations	2,674	3,314
Notes payable to unconsolidated affiliates	371	504
Liabilities from price risk management activities	1,950	1,868
Other	1,196	1,923
Total current liabilities	12,326	13,565
Debt		
Long-term debt and other financing obligations	14,372	12,816
Notes payable to unconsolidated affiliates	326	368
	14,698	13,184
Other liabilities		
Liabilities from price risk management activities	1,277	1,231
Deferred income taxes	4,513	4,459
Other	2,205	2,363
	7,995	8,053
Commitments and contingencies		
Securities of subsidiaries		
Company-obligated preferred securities of consolidated trusts	925	925
Minority interests	3,259	3,088
	4,184	4,013
Stockholders' equity		
Common stock, par value $3 per share; authorized 750,000,000 shares; issued 540,009,931 shares in 2002 and 538,363,664 shares in 2001	1,620	1,615
Additional paid-in capital	3,183	3,130
Retained earnings	5,169	4,902
Accumulated other comprehensive income	(171)	157
Treasury stock (at cost) 7,376,438 shares in 2002 and 7,628,799 shares in 2001	(254)	(261)
Unamortized compensation	(193)	(187)
Total stockholders' equity	9,354	9,356
Total liabilities and stockholders' equity	$48,557	$48,171

See accompanying notes.

EL PASO CORPORATION

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

	Quarter Ended March 31, 2002	Quarter Ended March 31, 2001
Cash flows from operating activities		
Net income (loss)	$ 383	$ (400)
Adjustments to reconcile net income (loss) to net cash from operating activities		
Non-cash gains from trading and power activities	(427)	(7)
Non-cash portion of merger-related costs and asset impairments	342	677
Depreciation, depletion and amortization	375	326
Ceiling test charge	33	—
Undistributed earnings of unconsolidated affiliates	(2)	(61)
Net (gain) loss on the sale of assets	(16)	5
Deferred income tax expense (benefit)	96	(61)
Extraordinary items	—	11
Cumulative effect of accounting change	(154)	—
Other non-cash income items	85	33
Working capital changes	(518)	306
Non-working capital changes and other	(111)	226
Net cash provided by operating activities	86	1,055
Cash flows from investing activities		
Additions to property, plant and equipment	(685)	(704)
Additions to investments	(280)	(134)
Net proceeds from the sale of assets	493	171
Proceeds from the sale of investments	19	10
Repayment of notes receivable from unconsolidated affiliates	62	77
Other	48	—
Net cash used in investing activities	(343)	(580)
Cash flows from financing activities		
Net borrowings (repayments) under commercial paper and short-term credit facilities	32	(1,130)
Borrowings under credit facilities	—	245
Repayments on credit facilities	—	(260)
Repayments of notes payable	(15)	—
Payments to retire long-term debt and other financing obligations	(751)	(848)
Net proceeds from the issuance of long-term debt and other financing obligations	1,378	1,746
Issuances of common stock	13	24
Dividends paid	(108)	(60)
Increase in notes payable to unconsolidated affiliates	3	—
Decrease in notes payable to unconsolidated affiliates	(175)	(347)
Net cash provided by (used in) financing activities	377	(630)
Increase (decrease) in cash and cash equivalents	120	(155)
Cash and cash equivalents		
Beginning of period	1,139	741
End of period	$ 1,259	$ 586

See accompanying notes.

EL PASO CORPORATION

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

	Quarter Ended March 31, 2002	Quarter Ended March 31, 2001
Net income (loss)	$ 383	$ (400)
Foreign currency translation adjustments	(1)	(14)
Unrealized net gains (losses) from cash flow hedging activity		
Cumulative-effect transition adjustment (net of tax of $673)	—	(1,280)
Unrealized mark-to-market losses arising during period (net of tax of $135 in 2002 and $123 in 2001)	(232)	(239)
Reclassification adjustments for changes in initial value to settlement date (net of tax of $54 in 2002 and $249 in 2001)	(95)	463
Other comprehensive loss	(328)	(1,070)
Comprehensive income (loss)	$ 55	$(1,470)

See accompanying notes.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation

Our 2001 Annual Report on Form 10-K includes a summary of our significant accounting policies and other disclosures. You should read it in conjunction with this Quarterly Report on Form 10-Q. The financial statements as of March 31, 2002, and for the quarters ended March 31, 2002 and 2001, are unaudited. The balance sheet as of December 31, 2001, is derived from the audited balance sheet filed in our Form 10-K. These financial statements have been prepared pursuant to the rules and regulations of the U.S. Securities and Exchange Commission and do not include all disclosures required by accounting principles generally accepted in the United States. In our opinion, we have made all adjustments, all of which are of a normal, recurring nature (except for merger-related costs, asset impairments, a ceiling test charge and a cumulative effect of accounting change, all discussed below), to fairly present our interim period results. Information for interim periods may not necessarily indicate the results of operations for the entire year due to the seasonal nature of our businesses. The prior period information also includes reclassifications which were made to conform to the current period presentation. These reclassifications have no effect on our reported net income or stockholders' equity.

Our accounting policies are consistent with those discussed in our Form 10-K, except as discussed below.

Goodwill and Other Intangible Assets

Our intangible assets consist primarily of goodwill recognized from acquisitions. On January 1, 2002, we adopted Statement of Financial Accounting Standards (SFAS) No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets*. These standards require that we recognize goodwill separately from other intangible assets. In addition, goodwill and indefinite-lived intangibles are no longer amortized. Rather, goodwill is tested periodically for impairment, at least on an annual basis, or whenever events or circumstances indicate that an impairment may have occurred. SFAS No. 141 requires that upon adoption of SFAS No. 142, any negative goodwill should be written off as a cumulative effect of a change in accounting. Prior to adoption of these standards, we amortized goodwill, negative goodwill and other intangibles using the straight-line method over periods ranging from 5 to 40 years. As a result of our adoption of these standards on January 1, 2002, we recognized a $154 million gain, net of income taxes, related to the write-off of negative goodwill as a cumulative effect of an accounting change in our income statement. Our initial periodic tests for impairment were completed during the first quarter of 2002, and did not indicate any impairment of our goodwill. In addition, we stopped amortizing goodwill and negative goodwill that was estimated to be approximately $7 million, net of income taxes, for the quarter ended March 31, 2002. If we had adopted SFAS No. 141 and 142 on January 1, 2001, for the quarter ended March 31, 2001, we would have reported a loss before extraordinary items and cumulative effect of accounting change of $383 million, or $(0.76) per share, and a net loss of $393 million, or $(0.78) per share.

Asset Impairments

On January 1, 2002, we adopted SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. The provisions of this statement supersede SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of*. There was no initial financial statement impact of adopting this standard.

2. Divestitures

In March 2002, we completed the sale of natural gas and oil properties located in east and south Texas. Net proceeds from this sale were approximately $500 million. We did not recognize a gain or loss on the properties sold.

In April 2002, we sold midstream assets to El Paso Energy Partners, L.P., a publicly traded master limited partnership in which we serve as the general partner, for approximately $735 million, net of $15 million of working capital changes due to natural gas imbalances. Net proceeds from this sale were approximately $420 million in cash, a $119 million note payable to us that was subsequently paid, common units of El Paso Energy Partners 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. No gain or loss was recognized on this sale.

In April 2002, we announced the sales of an additional $425 million of assets, including natural gas and oil production properties and related contracts and a natural gas gathering system.

3. Merger-Related Costs

On January 29, 2001, we merged with The Coastal Corporation in a merger that was accounted for as a pooling of interests. During the quarter ended March 31, 2001, we incurred costs related to this merger consisting of the following (in millions):

Employee severance, retention and transition costs	$ 802
Transaction costs	54
Business and operational integration costs	17
Merger-related asset impairments	134
Other	154
	$1,161

Employee severance, retention and transition costs include direct payments to, and benefit costs for, severed employees and early retirees that occurred as a result of our merger-related workforce reduction and consolidation. Following the Coastal merger, we completed an employee restructuring across all of our operating segments, resulting in the reduction of 3,285 full-time positions through a combination of early retirements and terminations. Employee severance costs include actual severance payments and costs for pension and post-retirement benefits settled and curtailed under existing benefit plans as a result of this restructuring. Retention charges include payments to employees who were retained following the merger and payments to employees to satisfy contractual obligations. Transition costs relate to costs to relocate employees and costs for severed and retired employees arising after their severance date to transition their jobs into the ongoing workforce. The amount of employee severance, retention and transition costs paid and charged against the accrued amount in the quarter ended March 31, 2001, was approximately $422 million. The remainder of the charges were paid during subsequent quarters in 2001.

Also included in employee severance, retention and transition costs for the quarter ended March 31, 2001, was a charge of $278 million resulting from the issuance of approximately 4 million shares of common stock incurred on the date of the Coastal merger in exchange for the fair value of Coastal employees' and directors' stock options.

Transaction costs include investment banking, legal, accounting, consulting and other advisory fees incurred to obtain federal and state regulatory approvals and take other actions necessary to complete our merger. All of these items were expensed as incurred.

Business and operational integration costs include charges to consolidate facilities and operations of our business segments, such as lease termination and abandonment charges and incremental fees under software and seismic license agreements. These charges were accrued at the time we completed our relocations and closed these offices. The amounts accrued will be paid over the term of the applicable non-cancelable lease agreement. All other costs were expensed as incurred.

Merger-related asset impairments relate to write-offs or write-downs of capitalized costs for duplicate systems, and facilities and assets whose value was impaired as a result of decisions on the strategic direction of our combined operations following our merger with Coastal. These charges occurred in our Merchant Energy and Production segments, and all of these assets have either had their operations suspended or continue to be held for use. The charges taken were based on a comparison of the cost of the assets to their estimated fair value to the ongoing operations based on the change in operating strategy.

Other costs include payments made in satisfaction of obligations arising from the Federal Trade Commission (FTC) approval of our merger with Coastal and other miscellaneous charges. These items were expensed as incurred.

4. Asset Impairments

During the first quarter of 2002, we recognized an asset impairment charge in our Merchant Energy segment of $342 million related to several of our investments in Argentina. During the latter part of 2001, economic conditions in Argentina deteriorated and the Argentine government defaulted on its public debt obligations. In the first quarter of 2002, the government changed several Argentine laws, including: (i) repealing the one-to-one exchange rate for the Argentine Peso with U.S. dollar; (ii) mandating that all Argentine contracts and obligations previously denominated in U.S. dollars be re-negotiated and denominated in Argentine Pesos; and (iii) imposing a tax on crude oil exports. The Argentine Peso devaluation combined with these new law changes effectively converted our projects' contracts and sources of revenue from U.S. dollars to Argentine Pesos and resulted in the impairment charge, which represents the full amount of each of the investments impacted by these law changes. We have a remaining investment in a pipeline project in Argentina with an aggregate investment of approximately $40 million. We continue to monitor the situation closely. However, should these conditions persist, or new unfavorable developments occur, we may also be required to evaluate our remaining investment for impairment.

5. Ceiling Test Charge

Under the full cost method of accounting for natural gas and oil properties, we perform quarterly ceiling tests to evaluate 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. At March 31, 2002, capitalized costs exceeded this ceiling limit by $33 million, including $10 million for our Brazilian full cost pool and $23 million for other international production operations in Turkey.

6. Extraordinary Items

Under an FTC order, as a result of our merger with Coastal, we sold our Gulfstream pipeline project, our 50 percent interest in the Stingray pipeline system and our investment in the Empire pipeline system during the first quarter of 2001. Net proceeds from these sales were approximately $144 million, and we recognized an extraordinary net loss of approximately $10 million, net of tax benefits of approximately $1 million.

7. Earnings Per Share

We calculated basic and diluted earnings per share amounts as follows for the quarters ended March 31:

	2002		2001
	Basic	Diluted(1)	Basic(1)
	(In millions, except per common share amounts)		
Income (loss) before extraordinary items and cumulative effect of accounting change	$ 229	$ 229	$ (390)
Interest on trust preferred securities and preferred stock dividends, net of income taxes	—	3	—
Adjusted income (loss) before extraordinary items and cumulative effect of accounting change	229	232	(390)
Extraordinary items, net of income taxes	—	—	(10)
Cumulative effect of accounting change, net of income taxes	154	154	—
Adjusted net income (loss)	$ 383	$ 386	$ (400)

	2002		2001
	Basic	Diluted[(1)]	Basic[(1)]
	(In millions, except per common share amounts)		
Average common shares outstanding	527	527	502
Effect of dilutive securities			
Stock options	—	2	—
Restricted stock	—	—	—
FELINE PRIDES[SM]	—	1	—
Trust preferred securities	—	8	—
Convertible debentures	—	—	—
Average common shares outstanding[(1)]	527	538	502
Earnings per common share			
Adjusted income (loss) before extraordinary items and cumulative effect of accounting change	$0.44	$0.43	$(0.78)
Extraordinary items, net of income taxes	—	—	(0.02)
Cumulative effect of accounting change, net of income taxes	0.29	0.29	—
Adjusted net income (loss)	$0.73	$0.72	$(0.80)

(1) Due to their antidilutive effect on earnings per share, for 2001, we excluded our 6 million shares of stock options, 1 million shares of restricted stock, 5 million shares of FELINE PRIDES[SM], 8 million shares of trust preferred securities and 3 million shares of convertible debentures, and for 2002, we excluded 8 million shares of convertible debentures.

8. Financial Instruments and Price Risk Management Activities

The following table summarizes the carrying value of our trading and non-trading price risk management assets and liabilities as of March 31, 2002 and December 31, 2001:

	March 31, 2002	December 31, 2001
	(In millions)	
Net assets (liabilities)		
Trading price risk management activities[(1)(2)]	$ 995	$1,295
Non-trading price risk management activities		
Derivatives designated as hedges	(116)	426
Other derivatives	968	—
	$1,847	$1,721

(1) Trading activities represent those that qualify for accounting under Emerging Issues Task Force Issue No. 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities.*

(2) Impacting our trading balance at March 31, 2002, was a charge to earnings of approximately $61 million related to our revised estimate of the fair value of long term positions in our trading price risk management activities. As a result of diminished liquidity in the marketplace for natural gas and power transactions in excess of ten years, we no longer recognize gains from the fair value of trading positions beyond ten years.

Included in other derivatives as of March 31, 2002, are $984 million of derivatives related to the fair value of power contracts that arose through our power restructuring activities. Power contract restructurings generally involve amending or terminating a power facility's power purchase agreement to eliminate the dedicated power supply requirements and provide for flexible sourcing of the power supply to the electric utility customer. In addition, the recorded value of the previously dedicated power facility is generally written down to fair value based on its new status as a merchant plant. Any related fuel supply and steam agreements are generally terminated or amended. We conduct the majority of our domestic power activities through Chaparral, our unconsolidated affiliate, and therefore the income impact of these activities on our financial statements is typically recognized through our equity earnings. However, we also conduct power restructurings on power assets owned by our consolidated subsidiaries. Restructured power contracts generally qualify as derivative instruments and are marked to their estimated fair value. On consolidated entities, these contracts are presented in our balance sheet as assets from price risk management activities and in our income statement as revenue. Costs associated with the restructuring activity, which typically include the impairment of the underlying power plant and any related intangible assets, contract termination fees and closing costs, are recorded in our income statement as costs of products and services.

Also included in other derivatives is a $16 million loss we recognized in connection with the sale of our natural gas and oil properties located in east and south Texas in March 2002. We recognized this loss on derivative positions that no longer qualify as cash flow hedges under SFAS No. 133 because they were designated as hedges of anticipated future production on the properties sold.

9. Inventory

Our inventory consisted of the following:

	March 31, 2002	December 31, 2001
	(In millions)	
Refined products, crude oil and chemicals	$ 738	$577
Coal, materials and supplies and other	217	207
Natural gas in storage	56	41
	$1,011	$825

10. Debt and Other Credit Facilities

At March 31, 2002, our weighted average interest rate on our commercial paper and short-term credit facilities was 2.7%, and at December 31, 2001, it was 3.2%. We had the following short-term borrowings and other financing obligations:

	March 31, 2002	December 31, 2001
	(In millions)	
Commercial paper	$1,435	$1,265
Short-term credit facility	35	111
Current maturities of long-term debt and other financing obligations	1,089	1,799
Notes payable	115	139
	$2,674	$3,314

Our significant borrowing and repayment activities during 2002 are presented below. These activities do not include borrowings or repayments on our short-term financing instruments with an original maturity of three months or less, including our commercial paper programs and short-term credit facilities.

Date	Company	Type	Interest Rate	Principal	Net Proceeds	Due Date
				(In millions)		
Issuances						
2002						
January	El Paso	Medium-term notes	7.75%	$1,100	$1,081	2032
February	SNG	Notes	8.00%	300	297	2032
April	Mohawk River Funding IV	Senior secured notes	7.75%	92	90	2008
May	El Paso	Euro notes	7.125%	450(1)	448	2009
Retirements						
2002						
January	SNG	Long-term debt	7.85%	$ 100		2002
January	EPNG	Long-term debt	7.75%	215		2002
March	El Paso CGP	Long-term debt	Variable	400		2002
Jan.-Mar.	El Paso Production	Natural gas production payment	LIBOR+ 0.372%	24		2002
Jan.-Mar.	Various	Long-term debt	Various	12		2002
May	SNG	Long-term debt	8.625%	100		2002

(1)Represents the U.S. dollar equivalent of 500 million Euros on the issuance date.

11. Commitments and Contingencies

Legal Proceedings

We and several of our subsidiaries were named defendants in eleven purported class action, municipal or individual lawsuits, filed in California state courts (a list of the *California* cases is included in Part II, Item 1, Legal Proceedings). The eleven 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. The lawsuits are at the preliminary pleading stages with trial not anticipated until late 2003 at the earliest. We and our directors also have been named in a shareholder derivative action, contending that our directors failed to prevent the conduct alleged in several of these underlying lawsuits. The derivative suit originally was filed in California, but was dismissed and refiled in Texas in March 2002.

In September 2001, we received a civil document subpoena from the California Department of Justice, seeking information said to be relevant to the Department's ongoing investigation into the high electricity prices in California. We have produced and expect to continue to produce materials pursuant to this subpoena.

In August 2000, a main transmission line owned and operated by El Paso Natural Gas Company (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 Proposed Violation to EPNG. The Notice alleged five probable violations of its regulations (a list of the alleged five probable violations is included in Part II, Item 1, Legal Proceedings), proposed fines totaling $2.5 million and proposed corrective actions. In October 2001, EPNG filed a detailed response with the Office of Pipeline Safety disputing each of the alleged violations. We are cooperating with the National Transportation Safety Board in an investigation into the facts and circumstances concerning the possible causes of the rupture. If we are required to pay the proposed fines, it will not have a material adverse effect on our financial position, operating results or cash flows. In addition, a number of personal injury and wrongful death lawsuits were filed against us in connection with the rupture. Several of these suits have been settled, with payments fully covered by insurance. Seven Carlsbad lawsuits remain, with one of the seven having reached a contingent settlement within insurance coverage (a list of the remaining *Carlsbad* lawsuits is included in Part II, Item 1, Legal Proceedings).

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 under report 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. 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.

A number of our subsidiaries were named 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. 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 Quinque complaint was transferred to the same court handling the Grynberg complaint and has now been sent back to Kansas State Court for further proceedings. A motion to dismiss this case is pending.

In compliance with the 1990 amendments to the Clean Air Act (CAA), 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 five such lawsuits in New York. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

In addition, 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 these matters, we evaluate the merits of the case, our exposure to the matter and 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 make the necessary accruals. As new information becomes available, our estimates may change. The impact of these changes may have a material effect on our results of operations. As of March 31, 2002, we had reserves totaling $171 million for all outstanding legal matters.

While the outcome of the matters discussed above cannot be predicted with certainty, based on information known to date and our existing accruals, we do not expect the ultimate resolution of these matters will have a material adverse effect on our ongoing financial position, operating results or cash flows.

Environmental Matters

We are subject to extensive 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 March 31, 2002, we had a reserve of approximately $562 million for expected remediation costs including $535 million for associated onsite, offsite and groundwater technical studies, and approximately $27 million for other costs which we anticipate incurring through 2027. In addition, we expect to make capital expenditures for environmental matters of approximately $341 million in the aggregate for the years 2002 through 2007. These expenditures primarily relate to compliance with clean air regulations.

Since 1988, our subsidiary, Tennessee Gas Pipeline Company (TGP), has been engaged in an internal project to identify and deal with the presence of polychlorinated biphenyls (PCBs) and other substances, including those on the Environmental Protection Agency's (EPA) List of Hazardous Substances, 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, to ensure that its efforts meet regulatory requirements. 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 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 agreed orders with the agency to resolve many of the issues raised in the complaint and received water discharge permits from the agency for its Kentucky compressor stations. The relevant Kentucky compressor stations are being characterized and remediated under the 1994 consent order with the EPA. Despite these remediation efforts, the agency may raise additional technical issues or require additional remediation work in the future.

In May 1995, following negotiations with its customers, TGP filed a stipulation and agreement with the Federal Energy Regulatory Commission (FERC) that established a mechanism for recovering a substantial portion of the environmental costs identified in its internal remediation project. The stipulation and agreement was effective July 1, 1995. Refunds may be required to the extent actual eligible expenditures are less than amounts collected.

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. All of the assessments are related to alleged noncompliances with the New Jersey Air Pollution Control 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 New Jersey Department of Environmental Protection has assessed penalties totaling approximately $1.1 million for these alleged violations. Our Eagle Point refinery has been granted an administrative hearing on issues raised by the assessments and, currently, is in negotiations to settle these assessments.

In February 2002, we received a Notice of Violation from the EPA alleging noncompliance with the EPA's fuel regulations from 1996 to 1998. The notice proposes a penalty of $165,000 for these alleged violations. We are investigating the allegations and are preparing a response.

We have been designated and 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 54 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 CERCLA sites, as appropriate, through indemnification by third parties and settlements which provide for payment of our allocable share of remediation costs. As of March 31, 2002, we have estimated our share of the remediation costs at these sites to be between $65 million and $203 million and have provided reserves that we believe are adequate for such costs. 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 the determination of our estimated liabilities. We presently believe that based on our existing reserves, and information known to date, the impact of the costs associated with these CERCLA sites will not have a material adverse effect on our financial position, operating results or cash flows.

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 on our evaluation and experience to date, we believe the recorded reserves are adequate. For a further discussion of specific environmental matters, see *Legal Proceedings* above.

Rates and Regulatory Matters

In April 2000, the California Public Utilities Commission (CPUC) filed a complaint with the FERC alleging that the sale of approximately 1.2 billion cubic feet per day of California capacity by EPNG to El Paso Merchant Energy Company, both of whom are our wholly-owned subsidiaries, was anticompetitive and an abuse of the affiliate relationship under the FERC's policies. Other parties in the proceeding requested that the original complaint be set for hearing and that Merchant Energy pay back any profits it earned under the contract. In March 2001, the FERC established a hearing, before an administrative law judge, to address the issue of whether EPNG and/or Merchant Energy had market power and, if so, had exercised it. In October 2001, a FERC administrative law judge issued a proposed decision finding that El Paso did not exercise market power and that the market power portion of the CPUC's complaint should be dismissed. The decision further found that El Paso had violated the FERC's marketing affiliate regulations. In October 2001, the Market Oversight and Enforcement (MOE) section of the FERC's Office of the General Counsel filed comments in this proceeding stating that record development at the trial was inadequate to conclude that EPNG and Merchant Energy complied with the FERC's regulation. We filed a motion to strike the MOE's pleading, but in December 2001, the FERC denied our motion and remanded the proceeding to the administrative law judge for a supplemental hearing on the availability of capacity at El Paso's California delivery points. The hearing commenced on March 21, 2002, and concluded on April 4, 2002. Oral argument was held on April 10, 2002, and post-hearing briefing is to be completed by June 5, 2002.

In late 1999, several of EPNG's customers filed complaints requesting that the FERC order us to cease and desist from selling primary firm delivery point capacity at the Southern California Gas Company Topock delivery point in excess of the downstream capacity available at that point and to cease and desist from overselling firm mainline capacity on the east-end of our mainline system. Several technical conferences and alternative dispute resolution meetings were held during the summer of 2000 but they failed to produce a settlement. In October 2000, the FERC ordered EPNG to make a one time allocation of available delivery point capacity at the Southern California Gas Company Topock delivery point among affected firm shippers, but deferred action on east-end and system wide capacity allocation issues. In February 2001, the FERC issued an order accepting EPNG's tariff filing affirming the results of the Topock delivery point allocation process and directing EPNG to formulate a system wide capacity allocation methodology to be addressed in EPNG's order No. 634 proceeding. In March 2001, EPNG filed its proposed system-wide allocation methodology with the FERC. In April 2001, the February 2001 order was appealed by a customer to the U.S. Court of Appeals for the 9th Circuit and that appeal is pending a decision. In July 2001 and August 2001, technical conferences were conducted by the FERC on EPNG's system-wide capacity allocation proposal, after which the parties submitted position papers to the FERC regarding the appropriate method for allocating receipt point capacity on EPNG's system.

Two groups of EPNG's customers, those within California and those east of California, have filed complaints against EPNG with the FERC. In July 2001, twelve parties composed of California customers, natural gas producers and natural gas marketers, filed a complaint alleging that EPNG's full requirements contracts with its east of California customers should be converted to contracts with specific volumetric entitlements, that EPNG should be required to expand its interstate pipeline system and that firm shippers who experience reductions in their nominated gas volumes should be awarded demand charge credits. Also, in July 2001, ten parties, most of which are east of California full-requirement contract customers, filed a complaint against EPNG with the FERC, alleging that EPNG violated the Natural Gas Act of 1938 and breached its contractual obligations by failing to expand its system in order to serve the needs of the full-requirement contract shippers. The complainants have requested that the FERC require EPNG to show cause why it should not be required to augment its system capacity. In September 2001, the July 2001 complainants filed a motion for partial summary disposition of their complaint, to which EPNG responded. In addition, in November 2001, one of the complainants submitted a type of settlement proposal that we and most other parties have opposed. At its March 13, 2002 public meeting, the FERC Staff made a presentation to the FERC Commissioners recommending that the FERC address the capacity allocation issues raised in these and other related EPNG proceedings, including its Order No. 637 proceeding, by, among other things, eliminating the full requirements provisions from all of EPNG's contracts except those in a small customer category and converting them to contracts with specific volumetric entitlements. The Staff also recommended scheduling a technical conference. A technical conference attended by the Commissioners was held on April 16, 2002, at which EPNG, state commissions and customers groups presented comments. Responses to the presentations were filed by EPNG and others on April 30, 2002.

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. In December 2001, we filed comments with the FERC addressing our concerns with the proposed rules. In April 2002, the FERC Staff issued a notice of a public conference to be held on May 21, 2002, at which interested parties will be given an opportunity to comment further on the NOPR. We cannot predict the outcome of the NOPR, but adoption of the regulations in substantially the form proposed would, at a minimum, place additional administrative and operational burdens on us.

While we cannot predict with certainty the final outcome or the timing of the resolution of all of our rates and regulatory matters discussed above, we believe the ultimate resolution of these issues, based on information known to date, will not have a material adverse effect on our financial position, results of operations or cash flows.

In June 2001, the Western Australia regulators issued a draft rate decision at lower than expected levels for the Dampier-to-Bunbury pipeline owned by EPIC Energy Australia Trust, in which we have a 33 percent ownership interest and a total investment, including financial guarantees, of approximately $195 million. EPIC Energy Australia has appealed a variety of issues related to the draft decision to the Western Australia Supreme Court. The appeal was heard at the Western Australia Supreme Court in November 2001, and a decision from the court is expected in the middle of 2002. If the draft decision rates are implemented, the new rates will adversely impact future operating results, liquidity and debt capacity, possibly reducing the value of our investment by up to $135 million.

We are engaged in arbitration proceedings with Southwestern Bell involving disputes regarding our telecommunications interconnection agreement in our metropolitan transport business. We anticipate a determination from an administrative law judge on this proceeding by the end of the second quarter. The Public Utilities Commission (PUC) of Texas will then rule on the administrative law judge's recommendation, the outcome of which could negatively impact our metro transport business. We also continue to evaluate the impact of ongoing industry issues, including credit concerns, on our business, which includes not only our metro business but also the operation of a telecommunications facility that we lease under an agreement supported by a residual value guarantee of $237 million. An adverse resolution to the arbitration proceeding by the PUC or continual decline in the industry could have a negative impact on our ongoing operations and prospects in this business.

Other Matters

In December 2001, Enron Corp. and a number of its subsidiaries, including Enron North America Corp. and Enron Power Marketing, Inc., filed for Chapter 11 bankruptcy protection in the United States Bankruptcy Court for the Southern District of New York. We had contracts with Enron North America, Enron Power Marketing and other Enron subsidiaries for, among other things, the transportation of natural gas and natural gas liquids, the trading of physical gas, power, petroleum and financial derivatives. We established reserves for potential losses related to the receivables from our transportation contracts, as well as the positions and receivables under our marketing and trading contracts that we believe are adequate. In addition, we have terminated most of our trading related contracts as a result of Enron's bankruptcy filings, and are analyzing our damage claims arising from the Enron bankruptcy proceedings.

Affiliates of Enron hold both short-term and long-term capacity on several of our pipeline systems. While some transportation contracts between various Enron entities with EPNG or TGP have been rejected, we are uncertain as to Enron's intent to maintain or release capacity associated with contracts on other El Paso pipeline entities and also Enron's ability to honor the terms of their contracts. Future revenue related to these capacity contracts will depend upon the outcome of Enron's bankruptcy proceedings and our pipelines' ability to re-market or otherwise maximize the value of the rejected or released capacity. We do not presently know the precise values that will be received by our pipelines as a result of these efforts.

12. Segment Information

We segregate our business activities into four distinct operating segments: Pipelines, Merchant Energy, Production and Field Services. 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 and marketing strategies. We measure segment performance using earnings before interest expense and income taxes (EBIT). The following are our segment results as of and for the quarters ended March 31, 2002 and 2001:

	2002					
	Pipelines	Merchant Energy	Production	Field Services	Other[1]	Total
	(In millions)					
Revenues from external customers	$ 647	$12,100	$ 155	$ 274	$ 12	$13,188
Intersegment revenues	56	26	395	266	(743)	—
Asset impairments	—	342	—	—	—	342
Ceiling test charge	—	—	33	—	—	33
Operating income (loss)	345	83	173	38	(14)	625
EBIT	399	63	176	51	(5)	684
Segment assets	14,437	18,203	7,791	3,635	4,491	48,557

	2001					
	Pipelines	Merchant Energy	Production	Field Services	Other[1]	Total
	(In millions)					
Revenues from external customers	$ 715	$15,984	$ 239	$ 647	$ 177	$17,762
Intersegment revenues	77	425	332	110	(944)	—
Merger-related costs	89	136	63	29	844	1,161
Operating income (loss)	294	169	188	20	(883)	(212)
EBIT	333	258	185	36	(880)	(68)

(1) Includes Corporate and eliminations as well as our telecommunications activities. In 2001, we also included our retail businesses.

The reconciliations of EBIT to income (loss) before extraordinary items and cumulative effect of accounting change are presented below for the quarters ended March 31:

	2002	2001
	(In millions)	
Total EBIT	$684	$ (68)
Interest and debt expense	307	295
Minority interest	40	62
Income taxes	108	(35)
Income (loss) before extraordinary items and cumulative effect of accounting change	$229	$(390)

13. Investments in Unconsolidated Affiliates and Related Party Transactions

We hold investments in various affiliates which we account for using the equity method of accounting. Summarized financial information of our proportionate share of unconsolidated affiliates below includes affiliates in which we hold a less than 50 percent interest as well as those in which we hold a greater than 50 percent interest. Our proportional shares of the unconsolidated affiliates in which we hold a greater than 50 percent interest had net income of $10 million and $16 million for March 31, 2002 and 2001.

	2002	2001
	(In millions)	
Operating results data		
Revenues and other income	$471	$526
Costs and expenses	$410	$390
Income from continuing operations	$ 51	$ 98
Net income	$ 51	$ 89

Consolidation of Investments

As of December 31, 2001, we had investments in the Eagle Point Cogeneration Partnership, in Capital District Energy Center Cogeneration Associates and in Mohawk River Funding IV. During 2002, we obtained additional rights from our partners in these investments and acquired an additional one percent ownership interest in Capital District Energy Cogeneration Associates and Mohawk River Funding IV. As a result of these actions, we began consolidating these investments effective January 1, 2002.

Gemstone

In November 2001, we issued debt securities to Gemstone with a principal balance of $462 million that carry a fixed annual interest rate of 5.25%. As of March 31, 2002 and December 31, 2001, the outstanding balance on these securities, plus accrued interest, was $225 million and $350 million.

In May 2002, we completed amendments to the Gemstone agreements by eliminating any stock price and credit ratings downgrade trigger and eliminating $950 million of mandatorily convertible preferred stock held in a share trust we control. In exchange, we issued a direct guarantee supporting Gemstone's notes in the amount of $950 million.

Chaparral

We have a credit facility with Chaparral that allows Chaparral to borrow funds from us at a variable interest rate. The outstanding balance, plus accrued interest, owed to us under this credit facility was $750 million and $552 million at March 31, 2002 and December 31, 2001. The interest rate on the facility is based on LIBOR plus a margin, and was 2.4% and 2.6% at March 31, 2002 and December 31, 2001.

In April 2002, we completed amendments to the Chaparral agreements by eliminating any stock price and credit ratings downgrade trigger and reducing the liquidation preference value of mandatorily convertible preferred stock held in a share trust we control to $200 million. In exchange, we issued a direct guarantee supporting Chaparral's notes totaling approximately $1 billion.

El Paso Energy Partners

In April 2002, we sold midstream assets to El Paso Energy Partners for total consideration of $735 million. Net proceeds were approximately $420 million in cash, a $119 million note payable to us, common units of El Paso Energy Partners 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.

14. New Accounting Pronouncements Not Yet Adopted

Accounting for Asset Retirement Obligations

In August 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, *Accounting for Asset Retirement Obligations.* This Statement requires companies to record a liability relating to the retirement and removal costs of assets used in their business. The liability is discounted to its present value, and the related asset value is increased by the amount of the resulting liability. Over the life of the asset, the liability will be accreted to its future value and eventually extinguished when the asset is taken out of service. Capitalized retirement and removal costs will be depreciated over the useful life of the related asset. The provisions of this Statement are effective for fiscal years beginning after June 15, 2002. We are currently evaluating the effects of this pronouncement.

Derivatives Implementation Group Issue C-16

In September 2001, the Derivatives Implementation Group of the FASB cleared guidance on Issue C-16, *Scope Exceptions: Applying the Normal Purchases and Normal Sales Exception to Contracts that Combine a Forward Contract and a Purchased Option Contract*. This guidance impacts the accounting for fuel supply contracts that require delivery of a contractual minimum quantity of a fuel other than electricity at a fixed price and have an option that permits the holder to take specified additional amounts of fuel at the same fixed price at various times. We use fuel supply contracts such as these in our power producing operations and currently do not reflect them in our balance sheet since they are considered normal purchases that are not classified as derivative instruments under SFAS No. 133. This guidance becomes effective in the second quarter of 2002, and we will be required to account for these contracts as derivative instruments under SFAS No. 133. We are currently evaluating the financial impact of this guidance on our financial statements.

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 Annual Report on Form 10-K filed March 15, 2002, in addition to the financial statements and notes presented in Item 1, Financial Statements, of this Quarterly Report on Form 10-Q.

Below is a list of terms that are common to our industry and used throughout our Management's Discussion and Analysis:

/d	= per day	MMBtu	= million British thermal units
Bbl	= barrel	Mcf	= thousand cubic feet
BBtu	= billion British thermal units	MMcf	= million cubic feet
BBtue	= billion British thermal unit equivalents	MTons	= thousand tons
Btu	= British thermal unit	MMWh	= thousand megawatt hours
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 is equal to six Mcf of natural gas. Also, when we refer to cubic feet measurements, all measurements are at 14.73 pounds per square inch.

Results of Operations

Our results of operations, along with the impact by segment of the merger-related costs, asset impairments and other charges, are presented below for the quarters ended March 31 (in millions):

	2002			2001		
EBIT by Segment	Reported	Charges(1)	Pro-forma(2)	Reported	Charges(1)	Pro-forma(2)
Pipelines	$ 399	$ —	$ 399	$ 333	$ 89	$ 422
Merchant Energy	63	342	405	258	136	394
Production	176	33	209	185	63	248
Field Services	51	—	51	36	29	65
Segment EBIT	689	375	1,064	812	317	1,129
Corporate and other	(5)	—	(5)	(880)	844	(36)
Consolidated EBIT	684	375	1,059	(68)	1,161	1,093
Interest and debt expense	(307)	—	(307)	(295)	—	(295)
Minority interest	(40)	—	(40)	(62)	—	(62)
Income taxes	(108)	(120)	(228)	35	(271)	(236)
Extraordinary items	—	—	—	(10)	10	—
Accounting changes	154	(154)	—	—	—	—
Net income	$ 383	$ 101	$ 484	$(400)	$ 900	$ 500

(1) Charges include merger-related costs, asset impairments, a ceiling test charge, extraordinary items and the cumulative effect of accounting change. See Item 1. Financial Statements Notes 1, 3, 4, 5 and 6 for further discussions of these charges.

(2) Pro-forma amounts should not be used as a substitute for amounts reported under generally accepted accounting principles. They are presented solely to improve the understanding of the impact of the charges reported during the periods presented.

Segment Results

Our four segments: Pipelines, Merchant Energy, Production and Field Services are strategic business units that offer a variety of different energy products and services; each requires different technology and marketing strategies. We evaluate our segment performance based on EBIT. Operating revenues and expenses by segment include intersegment revenues and expenses which are eliminated in consolidation. Because changes in energy commodity prices have a similar impact on both our operating revenues and cost of products sold from period to period, we believe that gross margin (revenue less cost of sales) provides a more accurate and meaningful basis for analyzing operating results for the trading and refining portions of Merchant Energy and for the Field Services segment. For a further discussion of our individual segments, see Item 1, Financial Statements, Note 12, as well as our Annual Report on Form 10-K for the year ended December 31, 2001. The segment EBIT results for the quarters ended March 31 presented below include the charges discussed above:

	2002	2001
	(In millions)	
Pipelines	$399	$ 333
Merchant Energy	63	258
Production	176	185
Field Services	51	36
Segment total	689	812
Corporate and other, net	(5)	(880)
Consolidated EBIT	$684	$ (68)

Pipelines

Our Pipelines segment holds our interstate transmission businesses. Results of our Pipelines segment operations were as follows for the quarters ended March 31:

	2002	2001
	(In millions, except volume amounts)	
Operating revenues	$ 703	$ 792
Operating expenses	(358)	(498)
Other income	54	39
EBIT	$ 399	$ 333
Throughput volumes (BBtu/d)[1]		
TGP	4,789	5,045
EPNG and MPC	4,203	4,826
ANR	3,779	3,938
CIG and WIC	2,789	2,431
SNG	2,283	2,231
Equity investments (our ownership share)	2,693	2,286
Total throughput	20,536	20,757

(1) Throughput volumes for 2001 exclude those related to pipeline systems sold in connection with FTC orders related to our Coastal merger including the Midwestern Gas Transmission system and investments in the Empire State and Iroquois pipelines. Throughput volumes also exclude intrasegment activities.

Operating revenues for the quarter ended March 31, 2002, were $89 million lower than the same period in 2001. The decrease was primarily due to the impact of lower prices on natural gas and liquids sales, including sales of natural gas produced, resales of natural gas purchased from the Dakota gasification facility and sales of excess natural gas. Also contributing to the decrease were lower transportation revenues from capacity sold under short-term contracts, lower throughput to California and other western states and to the northeast due to milder weather in these areas in 2002, and the sale of our Midwestern Gas Transmission system in April

2001. These decreases were partially offset by higher reservation revenues on the EPNG system as a result of a larger portion of its capacity sold at maximum tariff rates versus the same period in 2001 and revenues from SNG's Elba Island liquefied natural gas (LNG) facility which was placed in service in December 2001.

Operating expenses for the quarter ended March 31, 2002, were $140 million lower than the same period in 2001 primarily as a result of merger-related charges incurred in 2001 related to our merger with Coastal. Also contributing to the decrease were lower compressor fuel costs resulting from lower natural gas prices, lower prices on natural gas purchased from the Dakota gasification facility, lower operating expenses due to cost efficiencies following the merger with Coastal and lower benefit costs in the first quarter of 2002. The decrease was partially offset by increases to our reserve for bad debts in 2002 related to the bankruptcy of Enron Corp.

Other income for the quarter ended March 31, 2002, was $15 million higher than the same period in 2001 primarily due to a gain on the sale of pipeline expansion rights in February 2002.

Merchant Energy

Our Merchant Energy segment conducts our customer originations and trading activities along with our power, refining, chemical and coal businesses and other activities.

Trading Price Risk Management Activities

As of March 31, 2002, the fair value of our trading-related price risk management activities was $995 million, and total margins generated from these activities during the quarters ended March 31, 2002 and 2001 were $108 million and $291 million.

The following table details the fair value of Merchant Energy's price risk management activities by year of maturity and valuation methodology as of March 31, 2002.

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
Prices actively quoted	$(40)	$542	$260	$ 85	$ —	$847
Prices based on models and other valuation methods	91	58	21	(22)	—	148
Total net trading assets	$ 51	$600	$281	$ 63	$ —	$995

A reconciliation of our trading price risk management activities for the quarter ended March 31, 2002, is as follows (in millions):

Fair value of trading contracts outstanding at December 31, 2001	$1,295
Fair value of contracts settled during the period	(481)
Initial recorded value of new contracts	7
Change in fair value of contracts	133
Changes in fair value attributable to changes in valuation techniques	(69)
Other	110
Net change in trading contracts outstanding during the period	(300)
Fair value of trading contracts outstanding at March 31, 2002	$ 995

Included in "Changes in fair value attributable to changes in valuation techniques" is a charge of approximately $61 million related to our revised estimate of the fair value of long-term positions in our trading price risk management activities. Specifically, we have recently experienced diminished liquidity in the marketplace for natural gas and power transactions in excess of ten years. Because we do not expect this condition to change in the foreseeable future, we no longer recognize gains from the fair value of trading positions beyond ten years. Included in "Other" are option premiums and storage capacity transactions.

Results of Operations

Below are Merchant Energy's operating results and an analysis of these results for the quarters ended March 31:

	2002	2001
	(In millions, except volume amounts)	
Trading and refining gross margins	$ 691	$ 505
Operating and other revenues	196	207
Operating expenses	(804)	(543)
Other income (loss)	(20)	89
EBIT	$ 63	$ 258
Volumes		
Physical		
Natural gas (BBtue/d)	13,221	13,847
Power (MMWh)	105,783	36,307
Crude oil and refined products (MBbls)	166,842	169,237
Coal (MTons)	2,309	2,663
Financial settlements (BBtue/d)	222,745	247,596

Trading and refining gross margins consist of revenues from commodity trading and origination activities less the costs of commodities sold, the impact of power contract restructuring activities and revenues from refineries and chemical plants, less the cost of the feedstocks used in the refining and production processes. For the quarter ended March 31, 2002, these gross margins were $186 million higher than the same period in 2001. The increase was due to two power plant contract restructurings in the first quarter of 2002, partially offset by decreases in natural gas and power trading margins resulting from lower price volatility in the first quarter of 2002. Additionally, the first quarter of 2002 includes a charge of $61 million as a result of a change in our estimates of the fair value of our energy trading contracts with terms extending beyond ten years. Also partially offsetting the increase were lower refining margins resulting from lower spreads between the sales prices of the refined product and the underlying feedstock cost, lower throughput at the Eagle Point and Aruba refineries, the lease of our Corpus Christi refinery and related assets to Valero in June 2001, and lower margins in heavy crude-based refined products.

Operating and other revenues consist of revenues from domestic and international power generation facilities and investments, including our management fee from Chaparral, coal operations, and revenues from EnCap and our other financial services businesses. For the quarter ended March 31, 2002, operating and other revenues were $11 million lower than the same period in 2001. The decrease resulted from lower income from financial services activities in the first quarter of 2002 as a result of the sale of several investments in 2001, and lower coal revenues in 2002 as a result of lower volumes. Also contributing to the decrease were lower power facility revenues resulting from the sale of power facilities to Chaparral in 2001. Partially offsetting the decrease were higher management fees from Chaparral in the first quarter of 2002 as well as the consolidation of an international power facility in the fourth quarter of 2001.

Operating expenses for the quarter ended March 31, 2002, were $261 million higher than the same period in 2001. The increase was primarily a result of the impairment of our power investments in Argentina. Also contributing to the increase in the first quarter of 2002, were higher expenses resulting from the consolidation of several domestic power-related entities, additional reserves recorded related to our coal operations and a turbine forfeiture fee for a cancelled power project. These increases were partially offset by merger-related costs and asset impairments recorded in the first quarter of 2001 associated with combining operations with Coastal.

Other income for the quarter ended March 31, 2002, was $109 million lower than the same period in 2001. The decrease was primarily the result of the minority owners' interest in income recognized on our consolidated power restructuring transactions in the first quarter of 2002, as well as lower equity earnings from unconsolidated projects, primarily Chaparral.

Production

Our Production segment conducts our natural gas and oil exploration and production activities. Results of our Production segment operations were as follows for the quarters ended March 31:

	2002	2001
	(In millions, except volumes and prices)	
Natural gas	$ 480	$ 480
Oil, condensate and liquids	82	86
Other	(12)	5
Total operating revenues	550	571
Transportation and net product costs	(22)	(37)
Total operating margin	528	534
Operating expenses	(355)	(346)
Other income (loss)	3	(3)
EBIT	$ 176	$ 185
Volumes and prices		
Natural gas		
Volumes (MMcf)	133,266	133,944
Average realized prices ($/Mcf)	$ 3.46	$ 3.48
Oil, condensate and liquids		
Volumes (MBbls)	4,988	3,134
Average realized prices ($/Bbl)	$ 15.68	$ 27.42

Operating revenues for the quarter ended March 31, 2002, were $21 million lower than the same period in 2001. The decrease was primarily due to a loss on derivative positions that no longer qualify as cash flow hedges under SFAS No. 133 because they were designated as hedges of anticipated future production from oil and gas properties that were sold in March 2002. Also contributing to the decrease was a significant decline in average realized prices for oil, condensate and liquids in 2002 when compared to the same period of 2001.

Transportation and net product costs for the quarter ended March 31, 2002, were $15 million lower than the same period in 2001 primarily due to lower transported volumes and lower costs incurred to meet minimum payments on pipeline agreements.

Operating expenses for the quarter ended March 31, 2002, were $9 million higher than the same period in 2001. The increase was due to higher depletion expense in 2002 as a result of additional capital spending on assets in the full cost pool, a non-cash full cost ceiling test charge of $33 million incurred in the current quarter on international properties in Turkey and Brazil, higher corporate overhead allocations and increased oilfield services costs. Partially offsetting these increases were merger-related charges incurred in 2001 due to our merger with Coastal in January 2001 and lower severance and other taxes in 2002, which are generally tied to natural gas and oil prices.

Other income for the quarter ended March 31, 2002, was $6 million higher than the same period in 2001 primarily due to a gain on the sale of non-full cost pool assets in March 2002 and lower other miscellaneous expenses.

Field Services

Our Field Services segment conducts our midstream activities. Results of our Field Services segment operations were as follows for the quarters ended March 31:

	2002	2001
	(In millions, except volumes and prices)	
Gathering, treating and processing gross margins	$ 125	$ 150
Operating expenses	(87)	(130)
Other income	13	16
EBIT	$ 51	$ 36
Volumes and prices		
Gathering and treating		
Volumes (BBtu/d)	5,706	6,108
Prices ($/MMBtu)	$ 0.16	$ 0.14
Processing		
Volumes (inlet BBtu/d)	3,969	3,892
Prices ($/MMBtu)	$ 0.11	$ 0.17

Total gross margins for the quarter ended March 31, 2002, were $25 million lower than the same period in 2001. The decrease was primarily a result of lower processing and NGL marketing margins due to lower prices in 2002. Processing margins also decreased due to lower volumes in the south Texas and Rockies regions, changes in processing operations in the south Louisiana region and costs associated with a new processing arrangement at the Chaco processing facility entered into in the fourth quarter of 2001 with El Paso Energy Partners. Gathering and treating margins were higher due to the favorable resolution of fuel, rate and volume matters in the first quarter of 2002 and higher realized transportation rates in 2002 from the pipeline system acquired in our acquisition of PG&E's Texas Midstream operations in December 2000. Partially offsetting these increases were lower natural gas prices in the San Juan Basin in 2002.

Operating expenses for the quarter ended March 31, 2002, were $43 million lower than the same period of 2001. The decrease was primarily due to merger-related costs arising from payments to El Paso Energy Partners in 2001 related to FTC ordered sales of assets owned by the partnership, merger-related employee severance and relocation expenses in 2001 following our merger with Coastal and lower amortization of goodwill due to the implementation of SFAS No. 142 in 2002. Also contributing to the decrease were lower operations and depreciation expenses due to our sale of transportation and fractionation assets to El Paso Energy Partners in March 2001.

Other income for the quarter ended March 31, 2002, was $3 million lower than the same period in 2001 primarily due to gains we recognized as a result of not participating in the issuance of El Paso Energy Partners' common units in March 2001, partially offset by higher earnings in 2002 from our interests in El Paso Energy Partners.

Corporate and Other, net

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 March 31, 2002, were $875 million lower than the same period in 2001. The decrease was primarily a result of merger-related charges during 2001 in connection with our January 2001 merger with Coastal.

Interest and Debt Expense

Interest and debt expense for the quarter ended March 31, 2002, was $12 million higher than the same period in 2001. The increase was a result of higher long-term borrowings for ongoing capital projects, investment programs and operating requirements and lower capitalized interest in 2002. This increase was partially offset by lower interest rates on short-term borrowings. We anticipate interest and debt expenses will continue to exceed last year's levels throughout the remainder of 2002.

Minority Interest

Minority interest expense for the quarter ended March 31, 2002, was $22 million lower than the same period in 2001, primarily due to lower interest rates, partially offset by increased minority interest balances due to the formation of Gemstone in November 2001.

Income Taxes

The income tax expense for the quarter ended March 31, 2002, was $108 million, resulting in an effective tax rate of 32 percent. Our effective tax rate was different than the statutory rate of 35 percent primarily due to the following:

- state income taxes; and
- foreign income taxed at different rates.

The income tax benefit for the quarter ended March 31, 2001, was $35 million, resulting in an effective tax rate of 8 percent. This benefit is net of $110 million of tax expense associated with non-deductible merger charges and changes in our estimates of additional tax liabilities. The majority of these estimated additional liabilities were paid in 2001 and are being contested by us. The effective tax rate excluding these charges was 34 percent. Other differences between the effective rate and the statutory rate of 35 percent were primarily due to the following:

- state income taxes;
- earnings from unconsolidated affiliates where we anticipate receiving dividends; and
- foreign income taxed at different rates.

Liquidity and Capital Resources

General

During the first quarter of 2002, our cash and cash equivalents increased by $120 million. During the quarter, we generated an estimated $2.1 billion through a combination of cash-based earnings and the issuance of short and long-term debt. In addition, we generated approximately $0.5 billion through sales of natural gas and oil properties. From these cash inflows, we invested approximately $1.0 billion in fixed assets and investments, paid $0.8 billion on maturing debt issues and short-term debt, paid $0.1 billion in dividends, and funded working capital needs of approximately $0.5 billion, principally related to margins and option premiums in our price risk management activities. Our operating cash flow from period to period is significantly impacted, either positively or negatively, by movements in commodity prices. For the remainder of 2002, we expect to meet our cash investing and financing needs through cash generated from earnings in our operating businesses and through additional financing transactions, as needed. However, our working capital inflows or outflows for the remainder of 2002 will be dependent on fluctuations in commodity prices as well as strategies we may implement to offset the impact of commodity price fluctuations on our cash flows.

Cash From Operating Activities

Net cash provided by our operating activities was $86 million for the quarter ended March 31, 2002, compared to net cash provided by operating activities of $1,055 million for the same period in 2001. The decrease was primarily due to cash paid for broker and over-the-counter margins and option premiums in 2002, as well as less cash generated through liquidations of price risk management assets. Our operating cash flow reductions also related to petroleum inventory increases due to higher volumes and prices compared to last year. Partially offsetting these decreases were cash payments in 2001 for charges related to the merger with Coastal.

Cash From Investing Activities

Net cash used in our investing activities was $343 million for the quarter ended March 31, 2002. Our investing activities consisted primarily of additions to property, plant and equipment, including expenditures for developmental drilling and expansion and construction projects. Our additions to investments consisted mostly of short-term notes from unconsolidated affiliates, primarily related to a subsidiary of Chaparral. Cash inflows from investment-related activities included net proceeds from the sale of natural gas and oil properties located in east and south Texas. We also received repayments of notes related to our unconsolidated affiliates.

Cash From Financing Activities

Net cash provided by our financing activities was $377 million for the quarter ended March 31, 2002. Cash provided from our financing activities included the issuance of long-term debt, borrowings under our commercial paper and short-term credit facilities and issuances of common stock under employee benefit plans. We also retired long-term debt, repaid other financing obligations, paid dividends and repaid notes to unconsolidated affiliates, primarily related to Gemstone.

On April 30, 2002, we declared a quarterly dividend of $0.2175 per share on our common stock, payable on July 3, 2002, to stockholders of record on June 7, 2002. Also, during the quarter ended March 31, 2002, we paid dividends of $6 million on our Series A cumulative preferred stock, which is 8¼% per annum (2.0625% per quarter), on our subsidiary, El Paso Tennessee Pipeline Co.

Liquidity

Our 2001 Annual Report on 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 2001 Annual Report on Form 10-K.

Financing Activities

Our significant borrowing and repayment activities during 2002 are presented below. These amounts do not include borrowings or repayments on our short-term financing instruments with an original maturity of three months or less, including our commercial paper programs and short-term credit facilities.

Date	Company	Type	Interest Rate	Principal	Net Proceeds[1]	Due Date
				(In millions)		
Issuances						
2002						
January	El Paso	Medium-term notes	7.75%	$1,100	$1,081	2032
February	SNG	Notes	8.00%	300	297	2032
April	Mohawk River Funding IV	Senior secured notes	7.75%	92	90	2008
May	El Paso	Euro notes	7.125%	450[2]	448	2009
Retirements						
2002						
January	SNG	Long-term debt	7.85%	$ 100		2002
January	EPNG	Long-term debt	7.75%	215		2002
March	El Paso CGP	Long-term debt	Variable	400		2002
Jan.-Mar.	El Paso Production	Natural gas production payment	LIBOR+ 0.372%	24		2002
Jan.-Mar.	Various	Long-term debt	Various	12		2002
May	SNG	Long-term debt	8.625%	100		2002

(1) Net proceeds were primarily used to repay maturing long-term debt, short-term borrowings and for general corporate purposes.

(2) Represents the U.S. dollar equivalent of 500 million Euros on the issuance date.

In February 2002, we filed a new shelf registration statement with the Securities and Exchange Commission that allows us to issue up to $3 billion in securities. Under this registration statement, we can issue a combination of debt, equity and other instruments, including trust preferred securities of El Paso Capital Trust II and El Paso Capital Trust III, trusts wholly owned by us. If we issue securities from these trusts, we will be required to issue full and unconditional guarantees on these securities.

Future Liquidity

In December 2001, we announced a plan to strengthen our capital structure and enhance our balance sheet in response to changes in market conditions. Key elements of this plan were to raise cash from sales of assets and eliminate or renegotiate the rating triggers in our Chaparral and Gemstone investments and on our Trinity River and Clydesdale minority interest financing transactions.

During 2002, we sold or announced the sale of natural gas and oil properties and midstream assets which generated, or will generate upon final closing, cash totaling approximately $1.5 billion. We expect to close these sales by the third quarter of 2002. We expect to sell additional assets during the remainder of 2002 to meet the goals of our plan.

In March 2002, we completed the amendments to the Trinity River agreements removing the rating trigger that could have required us to liquidate the assets supporting the transaction in the event we are downgraded to below investment grade by both rating agencies. We completed amendments to the Chaparral agreements in April 2002 and completed the amendments to the Gemstone agreements in May 2002. We have also started the amendment process on the Clydesdale agreements.

Notes Payable to Affiliates

Our notes payable to unconsolidated affiliates as of March 31, 2002, were $697 million versus $872 million as of December 31, 2001. The decrease is primarily due to the partial repayment of Gemstone debt securities.

Securities of Subsidiaries and Minority Interests

Total amounts outstanding for securities of subsidiaries and minority interests were $4,184 million at March 31, 2002, versus $4,013 million at December 31, 2001. The increase was due to the consolidation of our Eagle Point Cogeneration Partnership and our Capital District Energy Center Cogeneration Associates investments in January 2002.

Lines of Credit

Mesquite, a subsidiary of Chaparral and our affiliate, may borrow from us under a line of credit facility. As of March 31, 2002, Mesquite had borrowed $750 million under this facility at an interest rate of 2.4%.

Commitments and Contingencies

See Item 1, Financial Statements, Note 11, which is incorporated herein by reference.

New Accounting Pronouncements Not Yet Adopted

See Item 1, Financial Statements, Note 14, 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. These statements are subject to risks and uncertainties. Forward-looking statements include information concerning possible or assumed future results of operations. 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;
- pending legal proceedings and claims, including environmental matters;
- future economic performance;
- operating income;
- management's plans; and
- goals and objectives for future operations.

Important factors that could cause actual results to differ materially from estimates or projections contained in forward-looking statements are described in our Annual Report on Form 10-K for the year ended December 31, 2001 and other filings with the Securities and Exchange Commission.

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 Annual Report on Form 10-K for the year ended December 31, 2001, except as presented below:

Commodity Price Risk

The following table presents our potential one-day unfavorable impact on earnings before interest and income taxes as measured by Value-at-Risk using the historical simulation technique for our commodity and energy related contracts and is prepared based on a confidence level of 95 percent and a one-day holding period.

	March 31, 2002	December 31, 2001
	(In millions)	
Trading Value-at-Risk	$11	$18
Non-Trading Value-at-Risk	$10	$15
Portfolio Value-at-Risk[1]	$12	$17

[1] Portfolio Value-at-Risk represents the combined Value-at-Risk for the trading and non-trading (primarily hedging) price risk management activities. The separate calculation of Value-at-Risk for trading and non-trading commodity contracts ignores the natural correlation that exists between traded and non-traded commodity contracts and prices. As a result, the individually determined values will be higher than the combined Value-at-Risk in most instances. We manage our risks through a portfolio approach that balances both trading and non-trading risks.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Financial Statements, Note 11, which is incorporated herein by reference.

The *California* cases 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); three filed in the Superior Court of San Francisco County (*Sweetie's, et al v. El Paso Corporation, et al*, filed March 22, 2001; *Philip Hackett, et al v. El Paso Corporation, et al*, filed May 9, 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). The shareholder derivative suit was filed in district court in Harris County, Texas (*Gebhardt v. Allumbaugh, et al,* filed March 15, 2002).

The alleged five probable violations of the regulations of the Department of Transportation's Office of Pipeline Safety are: 1) failure to perform appropriate tasks to prevent corrosion, 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 consider unusual operating and maintenance conditions and respond appropriately, with an associated proposed fine of $500,000; 4) failure to follow company procedures, with an associated proposed fine of $500,000; and 5) failure to maintain topographical diagrams, with an associated proposed fine of $25,000.

The six remaining *Carlsbad* lawsuits are as follows: one filed in district court in Harris County, Texas (*Geneva Smith, et al v. EPEC and EPNG*, filed October 23, 2000), and five filed in state district court in Carlsbad, New Mexico (*Chapman, as Personal Representative of the Estate of Amy Smith Heady, v. EPEC, EPNG and John Cole*, filed February 9, 2001; *Chapman, as Personal Representative of the Estate of Dustin Wayne Smith, v. EPEC, EPNG and John Cole; Chapman, as Personal Representative of the Estate of Terry Wayne Smith, v. EPNG, EPEC and John Cole; Rackley, as Personal Representative of the Estate of Glenda Gail Sumler, v. EPEC, EPNG and John Cole*; and *Rackley, as Personal Representative of the Estate of Amanda Sumler Smith, v. EPEC, EPNG, and John Cole*, all filed March 16, 2001). We have reached a contingent settlement in an additional case (*Dawson, as Personal Representative of Kirsten Janay Sumler, v. EPEC and EPNG*, filed November 8, 2000).

Item 2. Changes in Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

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

None.

Item 5. Other Information

None.

Item 6. Exhibits and Reports on Form 8-K

a. Exhibits

Each exhibit identified below is filed as a part of this report.

Exhibit Number	Description

None.

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

We filed a current report on Form 8-K, dated January 4, 2002 reporting the Computation of the Ratio of Earnings to Fixed Charges for the five years ended December 31, 2000 and for the nine months ended September 30, 2000 and 2001.

We filed an amended current report on Form 8-K/A, dated January 8, 2002, correcting a typographical error appearing in the January 4, 2002 report on Form 8-K.

We filed a current report on Form 8-K dated January 11, 2002, filing exhibits in connection with the offering of medium-term notes pursuant to a Registration Statement on Form S-3.

We filed a current report on Form 8-K, dated March 28, 2002, to correct a typographical error in the Report of Independent Accountants filed as an exhibit to our Form 10-K.

We filed a current report on Form 8-K, dated April 12, 2002, announcing the sale of Midstream assets and oil and natural gas properties.

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: May 10, 2002

/s/ H. BRENT AUSTIN

H. Brent Austin
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)

Date: May 10, 2002

/s/ JEFFREY I. BEASON

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